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November 4, 2026

VIA HAND DELIVERY

LA PUBLIC SERVICE COMM
NOV 04 2026 PM04:15

Kristina Abel
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Louisiana Public Service Commission
602 North 5th Street
Galvez Building, 12th Floor
Baton Rouge, LA 70802

Re: Docket No. R-37905; Louisiana Public Service Commission, ex parte. In Re: Notice of proceeding regarding determination and evaluation of private use electrical networks in order to enable generation to serve new large loads looking to locate in Louisiana.

Dear Ms. Abel,

I have enclosed Staff's *Final Report and Recommendation* which contains Staff's Final Proposed Rules. Please file the enclosed documents into the record. If you have any questions regarding this filing, please do not hesitate to contact me.

Respectfully submitted,

Lauren T. Evans

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LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. R-37905

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE

LA PUBLIC SERVICE COMM
NOV 04 2026 PM04:15

In Re: Notice of proceeding regarding determination and evaluation of private use electrical networks in order to enable generation to serve new large loads looking to locate in Louisiana.

STAFF'S FINAL REPORT AND RECOMMENDATION AND FINAL PROPOSED RULES

I. BACKGROUND AND PROCEDURAL HISTORY.

This docket was initiated by a directive at the Louisiana Public Service Commission's ("LPSC" or "Commission") April 15, 2026 Business & Executive Session. At that meeting, Vice Chairman Coussan issued the following:

> A Louisiana State Senate Task force created by SR 195 has been studying, *inter alia*, policies regarding energy self-generation, industrial microgrids, and expedited permitting in the state of Louisiana. Discussion at the task force also included: 1) potential statutory changes to ensure that Louisiana has the electrical generation needed to attract new large loads to Louisiana, and 2) more recently, how microgrids could serve these large loads.
>
> Incidentally, SB 490 has now been introduced in the 2026 Regular Session proposing "private use electrical networks" to enable construction of generation to support large industrial and digital infrastructure projects.
>
> The LPSC is actively participating in the task force meetings and has provided pertinent information garnered from relevant prior LPSC rulemaking proceedings including its position memorialized in Docket R-35462 that certain situations created by some utility customers could create stranded costs and the potential for increased costs to all other customers.
>
> Nevertheless, "private use electrical networks" were not directly addressed in Docket R-35462 and should be given due consideration. As the agency

> with a constitutional mandate to regulate electric public utilities, I direct Staff to open a docket to evaluate "private use electrical networks" to enable generation to serve new large load looking to locate in Louisiana. Further, I direct staff to work with the already retained counsel and consultant in Docket No. R-35462 under the remaining budgets therein.

There was no opposition to the directive.

A "Notice of Proceeding" was issued on April 22, 2026, which was published in the Commission's Official Bulletin # 1374 dated April 24, 2026, with a 15-day intervention period. Timely interventions were filed on behalf of Cleco Power, LLC ("Cleco"), Louisiana Energy Users Group ("LEUG"), 1803 Electric Cooperative, Inc. ("1803"), Association of Louisiana Electric Cooperatives, Inc. ("ALEC"), Southern Renewable Energy Association ("SREA"), Southwest Louisiana Electric Membership Corporation ("SLEMCO"), Entergy Louisiana, LLC ("ELL"), Alliance for Affordable Energy ("AAE"), Environmental Defense Fund ("EDF"), and Amplify Louisiana, LLC ("Amplify").

Petitions to intervene out of time were filed on behalf of the Pelican Institute for Public Policy ("Pelican Institute") and Pointe Coupee Electric Membership Corporation ("Pointe Coupee") on May 13, 2026 and May 15, 2026, respectively. Both petitions were granted on May 15, 2026. Additional petitions to intervene out of time were filed on behalf of Southwestern Electric Power Company ("SWEPCO") (filed on June 22, 2026 and granted on June 23, 2026), Gulf States Renewable Energy Industry Association ("GSREIA") (filed on June 18, 2026 and granted on June 26, 2026), Pelican Power LLC ("Pelican Power") (filed and granted on June 25, 2026), International Paper Company ("IPC") (filed and granted on July 6, 2026), Occidental Chemical Corporation ("OCC")

(filed on July 10, 2026 and granted on July 13, 2026), Powering Prosperity (filed on July 15, 2026 and granted on July 17, 2026), National Wildlife Federation ("NWF") (filed on July 16, 2026 and granted on July 17, 2026), the Louisiana Chemistry Association ("LCA") (filed and granted on July 17, 2026), the Louisiana Mid-Continent Oil and Gas Association ("LMOGA") (filed and granted on July 17, 2026), and Sierra Club (filed on July 28, 2026 and granted on August 3, 2026). Herein collectively referred to as "Intervenors."

On June 18, 2026, the Louisiana Public Service Commission Staff ("Staff") issued a "Notice of Procedural Schedule and First Request for Information" seeking responses to specific requests for information related to Private Use Electrical Networks ("PENs"[1]) – privately owned generation, storage, and delivery facilities intended to serve new large loads (particularly data centers and industrial facilities). Additionally, it noticed a Technical Conference for August 28, 2026. Written responses to Staff's requests for information were submitted by LEUG, Powering Prosperity, LMOGA, IPC, Pelican Institute, LCA, AAE, ALEC, SLEMCO, EDF, SREA, GSREIA, OCC, ELL, Cleco, 1803, and SWEPCO.

After receiving several comments from intervenors in response to Staff's Requests for Information, Staff issued its Initial Report and Recommendation ("Initial Report") in this docket on August 14, 2026, wherein it provided several recommendations and sought additional comments on those recommendations. Those recommendations included that PENs should be explicitly recognized in LPSC rules, but only for new large industrial and

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[1] The Staff's Initial Report and Proposed Rule used the acronym "PUEN" but changes the acronym in this Final Report and Rule to "PEN" because the shorter acronym is simpler and more descriptive.

digital load that is not connected to the grid and does not take service of any type from the public utility ("islanded" load). Staff recommended that PENs serve new industrial or digital load of 50 MW or more operating with a load factor of at least 80%, and that at least 85% of the capacity value and 70% of the energy output of PEN generation be dedicated to serving identified customer load. Staff further recommended that existing load not be permitted to exit the public system to be served by a PEN and recommended a five-year sunset provision (subject to renewal if requested and a Commission determination that the renewal serves the public interest). Staff stated it was still analyzing whether load served by PENs should be allowed to obtain backup or other services from the public utility and requested additional information on that issue. Staff attached a draft PEN rule consistent with these recommendations.[2]

Staff held a technical conference on August 28, 2026 to discuss and take comments on the Initial Report, and also accepted written comments on the proposed rule until September 25, 2026. Having participated in discussions with intervenors, reviewed party comments, examined the issues for consideration, and analyzed and researched PENs, Staff issues its "Staff Final Report and Recommendation" ("Final Report").[3] The Final Report takes into consideration the comments and responses to the requests for information

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[2] For brevity, Staff incorporates its Initial Report into this Final Report, which contains a summary of the responses to Staff's First Request for Information, as well as Staff's initial analysis and recommendation.

[3] In its *Notice of Procedural Schedule and First Request for Information*, Staff provided a procedural schedule with a Final Rule being issued on October 30, 2026; however, on October 23, 2026, Staff filed a *Notice of Schedule Change*, wherein Staff provided notice to stakeholders that a Final Rule would be filed on November 4, 2026.

provided by intervenors in this docket. Staff anticipates the Final Proposed Rule to be considered by the Commission at the November 18, 2026 Business and Executive Session.

II. COMMISSION JURISDICTION AND AUTHORITY.

The jurisdiction of the Commission is set forth in the Louisiana Constitution, Article IV, Section 21, which provides:

> The Commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.

Additional authority is granted in Louisiana Revised Statute 45:1163(A)(1), which provides:

> The Commission shall exercise all necessary power and authority over any street, railway, gas, electric light, heat, power, waterworks, or other local public utility for the purpose of fixing and regulating the rates charged or to be charged by and service furnished by such public utility.

III. SUMMARY OF AUGUST 28, 2026 TECHNICAL CONFERENCE.

Staff held a Technical Conference on August 28, 2026, where it sought comments on seven PEN requirements: (1) permissible transaction structure between PEN load and generation; (2) contiguous property requirement; (3) load type and size threshold; (4) dedicated use standard; (5) allowed interconnection/backup power service; (6) 5-year sunset provision; and (7) confirmation of qualification process. The following parties attended: ALEC, EDF, Dixie Electric Membership Corporation ("DEMCO"), Cleco, Powering Prosperity, Power for Tomorrow, LCA, SWEPCO, Pelican Power, Pelican Institute, SREA, ELL, Monarch Energy, NextEra Energy Resources, LMOGA, SLEMCO,

1803, IPC, LEUG, OCC, AAE, South Louisiana Electric Cooperative Association ("SLECA"), and Pointe Coupee.

Agenda Item No. 1: Permissible Transaction Structure Between PEN Load and Generation.

- **Staff** explained that current LPSC practice already allows load to self-supply through ownership or lease (behind-the-meter) arrangements, and the rule does not impose new regulation on them. The rule's new element is allowing load to be served by a PEN through a PPA or other contract with another party. The PEN must still meet the rule's other requirements, including that the load be islanded with no utility backup power, that all energy be delivered over privately owned facilities, and that the PEN be located on contiguous property.

- **LEUG** framed its analysis around two principles: ratepayer protection and economic development. It supports the rule's core feature of allowing a purchase power contract in addition to existing ownership or lease structures. LEUG stated this "unlocks the opportunity for more self-supply" because a third party can build and own the generation, rather than the load customer carrying it on its own balance sheet.

- **Cleco** argued that PENs create a "lost opportunity" for existing customers: when a PEN takes load that would otherwise go to the incumbent utility, the utility loses kilowatt-hour sales growth that could offset future rate increases. Cleco added that the PEN concept is not new, but the latest in a series of efforts by large industrial customers to bypass the regulated model.

- **Pelican Institute** supports the proposed structure because it "properly allocates capital risk, execution risk, and price risk between the PEN developer and the load it serves" and "keeps the rest of the utilities' ratepayers insulated from the costs and risks of that private transaction."

- **ELL** stated that the regulated model has worked well in Louisiana and there is "not necessarily a problem to solve." It added that the proposed rule may be workable with appropriate safeguards, the most important being the limitation to new load.

- **EDF** asked whether a PEN could include multiple customers, generation sources, or storage under separate contracts. Staff noted the rule does not address this, but stated its initial view that there should not be "any limitation on a number of contracts" if all generation and load are within the network and the load does not rely on the public grid.

- **AAE** stated its main concern is stranded costs if existing loads may participate. It is also concerned that the pace of the rulemaking leaves too little time for the analysis needed to understand potential costs.

- **Powering Prosperity** stated that PENs offer a new way to diversify risk among utilities, ratepayers, and new loads, and that unprecedented load growth makes today "drastically different" from even five years ago. It also saw opportunities for a "dynamic interplay between the networks and the utility grid" that could benefit all ratepayers.

- **Power for Tomorrow** stated that new large loads are best served by rate-regulated utilities, which protect all customers from cost shifts and reliability challenges. It credited LPSC regulation for Louisiana having the fourth lowest residential electricity rates in the country.

- **SWEPCO** echoed ELL and Cleco, stating that ratepayer protection and economic development are "more important than ever" under volumetric ratemaking. It warned that PENs "can indirectly harm ratepayers" by removing kilowatt-hour sales from the utility system.

Agenda Item No. 2: Contiguous Property Requirement.

- **Staff** addressed Agenda Item Nos. 2 and 3 together. Under the proposed rule, the PEN must be located on contiguous property within the network boundary, meaning a single undivided tract not interrupted by land owned or controlled by unrelated third parties. On Agenda Item No. 3, Staff explained that, consistent with the directive, PENs are limited to new industrial and digital load of 50 MW or more with at least an 80% load factor. Staff noted that allowing existing load to exit the system is outside the directive's scope and would increase the risk of significant stranded costs. The load must be one or more identified customers named in the PEN's confirmation of qualification filing.

- **LEUG** urged broadening the requirement to include "adjacent, contiguous, or commonly controlled" property. It noted that practical limits, such as the need to build a private line and the lack of expropriation rights, already restrict the distance between generation and load.

- **Pelican Institute** also urged allowing PENs on "commonly controlled property." It argued that a private line connecting non-contiguous, commonly controlled parcels involves no grid access and poses "no incremental risk to the public grid or to other ratepayers."

- **EDF** requested flexibility so the requirement does not effectively exclude land-intensive resources such as solar, while preserving the principles of no adverse reliability impacts and no unreasonable cost shifts.

- **Powering Prosperity** gave examples of sites separated by a private road or another industrial property, and urged that these not be excluded if all other requirements are met.

- **OCC** referred Staff to the Geismar industrial complex example in its written comments.

- **SWEPCO** argued that broadening the requirement through private lines does not protect ratepayers but "takes an opportunity away from other ratepayers" to spread costs over more kilowatt-hours. It added that Louisiana's economic development has succeeded without PENs.

- **SREA** views the requirement as unnecessary. It noted that a PEN may involve several parties owning generation, transmission, and distribution, and that requiring a single entity to control the property adds an "unnecessary hurdle."

Agenda Item No. 3: Load Type and Size Threshold.

- **Staff** addressed this item together with Agenda Item No. 2 as noted above.

- **LEUG** proposed a 5 MW threshold instead of 50 MW, noting that some industrials have smaller operations and that "economic development is economic development and new load is new load." LEUG also stressed that the rule should cover expansion projects.

- **Cleco** opposed lowering the threshold, stating that "the more permissive the rules, the greater the opportunity cost" for utilities and their customers. It noted that a 5 MW threshold would cover essentially every industrial customer Cleco serves, and that new, expansion, and existing load differ significantly.

- **ELL** stated that it receives 5 MW requests frequently and that the threshold should be well above 5 MW.

- **Powering Prosperity** urged that all members of the industrial customer class have the same opportunities, and encouraged a "future-proofed" rule rather than an "overly restrictive" one.

- **SREA** argued the 80% load factor is "unnecessarily high" and could exclude major projects, citing SpaceX's announced Louisiana facility.

Agenda Item No. 4: Dedicated Use Standard.

- **Staff** explained that the dedicated use standard reflects the directive's purpose of allowing new large loads to self-supply. The percentages are meant to keep a PEN from overbuilding generation simply to access the wholesale market. Staff proposed that at least 85% of the capacity value and 70% of the energy output of PEN generation serve identified customer load. Staff noted the market may be self-correcting and invited comment on whether the limits are too restrictive or not restrictive enough.

- **LEUG** proposed that at least 50% of generation serve the identified customer, allowing up to 49% for export instead of about 30%. It argued that more capacity in the wholesale market would help suppress prices, benefiting ratepayers.

- **SREA** argued that nameplate capacity is a poor metric, especially for renewables and storage. A solar facility's nameplate will not match its energy output, and a battery must be charged from some source. SREA warned that the standard could penalize loads that use diverse technologies and urged Staff to consider other metrics.

- **LCA** noted that it represents more than 75 large chemical manufacturers in the state, making this rulemaking especially important to it. LCA echoed LEUG's comments on each agenda item.

- **LMOGA** also echoed LEUG's comments.

- **Pelican Institute** urged Staff to revisit the 30% export cap, arguing that it "artificially restricts how much additional generation and capacity a PEN can make available to the wholesale market," while added supply "dampens the wholesale price pressure for everyone."

- **Powering Prosperity** raised practical concerns: a large campus may build generation before its load is fully online, so the two timelines may not align. It also noted that without backup or standby service, a PEN may need to oversize its generation for reliability, which affects the export threshold.

Agenda Item No. 5: Allowed Interconnection/Backup Power Service.

- **Staff** explained that to facilitate new loads quickly, it focused the rule on fully islanded PENs and set aside the complex questions of stranded assets and backup power. Staff sought feedback on whether a second step is needed to address backup power, including what service these loads would want (maintenance, backup, or as-available).

- **LEUG** confirmed its members want some form of backup power but acknowledged the issue is complex and that different circumstances call for different products and cost structures. It planned to provide more detail in written comments.

- **ELL** stated that existing standby and backup arrangements based on embedded cost rates "were not contemplated for this sort of arrangement at all and don't work." It argued that utilities should not be obligated to serve PENs under current standby rates, which would need to be "reconfigured" along the lines of the large load guidelines.

- **Powering Prosperity** urged viewing PENs not merely as "takers from the system" but as resources that can "give to the grid" through ancillary services, voltage regulation, and other services. It added that backup service "doesn't necessarily have to come from the interconnected utility," and could be contracted from an independent power producer's other assets.

- **Pelican Institute** supported requiring the PEN to bear the full cost of export interconnection. It also urged allowing PENs access to full cost-of-service tariffs for backup, maintenance, and standby power, provided the Commission keeps full authority over rates, terms, and conditions so that "ordinary ratepayers are never asked to subsidize a PEN's supplemental or emergency power needs."

- **SWEPCO** argued that if a PEN requires backup service from the incumbent utility, it "ceases to be a private network" and the risk is no longer borne entirely by the private network.

- **Cleco** responded that the further PENs stretch in that direction, the more it "sounds a lot like a public utility."

- **EDF** advocated technology-neutral, performance-based evaluation of resources and asked that interconnection rules not create barriers for variable resources like solar or for planned industrial outages. It also proposed an independent third-party analysis of backup service requirements and PEN configurations.

- **SREA** proposed three tiers: Tier 1 for fully islanded PENs with streamlined approval; Tier 2 for PENs seeking backup or other utility services; and Tier 3 for disaggregated configurations, where load and generation may be far apart. SREA also questioned whether the LPSC can restrict exports to the MISO market or prevent a battery from buying power from MISO.

Agenda Item No. 6: 5-Year Sunset Provision.

- **Staff** explained that the rule would sunset after five years, subject to renewal upon request and a Commission finding that renewal serves the public interest. After the

sunset, no new applications would be accepted, but existing PENs could continue to operate. The sunset provides a five-year window to meet immediate generation needs and a waypoint for the Commission to evaluate the rule, without requiring a new proceeding to keep a rule no one has used.

- **LEUG** opposed an automatic sunset and preferred a five-year evaluation point, at which the Commission decides whether to continue, modify, or end the program. It noted that an automatic sunset creates uncertainty for developers.

- **EDF** likewise preferred a renewal-focused evaluation at five years, assessing whether the program has been beneficial, rather than an automatic shutdown.

- **Powering Prosperity** warned that a five-year sunset leaves only about two years for development, given the time needed for site selection, community engagement, and negotiations with an independent power producer.

- **AAE** argued that neither a sunset nor a renewal is needed because the Commission can always change its rules. Instead, it suggested requiring regular reporting and review by Staff.

- **Cleco** supported a sunset with a "good cause exception" for parties that show, before expiration, that they are on a path toward a PEN.

- **Pelican Institute** supports sunset provisions as a policy matter but urged more consideration of their practical effects given long development timelines.

Agenda Item No. 7: Confirmation of Qualification Process.

- **Staff** took comments on the confirmation of qualification filing at the end of the conference. Responding to LEUG's question about the stranded investment analysis, Staff noted that such an analysis may not be necessary for an islanded PEN that otherwise meets the rule, and invited comment on removing or simplifying that requirement.

- **Pelican Institute** made two recommendations: (1) an expedited, time-bound declaratory process, with a firm decision deadline to match the commercial pace required of large load developers; and (2) the clear and durable confirmation of non-utility status, including for PENs with backup, standby, or export interconnections, so that reasonable grid-supported activity does not trigger public utility regulation.

IV. SUMMARIES OF WRITTEN COMMENTS ON THE INITIAL REPORT AND PROPOSED DRAFT RULE.

Staff accepted written comments on its Initial Report and the draft Rule until September 25, 2026. The following parties submitted written comments: 1803, AAE, ADC Solutions, Inc. ("ADC"), ALEC, Cleco, EDF, ELL, LCA, LEUG, LMOGA, NWF, OCC, Pelican Institute, Powering Prosperity, SREA, and SWEPCO. Their comments are summarized below.

- **1803** opposes recognizing PENs at all. It argues that a third party selling electricity to a retail customer is the defining activity of a public utility. If the Commission proceeds, 1803 supports Staff's core protections but urges tightening them. Specifically, it requests a narrower New Load definition with a five-year lookback; 100% dedicated capacity with exports capped at 10%; PEN responsibility for all transmission and later MISO project costs; and a strict ban on backup service. It also asks for "Serving Utility" and "Affected Transmission Owner" definitions that give wholesale suppliers notice and standing, no decision deadline or deemed approval, and a three-year sunset instead of a five-year sunset.

- **AAE** supports limiting PENs to new large loads and commends Staff's adherence to cost-causation principles. It questions whether the Commission has jurisdiction over a fully islanded PEN. AAE cautions that the 80% load factor and contiguity requirements could effectively limit PENs to gas-fired generation, increasing ratepayers' exposure to gas prices. AAE recommends that the Commission take more time to consider how PENs would operate within the system.

- **ADC**[4] supports PENs on narrow terms: new load only, no sales to the public, and cost-based standby service. Citing La. R.S. 45:121, which permits self-supply "at some other location," ADC argues that contiguity should not be required and proposes a "dedication" test instead. It supports a size floor based on existing large-load criteria and exclusive dedication, with surplus sold only to the utility. ADC concedes that sales to other end users likely require legislation. It also asks the Commission to require a tariffed, cost-based transport service, to address colocation

[4] ADC filed its Comments with its Motion to Intervene on September 25, 2026, which was granted by Deputy General Counsel Lauren T. Evans on October 9, 2026. ADC's Comments respond to Staff's First Requests for Information, stating it had not obtained the draft Rule at the time of drafting responses. ADC indicated it would supplement its responses upon review of the draft Rule. As of the date of this filing, no additional comments or responses were submitted by ADC.

expressly, and to offer tiered, cost-based backup options, ranging from full backup to none.

- **ALEC** opposes recognizing PENs, arguing that only regulated utilities should provide retail service. If the Commission proceeds, ALEC supports Staff's core protections but urges strengthening some of them. It requests 100% dedicated capacity with exports capped at 10%, PEN responsibility for all transmission costs, and no obligation for utilities to provide backup, standby, supplemental, maintenance, or emergency service. It also seeks a tighter New Load definition with a five-year lookback, application of the 50 MW threshold to each customer individually, and a "Serving Utility" definition giving the incumbent utility notice and standing.

- **Cleco** remains firmly opposed to PENs. It argues that a third-party supplier selling electricity to an end-use customer is an electric public utility under Louisiana law, and that a third-party PPA is the only new element the proposed rule adds. Cleco contends that Louisiana is already attracting large loads under the existing framework and that each PEN removes load that would otherwise help existing customers cover fixed costs. If the Commission proceeds, Cleco asks that Staff's core safeguards be retained. It also requests a clarified, single-entity contiguous property definition that excludes public roads and rights-of-way; a requirement to file the PPA with the application; and removal of post-confirmation expansion of the Network Boundary. Cleco further asks that PENs bear all interconnection, network upgrade, affected system, and regionally allocated transmission costs, backed by financial assurance, and that a firm "no rate increase" standard replace the "unreasonable cost shift" test.

- **EDF** supports recognizing PENs with appropriate safeguards. It urges a flexible framework focused on each PEN's actual impacts rather than categorical limits. EDF asks that the rule be technology-neutral and expressly allow renewables, storage, and emerging clean technologies and that contiguity not be absolute where a non-contiguous arrangement would not harm reliability or shift costs. It supports a threshold below 50 MW, or at least preserving the issue for later. EDF urges that cost causation and protection of non-participating customers remain central, and it identifies storm-damaged infrastructure as a potential PEN use case. Finally, it asks the Commission to pair any initial rule for islanded PENs with a procedural schedule for developing later tiers, such as backup service and non-contiguous configurations.

- **ELL** continues to view PENs as unnecessary, arguing that they would deprive existing customers of the benefits of load growth and would represent a major change in state policy. If the Commission proceeds, ELL supports Staff's core safeguards: islanding with export-only interconnection, new load and generation

only, and contiguous property. ELL asks that PEN Operators be treated as public utilities for oversight purposes, decline expropriation rights, and collect the same sales and ad valorem taxes as utilities. It also requests that "unrelated third parties" be revised to "third party," that the 30% export cap apply to total nameplate capacity, that PENs pay all current and future network upgrade costs up front, and that the rule include enforcement provisions for non-compliance. ELL supports the five-year sunset and urges the Commission to keep the blanket prohibition on backup and standby service.

- **LEUG** supports a PEN rule but argues that the proposed rule is overly restrictive and would prevent PENs from being used effectively. It asks that eligibility extend to "predominantly new load," including expansions of existing processes and replacement of existing self-generation, and that existing load not be foreclosed from case-by-case applications. LEUG proposes a 5 MW threshold with no load factor requirement, eligibility for "contiguous, adjacent or lawfully controlled" property, and a 49% export limit. It opposes the automatic sunset, preferring biannual reporting by Staff and a five-year review. LEUG also opposes the blanket exclusion of standby service, asks that the "cost-shift analysis" be deleted, and proposes a 25-day intervention period and a decision deadline. Finally, it argues that utility "lost opportunity" concerns ignore the cost risk that utility build-outs pose to existing ratepayers.

- **LCA** supports and adopts LEUG's comments and responses.

- **LMOGA** supports and adopts LEUG's comments and responses.

- **NWF** supports the rule's core ratepayer protections, including the new load limitation, cost causation, case-by-case review, and the 50 MW floor, which it opposes lowering. Arguing that the nameplate metric favors onsite gas, NWF asks that dedication be measured by energy delivered over a rolling 12-month period and by accredited rather than nameplate capacity, that storage count toward dedication, and that multiple owners be allowed. It recommends adding environmental, water, and wildlife disclosures to the application and pairing any contiguity flexibility with a habitat siting screen. NWF also urges that full islanding not be the only permitted configuration, and that a grid-connected option be allowed under a fully cost-based standby tariff. Finally, it asks the Commission to fix inconsistent export denominators, extend or toll the sunset for permitting and interconnection delays, and set reliability requirements matched to each network's size and technology.

- **OCC** supports PENs and argues that, if properly structured, they protect ratepayers. It explains that industrial cogeneration is driven by process steam needs, not displacement of utility service, and can provide reliability and resource adequacy benefits. OCC identifies four impediments in the proposed rule: the islanding

requirement, the new load limitation, the contiguous property requirement, and the lack of access to backup power. Citing the Geismar, Plaquemine, Baton Rouge, and Mississippi River corridors, it asks that PENs be allowed within "Industrial Hubs" and on nearby non-contiguous parcels with multiple owners. OCC also supports LEUG's proposals to treat expansions, self-generation, and public-interest cases as new load, and asks that PENs be able to buy backup and standby service from utilities subject to Commission jurisdiction.

- **Pelican Institute** reiterates its strong support for adopting PEN rules, arguing that PENs place capital, execution, and price risk on private developers and their customers rather than on ratepayers. It attaches its technical conference comments and encourages Staff to address industrial users' feedback on the new load definition, size and load factor thresholds, third-party sourcing of backup power, and comment, intervention, and decision timelines.

- **Powering Prosperity** supports PENs in Louisiana and asks that the threshold be lowered to 5 MW. It recommends replacing rigid dedication percentages with a "primary purpose" standard, or, alternatively, a 51% capacity requirement with no export cap. It also recommends replacing the islanding requirement with cost-of-service backup service from the utility or the RTO market. Finally, Powering Prosperity asks that contiguity be broadened to commonly controlled property connected by private lines, that the sunset be replaced with a Commission review right, and that the Commission act on complete applications within 120 days.

- **SREA** argues that the proposed rule may create new Commission jurisdiction, because a fully islanded system is unlikely to be a public utility under La. R.S. 45:1161. It proposes tiered designations, ranging from islanded systems needing no oversight to co-located and virtual systems. SREA contends that the rule imposes restrictions without corresponding benefits and would exclude configurations served mainly by renewables and storage.

- **SWEPCO** continues to oppose a PEN framework, arguing that Louisiana's existing structure already supports economic development and that third-party PPA sales to retail customers should remain subject to regulation. If the Commission proceeds, SWEPCO supports Staff's safeguards and asks that the prohibition on backup and other utility service be absolute, with any PEN that needs backup taking firm service for its entire load. It also asks that contiguity exclude parcels connected only by easements or rights-of-way, that PENs pay for all interconnection studies and upgrades, that the threshold be raised to 100 MW, and that the load factor and dedication percentages be consistent.

V. SUMMARIES OF PARTY RESPONSES TO STAFF'S SECOND REQUESTS FOR INFORMATION.

In its Initial Report, Staff requested additional information on utility services that a PEN may seek to inform its analysis. Cleco, ELL, LEUG, NWF, Powering Prosperity, SLEMCO, SREA, and SWEPCO submitted responses, which are summarized below.

RFI No. 1: What kind of service do PEN loads seek from the public utility: (a) maintenance; (b) backup; (c) as available; or (d) other?

- **Cleco** stated at the outset that it does not support the proposed rule and offers its responses only to help build the record. Cleco proposes that maintenance service be firm only during utility-approved windows limited to certain seasons and to roughly 30 to 45 days per year. Backup service should be non-firm and subject to utility approval; if a PEN needs backup at all times, Cleco views it as effectively firm service that should be limited to a set number of days. As-available service is non-firm, subject to interruption for reliability or economic reasons, and should not allow a PEN to arbitrage between self-generating and buying from the utility. For other service, Cleco states that service needed at all times is firm, while service used only when available may be non-firm, subject to utility approval.

- **ELL** states that, given the complexity and risk to utility customers, Staff should first develop clear, agreed-upon definitions of each service type before drafting policy.

- **LEUG** states that PEN loads should have access to maintenance, backup, as-available, and supplementary power from the interconnected utility at cost-of-service rates that do not shift costs to other ratepayers. It adds that PEN loads should also be able to buy standby power from other RTO market participants.

- **NWF** provides a combined response to RFI Nos. 1 through 5. It states that the terms of any service should follow cost causation, so backup, standby, supplemental, or maintenance service should recover from the PEN the full cost the utility incurs to stand ready. NWF recommends a published, Commission-approved cost-of-service tariff as the default, with any special contract filed publicly and approved on a cost-of-service basis.

- **Powering Prosperity** states that PENs should have the flexibility to obtain the service that fits their needs, often through a PEN-specific cost-of-service standby and maintenance tariff. It also recommends that Schedules SMQ and QFSS remain available to qualifying facilities ("QF") and be considered for non-QF PENs.

- **SLEMCO** states that a PEN could seek any of the listed services depending on its configuration and reliability needs, with cost allocated consistent with cost causation.

- **SREA** did not respond to each RFI individually. It expressed concern that the question could deny PENs FERC-jurisdictional services and stated that service agreements with a utility should be addressed through standard regulatory processes and engineering questions through the NERC stakeholder process.

- **SWEPCO** agrees with Staff that a PEN receiving any utility service is neither an island nor private.

RFI No. 2: For each type of service identified in response to Question 1, provide a detailed definition of the service and the specific terms and conditions under which it would be provided. The response should specifically address the extent to which the PEN customer would have a right or entitlement to receive such service and the circumstances under which the public utility could limit, curtail, interrupt, or deny service, including whether the utility's ability to do so would be unrestricted or subject to specified conditions or limitations. Identify any notice requirements, duration or frequency limitations, restoration priorities, or other operational parameters that would apply to the provision, limitation, curtailment, interruption, or denial of such service.

- **Cleco** proposes that maintenance requests be submitted at least 12 months in advance and that the utility be free to deny or reschedule them. Firm maintenance service would cover only the approved window, not forced outages or extensions, and would be capped at 30-45 days per year. For backup service, the utility, MISO, or the reliability coordinator could limit, curtail, or deny service whenever capability is insufficient or reliability is at risk, with notice where practicable but not as a precondition. As-available service should require day-ahead notice and could be denied based on planned outages or economics. Cleco recommends that the utility's right to curtail non-firm service be unrestricted if exercised in a non-discriminatory manner, and it opposes frequency or duration limits on curtailment. It would restore non-firm service only after firm customers are restored.

- **ELL** states that until there are clear, agreed-upon definitions for each type of service, it is not possible to take a position on the utility's right to limit, curtail, interrupt, or deny service.

- **LEUG** notes that ELL already offers standby service under its SMQ-G and QFSS-L schedules and argues PENs should have access to those terms where they apply, or to comparable terms modified as needed. It defines backup power as replacing PEN generation during unscheduled outages, maintenance power as replacing it

during scheduled outages, and supplementary power as regular additional service under the utility's normal rates.

- **NWF** addressed this question in its response to RFI No. 1.

- **Powering Prosperity** offers high-level principles, including service definitions set in the tariff or service agreement; firm entitlement for firm service and non-firm treatment for as-available service; enumerated curtailment triggers rather than unrestricted utility discretion; notice scaled to urgency; and the ability to mix firm and as-available service within one PEN.

- **SLEMCO** states that no service should carry an unrestricted entitlement, and that the utility's obligations and its rights to interrupt or curtail should be defined in advance through a tariff, service agreement, or other Commission-approved arrangement.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** points to its standby, backup, maintenance, and as-available rate schedules approved in Texas and Arkansas, its pending Louisiana Rate Schedule 71, and its standard terms on continuity and interruption of service.

RFI No. 3: For each kind of service, please explain in detail how cost-of-service rates should be developed.

- **Cleco** states that firm service should be priced using existing cost-of-service methods, with costs evaluated on an incremental rather than embedded basis. The PEN would pay demand costs on its full contracted capacity regardless of usage. Non-firm rates should recover, at a minimum, metering and equipment costs, study costs, energy costs reflecting MISO market costs, administrative costs, and a contribution to fixed transmission costs. Cleco recommends a Commission-approved Site Specific Contract for both types of service, with interconnection and upgrade costs directly assigned to the PEN so that existing customers do not subsidize the service.

- **ELL** refers to its responses to RFI Nos. 1 and 4 and states that any service should recover the utility's full incremental cost to serve the PEN.

- **LEUG** states that where existing backup or maintenance rates do not fit, they should be modified using cost-causation principles. Those rates should be based on the generator's expected performance during peak and other critical hours, rather than an assumption of simultaneous outages, with added charges if the PEN draws more backup than expected. Maintenance rates should reflect whether outages can be

coordinated to avoid critical periods, and supplementary power should be priced at normal full-service rates.

- **NWF** addressed this question in its response to RFI No. 1.

- **Powering Prosperity** recommends that the rules or tariffs set baseline cost-of-service principles, with PEN-specific terms in a negotiated service agreement. Firm backup should recover full capacity costs, as-available service should be priced mainly on a volumetric basis, and incremental infrastructure costs should be recovered directly from the PEN with appropriate security.

- **SLEMCO** states that the PEN should bear all costs of the service it requires, and that the rate structure should include recovery of the cost of maintaining standby capacity even if that capacity is rarely used.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** provides an example of its pricing methodology for standby, backup, maintenance, and as-available service.

RFI No. 4: For each kind of service, please state whether that would be provided via a special rate contract or via a published rate schedule.

- **Cleco** does not believe a single published rate schedule can be set in advance, because PENs will vary widely in size, location, operating characteristics, generation configuration, and service needs. It recommends service through a Site Specific Contract negotiated case by case, with the utility retaining discretion over rates and protective terms, subject to Commission review and approval.

- **ELL** recommends developing guiding principles similar to the Non-Binding Large Load Guidelines, and that any backup service be provided under a negotiated, site-specific rate and agreement subject to Commission approval.

- **LEUG** states that service under existing rates would use published rate schedules, and where a new rate is needed, the utility could propose either a new published rate or a special contract rate.

- **NWF** addressed this question in its response to RFI No. 1.

- **Powering Prosperity** states that both options should be available, with published schedules for standardized arrangements, such as a standard schedule for loads up to 100 MW, and special contracts for more complex ones.

- **SLEMCO** states that a special contract may be more appropriate for large or highly specific PENs, and that any published schedule should set clear, objective terms so similar PENs are treated consistently.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** notes that Arkansas and Texas use published rates for these services, though a special contract may be appropriate for unique requirements.

RFI No. 5: For each service, specifically state whether the utility would be required to plan for, procure, construct, or reserve generation, transmission, or distribution capability in order to ensure that the requested service will be available when called upon, or whether the service may be denied when sufficient capability is not otherwise available to the utility.

- **Cleco** states that the utility must plan for PEN load under every service type, because its obligation to serve remains unless the rule exempts it. For firm service, the utility must plan, procure, construct, and reserve capability at the PEN's full cost, including evaluating the load under N-2 conditions at summer and winter peak. For non-firm service, the utility must still stand ready because it cannot control when a forced outage will shift the load to the grid and must have capability in place in advance. Those standby costs should be recovered through reservation or standby charges. In Cleco's view, the non-firm designation should govern only curtailment priority, with non-firm PEN load curtailed before firm customers.

- **ELL** states that under the current export-only rule, no additional capacity would be needed to serve PEN load. PEN injections could still require transmission or distribution upgrades through MISO and ELL interconnection and planning processes, which the PEN should pay for. If backup service were allowed, the utility would also need to plan generation, transmission, reserves, and other resources for the PEN's load, potentially at significant cost.

- **LEUG** states that planning for backup and maintenance power under existing tariffs would be no different than today. For modified services, planning needs would depend on whether service is firm or as-available, with rates reflecting the cost so it is not shifted to others. Supplementary power would generally require planning and be provided under applicable tariffs.

- **NWF** addressed this question in its response to RFI No. 1.

- **Powering Prosperity** states that the utility's planning obligations should follow the service selected, as defined in the published schedule or negotiated in a special contract.

- **SLEMCO** states that a PEN should not automatically obligate the utility to build or procure resources, that the PEN should bear the cost of any firm obligation, and that non-firm service may be denied when capability is unavailable.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** states it should not be required to reserve or develop capacity for a PEN, and that any service should be as-available only and may be denied when capacity is unavailable.

RFI No. 6: If a PEN is interconnected with the public electric system, identify and describe in detail the reliability, engineering, operational, protection, and system studies and requirements that should apply to the PEN and its load to ensure that the interconnection does not adversely affect the reliability of the public electric system. The response should specifically address the potential for the sudden loss, reduction, or restoration of a large block of PEN load following a transmission or generation disturbance and should identify:

a. The studies that should be performed to evaluate the potential effects of such events on the public electric system, including any transient stability, voltage stability, frequency response, electromagnetic transient, protection coordination, or other dynamic studies;

- **Cleco** points to the July 2024 loss of roughly 1,500 MW of data center load and to pending NERC and FERC actions, and urges that any requirements remain consistent with forthcoming NERC standards. It recommends steady-state power flow, short-circuit, and dynamic stability analysis for all PENs, plus electromagnetic transient studies for computational loads. Cleco also recommends transient stability, voltage stability, frequency response, protection coordination, and oscillation screening analyses. These analyses should model the full and partial loss of PEN load at summer peak, winter peak, and light-load conditions, and should be repeated whenever the PEN materially changes.

- **ELL** refers to its response to RFI No. 5. It states that a PEN large enough to qualify as a Large Load under MISO and NERC definitions may trigger reliability, planning, and resource adequacy requirements for the host utility, and that the rule should be modified so the PEN bears those current and future costs.

- **LEUG** states that the same studies that apply to any other generation or load interconnection should apply to a PEN.

- **NWF** cites the July 2024 loss of roughly 1,500 MW of data center load and urges the Commission to address large-block disconnection directly. It recommends ride-through standards and system studies matched to the network's size,

technology, and interconnection, along with staged connection and disconnection and recognition of storage as a reliability resource.

- **Powering Prosperity** states that no additional LPSC interconnection rules are needed, because MISO's and SPP's interconnection procedures already require the relevant power flow, stability, and other studies.

- **SLEMCO** recommends load flow, contingency, short-circuit, and protection coordination studies, along with voltage and transient stability, frequency response, electromagnetic transient, and load disconnection and restoration studies.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** points to AEP's posted interconnection requirements and planning criteria, including steady state, short-circuit, and stability testing, and states that studies should evaluate the full range of PEN operating conditions.

b. The voltage and frequency ride-through capabilities and requirements that should apply to PEN loads and the circumstances, if any, under which some or all of the PEN load should be permitted to disconnect from the public electric system;

- **Cleco** states that PEN generation should meet all applicable NERC ride-through standards, and that PEN load should meet the utility's interconnection ride-through requirements and any future NERC standards for large or computational loads. PEN load should disconnect only (1) when voltage or frequency falls outside the approved ride-through envelope; (2) at the direction of the utility, MISO, or the reliability coordinator; or (3) under protection settings the utility has studied and accepted. Any scheme that shifts PEN load to on-site generation during disturbances should be disclosed in advance and coordinated with the utility's reclosing practices.

- **ELL** refers to its response to RFI No. 6(a). It states that planning studies must ensure the system can accommodate the PEN's full generation output if its load is suddenly lost due to voltage or frequency excursions.

- **LEUG** states that the same voltage and frequency ride-through requirements that apply to other load interconnections should apply to PEN loads.

- **NWF** addressed this question in its response to RFI No. 6(a).

- **Powering Prosperity** states that MISO's interconnection agreement already requires relay set points ensuring ride-through capability.

- **SLEMCO** states that PEN load should not automatically disconnect for every disturbance, and that ride-through and disconnection conditions should be set in advance through the interconnection agreement.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** states that any interconnected PEN should demonstrate ride-through for both load and generation and must meet SPP ride-through requirements for high impact large loads.

c. Any protection, control, telemetry, communications, monitoring, modeling, or other equipment or information that should be required to allow the public utility and applicable reliability coordinator or regional transmission organization to understand, anticipate, and manage the PEN's response to system disturbances.

- **Cleco** recommends the following as conditions of interconnection: real-time telemetry of PEN load and generation; digital fault recorders or phasor measurement units; validated steady-state, dynamic, and electromagnetic transient models; utility review of protection settings and equipment allowing the utility to curtail PEN load; redundant communications; day-ahead forecasts and outage notices; and timely reporting of disturbance-related changes.

- **ELL** refers to its response to RFI Nos. 6(a) and 6(b). It states that protective schemes preventing the PEN from accidentally drawing power from the grid, including after a sudden loss of PEN generation, must be in place before the PEN begins operating.

- **LEUG** states that PENs should be subject to the same protection, telemetry, communications, monitoring, and modeling requirements as other interconnecting generation or load.

- **NWF** addressed this question in its response to RFI No. 6(a).

- **Powering Prosperity** states that MISO's interconnection agreement already establishes the necessary communications, telemetry, protection, and modeling requirements.

- **SLEMCO** would require real-time telemetry of load, generation, voltage, frequency, and equipment status, reliable communications, accurate and updated models, and coordinated protection systems.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** would require real-time telemetry, accurate planning and operational models, protection coordination before energization, defined operating communications, and disturbance monitoring.

d. Any requirements governing the amount and rate at which PEN load may disconnect from or reconnect to the public electric system, including whether staged disconnection, reconnection, or load ramping should be required; and

- **Cleco** states that instantaneous disconnection may be acceptable only if the system has been upgraded to withstand loss of the full PEN load, but that staged disconnection is preferred. It recommends that PEN load reconnect only with utility authorization, in defined increments, and at ramp rates set through the interconnection studies.

- **ELL** refers to its responses to RFI Nos. 6(a) and 6(b).

- **LEUG** states that disconnection, reconnection, and ramping requirements that apply to other loads should apply to PEN loads.

- **NWF** addressed this question in its response to RFI No. 6(a).

- **Powering Prosperity** states that MISO's interconnection agreement already addresses synchronization and coordinated outage and restoration procedures.

- **SLEMCO** states that a PEN should not make uncontrolled load transitions unless studied and approved, and that the interconnection agreement should set staged reduction, block restoration, and ramping requirements.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** states that limits such as staged disconnection and restoration and ramp-rate limits should be set through the interconnection study, and notes SPP's maximum operational ramp rate of 20 MW per minute.

e. Whether the requirements identified above should vary based upon the size of the PEN load, the amount of load capable of disconnecting or reconnecting simultaneously, the characteristics of the PEN's generation and load, or the strength and characteristics of the public electric system at the point of interconnection.[5]

- **Cleco** agrees that requirements should vary. Baseline requirements would apply to every PEN, with further requirements set case by case based on load size, the

[5] Staff's Initial Report inadvertently numbered this question as RFI No. 7. It will be discussed as RFI No. 6(e) in this Report.

amount of load that can disconnect or reconnect at once, generation and load characteristics, system strength at the point of interconnection, and cumulative large load in the area. Because every PEN would exceed federal large-load thresholds, Cleco opposes any tier that relaxes requirements for smaller PENs and recommends against fixing technical requirements by rule.

- **ELL** states that a grid-connected PEN must comply with all applicable MISO and NERC requirements, and that its load behavior must be studied for impacts on the broader system. Because the amount of power a PEN can inject depends on system strength, studies must be specific to its point of interconnection.

- **LEUG** views the question as one for new large loads generally and notes that NERC, MISO, SPP, and FERC are actively developing requirements that will identify which load additions they apply to.

- **NWF** addressed this question in its response to RFI No. 6(a).

- **Powering Prosperity** states that MISO's and SPP's frameworks already scale requirements to facility size and characteristics, so separate LPSC requirements would be duplicative and risk inconsistency.

- **SLEMCO** states that requirements should be based on each PEN's potential impact, considering its size, how much load could change at once, and system characteristics at the point of interconnection.

- **SREA** addressed this question in its response to RFI No. 1.

- **SWEPCO** states that all PEN load and generation should be studied regardless of size, but that study scope and operating requirements should be tailored to each facility's reliability risks.

VI. OTHER JURISDICTIONS' EXPERIENCE WITH PRIVATE USE ELECTRICAL NETWORKS.

Other jurisdictions have permitted or are now evaluating private networks and co-located generation to serve large loads, and their experiences may provide useful guidance as Louisiana considers its own regulatory approach.[6] Staff reviewed the experiences of

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[6] *See* Idaho Nat'l Lab'y, *Power System Implications of Operating Large Loads: A Summary of International and Domestic Initiatives*, at 3-6 (Oct. 2, 2025) https://csdet.inl.gov/content/uploads/45/2025/11/INL-Data-Centers-T1M2-Initiatives.pdf.

several jurisdictions, including (1) the Electric Reliability Council of Texas ("ERCOT") region, where private use networks have long operated and where the legislature and the Public Utility Commission of Texas ("PUCT") recently adopted reforms; (2) the PJM Interconnection, L.L.C. ("PJM") region, where the Federal Energy Regulatory Commission ("FERC") rejected a proposed co-location arrangement and required new tariff rules for co-located large loads; (3) West Virginia and Utah, which enacted private-generation and microgrid legislation in 2025; and (4) Tennessee, Mississippi, and Virginia, where dedicated on-site generation serving data centers has raised environmental concerns. Each is discussed more fully below.

A. The ERCOT Region.

ERCOT defines a Private Use Network as an electric network connected to the ERCOT system that manages its own generation and load.[7] Historically, such networks could be established without PUCT approval, subject to ERCOT technical requirements for settlement and system operations.[8] Unlike islanded PENs, ERCOT Private Use Networks remain connected to the transmission system.[9] As discussed below, Texas's experience illustrates the cost-allocation and reliability concerns that can arise when large loads are served by private generation.

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7 Elec. Reliability Council of Tex., *ERCOT Grid Insights: Addressing issues important to maintaining a reliable and resilient grid*, at 1 (Nov. 2025), https://www.ercot.com/files/docs/2025/11/24/ERCOT-Grid-Insights-About-ERCOT.pdf.

8 Chris Reeder, *Private Use Networks & Self-Generation: What You Need to Know*, JD Supra (Feb. 8, 2021), https://www.jdsupra.com/legalnews/private-use-networks-self-generation-4515203/.

9 *Id.*

1. Transmission Cost Avoidance and Cost Shifting.

The reduction of transmission charges is a financial incentive for Private Use Networks in ERCOT.[10] ERCOT allocates wholesale transmission costs using the four coincident peak ("4CP") method, based on a customer's demand during the four summer monthly 15-minute intervals of highest system demand.[11] To reduce transmission costs, large customers could reduce consumption during those peak times, in turn reducing their share of transmission costs without reducing the cost of the system.[12] Those costs are then shifted to and recovered from other customers.

Several participants raised this concern in the PUCT's 2025 transmission cost allocation proceeding.[13] NRG explained that avoiding 4CP charges produces "no cost savings, only a reallocation of the costs to other customers"[14] and estimated that a single

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10 *Id.*

11 16 Tex. Admin. Code § 25.192; NRG Editorial Voices, *Summer heat? For Texas businesses, there's a summer solution*, NRG (June 21, 2023), https://www.nrg.com/en/insights/energy-education/how-texas-businesses-can-reduce-their-demand-charges-through-4cp.

12 Maria C. Faconti et al., *Request for Comments on Texas PUCT Draft Report Regarding Transmission Cost Recovery in the ERCOT Region*, K&L Gates (Mar. 30, 2026), https://www.klgates.com/thought-leadership/Request-for-Comments-on-Texas-PUCT-Draft-Report-Regarding-Transmission-Cost-Recovery-in-the-ERCOT-Region-3-30-2026.

13 *See, e.g.*, Office of Pub. Util. Counsel's Initial Comments on Questions for Public Comment Relating to the Evaluation of Transmission Cost Recovery at 4, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025) (arguing that large load customers "'gam[e]' the system by significantly reducing demand during 4CP intervals . . . [which] shifts the costs to the ratepayers, particularly residential and small business consumers."); Vistra Corporate Services Co. LLC's Comments at 3, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025) ("4CP results in cost shifting between customers, as certain entities are better able to coordinate response to the 4CP financial incentive."); AEP Companies' Comments on Questions for Public Comment at 3, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025) ("The 4CP paradigm results in cost-shifting . . . [and] many residential and small commercial customers end up with a higher cost burden due to their limited ability to reduce their demand at peak times.").

14 Comments of NRG Energy, Inc. in Response to Staff's August 5, 2025 Questions at 1, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025) (quoting *Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, William W. Hogan & Susan L. Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT" (filed May 22, 2017)).

large load could avoid approximately $20.4 to $42.7 million in annual transmission charges.[15] H-E-B, L.P., itself a large customer, likewise acknowledged and opposed this cost shift.[16] CPS Energy warned that failing to assign transmission costs to the customers that benefit creates opportunities for "free-riding."[17]

These consequences continue to grow as large-load demand increases. Transmission costs to serve large loads have historically been recovered from ERCOT customers generally.[18] By October 2025, ERCOT reported approximately 205 gigawatts ("GW") of proposed large-load demand requests; in 2024, those requests totaled only 56 GW.[19] The volume of requests underscores the need for large loads to pay for the infrastructure built to serve them.

2. Texas's Legislative and Regulatory Response.

In June 2025, Texas enacted Senate Bill 6 ("S.B. 6"), which established additional requirements for large loads and generation arrangements in ERCOT. Among other things, the new legislation:

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15 *Id.* at 5.

16 Joint Responses to Staff Questions of H-E-B, L.P. and South Texas Electric Cooperative, Inc. at 2, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025).

17 CPS Energy's Response to Questions for Comment at 2, *Evaluation of Transmission Cost Recovery*, Project No. 58484 (Pub. Util. Comm'n of Tex. Sept. 9, 2025).

18 Aparajita Datta & Ramanan Krishnamoorti, *Update to the Future of the Electric Grid in Texas*, at 4 (UH Energy, Univ. of Hous. 2026), https://www.uh.edu/energy/_docs/_papers-reports/update-to-the-future-of-the-electric-grid-in-texas.pdf.

19 Elec. Reliability Council of Tex., *ERCOT Monthly: A Recap of Key Information from the Previous Month, a Look at the Upcoming Month, and a Snapshot of Additional Key Items*, at 6 (Nov. 2025), https://www.ercot.com/files/docs/2025/11/14/ERCOT-Monthly-October-2025.pdf.

- Requires an ERCOT study and PUCT approval before certain generation owners implement net metering arrangements between existing stand-alone generation resources and new large loads of 75 MW or more;[20]

- Requires large loads to disclose on-site backup generation capable of serving at least 50% of their demand and authorizes ERCOT, during energy emergencies and with reasonable notice, to direct those customers to operate their backup generation or curtail consumption;[21] and

- Directs the PUCT to evaluate whether the existing 4CP methodology appropriately allocates transmission costs. [22]

Texas has since taken further steps to rectify the cost-shifting concerns. In September 2026, the PUCT adopted financial security requirements for large-loads based on requested peak demand, declining to exempt co-located generation or base collateral on net grid imports.[23] Governor Abbott also directed the Texas Commission on Environmental Quality to suspend certain data center-related permit approvals until developers comply with water-use reporting.[24]

3. Significance for Louisiana.

Texas's experience offers several lessons for Louisiana moving forward. First, the main cost-shifting risk arises when privately served loads rely on the grid while reducing their share of the grid's cost. Second, reforms are harder to adopt after private

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20 Tex. Util. Code Ann. §§ 37.0561, 39.169 (West 2025); *see also* 16 Tex. Admin. Code § 25.205.

21 Tex. Util. Code Ann. § 37.0561(e) (West 2025).

22 S.B. 6, 89th Leg., Reg. Sess. (Tex. 2025) (enrolled version), https://capitol.texas.gov/tlodocs/89R/billtext/html/SB00006F.HTM.

23 Monica Hwang et al., *PUCT sets financial commitments for data center interconnection as governor pauses permit approvals*, White & Case (Sept. 25, 2026), available at https://www.whitecase.com/insight-alert/puct-sets-financial-commitments-data-center-interconnection-governor-pauses-permit.

24 Press Release, Off. of the Tex. Governor, *Governor Abbott Directs TCEQ To Halt Data Center Permits* (Sept. 21, 2026), https://gov.texas.gov/news/post/governor-abbott-directs-tceq-to-halt-data-center-permits.

arrangements are already in place, as Texas found because ERCOT Private Use Networks historically required no approval. As a result, the scope of a private network, including interconnection rules, service to additional customers, and responsibility for infrastructure costs, should be defined at the outset.

B. The PJM Region and FERC.

1. The Susquehanna-Amazon Co-Location Arrangement.

The PJM region faces similar concerns. In March 2024, Amazon and Talen Energy announced a $650 million transaction to develop a data center co-located with the Susquehanna Steam Electric Station in Pennsylvania to be supplied with up to 960 MWs from the plant.[25]

In November 2024, FERC rejected an amendment to the plant's interconnection service agreement that would have increased the co-located load served behind the meter.[26] Opposing utilities argued that the arrangement could shift as much as $140 million annually to other PJM customers.[27] The U.S. Department of Energy later noted the concern that co-located data centers could "benefit from transmission systems without paying for them,

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[25] Off. of Nuclear Energy, U.S. Dep't of Energy, *Advantages and Challenges of Nuclear-Powered Data Centers* (Apr. 8, 2025), https://www.energy.gov/ne/articles/advantages-and-challenges-nuclear-powered-data-centers.

[26] *PJM Interconnection, L.L.C.*, Docket No. ER24-2172-000, 189 FERC ¶ 61,078 (Nov. 1, 2024) (order rejecting amendments to interconnection service agreement).

[27] Ethan Howland, *FERC rejects interconnection pact for Talen-Amazon data center deal at nuclear plant*, Utility Dive (Nov. 4, 2024), https://www.utilitydive.com/news/ferc-interconnection-isa-talen-amazon-data-center-susquehanna-exelon/731841/.

potentially raising costs for utility customers."[28] Susquehanna appealed to the Fifth Circuit.[29]

2. FERC's December 2025 Co-Location Order.

In February 2025, FERC opened a broader proceeding on the rates, terms, and conditions for co-located loads under PJM's tariff.[30] PJM recommended treating co-located loads as network loads taking firm transmission service because they remain synchronized to and benefit from the transmission system and ancillary services. [31]

On December 18, 2025, FERC found PJM's tariff unjust and unreasonable because its treatment of behind-the-meter generation "raise[d] cost-shifting concerns, reliability concerns, and resource adequacy concerns."[32] FERC ultimately directed PJM to develop new transmission service options for co-located loads.[33] Commissioner Chang separately emphasized that co-located loads benefiting from the transmission system should

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28 Off. of Nuclear Energy, *supra* note 25.

29 *See generally Susquehanna Nuclear, LLC v. FERC*, No. 25-60019 (5th Cir. filed Oct. 3, 2025).

30 *PJM Interconnection, L.L.C.*, Docket No. EL25-49-000, 190 FERC ¶ 61,115 (Feb. 20, 2025).

31 Answer of the Indicated PJM Transmission Owners to the Order Instituting the Proceeding Under Section 206 of the Federal Power Act and Consolidating With Other Proceedings at 3, *PJM Interconnection, L.L.C.*, Docket No. EL25-49-000 (FERC Mar. 24, 2025).

32 *See generally PJM Interconnection, L.L.C.*, Docket No. EL25-49-000, 193 FERC ¶ 61,217 (Dec. 18, 2025) (order on show cause proceeding, directing compliance filings, establishing paper hearing, and granting in part and denying in part complaint); Mark J. Stanisz, PJM, *Summary of FERC's December 18, 2025 Order on Co-Located Load* at slide 2 (Jan. 9, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/cllsco/2026/20260109/20260109-item-02---summary-of-december-18-co-located-load-order--presentation.pdf.

33 Fed. Energy Regul. Comm'n, *FACT SHEET: FERC Directs Nation's Largest Grid Operator to Create New Rules to Embrace Innovation and Protect Consumers* (Dec. 18, 2025), https://www.ferc.gov/news-events/news/fact-sheet-ferc-directs-nations-largest-grid-operator-create-new-rules-embrace.

contribute to its costs, warning that arrangements requiring little or no payment for system services risk shifting those costs to other customers.[34]

FERC's review has since expanded. On June 18, 2026, FERC issued show cause orders to all six FERC-jurisdictional regional transmission organizations and independent system operators, including the Midcontinent Independent System Operator, Inc. ("MISO") and Southwest Power Pool, Inc. ("SPP") (both of which serve portions of Louisiana), directing them to address large-load integration, co-location, behind-the-meter generation, and cost shifting.[35]

3. Significance for Louisiana.

The PJM experience confirms the Texas lesson: locating generation and load at the same site does not eliminate the need to pay for transmission, reliability, and other grid services if the load continues to rely on it. For Louisiana, this underscores the importance of a clear line between PENs that operate independently of the grid and grid-connected arrangements, and of ensuring that any grid service a PEN receives is priced to recover its full cost.

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[34] *PJM Interconnection, L.L.C.*, Docket No. EL25-49-000, 193 FERC ¶ 61,217 (Chang, Comm'r, concurring) at PP 7, 9.

[35] Press Release, Fed. Energy Regul. Comm'n, *FERC Launches Aggressive Targeted Action to Speed Large Load Integration* (June 18, 2026), https://www.ferc.gov/news-events/news/ferc-launches-aggressive-targeted-action-speed-large-load-integration.

C. West Virginia.

1. The Power Generation and Consumption Act (H.B. 2014).

West Virginia's Power Generation and Consumption Act (H.B. 2014), effective July 11, 2025, created a certified microgrid program through which qualifying data centers may generate and consume electricity independently of state-regulated utilities.[36] The program applies to new "high impact" data centers with loads of at least 90 MW, and requires that microgrid generation costs be borne by the generator or consumers within the microgrid district rather than utility ratepayers.[37]

The Act also preempts county and municipal ordinances governing "zoning, horticultural, noise, viewshed, lighting, development, or land use," as well as local building permitting and licensing requirements.[38] It permits on-site fossil generation, including coal and natural gas, which the implementing rule identifies as resources the program is intended to use.[39]

2. Implementation and Public Opposition.

As of October 2026, four projects, including a proposed Google campus, had met the high-impact threshold, but no microgrid districts had been designated.[40] The legislation has nonetheless drawn substantial opposition over loss of local control, environmental

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[36] H.B. 2014, 2025 Leg., Reg. Session (W. Va. 2025) (enrolled version), https://www.wvlegislature.gov/Bill_Text_HTML/2025_SESSIONS/RS/bills/hb2014%20sub1%20enr.pdf.

[37] *Id.* at 1, 6, 17.

[38] *Id.* at 12-13.

[39] *Id.*; Idaho Nat'l Lab'y, *supra* note 6, at 3-4.

[40] Sean Reilly, *Backlash Engulfs West Virginia Data Center Law*, RTO Insider (Oct. 1, 2026), https://www.rtoinsider.com/137837-is-w-va-microgrid-law-aimed-at-attracting-data-centers-working/.

impacts, allocation of tax revenues, water use, private property rights, and the adequacy of safeguards.[41] In August 2026, legislative leaders announced a nonbinding "Responsible Data Center Development Plan" calling for developers to bear the costs of needed infrastructure upgrades.[42]

3. Significance for Louisiana.

West Virginia's Act includes ratepayer protections, such as limiting participation to new load and assigning generation costs to participants, yet its implementation has raised separate concerns about land use, environmental impacts, and local oversight. For Louisiana, this shows that ratepayer protections do not solve issues that may be raised by the public concerning siting and environmental impacts.

D. Utah: Senate Bill 132.

Utah's Senate Bill 132 ("S.B. 132"), enacted in 2025, allows alternative arrangements for serving large loads, including contracts with independent generation providers.[43] It requires separate accounting for the costs of serving large loads and prohibits shifting those costs to other customers.[44] It also authorizes "closed private generation systems" that must meet their own electricity, transmission, and load needs without utility service.[45]

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41 *Id.*

42 *Id.*; *see also* W. Va. Dep't of Com., *West Virginia Responsible Data Center Development Plan* (Aug. 11, 2026), https://westvirginia.gov/wp-content/uploads/2026/08/Data-Center-Principles-August-2026-FINAL-8-26.pdf.

43 S.B. 132, 2025 Gen. Sess. (Utah 2025) (enrolled version), https://le.utah.gov/Session/2025/bills/enrolled/SB0132.pdf.

44 Utah House of Reps., *Utah Data Center Laws: Protecting Ratepayers, Water and Natural Resources* (Oct. 1, 2026), https://house.utleg.gov/2026-utah-data-center-regulations/.

45 S.B. 132, 2025 Gen. Sess. (Utah 2025).

S.B. 132 also addresses environmental considerations. Applicants must identify the permits required for qualifying generation, "including any environmental permits," and estimate effects on Utah's state air-quality implementation plan.[46] The facilities remain subject to environmental permitting, including review of projected emissions and public notice and comment.[47]

1. Significance for Louisiana.

Utah's approach could be a useful model for Louisiana because it permits private generation that operates without relying on utility infrastructure, while preserving both ratepayer protection and environmental oversight.

E. Environmental Experience with Dedicated On-Site Generation.

1. Memphis, Tennessee and Southaven, Mississippi (xAI).

xAI's Colossus data centers illustrate potential environmental consequences of building large generation to serve a single load. In April 2025, xAI was operating 35 natural gas turbines with more than 420 MW of capacity at its Memphis facility without required air permits.[48] Natural gas turbines are capable of emitting substantial nitrogen oxides, carbon monoxide, particulate matter, and hazardous air pollutants. The Shelby County Health Department later permitted 15 turbines totaling up to 247 MW.[49]

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46 *Id.* at 12-13.

47 Utah House of Reps., *supra* note 44.

48 Press Release, S. Env't L. Ctr., *Groups appeal permit for xAI's South Memphis data center, decisions around unpermitted methane gas turbines* (July 16, 2026), https://www.selc.org/press-release/groups-appeal-permit-for-xais-south-memphis-data-center-decisions-around-unpermitted-methane-gas-turbines/; *see also* Tim De Chant, *xAI gets permits for 15 natural gas generators at Memphis data center*, TechCrunch (July 3, 2025), https://techcrunch.com/2025/07/03/xai-gets-permits-for-15-natural-gas-generators-at-memphis-data-center/.

49 De Chant, *supra* note 48.

At its second data center in Southaven, Mississippi, xAI installed temporary natural gas turbines that reportedly reached approximately 1,775 MW by July 2026, and state regulators permitted 41 permanent turbines totaling approximately 1,200 MW.[50] The project drew objections over air quality and community health.[51] The scale of the facilities shows that "private" generation dedicated to a private load can have impacts comparable to a utility-scale power plant.

2. Virginia.

In Virginia, complaints have arisen regarding data centers using on-site natural gas generation instead of connecting to the grid.[52] Proximity to homes has also prompted noise complaints.[53]

3. Significance for Louisiana.

These experiences show that private generation may reduce reliance on utility infrastructure, but it could also cause more widespread environmental and other local impacts associated with new generation. And the trade off for those environmental impacts would be service to a single customer, as opposed to benefitting all customers in the state. The Louisiana Commission does not have jurisdiction over environmental issues and has

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50 Austyn Gaffney, *The data center backlash comes for SpaceXAI's Colossus*, Scientific American (Sept. 9, 2026), https://www.scientificamerican.com/article/spacexais-colossus-data-center-is-fueling-a-massive-backlash/.

51 *See, e.g.*, Press Release, S. Env't L. Ctr., *New study finds proposed xAI gas plant could worsen regional air pollution, cause millions of dollars in annual health damages* (Feb. 16, 2026), https://www.selc.org/press-release/new-study-finds-proposed-xai-gas-plant-could-worsen-regional-air-pollution-cause-millions-of-dollars-in-annual-health-damages/.

52 Julie Bolthouse, *New Study Highlights Public Health Impacts of Gas Turbine-Powered Data Centers*, Piedmont Env't Council (May 6, 2026), https://www.pecva.org/work/energy-work/data-centers/new-study-highlights-public-health-impacts-of-gas-turbine-powered-data-centers/.

53 *Id.*

generally deferred to local authorities on land-use impacts. Those issues must be addressed in the same manner as they would be addressed if a public utility were constructing the generation. A PEN's independence from the public grid does not eliminate the need for appropriate environmental permitting and oversight. A PEN should be required to demonstrate compliance with all environmental permitting and other applicable regulatory and siting requirements as a threshold to qualification. Utah's approach shows that basic information about a private network's generation, such as technology, fuel source, capacity, operating characteristics, water source, and permit status, can help a utility regulator understand the broader implications of private network development without duplicating the work of environmental permitting agencies.

F. What These Economic and Environmental Experiences Mean for Louisiana PENs.

Taken together, the experiences of other jurisdictions demonstrate that the risks associated with PENs depend largely on their structure and the regulatory requirements governing their operation. The most significant cost-shifting problems in Texas and PJM arose from arrangements that allowed connection to and reliance on the grid, while reducing the requisite contribution to the grid's cost, and both jurisdictions are now reforming those arrangements after the fact. West Virginia and Utah show that ratepayer economic protections alone do not address the siting, environmental, and local-oversight concerns that large, single-use dedicated generation can raise. Tennessee, Mississippi, and Virginia confirm that those impacts may be comparable to a utility-scale power plant even

when the generation serves a single private customer that is not contributing to the funding of the public grid.

For Louisiana, these lessons point to the value of defining at the outset which loads may be served by a PEN, how independent the PEN must be from the public grid, who bears the costs of any grid service or infrastructure, and how environmental and siting information will be considered, while preserving the Commission's ability to revisit its approach as experience develops. The Staff has considered these lessons in developing its final recommendation, which is discussed below and reflected in the attached Rule.

VII. STAFF RESPONSE TO ISSUES RAISED.

The Staff appreciates the robust participation in the Technical Conference as well as the written comments, proposed rule redlines, and responses to the requests for information. The Staff has carefully considered that feedback and, as a result, proposes changes to various aspects of its proposed rule, as discussed in the following sections. The purpose of this rule is narrow -- to provide a limited additional avenue to serve new large load customers in Louisiana. Staff recognizes the extraordinary circumstances the state is now facing with unprecedented load growth and need for speed in power development. The PEN configuration sets forth a clear path for an alternative means of service for configurations that comply with the rule. Where the rule permits an exception, an applicant must identify the specific requirement at issue and substantiate why the requested exception remains consistent with the rule's purpose and protections. The rule does not limit authority the Commission otherwise possesses under applicable law.

Based on the significant large load that has located in Louisiana and that has expressed interest in doing so, the Staff finds that the current system in Louisiana has not deterred new large load customers from coming into the state. Throughout this process the Staff has adhered to the purpose of this docket: to provide an alternative way to provide power to new large load looking to locate in Louisiana, as a means of attracting and serving new large load while protecting existing Louisiana utility customers from harm. The purpose of this rulemaking is not to provide a mechanism to enable private businesses to assemble private networks of disparate industrial customers without regard to the rule's geographic and eligibility requirements or to allow unregulated wholesale suppliers to compete with public utilities holding rights to serve exclusive service areas under the regulatory compact.

This rule is intended to provide a narrowly tailored alternative within Louisiana's regulated electric-service framework, which has served the state well and facilitated the development of a reliable and efficient public grid. Further, Louisiana's system has allowed capital to be invested in a manner that benefits all electric customers in the state, maximizing the efficient use of resources while minimizing negative economic and environmental impacts. Allowing private networks to develop alongside the public grid risks diverting capital to inefficient duplicative buildout and losing economies of scale jointly supported by all ratepayers. The PEN requirements are intended to address those risks, including the risk of cost shifts to remaining utility customers, while accommodating qualifying new development.

Given the complexity of the circumstances, the demand of large load customers, and cost concerns of existing Louisiana customers, the Staff navigated multiple competing factors to propose a rule that allows an additional avenue to serve large load customers, while also ensuring that other customers are not harmed. In providing this alternative avenue, the Staff urges the Commission to closely monitor how any final approved rule functions in reality and to assess the impact on the public electric system on which the majority of Louisiana depends and to make necessary adjustments to prevent unintended consequences. Accordingly, Staff has recommended an automatic review of the rule starting four years after the rule's adoption. The Commission should undertake a review whenever circumstances warrant and each application should demonstrate that the proposed PEN is both compliant and consistent with the public interest in light of the rule's stated purpose and protections.

The Staff rejects the notion expressed by some commenters that the Commission does not have jurisdiction to place limits on PEN recognition, or that those limits may run afoul of federal law allowing wholesale power transactions. As proposed, the PEN rules create an alternative avenue for load to obtain electric service in a PEN configuration. If the PEN does not meet those qualifications, including the applicable eligibility, capacity-sales, and majority-customer-energy-use requirements, it will not be recognized as a PEN under the Commission's rules and no retail sales to load will be allowed within the PEN construct. Further, there is no federal law creating a right to make sales to load within a PEN, and any such law would run headfirst into well-settled state jurisdiction over retail

sales of electricity. The Staff recognizes the limitations that states have regarding wholesale sales, but the Commission is the arbitrator of PEN existence within Louisiana, including the denial or revocation of PEN status and the concomitant right to make retail sales to retail load when the PEN requirements are not followed.

The Staff also emphasizes that, under its recommendation, the Commission is prescribing the manner in which it exercises its jurisdiction over retail service within duly recognized PENs. It would be exercising that authority to determine if a PEN is in the public interest and if the proposed PEN qualifies as such under the Commission's rules, to ensure that no costs attributable to a PEN are shifted to utility customers, and to ensure that PENs do not degrade reliability for the remainder of Louisiana citizens who use and rely on the public grid. The framework would permit PEN Load and PEN Generators, as defined in the PEN rules, to establish rates and service obligations through negotiated PPAs, subject to Commission regulatory jurisdiction, including review for compliance with the PEN requirements and applicable law. If approved, those contractual terms would govern pricing, availability, maintenance, performance, and remedies. PEN Load takes service from a PEN Generator at its own risk under the terms it voluntarily negotiates. Commercial disappointment or service performance within the agreed terms would not, standing alone, justify relief from the parties' bargain or impose an obligation on the incumbent utility or its other customers to support the negotiated arrangement. The Commission would retain its enforcement authority and any continuing jurisdiction required by law. Contractual remedies would remain available in the appropriate forum.

As proposed, PEN service is islanded service at the full risk and responsibility of the PEN's voluntary participants.

A. "New Load" Eligible to Be Served by a PEN.

Consistent with the directive that initiated this rulemaking, the Staff's original proposed rule provided that PEN service is only available "to serve new large load looking to locate in Louisiana."[54] The Staff maintains that this is the appropriate focus, but acknowledges that there are open issues as to how "new load" is defined. Regulated utility commenters generally support a narrow definition of new load to require a new facility or customer, while industrial customer and related trade group comments advocate allowing expansion of an existing facility or business. LEUG expressly describes expansion through an existing or new industrial process with separate metering. Powering Prosperity also contemplates new or expanded industrial processes. OCC supports LEUG's expansion concept, but its broader request also reaches existing loads and self-generation. Pelican Institute supports accommodating expansions.

The Staff finds that the rule should allow for "new loads" whether or not that new load comes from a new or existing customer and whether that new load is built at an existing or new facility or location. The new load, however, must be clearly delineated and distinguished as new incremental load to qualify to be served by a PEN. These rules should not allow PEN service for existing retail load.

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[54] Transcript of Business & Executive Open Session at 11:16-12:14 (La. Pub. Serv. Comm'n Apr. 15, 2026) (directive to Staff to open a rulemaking to evaluate private use electrical networks), https://lpsc.louisiana.gov/docs/transcripts/April-15-2026-BE.pdf.

A narrow interpretation of "new load" to require a new customer or facility would be inconsistent with the purpose of the rule, which is to facilitate new economic development from the location of large loads in Louisiana. It could exclude a substantial new investment by an existing Louisiana business even when the project creates genuinely additional electrical demand and could exclude economic development from investment in an addition to an existing plant. Although that distinction offers an identifiable physical boundary, it does not necessarily resolve the underlying concern. A new facility could replace production at an existing facility, while an expansion at an existing plant could represent entirely additional production and load. The new-load requirement should focus on whether the project creates incremental electrical demand, whether it comes from a new customer building a new facility, a new facility constructed by an existing Louisiana company, or an expansion of an existing operation.

1. New Load Should Be Incremental to Existing Load.

The Staff's recommended approach would require a supported distinction between additional and incremental demand and existing demand that has been transferred, replaced or relabeled. The PEN rules should not become a means of moving existing utility-served activity into a privately supplied network rather than supporting truly additional economic activity and electrical demand from large-load customers. Separate metering, as suggested by some of the industrial commenters, would help to identify consumption, but would not establish that the consumption is incremental to existing load. An industrial customer could move production between processes or facilities, allowing consumption behind the

PEN meter to increase while consumption behind its existing utility meter declines. Geographic separation would not, by itself, resolve that issue either. A company could construct a distinct new facility while reducing or closing an existing Louisiana operation that performs the same work. Thus, a new meter or a new parcel alone is not sufficient evidence of new load.

The PEN applicant should be required to demonstrate that its proposed service arrangement supports genuinely additional demand to qualify and meet all other PEN requirements, including minimum size, geographic and electrical separation, independent supply, load factor, capacity limitations, and energy-export limitations. The qualifying additional load must be separately metered and independently served by PEN generation, apart from the existing utility-served operations. In addition, the applicant must affirmatively show that:

- The proposed demand is incremental to existing Louisiana operations.
- The project is not expected to cause a material reduction in load at an existing Louisiana facility through the transfer, replacement, or consolidation of production or services.
- There is a reasonable basis to expect the existing operations' electrical demand to continue without a material decline attributable to the proposed project.

That showing must explain what the new activity will produce or provide, how it relates to existing Louisiana operations, and what supports the forecast of additional demand. It must identify relevant planned transfers, closures, retirements, or reductions in production and explain why the new activity is independent, new and incremental to existing economic activity, and is not dependent on shifting work from an existing operation.

The applicant should also be required to demonstrate that the existing electrical load will remain. Relevant support could include production plans, demand forecasts, customer commitments, or other business information appropriate to the project, with commercially sensitive information protected. A separate product or service could help establish that distinction, but should not be mandatory. An expansion that produces more of the same product could still create genuinely additional demand. The applicant must demonstrate that the output is additional and that it is not expected to displace production at its related existing Louisiana operations.

This demonstration should be based on the information reasonably available when the Commission considers the application; it should not require a guarantee that existing operations will maintain their demand throughout a long-term PPA. Market conditions, technology, and business circumstances can change independently of the PEN. However, the applicant should be required to verify the accuracy of its demonstration that the PEN is serving load that is incremental to existing load in a filing made within one (1) year of the PEN load entering full commercial operation.

ALEC requests that the definition of "new load" exclude load that has received service from a jurisdictional public utility within five (5) years prior to its application. The Staff supports this concept as an additional eligibility protection but recommends that the lookback period be two (2) years instead of five (5). The purpose of this exclusion is to prevent existing load from being characterized as new simply because utility service was discontinued before the PEN application. This two-year lookback requirement would

supplement the incremental-load showing. Expiration of two years since taking utility service should not by itself convert a relocation or transfer of existing operations into genuinely new load.

ALEC also proposes to incorporate into the rule protection for utilities and their customers from absorbing costs incurred or committed in reasonable reliance on a prospective customer's request for service before that customer elects to pursue instead PEN. The Staff agrees and recommends that this protection apply to prior requests for service, including requests that have not yet resulted in electricity being delivered. A prospective customer could have caused a utility to perform studies, engineering, facility development, or other service preparations and subsequently chosen PEN service. For load included in a PEN application that has previously requested utility service, the application should identify the prior service request, describe the resulting utility commitments, identify the utility costs attributable to the service request, and how the applicant will reimburse the utility for those costs. Mere discussions with a utility would not establish a recoverable cost, and the utility's lost opportunity to make future sales would not itself constitute a cost recoverable from the PEN applicant.

2. New Load Must be Served by New Generation.

The Staff's Initial Report did not expressly address whether the generation to supply new load also has to be new in order to qualify as a PEN. In response to ELL's comment suggesting that requirement be made explicit, the Staff clarifies that a PEN must rely on additional generation investment to serve new load to qualify as a PEN. Without an express

supply-side requirement, an applicant might propose assigning existing generation to a new customer arrangement without constructing additional generating capability. An existing wholesale generator should not be able to obtain PEN status merely by entering a supply agreement with a qualifying customer. To support reliability at a reasonable cost for all customers, otherwise qualifying PENs must develop new sources of generation and cannot rely on existing generation.

A PEN applicant should identify the generation that will serve it, its development status, its proposed commercial-operation date, and its relationship to the participating load. That new generation can be under development when the PEN application is filed, but it cannot yet be in commercial operation as of the date of the application. Relocated generating equipment and conversion of an existing resource do not qualify as new generation. A repowering of a retired or mothballed unit can qualify as new generation, if it is shown that it is incremental to existing generation that would not have been developed but for the PEN load.

The Staff recommends that the rule allow an approved PEN to renew or replace expiring or retiring generation while demonstrating continued compliance. A PPA renewal with the same qualifying generation should not require construction of another generator merely because the contract term changes.

Staff Conclusion. **Both load and generation must be new to qualify as a PEN. Load must demonstrate that it is new load incremental to existing load, whether it comes from a new customer building a new facility, a new facility constructed by an existing Louisiana company, or an expansion of an existing project, and must verify the accuracy of that demonstration within one year of the PEN load entering commercial service. To qualify as "new load," it must not have received utility service**

for two (2) years prior to its application. If PEN load has previously requested utility service and caused the utility to incur costs related to that service request, it must fully reimburse the utility for that cost, but PEN load is not responsible for the utility's lost opportunity cost. PEN load must be supplied by new generation. Repowering a retired or mothballed unit can qualify as new, as can renewal or replacement of approved PEN power supply that is expiring or retiring.

B. Physical PEN Site Requirements.

In its Initial Report, Staff noted that most parties agreed a PEN should be located on property contiguous or adjacent to the customer.[55] A few commenters supported broader "industrial hub" arrangements.[56] Staff recommended requiring PENs to be located on contiguous property and to deliver electricity through private facilities, without using the public transmission or distribution system.[57] Consistent with that recommendation, Section 202 of Staff's proposed rules required all PEN facilities to be located on contiguous property owned, leased, or otherwise lawfully controlled by a single entity.[58]

The parties disagreed over whether to retain this requirement. Industrial customers, developers, policy groups, and environmental organizations generally supported a more flexible approach, while utilities and cooperatives favored keeping the restriction. LEUG, Powering Prosperity, and the Pelican Institute proposed allowing adjacent or commonly controlled parcels connected by private lines.[59] OCC and ADC noted that many existing

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55 LPSC Staff Initial Report and Recommendation at 73, *In re Notice of proceeding regarding determination and evaluation of private use electrical networks in order to enable generation to serve new large loads looking to locate in Louisiana*, Docket No. R-37905 (La. Pub. Serv. Comm'n Aug. 14, 2026) ("Initial Report").

56 *Id.*

57 *Id.*

58 *Id.*, Attach. A, Rules Governing the Authorization and Operation of Private Use Electrical Networks § 202(1)-(2) ("Proposed Rule").

59 LEUG Comments on LPSC Staff Initial Report at 6-7; Powering Prosperity Comments on LPSC Staff Initial Report at 10-11; Pelican Institute Comments on LPSC Staff Initial Report, Appendix, at 6.

industrial sites in Louisiana are not contiguous.[60] EDF, AAE, and SREA expressed concern that a strict contiguity requirement could exclude renewable generation and storage projects that require larger areas of land.[61] NWF supported greater flexibility if accompanied by wildlife siting protections.[62] On the other hand, Cleco, ALEC, SWEPCO, and ELL supported retaining the requirement and clarifying that public roads, servitudes, rights-of-way, and other intervening property break contiguity.[63] 1803 argued that contiguity is necessary to enforcing the new load requirement.[64]

After reviewing the parties' comments, Staff recommends retaining a geographic limit on PEN facilities while allowing some flexibility. Specifically, a project should not be disqualified simply because its parcels are separated by a road, railroad, waterway, right-of-way, or other intervening property, provided the parcels are connected by an Approved Crossing of limited length, as described below. Staff also recommends a maximum enclosing area for the network as a whole, subject to a supported request for an exception. Each aspect of the physical PEN site requirements is discussed below.

Contiguity or Approved Crossing. Staff recommends requiring all PEN generation, storage, delivery facilities and participating loads to be located on parcels that are either

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60 OCC Comments on LPSC Staff Initial Report at 15-16; ADC Comments and Responses to LPSC Staff's First Requests for Information at 4.

61 EDF Comments on LPSC Staff Initial Report at 3-4; AAE Comments on LPSC Staff Initial Report at 3; SREA Comments on LPSC Staff Initial Report at 4-5.

62 NWF Comments on LPSC Staff Initial Report at 4-5.

63 Cleco Comments on LPSC Staff Initial Report at 7-9; ALEC Comments on LPSC Staff Initial Report at 9-10; SWEPCO Comments on LPSC Staff Initial Report at 3; ELL Comments on LPSC Staff Initial Report at 4-6.

64 1803 Comments on LPSC Staff Initial Report at 9-10.

(1) contiguous or (2) connected to one another by an Approved Crossing. An Approved Crossing would include a servitude, right-of-way or other lawfully obtained property right that allows private electrical facilities to cross over or under a public road, highway, railroad, waterway, utility right-of-way or third-party tract. Applicants must obtain all necessary property rights, permits, agreements, and governmental approvals. Approval as a PEN would not eliminate these requirements or independently authorize a crossing.

Distance Limit. Staff recommends limiting each Approved Crossing to five (5) miles, measured along the route of the privately owned connecting facilities from the boundary of one otherwise contiguous block of participating property to the boundary of the next. This limit would help ensure that a PEN remains a geographically confined, independent network rather than a collection of distant facilities connected by private lines within a regulated utility's service area. Staff believes a five-mile limit would accommodate nearby facilities in industrial corridors while keeping the network compact. Applicants could request an exception to the five-mile rule by showing that the proposed arrangement remains a reasonably confined development. In evaluating an exception, Staff recommends considering the entire project, including the location of participating facilities, connecting routes, and overall geographic footprint.

Overall Enclosing Area. Staff recommends limiting the entire enclosing area of a PEN to fifteen (15) square miles, or 9,600 acres, subject to an exception process. This limit would apply to the geographic footprint enclosing the network, rather than merely the sum of the acreage occupied by participating parcels and connecting rights-of-way.

The measurement would use the smallest convex boundary enclosing all participating sites and connecting infrastructure, *i.e.* essentially the boundary that would be formed by stretching a metaphorical rubber band around the network's outermost points. It would include intervening land, and applicants could not exclude that land by drawing narrow boundaries along connecting wires. Counting intervening land for this measurement would confer no ownership, service, crossing, or expropriation rights over it.

The enclosing-area limit would operate independently of the five-mile limit on Approved Crossings. Compliance with each individual crossing limit would not establish compliance with the overall area limit. The Commission would evaluate the network as a whole, including any proposed expansion.

Support for the Area Limit. To assess a reasonable geographic allowance, Staff considered hypothetical layouts using the reported acreages of substantial Louisiana industrial facilities. Phillips 66 reports that its Lake Charles Manufacturing Complex in Westlake occupies approximately 690 acres, or 1.08 square miles.[65] Louisiana Economic Development identifies 1,700 acres, or approximately 2.66 square miles, for Hyundai Steel's announced Louisiana facility.[66] CITGO reports a geographic size of 2,000 acres, or 3.13 square miles, for its Lake Charles refinery.[67] These facilities provide references

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65 *Lake Charles Manufacturing Complex*, Phillips 66, https://www.phillips66.com/refining/lake-charles-refinery/ (last visited Nov. 4, 2026).

66 La. Econ. Dev., *Hyundai Steel in Louisiana*, https://www.opportunitylouisiana.gov/hyundai-steel (last visited Nov. 4, 2026).

67 CITGO Lubricants, *Lake Charles Refinery Saves Hundreds of Thousands of Dollars Per Day in Compressor Costs & Downtime with CITGO CompressorGard XA 200*, at 2, https://www.citgolubes.com/documents/Case-Study-CITGOLakeCharlesRefinery.pdf (last visited Nov. 4, 2026).

for physical scale; the examples do not suggest that the existing facilities would qualify for a PEN.

For these illustrative calculations, each industrial block is assumed to be square. Two equal-sized blocks are placed in a straight line, with their facing boundaries five miles apart and a direct connection between them. The enclosing area includes both blocks and the full intervening gap. These assumptions do not reproduce the facilities' actual shapes or locations.

Hypothetical layout	**Approximate dimensions of each block**	**Combined area of participating blocks**	**Total enclosing area**
Two 690-acre blocks	1.04 miles × 1.04 miles	2.16 square miles	7.35 square miles
Two 1,700-acre blocks	1.63 miles × 1.63 miles	5.31 square miles	13.46 square miles
Two 2,000-acre blocks	1.77 miles × 1.77 miles	6.25 square miles	15.09 square miles

For example, each hypothetical 2,000-acre block would be approximately 1.77 miles wide. With a five-mile gap between the blocks, the enclosing rectangle would be approximately 8.54 miles long and 1.77 miles wide, producing an enclosing area of 15.09 square miles. Only 6.25 square miles would consist of participating blocks; the remaining approximately 8.84 square miles would be intervening land counted solely for measuring the network's geographic extent. Calculations use unrounded dimensions, with rounding applied for presentation.

These examples indicate that a ten-square-mile enclosing-area limit could exclude a development consisting of only two substantial industrial blocks that otherwise satisfies the five-mile separation limit. A fifteen-square-mile limit would accommodate the illustrated 690-acre and 1,700-acre two-block configurations. The 2,000-acre two-block configuration would slightly exceed the ordinary allowance and require an exception or a more compact layout.

The proposed allowance would leave additional room within some configurations for generation, storage, and associated facilities, but would not guarantee that every such addition fits. Compliance would depend on the location and shape of the complete development, not simply its participating acreage. The purpose of these examples is not to prescribe a permissible number of participants. They demonstrate how the enclosing-area limit would operate alongside the five-mile crossing limit: substantial sites could qualify when sufficiently clustered, while more extensive configurations would require additional Commission review.

As a broader scale reference, RiverPlex MegaPark is reported to contain approximately 17,000 acres, or 26.56 square miles.[68] The proposed fifteen-square-mile enclosing-area allowance would be smaller than RiverPlex's reported land area. This comparison is approximate because RiverPlex's reported acreage is not necessarily the area of its smallest enclosing convex boundary.

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[68] Ascension Econ. Dev. Corp., *RiverPlex MegaPark of Louisiana*, https://ascensionedc.com/site-selection/megasite/riverplex-megapark-of-louisiana/?print=print (last visited Nov. 4, 2026).

Multiple Owners. Cleco and ALEC asked the Commission to retain and clarify the single-entity ownership requirement.[69] Staff, however, does not believe common ownership is necessary to achieve the purpose of the rule. Requiring a single owner could exclude otherwise qualifying projects based solely on how the participants structure their businesses or property ownership, rather than their electrical arrangement. Staff therefore recommends allowing PEN parcels to be owned, leased, or otherwise lawfully controlled by "PEN Participants," provided such participants are either a "PEN Generator," a "PEN Load," or a "PEN Operator," as defined in Section 101 of the attached rule, or a party under the common control of a PEN Generator or PEN Load. The application must clearly identify the parties responsible for the generation facilities, delivery infrastructure, operation, maintenance, and compliance.

Private Infrastructure; No Expropriation. All facilities used to deliver electricity within the PEN, including those within an Approved Crossing, must be privately owned and paid for by the participating generators or loads. PENs may not use utility-owned facilities to deliver electricity. Further, PEN status would not grant participants the right to expropriate property or to occupy, cross, or attach to utility facilities or rights-of-way without the utility's consent.[70] Participants must obtain all necessary property rights and approvals through the ordinary processes.

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[69] Cleco Comments on LPSC Staff Initial Report at 8; ALEC Comments on LPSC Staff Initial Report at 9-10.

[70] *See* 1803 Comments on LPSC Staff Initial Report at 10 (requesting evidence of utility consent for crossings and a statement that confirmation confers no right of expropriation); ELL Comments on LPSC Staff Initial Report at 3.

Application Requirements. To demonstrate compliance, Staff recommends requiring applicants to provide: (1) a survey plat drawn to scale with a metes-and-bounds description or recorded plat of each parcel; (2) each parcel's acreage and dimensions, and the location of all participating facilities; (3) the route and length of each Approved Crossing, and the network's overall extent; (4) evidence of the servitudes, approvals, and consents supporting each Approved Crossing; and (5) a map identifying each otherwise contiguous block of participating property, all connecting infrastructure, and the smallest convex boundary enclosing the complete network, together with the calculation of its enclosing area. Any request for an exception to the crossing-distance or enclosing-area limit should identify the limit exceeded and substantiate why the proposed arrangement remains a reasonably confined development.

Staff Conclusion. **After considering the parties' comments, Staff recommends three changes to its initial proposal. First, PEN facilities may be located on contiguous parcels or parcels connected by an Approved Crossing, subject to a five-mile limit and an exception process. Second, PEN parcels may be owned or controlled by multiple PEN participants rather than a single entity. Third, the complete network would be subject to a fifteen-square-mile enclosing areal limit. Staff continues to recommend that all delivery infrastructure be privately owned and funded by PEN participants, without relying on utility-owned infrastructure. Staff also clarifies that PEN status does not grant expropriation rights or authorize the use or crossing of utility facilities or rights-of-way without consent. These changes provide greater flexibility for qualifying projects while preserving the requirement that PENs remain geographically confined privately funded networks distinct from the regulated utility system.**

C. Allowance of Third-Party Contracts.

As Staff explained in its Initial Report, Commission practice already allows customers to obtain electricity without taking service from a regulated utility.[71] An industrial customer may procure its own electricity without becoming a public utility subject to Commission jurisdiction if it (1) owns or leases an interest in the generating facility; and (2) uses the electricity through its own facilities, rather than primarily engaged in the generation, transmission, distribution, or sale of electricity.[72] The Commission has also found that industrial customers may share cogeneration output through joint ownership or lease arrangements, typically after obtaining a statement of non-jurisdiction from the Commission.[73] Additionally, the Commission's August 1, 2024 General Order allows industrial customers to enter into Wholesale Pass-Through Sleeved Purchase Power Agreements ("PPAs")s.[74]

The PEN rules add an additional avenue in the transactional structure of power supply for industrial customers within a PEN, but the rules do not impose additional requirements on the arrangements previously permitted by the Commission. The PEN rules provide what the Commission has not previously allowed – a non-utility sale of electricity to an industrial customer through a PPA – because a third-party sale of electricity

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71 Initial Report at 60.

72 *Id.* at 60-61; *see* La. R.S. 45:121.

73 Initial Report at 61.

74 *Id.* at 62.

to an industrial end-use customer through a PPA is a retail transaction subject to Commission jurisdiction, rather than a non-jurisdictional self-supply arrangement.

In its Initial Report, Staff recommended allowing a PEN Generator or Operator to sell electricity to a customer through a PPA if (1) the PEN Generator/Operator and PEN Load satisfy all PEN requirements under the Commission's PEN rules; and (2) the parties obtain Commission confirmation that the arrangement qualifies as a compliant PEN.[75] In this final recommendation, Staff continues to recommend allowing negotiated PPAs as a means of determining rates and service obligations for qualifying arrangements while retaining Commission jurisdiction over PENs. Staff's recommendation additionally requires studies and protections to ensure that there is no degradation to the service quality for Louisiana customers served by regulated utilities. The PPA and proposed arrangement would be subject to Commission review for compliance with the PEN requirements and applicable law, with the Commission retaining its enforcement authority and any continuing jurisdiction required by law.

Parties remain divided on the PPA proposal. Cleco, SWEPCO, ELL, and 1803 argue that selling electricity to an end-use customer is a defining characteristic of a public utility under La. R.S. 45:121,[76] while the Pelican Institute, LEUG, OCC, and SREA viewed PPAs as an expansion of existing self-supply options rather than deregulation.[77]

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75 *Id.* at 75.

76 Cleco Comments on LPSC Staff Initial Report at 2-3; SWEPCO Comments on LPSC Staff Initial Report at 3; ELL Comments on LPSC Staff Initial Report at 3-4; 1803 Comments on LPSC Staff Initial Report at 1.

77 OCC Comments on LPSC Staff Initial Report at 13; Initial Report at 39 (summarizing SREA's position), 74 (quoting LEUG); Pelican Institute Comments on LPSC Staff Initial Report, Appendix, at 1.

Several parties also question how the PEN rules would affect existing self-supply arrangements. Cleco noted that customers can already engage in every aspect of the proposed PEN structure except third-party sales through PPAs.[78] LEUG and OCC argued that customers currently using self-generation, with utility service only as backup, should be allowed to qualify as PENs when replacing or upgrading their generation facilities.[79] In contrast, 1803 argue that these customers serve existing loads and therefore should not qualify under the PEN rules.[80]

Staff clarifies that the PEN rules would not change the requirements governing existing self-supply arrangements. Instead, the rules provide an additional avenue to new load only by allowing a qualifying PEN operator to sell electricity directly to an identified industrial customer through a PPA, subject to Commission confirmation that all PEN requirements are met. Existing arrangements that are already permitted under other Commission rules or orders, or that fall outside the Commission's jurisdiction, would remain subject to their existing legal and regulatory requirements. Those arrangements would not need to qualify as PENs to continue operating lawfully.

At the same time, preservation of an existing lawful self-supply arrangement would not confer PEN status or authorize additional retail sales under the PEN rules. Self-suppliers cannot claim PEN benefits while continuing to operate under existing conditions that conflict with the PEN requirements. Generation replacing supply to existing load

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78 Cleco Comments on LPSC Staff Initial Report at 2.

79 LEUG Comments on LPSC Staff Initial Report at 4; OCC Comments on LPSC Staff Initial Report at 6-7.

80 1803 Comments on LPSC Staff Initial Report at 4.

would not qualify that load as new load. A party seeking authorization to serve qualifying new load through a PEN must demonstrate compliance with the final rule's eligibility, configuration, and service requirements. Staff also clarifies that preserving existing arrangements is not blanketed Commission approval or a sweeping determination that every existing arrangement is lawful; rather, the proposed language only preserves those rights already available under applicable law.

Staff Conclusion. **Staff recommends adding express language to the final rules clarifying that the PEN framework does not change or impose additional requirements on lawful self-supply arrangements or other rights available under existing law. Instead, the PEN rules would provide an additional, optional means of supplying electricity to qualifying new load through negotiated PPAs under Commission jurisdiction. PEN authorization would require compliance with the final rule and applicable law and would not confer a non-jurisdictional determination. Nothing the recommended rule would authorize or validate an existing arrangement that has not otherwise been established as lawful.**

D. Load Size and Load Factor Requirements.

In its Initial Report, Staff explained that PENs are intended to serve new large industrial and digital loads, like data centers.[81] The parties proposed minimum load sizes ranging from 5 MW to 100 MW.[82] Staff recommended a middle ground, requiring PENs to serve at least 50 MW of new industrial or digital load with a load factor of at least 80 percent.[83] Section 201(3) of Staff's proposed rules applied these requirements to the aggregate connected load of the Identified Load Customer(s).[84]

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81 Initial Report at 75-76.

82 *Id.*

83 *Id.*

84 Proposed Rule § 201(3).

The parties are divided on these requirements. Industrial customers and related trade organizations generally support a lower threshold. LEUG and Powering Prosperity propose a 5 MW minimum with no load factor requirement.[85] They note that the Commission and utility rate schedules already consider loads of that size to be large industrial customers.[86] They also argue that smaller expansions at existing facilities can contribute significantly to economic development.[87] EDF supports a lower threshold as well, arguing that cost and system-impact protections would better protect other customers than a high minimum load requirement.[88]

In contrast, SWEPCO recommends increasing the minimum to 100 MW, while NWF opposes lowering it below 50 MW.[89] 1803 and ALEC supports the proposed 50 MW minimum and 80 percent load factor, but opposes allowing unrelated customers to aggregate their loads to qualify.[90] 1803 recommends applying the threshold to each Identified Load Customer's contract demand and allowing confirmation to lapse, subject to Commission review, if the customer later fell short of either requirement for a sustained period.[91]

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85 LEUG Comments on LPSC Staff Initial Report at 6; Powering Prosperity Comments on LPSC Staff Initial Report at 4, 6.

86 Powering Prosperity Comments on LPSC Staff Initial Report at 4.

87 LEUG Comments on LPSC Staff Initial Report at 6; Powering Prosperity Comments on LPSC Staff Initial Report at 4.

88 EDF Comments on LPSC Staff Initial Report at 4-5.

89 SWEPCO Comments on LPSC Staff Initial Report at 3; NWF Comments on LPSC Staff Initial Report at 2.

90 1803 Comments on LPSC Staff Initial Report at 4-5; ALEC Comments on LPSC Staff Initial Report at 8.

91 1803 Comments on LPSC Staff Initial Report at 5.

On load factor, Powering Prosperity argues that load factor describes how a customer uses electricity, not whether a project represents legitimate economic development, while 1803 argues that load factor is what separates the continuous loads that prompted this proceeding from ordinary retail load.[92]

Minimum Size. Staff continues to recommend a 50 MW minimum. The directive initiating this proceeding asked Staff to consider PENs as a means of serving "new large load looking to locate in Louisiana."[93] Staff believes a 50 MW threshold is consistent with that purpose and would focus the initial PEN rules on substantial new developments. Regional transmission organizations have adopted or proposed similar thresholds. For example, SPP uses a 50 MW threshold for higher-voltage connections under its large-load framework, and MISO has proposed a similar threshold in its definition of large loads.[94] Although these frameworks serve different purposes and do not establish 50 MW as the only appropriate threshold, they provide useful context. Staff's recommendation is ultimately a policy judgment about the appropriate scope of the initial PEN framework. Staff recognizes that smaller projects can represent meaningful investment, but in the context of the large load issues the industry is facing, 50 MWs seems to be the most appropriate threshold and is consistent with the RTOs' definitions.

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92 Powering Prosperity Comments on LPSC Staff Initial Report at 6; 1803 Comments on LPSC Staff Initial Report at 5.

93 Transcript of Business & Executive Open Session at 11:16-12:14 (La. Pub. Serv. Comm'n Apr. 15, 2026) (directive to Staff to open a rulemaking to evaluate private use electrical networks), https://lpsc.louisiana.gov/docs/transcripts/April-15-2026-BE.pdf.

94 See Cleco Comments on LPSC Staff Initial Report at 18 (describing MISO's proposed definition of "Large Load" as 50 MW or more of demand at a single substation, filed in FERC Docket No. ER26-3650).

Aggregation. Staff recommends allowing a PEN to serve multiple Identified Load Customers, provided that each customer independently meets the 50 MW minimum. Smaller loads could not be combined to reach the threshold requirement. Staff shares the concerns raised by 1803 and ALEC that allowing smaller, unrelated customers to aggregate their loads could effectively create an unregulated retail utility.[95] It could also encourage the development of numerous private networks of relatively small users, resulting in duplicative infrastructure, unnecessary environmental impacts, and potential conflicts with utilities holding franchise rights in those areas. For example, a PEN serving twenty-five 2 MW customers would meet a combined 50 MW threshold, but would operate very differently from a PEN serving one or two large industrial facilities. Because the purpose of these rules is to provide another option for serving large loads, Staff believes the minimum should apply to each customer rather than the PEN as a whole. At the same time, allowing multiple qualifying customers to share a PEN would permit them to share generation and delivery infrastructure, consistent with the purpose of the rules.

The Commission may choose to allow an applicant to request a limited exception to the requirement that each Identified Load Customer independently meet the 50 MW minimum. The PEN would still be required to meet an aggregate minimum of 50 MW and the exception would be limited to no more than 4 Identified Customer Loads aggregated together to meet the 50 MW minimum. The applicant would bear the burden of demonstrating that the proposed aggregation is necessary for the attraction or development

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[95] ALEC Comments at 8; 1803 Comments at 5.

of new large load in Louisiana, is required in order for the new large load to operate, avoids unnecessary duplication of infrastructure, and remains a confined arrangement serving identified customers rather than a general retail supply network for smaller loads. The showing should explain the relationship among the participating loads, the benefits of sharing generation and delivery facilities, and why inclusion of the smaller load would not result in unnecessary duplication of infrastructure or establish a network functioning as a general retail supplier to smaller customers. The Commission would consider the size, number, location, and operational relationship of the participating loads, together with the extent of the proposed delivery infrastructure. Any exception would require express Commission approval and apply only to the Identified Load Customer and approved arrangement; all other PEN requirements would remain applicable.

Load Factor. Staff initially recommended an 80 percent load factor to limit PEN eligibility to industrial and digital loads with substantial, relatively consistent electricity demand. After considering the parties' comments, Staff believes this requirement is unnecessarily restrictive and would prohibit industries with varying usage patterns from participating in PENs. Industrial electricity usage can vary based on the type of industry, production schedules, maintenance, seasonal demand, and other operating conditions. These variations do not necessarily make a project unsuitable for PEN service. The Commission rules should be indifferent to the type of industry that PEN service may help to attract to Louisiana, and its rules should have a neutral impact on those potential industries.

Staff recognizes that eliminating the load factor requirement may raise some concerns. In particular, because the proposed capacity limits are based on peak demand, a customer with occasional high demand could support a large generation facility even if it uses relatively little electricity throughout the year. That facility could also make wholesale capacity sales despite serving a customer with limited annual electricity usage. However, Staff believes the proposed dedication requirements and limits on wholesale exports adequately address this concern by keeping PEN generation focused on serving its identified customers rather than participating primarily in wholesale markets. If a customer chooses to invest in generation that it uses only occasionally due to its ordinary work processes, Staff does not believe that decision alone should prevent the project from qualifying as a PEN.

Staff Conclusion. **Staff continues to recommend a 50 MW minimum load size, with the requirement applying separately to each Identified Load Customer. A PEN may serve multiple qualifying customers, but smaller loads may not be combined to meet the minimum threshold. Exceptions may be requested under specific standards. Staff also recommends eliminating the 80 percent load factor requirement. Instead, Staff relies on the dedication requirements and wholesale export limits to ensure PENs remain focused primarily on serving their identified customers.**

E. The Appropriate Dedicated Use Standard.

The PEN rule proposed by Staff in its Initial Report recommended that at least 85 percent of the nameplate capacity of PEN generating resources (in MWs) be dedicated to serving the capacity needs of identified customer load and 70 percent of the energy output of PEN generating resources (in MWhs) be dedicated to serving the energy needs of identified customer load. The industrial customer and related trade group commenters oppose this dedicated use requirement and argue there should be a lower cap on exports to

the wholesale market or even no cap on such exports. The Staff continues to support a dedicated use standard to ensure that the primary purpose of a PEN is to provide electric service to new large load. However, the Staff agrees with lowering the dedicated energy use standard from 70 percent to 51 percent, thus allowing up to 49 percent of energy to be sold in the wholesale market. This change would allow additional operating flexibility while also ensuring that the primary purpose of the PEN is to serve the new dedicated load.

1. Capacity Limits – Initial Sizing.

The Staff supports retaining an 85 percent capacity eligibility test, using the PEN's approved coincident peak demand plus a reserve allowance, but applying an approved planning accreditation methodology rather than treating all generation nameplate capacity as equivalent. The purpose of this rule is to facilitate the development of generation to support new large industrial and digital infrastructure loads locating in Louisiana. The PEN framework should therefore be narrowly tailored to accomplish that objective while preserving the Commission's existing retail regulatory framework and protecting customers who continue to receive regulated utility service.

PEN qualification should be based on identified customer load supported by credible development plans and load projections. It should not authorize generation sized to serve speculative future customers or unsubstantiated future demand. Nor should it provide a platform for developing a competing retail supply network or use a qualifying retail customer as an anchor for a predominantly wholesale generation business model. Additional customer load or expansion of the approved arrangement should be addressed

through the application and review process, rather than through an initial allowance for generation justified by unspecified future growth.

The capacity-sizing limitation gives effect to this distinction. It links the ordinary generation allowance to the approved participating load and a defined reserve allowance, while providing reasonable flexibility for generating-equipment size increments. The steam and islanded-reliability exceptions recognize that a particular installation may require additional generation to support its customers' industrial processes or maintain dependable service without utility supply. Those exceptions should be supported by demonstrated customer needs and should not create additional wholesale capacity-sales rights.

Wholesale sales would remain a permitted means of realizing value from the limited surplus associated with an approved customer-serving arrangement. They would not provide an independent justification for enlarging the generation installation. The possibility of wholesale revenue, standing alone, should therefore be insufficient to support additional generation beyond the ordinary allowance or an approved customer-serving exception.

This approach does not require Staff to determine an applicant's subjective business motives or prohibit wholesale revenues from contributing to project economics. Instead, eligibility would turn on objective requirements: identified qualifying load, supported projections, generation sizing tied to that load, substantiated exceptions, and enforceable capacity-sales and energy-export limits. Together, those requirements would preserve the

PEN as a limited vehicle for attracting new large load, rather than a broader exception to the Commission's retail regulatory structure.

Staff proposes a change to an accreditation-based methodology because a nameplate-only comparison does not recognize differences in the dependable capacity contribution of different generation technologies. Solar may require substantially more nameplate capacity than thermal generation to provide an equivalent capacity contribution. Thermal generation also may receive accreditation below its installed rating. An accreditation-based calculation would recognize those differences without granting additional wholesale capacity-sales rights merely because a technology requires a larger physical installation.

a. Approved Planning Accreditation Factor.

For initial sizing, each non-storage generation resource would receive an approved planning accreditation factor based on the applicable RTO's published class accreditation information.

The starting point would be the simple arithmetic average of the seasonal accreditation percentages for the appropriate resource class within a single, identified planning year. Each applicable season would receive equal weight. MISO and SPP would not need to have identical seasons: the calculation would use the applicable RTO's own seasonal structure and would not combine percentages from the two RTOs. For example, hypothetical seasonal class accreditation percentages of 95, 85, 75, and 85 percent would produce an approved planning factor of 85 percent. Hypothetical percentages of 40, 20, 10, and 30 percent would produce a planning factor of 25 percent.

This averaging convention would establish one factor for the initial installation calculation. It would not require the same installation to satisfy a separate sizing ceiling in every season, and it would not represent the capacity actually available for wholesale sale in each season.

The applicant would identify the appropriate technology class and any relevant subclass or tier, provide the underlying RTO publications, and explain the calculation. The reference would ordinarily be the latest complete planning-year dataset available when the application is filed. The filing would identify any proposed use of forward-looking or indicative accreditation values, including MISO DLOL values, and explain why those values are appropriate for the proposed project.

Published percentages must also be applied to the capacity rating against which they were developed. If an RTO percentage uses tested or seasonal installed capacity rather than manufacturer nameplate capacity, the applicant must show the conversion. The approval would identify both the physical nameplate installation and its contribution under the planning calculation.

If the applicable RTO does not publish a suitable class value, or its published categories do not reasonably address the proposed equipment or configuration, the applicant would propose an alternative factor for Staff review and Commission approval. The proposal should use comparable RTO information or a supported engineering analysis and explain its applicability to the proposed equipment. An applicant could not establish

its own factor simply by asserting that a published value is unsuitable. The Commission would approve the factor as part of the PEN application.

b. Demand - The Reserve Allowance.

Approved coincident peak demand would be multiplied by one plus the approved reserve allowance to establish the customer requirement. For an aggregated PEN load, coincident peak demand would combine aligned hourly projections for all participating loads during the same hour, rather than adding individual peaks occurring at different times. While this test would determine the baseline capacity amount allowed for an eligible PEN, it is not intended to and would not establish the PEN's actual RTO capacity or reserve obligation or demonstrate that its proposed equipment is sufficient to serve an islanded system.

The reserve allowance must be consistent with the accreditation basis used to measure generation. The applicant would propose a corresponding annual reserve benchmark, ordinarily calculated by averaging the applicable RTO's seasonal reserve margins on the same accredited-capacity basis and for the same reference planning year. An installed-capacity reserve margin should not be combined with discounted generation accreditation without a demonstrated reconciliation. Where a corresponding published reserve benchmark is unavailable, the applicant would propose a supported alternative for Commission approval.

This reserve allowance would serve the Commission's sizing policy. It would not establish that the PEN load has an actual RTO reserve obligation or determine which entity bears any such obligation.

c. The 85 Percent Initial Sizing Calculation.

The Baseline Allowed Size for Capacity is as follows:

Customer requirement ÷ planning-equivalent generation ≥ 85 percent.

or:

Planning-equivalent generation ≤ customer requirement ÷ 0.85.

Customer requirement = approved coincident peak demand × (1 + approved reserve allowance).

Planning-equivalent generation = the sum of each non-storage generator's capacity contribution after applying its approved planning accreditation factor.

This permits approximately 17.65 percent additional planning-equivalent generation above the approved customer requirement. Calculated as $(1 \div 0.85 - 1) \times 100 = 17.647\% \approx 17.65\%$. For example, if the customer requirement, including reserves, is 100 MW:

- Maximum planning-equivalent generation: $100 \div 0.85 = 117.647$ MW
- Additional generation: $117.647 - 100 = 17.647$ MW
- Additional generation as a percentage of customer requirement: $17.647 \div 100 \times 100 = 17.65\%$

The allowance accommodates generating-equipment size increments and permits a limited amount of surplus capacity to be monetized.

For further illustration, assume the approved customer requirement, including the appropriately matched reserve allowance, is 65 MW. The maximum ordinary allowance would be:

65 ÷ 0.85 = approximately 76.47 MW of planning-equivalent generation.

Using hypothetical approved accreditation factors:

Generation portfolio	Planning Accreditation Factor	Physical capacity corresponding to the ordinary ceiling
Entirely thermal	85 percent	Approximately 89.97 MW
Entirely solar	25 percent	Approximately 305.88 MW

These percentages are illustrative, not proposed accreditation values. A mixed portfolio would add the adjusted contributions of its individual generators. The larger physical installation would not, by itself, create greater wholesale capacity-sales rights.

d. Exceptions to Baseline Initial Capacity Sizing Limit.

Steam production and islanded reliability may necessitate more generating equipment than may be allowed under the baseline test. Additional generation should be allowed when the applicant demonstrates that an integrated arrangement serving the PEN's islanded electrical load and/or legitimate steam-process requirements needs more generating equipment than the baseline test would otherwise permit. The Commission should have the flexibility to approve additional generation on a supported demonstration of (1) steam-process requirements or (2) islanded reliability needs. The demonstrated customer-serving needs in those two exceptional circumstances should be accommodated, however, without automatically expanding the permitted wholesale capacity sales allowance.

Steam-process exception. For this exception to apply, the showing should explain the relationship between electrical and steam production, support the relevant operating requirements, and establish why additional generation is reasonably needed. The Commission would approve a specific installation based on that evidence. Using steam

would not automatically justify an exception. The applicant would need to show why the ordinary allowance does not accommodate the integrated process, without counting the same requirement twice.

Islanded reliability exception. Additional generation should also be allowed when the applicant demonstrates that its islanded reliability requirements reasonably require generating equipment beyond the ordinary allowance. RTO accreditation reflects a resource's contribution within a larger interconnected system; it does not establish that the same resource or portfolio can independently maintain service to PEN customers. The showing should explain the proposed equipment configuration, outage and maintenance assumptions, redundancy standard, seasonal resource limitations and other relevant operating contingencies, and the resulting amount of generation needed. It should identify why the ordinary reserve allowance and sizing cushion provided by the baseline test are insufficient and how the additional equipment would maintain service to PEN customers.

An applicant's desire for greater reliability may be legitimate, particularly where no utility backup is available. However, the applicant should be required to substantiate the additional installation rather than obtain an unrestricted allowance by invoking reliability. For example, a proposed installation equal to 170 percent of customer peak demand would neither automatically qualify for the exception nor require denial; the applicant would need to substantiate that amount based on its islanded reliability needs. Under these circumstances, the Commission would approve a specific generation amount and the conditions supporting the exception.

Additional generation approved through this exception could support service to PEN customers and capacity sales within the existing approved capacity sales ceiling, but would not increase that ceiling. The separate requirement that participating PEN customers receive at least 51 percent of the total electrical energy delivered to those customers or exported to the wholesale market, measured in MWh over a rolling twelve-month period, would continue to apply without a reliability exception.

2. Capacity Limits – Capacity-Sales Ceiling.

Under the Staff's proposal, the baseline 85 percent framework would establish the maximum wholesale capacity-sales allowed and that capacity sales allowance would not expand when there is an exception for steam process or islanded load requirements. Neither would these exceptions increase the separate energy requirement, discussed below, that PEN customers receive at least 51 percent of all customer deliveries plus wholesale energy exports over the applicable rolling twelve-month period.

The Commission would establish the sales ceiling using the approved portfolio's planning-equivalent generation less the approved customer requirement, with no sales allowance below zero. "Planning-equivalent generation" means the capacity of the ordinary approved non-storage generation portfolio after applying the accreditation factors approved by the Commission for the initial sizing limitation.

Those factors would ordinarily be calculated by averaging the applicable RTO's seasonal class accreditation percentages under the methodology described above. They provide a common measure for determining the permitted installation and establishing the

Commission's wholesale capacity-sales ceiling. They do not determine the resource's actual seasonal accreditation, which remains subject to the applicable RTO's rules.

For each generator:

> Planning-equivalent contribution = generator capacity × approved planning accreditation factor.

For a portfolio containing multiple generators, those contributions would be added together:

> Total planning-equivalent generation = sum of the individual generators' adjusted contributions

The capacity rating used in that calculation must be consistent with the approved factor, including any required conversion from nameplate to the capacity rating underlying the RTO data.

Example 1: A portfolio built to the ordinary maximum.

Assume the approved customer requirement, including the approved reserve allowance, is 65 MW.

The 85 percent eligibility test would permit:

> Maximum ordinary planning-equivalent generation = 65 ÷ 0.85 = approximately 76.47 MW.

If the applicant proposed thermal generation with a hypothetical approved planning accreditation factor of 85 percent, the corresponding physical installation would be:

> 76.47 ÷ 0.85 = approximately 89.97 MW.

Applying the accreditation factor to that installation:

> 89.97 MW × 85 percent = approximately 76.47 planning-equivalent MW.

The wholesale capacity-sales ceiling would therefore be:

76.47 − 65 = approximately 11.47 MW.

The ceiling would be 11.47 MW, rather than the 24.97 MW difference between physical generation capacity of 89.97 MW and the 65 MW customer requirement. The accreditation adjustment recognizes that the entire physical installation is not treated as dependable capacity for this planning calculation.

Example 2: A smaller ordinary approved portfolio.

Assume the approved customer requirement, including reserves, is 65 MW, and the applicant proposes 80 MW of thermal generating equipment with an approved planning accreditation factor of 90 percent.

First, calculate the maximum allowed under the ordinary sizing limit:

65 MW ÷ 0.85 = approximately 76.47 planning-equivalent MW.

Next, apply the accreditation factor to the proposed equipment:

80 MW × 0.90 = 72 planning-equivalent MW.

The proposed installation is within the ordinary sizing limit because 72 MW is less than the permitted maximum of 76.47 MW. No steam or islanded-reliability exception would be needed.

The wholesale capacity-sales ceiling would equal the approved portfolio's planning-equivalent generation minus the approved customer requirement:

72 MW − 65 MW = 7 MW.

The applicant would therefore receive a 7 MW wholesale capacity-sales ceiling. It would not receive the maximum possible allowance of approximately 11.47 MW because it proposes less generation than the ordinary sizing limit permits.

The 7 MW ceiling would remain subject to applicable RTO accreditation and market requirements and the ability to fulfill commitments while serving PEN customers.

Example 3: A mixed generation portfolio.

Again, assume a 65 MW customer requirement. Suppose the ordinary approved portfolio contains:

Resource	Physical capacity used in the calculation	Hypothetical approved planning factor	Planning-equivalent contribution
Thermal generation	70 MW	90 percent	63 MW
Solar generation	40 MW	25 percent	10 MW
Total	110 MW	—	73 MW

First, calculate the maximum allowed under the ordinary sizing limit:

65 MW ÷ 0.85 = approximately 76.47 planning-equivalent MW.

Next, apply the accreditation factor to each type of equipment::

Thermal: 70 × 0.90 = 63 MW.

Solar: 40 × 0.25 = 10 MW.

Total planning-equivalent generation: 63 + 10 = 73 MW.

The proposed installation is within the ordinary sizing limit because 73 MW is less than the permitted maximum of 76.47 MW. No steam or islanded-reliability exception would be needed.

> The wholesale capacity-sales ceiling would equal the approved portfolio's planning-equivalent generation minus the approved customer requirement:
> $73 - 65 = 8$ MW.

The applicant would therefore receive an 8 MW wholesale capacity-sales ceiling. Although the physical installation totals 110 MW, the sales ceiling would use its 73 MW planning-equivalent contribution, after applying the approved accreditation factors.

The 8 MW ceiling would remain subject to applicable RTO accreditation and market requirements and the ability to fulfill commitments while serving PEN customers.

Effect of exceptions and actual market accreditation. The sales ceiling would apply to the PEN as a whole, without requiring particular generating units to be assigned to each sale.

The wholesale sales ceiling would be based on the customer demand and reserve allowance established in the approval. Lower actual customer demand or a later reserve-margin change would not automatically create additional sales rights. Any increase in the ceiling would require express Commission consideration and approval under the applicable change procedures.

The sales ceiling establishes a maximum permission and does not guarantee that the entire amount can be accredited, offered, or sold under MISO or SPP rules. The approved planning factors do not establish actual seasonal RTO accreditation. Such sales would be

subject to the applicable market treatment, and ability to fulfill commitments while serving PEN customers, situations over which the Commission declines to exercise jurisdiction for qualifying PEN arrangements.

The sales ceiling would be established from the ordinary approved portfolio before adding generation approved through a steam or islanded-reliability exception. Such additional generation would not increase the ceiling. Batteries likewise would not create additional sales rights, although they could support sales within the approved ceiling.

3. Capacity Limits – Battery Capacity Treatment.

Battery capacity should be excluded from planning-equivalent generation capacity when applying the 85 percent eligibility test. Adding a battery also should not increase the approved wholesale capacity-sales ceiling. However, a battery could support wholesale capacity sales within that ceiling, subject to applicable accreditation, operating, and market requirements. This treatment would recognize battery storage's usefulness without allowing the addition of storage to enlarge the PEN's wholesale capacity sales permissions.

A battery provides distinct attributes from generation. It stores electricity produced by other equipment and delivers it later. It can charge when electricity is available, provide operating flexibility, and support reliable service. It does not independently produce the electricity used to charge it. Counting both the generating equipment and the battery's discharge capability in planning equivalent generation could therefore distort the relationship the 85 percent test is intended to measure. For example, adding a battery to an otherwise unchanged generation installation could make the PEN appear to have

increased its generation for eligibility purposes, even though its underlying electricity-producing equipment has not changed. Excluding storage from that calculation would allow participants to add useful storage without treating it as additional generation subject to the sizing limit.

Exclusion from the baseline capacity limit test would not mean batteries lack capacity value. A battery can make electricity available during hours when it is needed, and market accreditation can recognize that capability subject to the relevant requirements. Its contribution depends on matters such as discharge capability, stored energy, duration, and the ability to recharge. The eligibility calculation serves a different purpose. It establishes the permissible scale of generation relative to customer demand and reserves. The wholesale capacity-sales ceiling establishes the scope of the PEN's permission to make capacity commitments. Battery storage provides operational and market contributions but its accredited capacity should not be an automatic addition to either the eligibility or market contribution calculation.

Thus, the approved sales ceiling would remain based on the planning-equivalent contribution of approved non-storage generation, approved coincident peak demand, and the reserve allowance, subject to the separate limitation for generation approved through the steam or islanded reliability exception. Installing a battery would not increase that ceiling, even if the battery receives separate capacity accreditation.

Assume the approved coincident peak demand is 50 MW, with an illustrative approved reserve allowance of 30 percent, stated on the matching accredited-capacity basis. First, calculate the customer requirement, including reserves:

50 MW × 1.30 = 65 MW.

The maximum allowed under the ordinary sizing limit would be:

65 MW ÷ 0.85 = approximately 76.47 planning-equivalent MW.

The applicant proposes 80 MW of thermal generating equipment with an approved planning accreditation factor of 90 percent. Its contribution to the sizing calculation would be:

80 MW × 0.90 = 72 planning-equivalent MW.

The proposed generation is within the ordinary sizing limit because 72 MW is less than the permitted maximum of 76.47 MW. The wholesale capacity-sales ceiling would equal the approved portfolio's planning-equivalent generation minus the customer requirement:

72 MW − 65 MW = 7 MW.

Now assume the applicant adds a 20 MW battery. Because batteries are excluded from the initial sizing calculation and do not create additional capacity-sales rights, the generation contribution used in that calculation would remain 72 planning-equivalent MW, and the sales ceiling would remain 7 MW. Adding the battery would not increase the ceiling to 27 MW. Even if the battery received 20 MW of separate RTO capacity accreditation, that accreditation would not add 20 MW to the Commission's approved sales

allowance. The battery could nevertheless help support capacity sales within the existing 7 MW ceiling, subject to applicable RTO requirements and the ability to serve PEN customers. Total capacity commitments supported by generation, storage, or a combination would remain subject to that aggregate ceiling.

The rule should not require every permitted capacity commitment to be supplied exclusively by the generating units used to calculate the ceiling. The total commitments supported by the PEN's resources would remain within the approved cap. Separate accreditation or separate resource registration should not allow the participants to exceed that aggregate limitation.

The battery would also remain part of the applicant's demonstration that wholesale commitments are consistent with serving the islanded customers. Exclusion from the sizing calculation would not establish that stored electricity is available simultaneously for every proposed use.

Batteries would charge only from PEN generation. Allowing storage to support a capacity commitment would not authorize imports through the export connection. The separate energy-use requirement would continue to apply. Electricity discharged to participating customers would count as customer use, and electricity exported would count as exports. Charging would not count as customer use, and stored electricity would be counted when ultimately delivered. Capacity accreditation would not create an exception to those operating boundaries.

4. Capacity Limits – Continuing Effect of the Approval.

Under the Staff's proposal the Commission would approve the physical installation, planning factors, reserve benchmark, and sales ceiling together. Later changes in published RTO factors would not make that installation ineligible, authorize additional construction, or enlarge its approved sales ceiling. Actual wholesale market qualification would remain subject to applicable market requirements.

A proposed expansion or material supply change would require the applicable Commission review.

Finally, satisfying this sizing test would not demonstrate that a portfolio can reliably serve an islanded system. The applicant would separately substantiate its ability to serve the PEN's electrical requirements, including relevant outages, maintenance, and resource limitations. The 51 percent customer-energy-use requirement would also remain independently applicable, including to generation approved through a steam or reliability exception.

5. Customer Energy Use and Energy Export Limits.

The Staff recommends replacing its original proposal that 70 percent of energy output be dedicated to PEN customer use with a requirement that at least 51 percent of the combined electrical energy metered to participating customer load and metered for wholesale sales be metered to participating customer load, measured in MWh over a rolling twelve-month period. Energy metered for wholesale sales could therefore account for no more than 49 percent of that combined amount.

The calculation would exclude energy consumed in providing generation auxiliary services and energy losses within the PEN, including verified storage losses. Those quantities would count as neither participating customer load nor wholesale sales.

The calculation would be:

> Energy metered to participating customer load ÷ (energy metered to participating customer load + energy metered for wholesale sales) ≥ 51 percent.

This requirement would apply to the PEN as a whole. It would not require each participating customer to consume a particular share or require customers to receive a majority of generation during every hour.

Staff's initial proposal combined an 85 percent capacity-dedication requirement, a 70 percent customer-energy dedication requirement, and a 30 percent energy-export cap. The Staff's revised recommendation would provide greater operating flexibility while retaining an express majority-customer-use requirement. The industrial concerns about integrated processes and steam production are relevant. Generation may produce electricity beyond the customers' immediate needs as part of operating an industrial process. Allowing more of that electricity to reach the wholesale market could improve project economics and make useful supply available to other market participants. LEUG's proposed 51 percent customer-use compromise provides a way to accommodate those circumstances without eliminating the energy boundary entirely.

A 51 percent requirement would ensure that the participating PEN customers remain the majority destination for delivered electricity consistent with the purpose of the PEN offering to enable generation supporting qualifying industrial and digital infrastructure

development. Wholesale opportunities would help accommodate surplus output and support project economics, but the arrangement should continue to serve primarily its participating customers, not a wholesale sales business model. A 51 percent threshold would preserve the intended relationship between customer supply and wholesale activity while providing substantially more flexibility than the original 70 percent customer-use requirement.

The demonstrated steam-process and islanded reliability exceptions to the capacity-sizing limit that the Staff recommends should not apply to the majority-customer-energy-use requirement. Additional generation justified by steam or islanded reliability needs could produce electricity for wholesale sale within the 49 percent export allowance. The exceptions would permit the installation; they would not remove the operating boundary on energy exports.

The 51 percent requirement should measure electricity supplied to PEN customers compared with electricity exported to the wholesale grid. This directly answers the policy question: Did participating customers receive the majority of the electricity supplied to those two destinations? Electricity should be counted when it reaches customers or is exported, rather than when it first leaves the generator. Electricity placed in a battery has not yet reached either destination.

For example, assume the PEN generators produce 100 MWh:

- 50 MWh go directly to PEN customers.
- 30 MWh is exported to the wholesale grid.
- 20 MWh goes into a battery.

Assume the battery subsequently supplies 15 MWh to customers, loses 2 MWh through charging, storage, and discharging, and still holds 3 MWh at the end of the measurement period. The calculation would be:

Amount counted	MWh
Customer use: 50 directly supplied + 15 from the battery	**65**
Wholesale exports	**30**
Total customer use plus exports	**95**

In this example, the customer share would be 65 ÷ 95 = approximately 68.4 percent, satisfying the 51 percent requirement. The 2 MWh lost in the battery would count as neither customer use nor exports because neither destination received it. The applicant would have to support those losses with metering and a reconciliation of electricity entering the battery, electricity leaving it, and changes in the amount stored. The 3 MWh remaining in the battery would not count yet. It would count when subsequently supplied to customers or exported, in the measurement period when that delivery occurs. This defers counting stored electricity until its destination is known; it does not permanently exclude it.

Charging a battery would therefore not count as customer use, and discharging it would not be counted as additional generation. Electricity would be counted once, at its ultimate destination. Batteries would charge only from PEN generation, consistent with the islanded approach.

Staff Conclusion. **Staff recommends retaining the 85 percent initial capacity-sizing standard while applying approved planning accreditation factors to recognize differences among generation technologies. The baseline allowance would be tied to approved coincident peak demand plus a consistent reserve allowance, permitting approximately 17.65 percent additional planning-equivalent generation. The Commission could approve additional generation for demonstrated steam-process or islanded-reliability needs, without increasing the wholesale capacity-sales ceiling**

established from the ordinary approved portfolio. Batteries would be excluded from the sizing calculation and would not enlarge that ceiling, but could support capacity sales within it, subject to applicable requirements.

Staff also recommends reducing the customer-energy-use requirement from 70 percent to 51 percent of the combined energy metered to participating customer load and metered for wholesale sales, measured over a rolling twelve-month period. Generation auxiliary consumption and losses would be excluded, and stored energy would be counted when ultimately supplied to customers or exported. The steam and reliability exceptions would not relax this energy requirement. Together, these provisions would accommodate customer needs and reasonable operating flexibility while keeping PEN development tied to identified qualifying load, preserving the Commission's regulated retail framework, and limiting the use of PEN status to support speculative expansion or predominantly wholesale generation business models.

F. Export Connection Engineering Requirements.

The Staff's original proposed rule would prohibit imports to serve PEN customers and allow utility interconnection only for export of surplus electricity to the wholesale market.[96] It would require the PEN to bear all the costs of the interconnection and to comply with RTO wholesale market and transmission requirements.[97] It further would require the PEN applicant to provide "a single-line electrical diagram showing all generation resources, distribution/transmission infrastructure, switching equipment, protective relays, customer delivery points, and Points of Common Coupling . . ."[98] Several of the commenters, including ALEC, 1803, and Cleco, urge the Staff to incorporate more explicit and specific export interconnection engineering requirements on PEN applicants so that the electrical design and operating arrangements enforce the export-only limitation.

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96 *See* Proposed Rule § 203.

97 *Id.*

98 *Id.*, § 202(3)(B).

Staff recommends revising its proposed rule to distinguish between requirements applicable to an islanded-load PEN with an export-only interconnection and additional requirements applicable if the Commission subsequently authorizes backup or other utility supply service. Both configurations require appropriate engineering studies, protection, monitoring, and operating procedures. Their effects on the public system differ, however. In an export-only arrangement, the utility does not supply participating customer load, but changes in that load or the PEN's generation can affect exports and conditions at the interconnection. If utility supply is authorized, the public system may also experience the sudden addition, loss, or restoration of PEN customer load.

Cleco's proposed language provides a useful basis for these requirements, but portions addressing utility control of customer load, load transfers, and reconnection should be distinguished from requirements applicable to export-only operation. Establishing that distinction would establish necessary protections without implying that backup service is authorized by this rule.

1. Requirements where utility supply is not authorized.

The Staff agrees that the rules should allow an export connection only when the applicant demonstrates that it can operate safely and reliably without supplying PEN customers through that connection. The applicant should provide the necessary engineering studies, protection arrangements, models, monitoring, and operating procedures before the export-connected network is energized. The requirements should reflect the technology, connection voltage, and characteristics of the proposed installation.

This would implement the islanded-load requirement while allowing the permitted wholesale exports.

An electrical connection used for exports can also provide a path for electricity to flow in the opposite direction unless the design prevents it. If PEN generation trips or becomes insufficient, the export connection could otherwise allow the utility grid to supply participating customers. That could occur through the physical operation of the system even though the commercial arrangement describes the connection as export-only. The connection must prevent the utility system from becoming an unintended source of customer supply.

The Staff thus supports ALEC's and 1803's request for express protective-relaying and switching requirements that prevent the export connection from supplying PEN customers. The applicant should demonstrate how the arrangement responds to loss of generation, electrical faults, and other relevant operating conditions. The design should isolate or disconnect the appropriate facilities when necessary to prevent prohibited imports, with settings and operating procedures supported by the engineering studies. The Interconnected Utility should review and approve the protection and switching arrangements applicable to the interconnection. That technical approval should address compliance and protection of the interconnected system; it should not be a general utility right to veto an otherwise qualifying PEN.

The Staff recommends including a checklist in the final rule similar to that proposed by Cleco and NWF, with requirements applied as appropriate to the installation:

- Steady-state power-flow, short-circuit, and dynamic-stability studies, with electromagnetic-transient analysis or other additional modeling where warranted by the equipment, controls, or system conditions. Studies should evaluate relevant summer peak, winter peak, and light-load conditions.

- Relevant contingencies. Studies should address the loss of PEN generation, sudden reductions or loss of participating customer load, and changes in storage operation where relevant. In an export-only configuration, the analysis should evaluate the resulting changes in exports, voltage, frequency, and protection performance, including the possibility that a sudden reduction in customer demand increases export.

- Protective-relaying and switching studies, including the arrangements and controls preventing imports to participating customers. The arrangements should be studied and accepted by the Interconnected Utility under applicable interconnection requirements.

- Applicable ride-through requirements for generation and other applicable equipment, coordinated with the protection necessary to maintain the islanded-load arrangement and the export connection's response to disturbances.

- Telemetry, communications, and metering sufficient for required monitoring, coordination, and verification of the export-only arrangement and the PEN's effects on the public system. Relevant internal load, generation, and storage information should be provided where necessary for those purposes.

- Validated equipment and system models, together with relevant protection and control settings, appropriate to the studies and applicable interconnection requirements. Models, studies, and settings should be updated when material changes affect their validity.

- Disturbance monitoring appropriate to the installation.

- Operating procedures addressing normal operation, disturbances, loss of generation or customer load, export limitation or cessation, disconnection, and restoration of the export interconnection. The procedures should identify the circumstances and means by which exports or the interconnection may be curtailed or disconnected under applicable requirements.

As noted by NWF, the studies and standards should be appropriate to the technology and connection voltage. The checklist should establish the subjects that must be addressed without assuming that every project requires identical equipment or study methods. The

applicant should identify which requirements apply and support any conclusion that a listed item is unnecessary. Applicable utility and RTO interconnection requirements would apply.

Before the export-connected network is energized, the applicant should establish that the required studies are complete, necessary interconnection approvals have been obtained, and the required protection, communications, monitoring, and operating arrangements are in place. The demonstration should include testing and commissioning sufficient to establish that the approved protection and switching operate as intended. A diagram showing a proposed protective device would not, by itself, demonstrate that the installed arrangement prevents imports.

The Staff's original proposed rules would require that a PEN must "solely bear the entire cost" of the export interconnection, but the rules should also make clear that PEN participants should pay the direct study, consultant, protection, communications, testing, and other costs attributable to their proposed export arrangement, with credit for work or payments already satisfying the same obligation.

The approved protection and operating arrangements should remain effective after energization and through the life of the PEN, barring an approved change. Changes affecting the export interconnection, import prevention, or the assumptions underlying the studies, including material changes to generation, load, storage, or controls, should be identified and reviewed through the applicable compliance and change procedures and receive additional study where appropriate.

These provisions would not create a right to import electricity or receive backup service. Utility authority over the export interconnection should not, by itself, be treated as authority to direct curtailment of electrically islanded customer load. Any internal controls necessary to protect the public system should be identified and supported through the interconnection studies.

2. Additional requirements if backup or other utility supply is subsequently authorized.

If the Commission subsequently authorizes backup, standby, maintenance, supplemental, or other utility supply service, the PEN should satisfy additional requirements before receiving that service. The requirements should reflect the particular service authorized, the amount of load that may be supplied, and the applicable utility and RTO arrangements.

Cleco's proposed provisions concerning customer-load transfers, ride-through, curtailment, and reconnection would provide a basis for these additional requirements, including:

- Studies of utility-supplied load. Analysis of the sudden transfer of PEN load to the public system, loss or reduction of that load, and its subsequent restoration. Studies should evaluate the loss of PEN generation while utility supply is available, credible combinations of events, and the cumulative effects of other relevant large loads.

- Transfer and restoration controls. Approved procedures and controls governing transfers between PEN generation and utility supply, including permissible transfer quantities, staged restoration, ramp rates, and coordination with utility protection and automatic reclosing practices.

- Load ride-through requirements. Applicable voltage and frequency ride-through requirements for customer load while supplied by or electrically

connected to the public system, coordinated with equipment protection and applicable reliability requirements.

- Curtailment and disconnection capability. Equipment and procedures allowing utility-supplied load to be curtailed or disconnected where required by the authorized service terms, interconnection studies, or applicable reliability requirements.

- Additional monitoring and operational coordination. Real-time load and generation telemetry, communications redundancy, forecasts, generation schedules, outage notices, and disturbance reporting to the extent required for the authorized service and its effects on the public system.

- Updated agreements and demonstrations. Revised studies, protection settings, operating procedures, interconnection agreements, and any required utility or RTO approvals reflecting the change from export-only operation.

Meeting these engineering requirements would not independently establish entitlement to utility supply. Any such service would also require Commission authorization, applicable rate and contractual arrangements, and resolution of the associated cost responsibility and RTO obligations.

Staff continues to recommend proceeding initially with the islanded-load, export-only approach. The additional requirements above identify matters that would need to be addressed if utility supply is authorized later; they do not resolve the separate rate, planning, transmission-cost, or resource-adequacy issues supporting deferral of that service.

Staff Conclusion. **The PEN rule should be modified to require an engineering checklist and a demonstrated protective-relaying and switching arrangement that prevents imports to participating customers through the export interconnection. These requirements would make the islanded-load condition enforceable in the physical design and operation of the network and address the effects of changes in PEN generation, load, and storage on the interconnected public system. Staff also recommends identifying additional studies, transfer and restoration controls, load ride-through, curtailment, monitoring, and coordination requirements that would**

apply before any subsequently authorized utility supply service begins. These requirements would supplement the applicable interconnection processes and would not resolve or authorize the separate question of utility backup or station-power service, which remains subject to the Commission's consideration of applicable rates, cost responsibility, and RTO obligations.

G. Cost Protection and Financial Security.

The Staff's original proposed rule contains a "ratepayer harmlessness principle" that prohibits PENs from raising and shifting costs cannot to utility customers.[99] Commenters ALEC and Cleco support this principle, but noted a conflict with Section 301(3)(H), which requires a cost-shift analysis showing that the PEN will not "result in an unreasonable shift of costs." They ask for clarification that *no* cost shift is allowed.

The Staff agrees that clarification is necessary. The PEN applicant must demonstrate that costs caused by the PEN will be borne by its participants rather than shifted to utility customers, consistent with cost causation principles. That protection covers actual costs the utility incurs or committed to because of the PEN project, including attributable obligations that become identifiable after approval. Those costs could include (but should not be limited to) study costs, ordered equipment, entered commitments, or constructed facilities. The applicant must fully account for costs its project causes and establish how those costs will be paid.

However, the utility's lost opportunity to serve PEN load should not itself constitute a cost shift. The possibility that the utility could have earned additional revenues or spread existing fixed costs over more sales is different from an expense or commitment caused by

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[99] *See* Proposed Rule § 501.

the PEN. Foregone sales and hypothetical contributions to existing costs are not amounts that the PEN must pay and could only be considered in conjunction with increased costs associated with such revenues. Further, to impose such a requirement would undermine the decision to offer qualifying new load an alternative supply arrangement.

The applicant must identify the utility and transmission obligations associated with its proposed arrangement and support how they will be satisfied. The showing must address, as applicable:

- Studies, engineering, consultant work, and application review.
- Interconnection facilities, protection, communications, and required upgrades.
- Actual utility commitments made in reasonable reliance on a prior service request.
- Other attributable transmission or facility obligations, including identified exposure to later charges.
- Responsibility for obligations if the project changes, fails, or ceases operation.

For shared facilities or costs serving several purposes, the applicant should support the portion attributable to the PEN. The standard should neither shift that portion to other customers nor make the PEN responsible for unrelated utility expenditures. The comparison should examine the obligations and costs with and without the proposed arrangement. It should not assume that the utility would otherwise have obtained the customer's business. All costs attributable to the PEN may not be known at the time of application. They may arise as a result of a later study, planning decision, or transmission project. PEN authorization should be conditioned on the PEN assuming later costs that are

properly attributable to it. The rule should include a provision to require the identification of such costs and how payment is enforced. The provision should include a mechanism that identifies the basis for attribution to the PEN and allows the PEN to respond. The provision should also address obligations that remain after a change of ownership, closure, or loss of PEN status.

The rule should further require financial security for any identified PEN-attributable obligations that the utility is obligated to incur and that the PEN does not immediately reimburse. The security must reflect the exposure and be updated as that exposure changes. Additional commitments or newly identified obligations may justify an increase in security. Those obligations could include an unpaid facility obligation, a binding construction commitment, or another exposure arising from the PEN arrangement. Payments and the satisfaction or release of commitments could merit a reduction in the remaining exposure and permit a corresponding reduction in security. Where exposure is not yet sufficiently defined, the framework should establish continuing disclosure, payment, and security-update obligations as the amount becomes identifiable.

Security should protect against nonpayment of concrete obligations. It should not become a charge for the utility's lost sales opportunity or a substitute for identifying what the PEN actually owes.

Existing security should be credited when it already protects the same obligation for the benefit of the party exposed to the loss. For example, a participant may have provided

security through an interconnection agreement. Another instrument to protect against that same exposure should not be required.

Changes in ownership or contractual arrangements should not create a gap in protection. Responsibility and any replacement security should be established through the applicable notice and compliance process.

Staff Conclusion. **PEN participants should be required to pay costs attributable to their arrangement, including actual utility commitments and appropriately established later obligations. Lost opportunities to serve new load are not compensable cost shifts. PEN participants should provide security for identified unpaid exposure, with credit for existing protection of the same obligation, and requiring updates as exposure changes.**

H. Sunset Provision.

In its Initial Report, Staff recommended a five-year window for filing PEN applications if the Commission adopts the proposed rules.[100] Staff explained that, even with strict requirements, PENs could deprive existing customers of significant contributions toward current and future electric system costs.[101] PENs could also lead to inefficient use of limited capital and unnecessary duplication of expensive electric infrastructure.[102] Under Staff's initial proposal, the application window would automatically close after five years unless a party requested renewal and the Commission found that renewal would serve the public interest.[103] Applications submitted before the deadline would still be processed, and approved PENs could continue operating after the

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100 Initial Report at 79-80.

101 *Id.*

102 *Id.*

103 *Id.*

window closed.[104] Staff believed five years would provide enough time to accommodate new large loads while allowing the Commission to reevaluate the rules after gaining some experience with them.[105]

The parties disagreed over whether to retain the sunset provision. ALEC, SLEMCO, SREA, SWEPCO, and Cleco supported the five-year sunset or left it unchanged in their proposed revisions to the rule.[106] ELL also supported the provision, viewing it as a safeguard against rules that produce little activity or have unintended consequences.[107] ALEC recommended that Staff prepare a report before the Commission considers renewal.[108] The report would address approved PENs, their compliance history, and their effects on utilities, customers, and system reliability.[109] 1803 similarly supported an automatic sunset, but recommended shortening the window to three years and requiring a Staff report before renewal.[110] In contrast, Powering Prosperity opposed the sunset provision and proposed allowing the Commission to review the rules without automatically ending the application window.[111] It argued that five years may be insufficient given the

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104 *Id.*

105 *Id.*

106 ALEC Comments on LPSC Staff Initial Report at 13 & Exhibit A at 12; SLEMCO Responses to Staff's Second Requests for Information, Redlined Rule § 502; SREA Comments on LPSC Staff Initial Report, Appendix § 502; SWEPCO Comments on LPSC Staff Initial Report, Attach. A § 502; Cleco Comments on LPSC Staff Initial Report, Attach. A § 502.

107 ELL Comments on LPSC Staff Initial Report at 9.

108 ALEC Comments on LPSC Staff Initial Report at 14.

109 *Id.*

110 1803 Comments on LPSC Staff Initial Report at 12-13 & Exhibit A § 502.

111 Powering Prosperity Comments on LPSC Staff Initial Report at 10-11.

time needed to develop large projects and that a sunset could discourage investment.[112] LEUG also opposed automatic expiration and instead recommended biannual Staff reports and a Commission review after five years.[113] NWF expressed concern that a five-year deadline could favor fossil fuel projects that can be developed more quickly.[114] It recommended a longer window or extensions for permitting and interconnection delays outside an applicant's control.[115] The Pelican Institute generally supported sunset provisions but recognized the uncertainty that automatic expiration could create after significant investments have been made.[116]

After considering the parties' comments, Staff continues to recommend a five-year application window. However, Staff also recommends beginning a review of the PEN framework in the fourth year, giving the Commission time to decide whether to renew or modify the rules before the window closes. The PEN rules would create a limited exception to Louisiana's existing electric-service structure. Although the proposed rules include eligibility requirements and cost protections, actual applications will provide a better understanding of how the framework works in practice. Staff believes five years would give developers a reasonable opportunity to use the PEN option while allowing the Commission to reconsider whether the rules should continue. Based on that review, the

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[112] *Id.*

[113] LEUG Comments on LPSC Staff Initial Report at 8-9.

[114] NWF Comments on LPSC Staff Initial Report at 6-7.

[115] *Id.*

[116] Pelican Institute Comments on LPSC Staff Initial Report at 6.

Commission could retain the existing framework, modify it, or allow the application window to close.

Beginning the review in the fourth year would give Staff time to gather information and make a recommendation before the five-year period ends. Waiting until the window expires could create a gap in the availability of PENs and uncertainty for potential applicants. The purpose of an earlier review is to allow the Commission to make a decision before expiration. However, beginning the review would not automatically extend the application window or guarantee renewal.

Staff recommends that the review address the following:

1. The number, size, and types of PEN applications, including any proposed arrangements involving multiple customers;

2. Whether the PEN framework is attracting the new industrial and digital development contemplated by the Commission's directive;

3. The types of generation, property arrangements, contracts, and operating structures proposed by applicants;

4. Issues identified during application review, including questions about eligibility requirements and requests for exceptions;

5. Identified utility and transmission costs, financial security arrangements, and any difficulties determining or recovering costs;

6. The status of proposed projects, including withdrawals, delays, construction progress, and expected operation dates;

7. The compliance and operating history of any PENs that have begun operating;

8. Whether PENs have negatively affected reliability, unduly increased rates for other customers, or unduly impaired regulated utilities' ability to attract capital at reasonable rates; and

9. Whether continuing the PEN rules, including allowing new applications or expansions after five years, would serve the public interest.

Based on this information, Staff would recommend whether to retain the existing requirements, modify them, or gather additional information before deciding certain issues.

Staff recognizes that a review beginning in the fourth year may have limited information about actual PEN operations. Because these projects may take three to five years to develop, Staff will likely have more information about applications and proposed projects than about long-term operating experience. Nevertheless, this information would help determine whether the requirements are clear, whether applicants can meet them, and whether proposed projects are consistent with the purpose of the rules. The review may not provide enough information to determine whether the operating restrictions and long-term cost protections are effective. Staff would identify any issues that cannot yet be evaluated and consider whatever operating experience is available.

Expiration of the five-year window would prevent new PEN applications unless the Commission renews the rules. However, it would not terminate previously approved PENs or impose a five-year limit on their contracts or facilities. Applications filed before expiration would remain eligible for review, even after the window closes. Approved PENs could continue operating as long as they comply with their approval conditions, reporting requirements, and other obligations. They could also renew or replace their power supply arrangements, provided they continue to meet the applicable requirements. Requests to expand an approved PEN after the application window closes raise separate

issues and should be addressed independently from the continued operation of an existing, compliant PEN.

Staff Conclusion. **Staff recommends retaining the five-year application window, with a review beginning in the fourth year to allow the Commission to consider renewal or modification before expiration. The review would consider available information about applications, project development, and actual operations, while identifying issues that cannot yet be fully evaluated. Expiration of the window would prevent only new applications. Applications submitted before the deadline would still be processed, and approved PENs could continue operating subject to their existing conditions and compliance requirements.**

I. Environmental and Siting Requirements.

Staff's Initial Report and proposed rules did not include separate environmental or siting requirements for PENs. The proposed rule required applicants to identify "the type, capacity, and fuel source of each generation resource."[117] It also required the Commission to find that the PEN "is consistent with the public interest" before granting confirmation.[118] However, applicants were not required to provide information about emissions, water use, or potential impacts on wildlife and habitat.

Few parties addressed environmental and siting requirements directly. NWF recommended requiring applicants to provide information regarding environmental, water, and wildlife impacts.[119] Specifically, NWF proposed disclosures covering the generation's fuel type and expected air emissions, the status of Clean Air Act permits, water sources and consumption for both the generation and the customer load, and Louisiana Pollutant

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[117] Proposed Rule § 301(3)(D).

[118] *Id.*, § 301(5)(F).

[119] NWF Comments on LPSC Staff Initial Report at 4-5.

Discharge Elimination System permits.[120] NWF also recommended a desktop wildlife and habitat siting screen and, for projects in industrial corridors, an assessment of cumulative environmental and community impacts.[121] NWF further argued that any flexibility in the contiguity requirement should be accompanied by a wildlife and habitat assessment.[122] NWF explained that its recommendations were intended to provide information through existing regulatory processes rather than establish a new environmental review.[123] Separately, AAE and EDF expressed concern that the proposed PEN requirements could favor natural gas generation while limiting opportunities for renewable energy and storage.[124]

Experiences in other jurisdictions show that privately owned generation can have significant environmental and siting impacts, even when it serves only one customer. Section VI discusses these experiences in greater detail. In Memphis, Tennessee and Southaven, Mississippi, natural gas generation serving xAI's data centers reached a scale comparable to a utility power plant and raised concerns about air quality and public health. In West Virginia, legislation creating a certified microgrid program included ratepayer protections, but its implementation has raised separate concerns about land use, environmental impacts, and local oversight. Utah, on the other hand, requires applicants

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120 *Id.*

121 *Id.*

122 *Id.*

123 *Id.*

124 AAE Comments on LPSC Staff Initial Report at 3; EDF Comments on LPSC Staff Initial Report at 3-4.

to identify necessary permits, including environmental permits, while leaving environmental review to the responsible permitting agencies.

Staff agrees that PENs should remain subject to applicable environmental and siting requirements, even if they operate independently of the public grid. However, environmental permitting falls within the jurisdiction of the Louisiana Department of Environmental Quality and other responsible agencies. Staff therefore recommends requiring PEN applicants to demonstrate compliance with all applicable environmental, siting, construction, and other permitting requirements. Staff does not recommend creating a separate Commission review of environmental or siting issues already addressed by those agencies. Doing so could expand the scope of PEN proceedings, duplicate technical reviews conducted by other authorities, and create uncertainty about what applicants must demonstrate to qualify. The Commission also does not conduct separate environmental reviews for other generation facilities or loads.

Application Requirements. Staff recommends requiring PEN applicants to provide the following information:

1. A list of all required permits and approvals, the agencies responsible for issuing them, and their current status;
2. Documentation showing that any permits or approvals already obtained apply to the proposed facilities;
3. For pending permits or approvals, the remaining steps and expected timeline for obtaining them; and
4. Disclosure of material permit conditions affecting the proposed PEN, including changes to generation facilities, location, or operations necessary to comply with those conditions.

Consistent with the lessons from Utah, Staff also recommends requiring basic information about the proposed generation, including its technology, fuel source, capacity, operating characteristics, and water source. This information would help the Commission understand the broader implications of PEN development without duplicating the permitting agencies' work.

Permitting Milestones. Staff recognizes that some permits may still be pending when the Commission reviews a PEN application. Staff therefore recommends requiring applicants to obtain the necessary permits and approvals before proceeding with the applicable stage of development. PEN confirmation would not authorize construction, energization, or operation without the approvals required by the responsible agencies. Staff also recommends requiring applicants to notify the Commission of any material denial, modification, suspension, or loss of a required permit or approval.

Separate Responsibilities. Although Staff recommends relying on the appropriate permitting agencies for environmental and siting matters, the Commission would remain responsible for determining whether a project meets the PEN requirements. Obtaining environmental permits would not, by itself, establish that a project qualifies as a PEN. Likewise, PEN confirmation would not replace any required environmental permits, property rights, crossing permissions, or other approvals from other authorities.

Staff Conclusion. **Staff recommends requiring PEN applicants to demonstrate compliance with all applicable environmental, siting, construction, and other permitting requirements and to notify the Commission of material changes to those approvals. Staff does not recommend a separate Commission environmental or siting review that would duplicate the responsibilities of existing permitting agencies. This approach would ensure that PENs remain subject to applicable environmental and**

siting protections without creating an additional approval process under the PEN rules.

J. Public Utility Service Availability.

The Staff's proposed rule would prohibit a PEN from connecting to or receiving any kind of service from the public grid, except for an interconnection to export power to the wholesale market. The Staff found that a PEN should be fully islanded and private. In its Initial Report, the Staff asked the parties to provide detailed information on back-up, stand-by and other potential services that could be provided to a PEN. The Staff received robust responses to those requests. The responses were wide ranging, from regulated utilities, which said that utilities should not be obligated to supply any kind of back-up power, to industrial energy user groups, which said that PENs should have access to various kinds of utility service. All commenters seem to agree that if such services are offered, they should be priced at cost-of-service rates that capture the true cost of the particular service being provided.

There are several distinct kinds of services that a regulated utility could provide to a PEN, including Scheduled-maintenance Power, Back-up Power, As-available Power, Supplementary Power, and Station Service. Each of these services would require different resources and costs. There can be no question that the issues associated with each of these potential services to PENs are complex, and would require detailed technical analysis to determine the actual cost of each type of service and careful rate design to capture those costs.

Allowing PENs access to utility backup and maintenance service would undoubtedly be beneficial to PENs by reducing redundancy and improving the feasibility of a PEN project. However, the stated purpose of this rulemaking is for a ***Private*** Use Electric Network, and a PEN's reliance on the utility grid would not be consistent with private use. Further, if those services were allowed, they must be priced appropriately to ensure that all of the costs of that service are borne by the PEN and not by other customers. In addition, there would need to be mechanisms for tracking costs that may be incurred in the future and assigning those costs to the PEN. Security and collateral requirements should also be developed to ensure that costs are not shifted to utilities and their customers in the event of a PEN closing its business or defaulting on an obligation. All of this would require further analysis and development; this record does not have sufficient information to allow the determination of the appropriate pricing and rate structure for those services, tracking mechanisms and security measures.

The Staff thus recommends that the PEN rule retain the prohibition on these services and defer consideration of utility Backup, Scheduled-maintenance, As-available, Supplementary, and Station-power services for PENs until the Commission provides direction of its intent with respect to those services for PENs. If the Commission directs the Staff to propose rules to allow PENs access to utility services, that would require the engineering, resource support, cost and rate issues associated with each type of service to be fully researched, analyzed and addressed.

An existing backup-service rate schedule should not automatically carry into a newly qualifying PEN. If the Commission authorizes utility service for a PEN, the participant should satisfy the requirements and pay the rates established for that service. Similarly, an export connection for a PEN does not make the utility responsible for supplying service to the PEN, absent explicit Commission authorization and an appropriate rate for that service.

This is a sequencing recommendation, not a conclusion that those services should never be available. The Commission could expand the framework once the relevant transmission-cost arrangements are final and utility service rates assigning and recovering the full costs attributable to PEN service are developed. If the Commission wishes to pursue that broader offering, it should direct the Staff to continue to analyze these issues and allow for public participation as appropriate.

1. Existing Service Schedules are Not Sufficient.

Existing service schedules are not sufficient to accommodate PEN load seeking utility services. The issue is what the utility must acquire, reserve, build, or maintain to provide the requested service—and how to ensure that the PEN, and not other customers, will pay those costs. A participant seeking infrequent energy deliveries could still require substantial capacity, transmission capability, and facilities to be available when its own generation is unavailable. Occasional use does not necessarily mean a small service obligation.

This concern is particularly acute for ELL, in whose service territory there could be substantial PEN participation. ELL's rates have not been updated through a full cost-of-service allocation in approximately 20 years. More fundamentally, the resource conditions underlying existing rates may differ substantially from the conditions under which these services would now be provided. A schedule developed when embedded generation capacity was relatively abundant may not recover the cost of supporting a new obligation when additional capacity must be acquired at materially higher cost.

PEN participation could also change the allocation of costs among customers. Having an obligation to supply a PEN during outages or maintenance while not having the PEN load's regular consumption, could produce a service profile quite different from the one reflected in existing allocations. Developing appropriate rates for utility service to PENs would require a current service-specific assessment rather than assuming legacy backup or related schedules adequately protect other customers.

If the Commission wishes to expand beyond the islanded approach, utilities should be directed to propose appropriate cost of service allocations and rate designs once the relevant RTO allocations and recovery arrangements are sufficiently finalized to support those filings, as discussed in the following section. The utility proposals should identify the obligations created by each service and demonstrate how the participant would pay the full attributable cost. Depending on the service, that could include capacity reservations, energy, transmission and distribution facilities, operating costs, study costs, and financial security. The proposals should also address the amount of service reserved, scheduling

and availability conditions, contract duration, and responsibility for commitments extending beyond the participant's actual use of service. The objective would be to develop rates and terms for the PEN service being offered, rather than permit participants to select legacy schedules that do not reflect the resulting obligations.

2. RTO-Imposed Costs That Are Caused by a PEN Must Be Captured and Assigned to the PEN.

Backup and maintenance service can create RTO-imposed obligations, including resource-adequacy obligations in addition to transmission costs, on load-serving entities. ELL distinguishes the export-only arrangement from one permitted to withdraw grid power. The latter would require planning for the PEN customer peak, reserves, and energy needs, with potential MISO Planning Resource Auction costs. Cleco expressly identifies the utility's MISO load-serving responsibility for firm backup and maintenance service, and 1803 identifies the corresponding obligation as the wholesale supplier serving its cooperative members. These potential RTO-imposed obligations are not yet known. This uncertainty is an additional reason to defer consideration of backup and related services while proceeding with the islanded-load offering.

Before implementing any requirements for utility service to PENs, the Commission would also need to develop a mechanism to track and assign transmission costs that are caused by PENs, but likely will not be assigned to the PENs, but rather would be assigned to the member utility in whose service territory the PEN operates. MISO and SPP are developing and implementing approaches to identify, study, assign, and recover transmission costs associated with large-load development. Once those transmission costs

are determined, costs could be assigned or billed to a transmission owner, transmission customer, utility, generator, or another responsible party. The Commission needs a process to assign to and collect from a PEN any of those costs that are caused by it. This issue cannot be resolved merely by stating that the PEN will pay its own interconnection costs. Interconnection facilities and upgrades are only part of the potential exposure. Later planning decisions and regional transmission projects may result in costs and raise additional attribution and recovery questions.

MISO and SPP have different processes for handling interconnection, transmission planning and large load. MISO imposes generator-interconnection obligations, large load costs, and transmission investments arising through the planning process. For SPP, the cost analysis must also address the interaction between direct assignment and applicable base-plan funding or safe-harbor provisions. Those arrangements could affect whether a project-related cost is borne directly by the participant or enters a broader regional or sub-regional allocation. For each RTO process that can result in assigned costs, the Commission should identify who incurs the obligation, who receives the charge, when the exposure becomes known, and what mechanism would require the PEN to bear the amount attributable to it. The mechanism would need to address financial security, continuing obligations, and responsibility if the PEN fails, changes ownership, or ceases operation. This work has not yet been done, but could be if the Commission determines that it wants to explore utility service for PENs.

Staff Conclusion. **The PEN rule should move forward with the islanded-load framework, while deferring consideration of utility services for PENs. The principal**

reasons are (1) the need to update and develop utility rates to reflect the full service obligation; (2) unresolved project-specific RTO load-serving and resource-adequacy obligations and costs, and (3) the unresolved path for tracking, assigning and collecting PEN-attributable transmission costs under evolving MISO and SPP frameworks. Should the Commission wish to broaden the offering, it could direct further work and subsequent utility filings once those arrangements support an enforceable cost-recovery framework. Deferral would preserve that option while allowing the initial offering to proceed.

K. Post-PEN-Approval Issues.

There are several issues that may arise after a PEN is approved that were not addressed in the Staff's original proposed rule. Those items should be explicitly addressed in the rule as follows:

1. PPA Continuity and Replacement Generation.

An approved PEN should be allowed to renew or replace its power purchase agreement ("PPA") and replace retiring generation provided it demonstrates that the resulting arrangement continues to satisfy all PEN requirements. Qualification should not end merely because the original PPA expires or the generation is retired. At the same time, continued qualification should not be assumed without a showing that the renewed or replacement supply preserves the approved arrangement's compliance with all aspects of the PEN rule.

A qualifying industrial development may operate longer than its original supply contract or generating equipment. Requiring the original PPA and generation to remain unchanged would unnecessarily limit the useful life of the PEN. The relevant question is whether the continuing arrangement meets the rule, rather than whether the original contract remains in place. A renewal or replacement could preserve the same customer-

serving purpose while accommodating equipment retirement, changed counterparties, or a different supply configuration.

A participant that seeks to replace or renew generation, however, should be required to demonstrate that the renewed or replacement arrangement continues to meet all applicable requirements, including independent supply, islanding, capacity sizing, wholesale capacity-sales limits, energy use and export limits, property boundaries, engineering requirements, and cost responsibility. The renewal/replacement filing should explain what is changing and identify any effect on the PEN requirements. A replacement contract should not automatically authorize more generation, additional customers, a higher capacity-sales ceiling, a broader network, or authorize any other PEN modification. Such changes should require Commission approval. The ability to replace supply should preserve a compliant PEN; it should not provide a route around the PEN requirements.

A PPA supplying the generation for a PEN, including a renewal or replacement agreement, should be filed with confidential treatment for commercially sensitive information. Confidentiality should protect legitimate commercial interests while allowing the Commission, Staff, and other parties entitled to access under appropriate protections to evaluate qualification and continuing obligations.

PPA filings should address contractual provisions relevant to continuity including duration, termination, default, assignment, and credit support. The purpose is to establish that the supply arrangement supports compliance, rather than the Commission assuming responsibility for negotiating the participants' commercial bargain. Nothing in the PEN

rules should be interpreted as giving the Commission responsibility for the fairness of the terms of any agreement that a PEN negotiates.

For scheduled PPA expiration or generation retirement, the rule should require two advance filings:

- **Two years before expiration or retirement:** a plan explaining how the supply will be renewed or replaced; and
- **Six months before expiration or retirement:** a filing identifying and documenting the actual renewal or replacement arrangement and demonstrating continued compliance with PEN rules.

The two-year replacement plan. Two years before a scheduled PPA expiration or generating-unit retirement, the participant should explain how it intends to maintain qualifying supply. The plan should identify the affected agreement or equipment, the expected termination or retirement date, the supply options being pursued, and the anticipated schedule for contracting, construction, studies, and other necessary approvals. At this stage, the participant may not have completed its replacement arrangements. The purpose is to identify the approaching transition early enough for the Commission and affected parties to understand the plan, its milestones, and any significant risk to continued compliance. The filing should also identify how the PEN expects to operate if the preferred replacement is delayed. That explanation should remain consistent with the service arrangements the Commission has authorized; it should not assume utility backup or immediate return to utility service.

The six-month replacement filing. Six months before expiration or retirement, the participant should file the actual renewal or replacement arrangement. That filing should

identify the committed supply, provide the relevant contractual and technical documentation, demonstrate continued compliance, and describe the remaining steps needed for the transition. The filing of the arrangement should be made six months in advance, but does not necessarily require replacement generation to be in service six months early. Any construction, testing, interconnection, or other milestones remaining after the filing should be identified and completed when required for lawful operation. If the replacement includes a proposal to change a PEN feature requiring Commission approval, the applicant is responsible for obtaining that approval before implementing the change and should provide sufficient time for Commission review prior to making the change effective. Continuing qualification as a PEN should not be automatic or assumed.

Unexpected loss of supply. The two-year and six-month requirements are intended to address scheduled transitions. An unexpected default, early termination, or equipment failure may make the advance deadlines for those filings impossible to meet. The rule should provide a separate notice and corrective-plan process for those unexpected circumstances. An unforeseen loss of supply should not create an automatic right to utility service or to allow variances outside the approved PEN requirements.

Staff Conclusion. **The rule should permit continued qualification through PPA renewal or replacement of retiring generation, supported by a demonstration that the PEN continues to meet its requirements. For scheduled transitions, the rule should require a replacement plan two years in advance and the actual renewal or replacement filing six months in advance. This would provide early visibility and a concrete arrangement for review without tying qualification permanently to the original contract or equipment.**

2. Ownership Changes and Assignments.

The rule should require prior notice and a supported showing of continued compliance when ownership, control, or contractual responsibilities change. Unless substantive changes are made to the configuration of the PEN, this would be a notice filing for transparency purposes. The transaction should not automatically require prior Commission approval merely because a different party assumes an existing role. This filing should be made 180 days in advance of the effective date of the ownership change when possible; if the agreement confecting the ownership change is not finalized by then, it should be filed as soon as possible after the agreement is finalized.

If the ownership change transaction also changes the approved electrical arrangement, participating load, generation, geographic boundaries, wholesale permissions, or other substantive qualification conditions, the requirements governing those changes would apply and prior Commission approval may be required. The distinction between when a notice filing is required versus an application for Commission approval should turn on the changes to the PEN and its compliance with the PEN rules; the occurrence of a commercial transaction alone does not trigger the need for Commission approval. An applicant that fails to provide a notice filing 180 days in advance of the effective date of the change bears the risk that there will be insufficient time for the Commission to consider approval of a changed circumstance, should it be determined that such approval is necessary.

Several different transactions could arise in the life of a PEN. There could be a sale of the generating facility or other PEN assets, a change in ownership or control of a participating company, an assignment of a PPA or another agreement transferring contractual rights and responsibilities to a different party, a change in the entity responsible for operating the network or satisfying particular obligations. These transactions do not necessarily change the customers served, the equipment installed, or the way the network operates. For example, a generating facility could have a new owner while continuing to supply the same customers under the same operating restrictions. An assignment also does not necessarily replace the underlying supply arrangement. It may transfer an existing agreement to a new party. That situation should be distinguished from replacing the generation or negotiating a materially different supply arrangement.

The Commission's interest is in preserving compliance with the PEN framework and protecting LPSC-jurisdictional customers who could otherwise bear costs attributable to the PEN. A transaction that preserves compliance with the PEN Rules should not present a new eligibility decision. Requiring full prior approval for every ownership change or assignment could subject ordinary commercial transactions to a broader review than is needed to protect the rule's purposes. The notice and compliance filing is intended to provide visibility before the change occurs and an opportunity to identify any issues needing approval.

The notice filing should not excuse a participant from obtaining approval for a substantive change that independently requires it. For example, adding customers,

expanding generation, enlarging the network, or seeking a higher wholesale capacity-sales ceiling would remain subject to the applicable application or amendment requirements. Calling the transaction an assignment would not alter that result. Similarly, a new owner could not assume that an existing service arrangement, financial-security instrument, or property right transfers automatically. The notice should establish that the necessary rights and obligations remain effective or have been appropriately replaced.

The notice filing should identify the transaction, the affected parties and agreements, the proposed effective date, and any resulting changes in responsibility. It should explain why the PEN will continue to satisfy its requirements, including:

- Continued qualifying supply and compliance with the islanding and export restrictions.
- Continued responsibility for operation, maintenance, reporting, and Commission filings.
- Assumption of applicable cost obligations and preservation or replacement of required financial security.
- Continued property rights and access needed to operate the approved network.
- Any changes to the facts or conditions supporting qualification.

The showing should make clear who will be responsible after the transaction. A change in ownership should not create a gap in accountability or leave existing obligations unfulfilled. Commercially sensitive information should receive appropriate confidential treatment.

Regulated utilities are treated differently under existing Commission rules because, unlike a PEN, the Commission is responsible for those utilities' rates and reliability of

service to its customers. Changes in ownership and control of regulated utility assets require Commission approval pursuant to the Commission's General Order dated March 18, 1994 (the "1994 General Order").[125] The Commission's responsibility for a regulated utility extends to a broad customer base that depends on the utility's service, facilities, financial condition, and continuing obligations. Utility transactions affect customers who have not voluntarily selected their supplier or negotiated the underlying arrangements. The Commission is not responsible for the rates or reliability of service to PEN customers. PEN participants are free to negotiate their own rates and to manage their own reliability, and are accepting the risks associated with both. The Commission should protect compliance with the requisite conditions of the PEN offering and prevent costs from being shifted to jurisdictional customers, but should not assume the same responsibility for protecting PEN participants from their negotiated voluntary business decisions.

Staff Conclusion. **For changes in PEN ownership or control, prior notice and a demonstration of continued compliance is required. Prior Commission approval of every ownership change, change of control, or assignment is not necessary. The Commission should, however, review and determine whether changes to the approved PEN arrangement is in the public interest. Unlike regulated utilities, the Commission should not exercise oversight over the voluntary commercial risks undertaken by PEN participants**.

3. Expansion of an Approved PEN.

Staff's Initial Report did not separately address how an approved PEN could expand after receiving Commission confirmation. Section 301(7) of Staff's initial proposed rules

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[125] *In re Commission Approval Required of Sales, Leases, Mergers, Consolidations, Stock Transfers, and All Other Changes of Ownership or Control of Public Utilities Subject to Commission Jurisdiction*, General Order (La. Pub. Serv. Comm'n Mar. 18, 1994), https://lpsc.louisiana.gov/docs/orders/GO-3-18-1994.pdf.

provided only that any material change to a PEN after confirmation, including "the addition of new Identified Load Customers, expansion of the Network Boundary, or material increase in generating capacity," would require a supplemental application and Commission approval before implementation.[126] However, the proposed rules did not specify what information a supplemental application must include or which eligibility requirements and approval standards would apply.

Several parties commented on this issue. Cleco opposed allowing an approved PEN to expand its Network Boundary, noting that the boundary is the basis for several other protections in the rules.[127] Cleco recommended requiring a new application whenever a PEN seeks to serve additional load or expand onto additional property.[128] The Commission would then review the expanded PEN under all applicable eligibility requirements and approval standards.[129] SLEMCO similarly recommended requiring a new application when a PEN adds an Identified Load Customer who was not included in the original approval.[130] 1803 proposed requiring supplemental applications for additional changes, including changes in the PEN Operator, transfers of ownership or control, and assignment of customer contracts.[131]

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126 Proposed Rule § 301(7).

127 Cleco Comments on LPSC Staff Initial Report at 11.

128 *Id.*; Cleco Comments on LPSC Staff Initial Report, Attach. A § 301(7).

129 Cleco Comments on LPSC Staff Initial Report at 11.

130 SLEMCO Responses to Staff's Second Requests for Information, Redlined Rule § 301(7).

131 1803 Comments on LPSC Staff Initial Report, Exhibit A § 301(7).

New Application Required. Staff agrees with Cleco and SLEMCO that expanding an approved PEN should require a new application. The original approval would apply to a specific arrangement, including the participating load, generation facilities, property boundaries, capacity-sales ceiling, and other applicable conditions. It should not provide unlimited authority to expand the network.

Staff recommends requiring a new application because an expansion could change the circumstances that supported the original approval or affect the obligations of other parties. For example:

- Additional customers or load could change the PEN's coincident peak demand and generation needs.
- Additional generation could affect interconnection requirements and capacity calculations.
- Additional property or connecting infrastructure could increase the geographic size of the network.

The original approval would not necessarily address these changes. A new application would allow the Commission to review the expanded arrangement and give affected parties notice and an opportunity to raise concerns. It would also keep a relatively confined initial project from becoming a substantially different network through a series of additions that never receive comprehensive review.

What Constitutes an Expansion. Staff recommends treating the following changes as expansions: adding new participating customers or facilities; adding industrial processes or production capacity that materially increase the approved load; increasing generating capability beyond the approved installation; and adding property or connections that

enlarge the approved network. Any increase in the approved wholesale capacity-sales limit would also require express Commission review and approval. It should not increase automatically because generation is added, demand changes, or a participant characterizes the change as part of an existing project.

What Does Not Constitute an Expansion. Routine maintenance and equipment replacement within the approved arrangements are not expansions. Likewise, PPA renewals, ownership changes, or replacement of retiring equipment would not necessarily require a new application. Instead, those changes should follow the applicable notice, continued compliance, or supply-replacement procedures. This is consistent with Staff's recommendation to allow approved PENs to renew or replace expiring or retiring generation while demonstrating continued compliance. Calling a project a "replacement," however, should not avoid expansion review if the project adds customers, materially increases approved generating capability, or enlarges the network. In other words, the substance of the change, not its label, should determine the process.

Contents of the Expansion Application. Staff recommends requiring applicants to identify the original PEN approval, describe the proposed expansion, and demonstrate that the expanded PEN would continue to meet all applicable requirements. The application should update relevant load projections, coincident peak demand, reserve allowance, generation configuration, capacity calculations, energy balance, property boundaries, engineering studies, and cost responsibilities. Staff also agrees with Cleco that any added

load must independently meet the eligibility requirements. Load already served by a utility would not become eligible simply because it is added to an approved PEN.

However, Staff does not believe applicants should have to repeat studies or submit documents that remain valid from the original approval. The Commission should rely on the existing record and prior approvals where appropriate. Applicants would need to explain why the earlier information remains sufficient to evaluate the expanded arrangement.

Expansion After the Five-Year Application Window. Requests to expand an approved PEN after the five-year application window raise additional questions. Staff recognizes that allowing expansions could benefit industrial developments that grow over time. The ability to serve additional qualifying load could encourage further investment and support continued development. However, allowing expansions indefinitely could also undermine the purpose of the five-year application window. An existing PEN approval could become a way to add substantial new load after the Commission has stopped accepting applications for new PENs.

Staff does not recommend deciding this issue now. Instead, Staff recommends addressing it during the Commission's review beginning in the fourth year. That review should consider whether allowing expansions after the five-year window closes would serve the public interest.

Staff Conclusion. **Staff recommends requiring a new application for any proposed expansion of an approved PEN. The application must demonstrate that the expanded PEN would continue to meet all applicable requirements and address any additional costs or obligations resulting from the expansion. Any added load must**

independently satisfy the eligibility requirements. Routine maintenance, ownership changes, and qualifying supply replacements would follow their applicable procedures unless they materially expand the approved arrangement. Staff also recommends addressing whether expansions should be allowed after the five-year application window closes as part of the fourth-year review.

4. Failure, Exit, and Requests for Utility Service.

Staff's Initial Report did not address what happens when a PEN fails or a participant leaves the arrangement and seeks utility service. Although Staff's initial proposed rules prohibited Identified Load Customers from receiving utility service while participating in a PEN, they did not address how those customers could obtain utility service after leaving the PEN.[132]

In their responses to Staff's First Requests for Information, some parties discussed related protections, including exit fees and loss of PEN qualification if load later falls short.[133] Several parties addressed the issue more directly in their comments on the Initial Report. ALEC warned that a PEN failure could leave a utility facing an unexpected request to serve hundreds of megawatts of load, potentially shifting costs and reliability risks to existing customers.[134] To address this concern, ALEC proposed a "Return to Utility Service" provision.[135] Under that provision, a customer seeking utility service after a PEN failure, loss of qualification, or voluntary departure would be treated as a new large load customer.[136] The request would be subject to the utility's line extension policies, tariffs,

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[132] Proposed Rule § 201(6).

[133] Initial Report at 10, 44-45 (summarizing AAE and 1803 responses).

[134] ALEC Comments on LPSC Staff Initial Report, Exhibit A at 6.

[135] *Id.*

[136] *Id.*

and contract terms, and the utility would have reasonable time to plan for and construct any necessary facilities.[137] 1803 supported the same approach, noting that utilities cannot necessarily accommodate hundreds of megawatts of additional load on short notice.[138] Cleco observed that the proposed rules do not prevent a customer from requesting utility service if PEN generation fails or a PPA expires.[139] SWEPCO similarly argued that PEN customers should not have an automatic right to return to utility service on demand.[140] Staff agrees with these comments.

New Large Load Service Request. Staff recommends requiring a PEN participant seeking utility service to submit a new large load service request to the utility that would ordinarily serve the location. This requirement would apply whether the request results from an unexpected loss of generation, failure of the PEN arrangement, loss of PEN qualification, or a voluntary decision to leave the PEN. The request should be reviewed under the Commission's large load guidelines, any rules adopted in a subsequent large-load rulemaking proceeding, and any other law applicable to large load.

Because PEN participants choose to obtain electricity independently of the utility system, participation in a PEN should not create a right to immediate utility service. It also should not require the utility to reserve generation, transmission capacity, or delivery facilities in case a participant later requests service. The utility would only be expected to

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137 *Id.*

138 1803 Comments on LPSC Staff Initial Report at 8.

139 Cleco Comments on LPSC Staff Initial Report at 16.

140 SWEPCO Comments on LPSC Staff Initial Report at 2.

maintain those resources if an approved service arrangement requires it and provides for the associated costs. Although a PEN failure may create an urgent need for electricity, that does not mean the utility will have the resources or facilities available to provide service immediately.

Scope of the Service Request. The utility service request should be reviewed under the applicable large load service process. That review should address: (1) necessary studies; (2) facilities, generation, or other resources; (3) transmission arrangements; (4) expected timeline; (5) costs and financial security; and (6) contractual commitments. Consistent with cost-protection standards, the requesting participant should bear the costs attributable to its request.

Continuing Obligations. A PEN's failure, termination of operations, or loss of qualification should not relieve its participants of outstanding costs or commitments attributable to the PEN arrangement.

Staff Conclusion. **Staff recommends that PEN participants seeking utility service after a PEN failure, loss of qualification, or voluntary departure be treated as new large load customers. Any request for service would be subject to the applicable utility requirements, including necessary studies, construction timelines, costs, and financial security. PEN participation would not create a right to immediate utility service or require utilities to reserve resources for a potential return. Staff also recommends that any outstanding costs or obligations attributable to the PEN remain enforceable after the arrangement ends.**

L. PEN Rule Implementation Details.

Staff's initial proposed rules established the basic application, reporting, and inspection requirements for PENs. However, they did not address several procedural and administrative issues needed to make the rules clear and predictable for applicants,

workable for affected utilities, and enforceable by the Commission. Staff addresses those issues in three areas: (1) applications and affected parties; (2) reporting, compliance, and enforcement; and (3) fees, study costs, and taxes.

1. Applications and Affected Parties.

Sections 301(3) and (4) of Staff's initial proposed rules identified the information required in a PEN application and established the application review process. That process included publication in the Commission's Official Bulletin, allowing at least sixty (60) days for comments, protests, and interventions, and technical conferences or hearings at the Commission's discretion. The rules also gave the Interconnected Utility standing to participate. However, they did not address several other issues, including the filings required of intervening parties, Commission decision deadlines, direct notice to affected utilities, participation by other affected parties, and access to confidential application information.

Intervention. Staff initially recommended sixty (60) days from the date of notice in the Commission's Official Bulletin to file comments, protests, or petitions to intervene.[141] Most parties supported the 60-day intervention period or had no comment on it, with the exception of LEUG, who opposed the 60-day period as too long and recommended 25 days instead. and Powering Prosperity, who suggested a 45-day period.[142] Staff recommends three changes to the intervention process. First, interventions must be filed within twenty-

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[141] Proposed Rule § 301(4)(B).

[142] LEUG Comments to LPSC Staff Initial Report at 11; Powering Prosperity Comments to LPSC Staff Initial Report, Exhibit A § 301(4)(B).

five (25) days of the date of publication in the Official Bulletin. Second, any protest must be stated at the time of intervention. Finally, a protesting intervenor will have ninety (90) days from the date of publication in the Official Bulletin to file the support for its protest. Staff believes this approach gives applicants early notice of any opposition, while still giving protesting parties enough time to develop and support their positions.

Commission Decision Deadline. Several parties recommended establishing a timeline for Commission decisions. Powering Prosperity proposed requiring the Commission to act on complete applications within 120 days, with automatic approval if the deadline is missed.[143] LEUG recommended best-efforts targets of 90 days for uncontested applications and 180 days for contested applications, based on the Commission's Transmission Facility Certification and Siting Rule.[144] 1803 opposed both a decision deadline and automatic approval.[145]

Staff recommends establishing best-efforts targets for Commission consideration of 150 days for applications that are not protested and 230 days for applications that do receive a protest from an intervening party, measured from the date of publication in the bulletin. These timelines would allow time for the intervention period to close, the parties' positions to become clear, and Staff to review additional information or disputed issues. The deadlines would be targets rather than firm requirements and there will be no automatic approvals from the failure to act on an application within the target number of days.

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[143] Powering Prosperity Comments on LPSC Staff Initial Report at 11-12, 24.

[144] LEUG Comments on LPSC Staff Initial Report at 11 (citing LPSC Order No. R-36199, Section X).

[145] 1803 Comments on LPSC Staff Initial Report, Exhibit A at 10.

Incomplete applications, material amendments, or unresolved issues will undoubtedly require more time, and the Commission can, at its discretion, take more time than the targets contemplate. To support this Commission decision timeline, Staff is also recommending procedural timelines to ensure that intervening parties express their positions and provide relevant information that may support the Commission's determination in a timely manner. To this end, Staff has instituted a forty-five day deadline for an intervening party to express whether it opposes the PEN designation, at which point the application, and a ninety day deadline to provide information in support of any such expressed opposition. Staff will use this information and the information it obtains from the PEN Participants to provide a summary to the Commission. The intervening parties and the PEN Participants shall comply with any of Staff's requests for information reasonably needed to support Staff's analysis and summary to the Commission.

Direct Notice to Affected Parties. The utility that would ordinarily serve the PEN location may be different from the utility that owns the export interconnection. Each may have different interests and information relevant to the application. For example, the serving utility may have information about prior service requests, existing operations, service commitments, and potential costs. The interconnecting utility, on the other hand, must evaluate the proposed export connection and its effects on the system. ALEC and 1803 recommend requiring applicants to serve both utilities when filing an application.[146]

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[146] ALEC Comments on LPSC Staff Initial Report, Exhibit A at 9; 1803 Comments on LPSC Staff Initial Report, Exhibit A at 11.

They also request standing for affected utilities, transmission owners, and wholesale power suppliers.[147]

Staff agrees. Staff recommends requiring applicants to identify in the application the Interconnected Utility, the utility that would ordinarily serve the PEN location, and any transmission owner or wholesale power supplier whose facilities, obligations, or costs may be affected. Applicants should explain why each party was identified and provide each with a copy of the application when filed. Publication in the Official Bulletin would still be required and the intervention period established, but it would not replace direct notice to known affected parties.

Participation and Access to Information. Staff recommends allowing each directly notified affected party to participate in the proceeding and review application information relevant to PEN qualification, engineering, and costs attributable to the project. Access would be subject to appropriate confidentiality protections for sensitive contracts, business forecasts, and other protected information. ALEC and 1803 similarly request access to the information supporting an applicant's cost analysis.[148] Staff believes confidentiality protections would allow affected parties to meaningfully review potential impacts without unnecessarily disclosing sensitive information. Participation would help the Commission establish the facts and resolve legitimate concerns. Staff also does not recommend

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147 *Id.*

148 ALEC Comments on LPSC Staff Initial Report, Exhibit A at 12; 1803 Comments on LPSC Staff Initial Report, Exhibit A at 14.

requiring applicants to request utility service or reject a utility offer before seeking PEN qualification.

2. Reporting, Compliance, and Enforcement.

Section 401 of Staff's initial proposed rules required external and internal metering, an Annual Compliance Report due March 31, five-year records retention, and a right of inspection. The Annual Compliance Report would address generation, customer deliveries, exports, the dedication percentages, and the minimum size and load factor requirements, along with material changes. However, the initial proposed rules did not fully address several compliance issues. These include providing annual reports to affected utilities, notifying the Commission of noncompliance before the next annual report, and establishing procedures for correcting violations or suspending or revoking PEN status.

Annual Compliance Report. Staff recommends retaining the March 31 reporting deadline, five-year records retention requirement, and access to records, meters, and facilities. ALEC and 1803 recommended requiring PEN Operators to provide annual reports to the serving and interconnected utilities, subject to confidentiality protections.[149] Staff agrees because these utilities may have information needed to identify interconnection, cost, or operational issues. However, their access should be limited to information relevant to their interests and subject to appropriate confidentiality protections. Receiving an annual report would not give a utility authority to determine PEN qualification or to impose new conditions on its own.

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[149] ALEC Comments on LPSC Staff Initial Report at 13; 1803 Comments on LPSC Staff Initial Report, Exhibit A at 13.

Thirty-Day Notice of Noncompliance. Staff agrees with ALEC and 1803 that PEN Operators should notify the Commission and affected utilities within thirty (30) days after discovering noncompliance, rather than waiting until the next annual report.[150] The notice should identify the requirement involved, when the issue began or was discovered, its known extent and cause, any corrective actions already taken, and the proposed steps and timeline for resolving it. If all relevant information is not yet available, the PEN Operator would be required to provide updates.

The thirty-day period would apply only to notification. It would not give the PEN Operator thirty days to correct a violation or authorize continued operation that is otherwise prohibited. It also would not replace any immediate reporting or corrective action required under an interconnection agreement or other applicable requirements.

Opportunity to Respond and Cure; Loss of PEN Status. ALEC and 1803 recommended expressly preserving the Commission's enforcement authority. They proposed allowing the Commission, after notice and an opportunity to be heard, to impose conditions, assess penalties as permitted by law, or suspend or revoke a Confirmation of Qualification.[151]

Staff generally agrees. Staff recommends providing PEN Operators with notice of an alleged violation and a reasonable opportunity to respond, explain the circumstances, and correct the issue. The appropriate action would depend on the nature, seriousness, and

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[150] ALEC Comments on LPSC Staff Initial Report at 13 and Exhibit A at 12; 1803 Comments on LPSC Staff Initial Report, Exhibit A at 14.

[151] ALEC Comments on LPSC Staff Initial Report at 13; 1803 Comments on LPSC Staff Initial Report at 11 and Exhibit A at 14.

duration of the violation, as well as whether similar violations have occurred before. An isolated reporting error should not necessarily be treated the same as a PEN that no longer meets a fundamental qualification requirement.

The Commission could impose corrective conditions and establish a schedule for compliance. However, an opportunity to correct a violation would not permit noncompliance to continue indefinitely. Material or persistent violations could result in suspension or revocation of PEN status. Such action would require a Commission determination after notice and an opportunity to be heard. PEN status would not be suspended or revoked automatically based on an allegation or a single instance of unfavorable compliance data point.

3. Fees, Study Costs, and Taxes.

Section 501 of Staff's initial proposed rules required PEN Operators and/or Identified Load Customers to pay all costs associated with PEN generation, delivery, and internal operations. Section 203 also required PENs to bear the cost of its export interconnection. However, the proposed rules did not specifically address Commission inspection and supervision fees, costs for consultants, outside counsel, or studies needed to review applications and monitor compliance, or applicable taxes. These obligations should be expressly addressed rather than relying solely on the general Ratepayer Harmlessness Principle.

Inspection and Supervision Fees. ELL recommends requiring PEN Operators to pay the Commission's inspection and supervision fees.[152] Staff agrees. PENs would require Commission and Staff review, ongoing reporting, and compliance oversight. Staff recommends requiring PEN Operators to pay applicable Commission inspection and supervision fees to the extent permitted by law.[153]

Direct Consultant, Legal, and Study Costs. 1803 recommends requiring applicants to pay the Commission's reasonable application review costs, including Staff, outside counsel, consultants, and necessary studies.[154] Staff agrees that costs directly attributable to a PEN should be paid by the applicant or PEN Operator and that those costs are chargeable to the PEN Operator under Louisiana Revised Statute 45:1197. These would include consultant fees, outside legal expenses, and studies needed to evaluate the application, interconnection, engineering requirements, cost impacts, and ongoing compliance. Other customers should not bear these costs simply because a PEN requires specialized review. When a study benefits multiple projects or serves several purposes, the amount charged to the PEN should reflect its attributable share. Applicants should also receive credit for existing payments or studies that satisfy the same requirement to avoid duplicate charges.

Legally Applicable taxes. ELL recommends requiring PEN Operators collect and remit the same sales and use taxes that utilities collect and that PEN property be taxed as

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[152] ELL Comments on LPSC Staff Initial Report at 4.

[153] *See, e.g.*, La. R.S. 45:1197.

[154] 1803 Comments on LPSC Staff Initial Report, Exhibit A at 11.

public service property, with the Commission coordinating with the Louisiana Department of Revenue and local authorities.[155]

Staff recommends that the relevant taxing authorities require PEN participants pay all taxes that apply under existing law. Staff further recommends expressly stating that PEN qualification, in and of itself, should not create a tax exemption or determine whether a participant qualifies for an exemption under other law. The responsible tax authorities, not the Commission, would determine which taxes apply, who must pay them, and how they are assessed and collected. The Commission would coordinate only when necessary. This is especially relevant where an arrangement involves several owners or contractual entities, because PEN status does not resolve their separate tax obligations.

Staff further clarifies that inspection and supervision fees, direct review and study costs, and applicable taxes are separate and distinct obligations. Each reflects the broader principle that PEN participants should bear the costs associated with their arrangements. Payment of one is not assumed to satisfy another, although duplicate recovery of the same expense should be avoided.

Staff Conclusion. **Staff recommends several changes to address the procedural and administrative issues identified: (1) establishing a best-efforts decision target of 150 days for uncontested and 230 days for contested applications, measured from publication, with no deemed approval; (2) requiring direct notice to, and allow participation and confidential access to information by, identifiable affected utilities, transmission owners, and wholesale suppliers, without a utility-service prerequisite; (3) requiring intervention for interested parties; (4) requiring service of the Annual Compliance Report to affected utilities; (5) requiring notice within thirty days of discovering noncompliance; (6) providing notice, an opportunity to respond and cure, and loss of PEN status for material or persistent violations after Commission**

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[155] ELL Comments on LPSC Staff Initial Report at 4-5.

determination; and (7) expressly requiring payment of Commission inspection and supervision fees, attributable consultant, legal, and study costs, and all legally applicable taxes, with PEN qualification creating no tax exemption.

Attached to this Final Report is the Clean Version of the Final Proposed Rules (Attachment A) and the redlined version of the Final Proposed Rules (Attachment B).

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing "Staff's Final Report and Recommendation" has been served upon all counsel of record by e-mail this 4th day of November, 2026.

Lauren Temento Evans