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HEARING TO EXAMINE THE STATE OF THE BULK POWER SYSTEM

Chairman Lee and Ranking Member Heinrich, thank you for the invitation to join today's important discussion. On behalf of the competitive power supplier community represented by the Electric Power Supply Association (EPSA),[1] we appreciate the committee's continued focus on both electricity affordability and the present and future reliability of the nation's electric grid during a time of substantial growth in electricity demand. Given the importance of the affordability of electricity, and EPSA's unrelenting commitment to electric grid reliability, I am pleased to highlight how EPSA's policy and regulatory priorities strive to ensure both an affordable and reliable bulk power system.

EPSA is the only national trade association representing America's competitive power suppliers.[2] EPSA members own and operate approximately 225,000 megawatts (MW) of reliable and competitively priced, environmentally responsible generation facilities in all seven U.S. regions operating competitive wholesale energy markets – markets overseen by an Independent System Operator or Regional Transmission Organization (ISO/RTO), and with one exception, regulated by the Federal Energy Regulatory Commission (FERC).[3] EPSA member assets are comprised of a diverse mix of fuels and technologies, including natural gas, nuclear, wind, solar, hydropower, battery storage, geothermal, and coal.

It seems as if a new load forecast announcing significant demand growth not seen in decades is announced almost weekly. It is not an overstatement to say that our nation is at an inflection point relative to demands on the electric grid, and whether these demand increases are driven by the construction of data centers to win the global race to develop Artificial Intelligence (AI), increased domestic manufacturing, digital currency mining, or electrification policies, our nation will need far more electricity in the coming decade (and beyond) than we currently produce. How much more, and when and where that demand will materialize, remains less certain. This uncertainty is not specific just to electricity *demand* but extends to the policy and regulatory environments for building new (and maintaining existing) *supply* as well.

It is this uncertainty that creates perhaps the greatest risks to both reliability and affordability for electricity consumers – the dangers of significantly under- or over-producing capacity during a time of volatile demand projections.

[1] This testimony represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.
[2] https://epsa.org/about-epsa/
[3] Competitive markets in Texas, administered by the Electric Reliability Council of Texas (ERCOT), are not subject to FERC jurisdiction but rather are regulated at the state level.

Fortunately, there are policy and regulatory tools available to hedge this uncertainty. For your consideration, EPSA has identified five solutions (and one word of caution) where both policymakers and regulators can sharpen a simultaneous focus on reliability and affordability while accounting for volatile and constantly shifting demand forecasts. These solutions include continuing to harness the benefits of competitive wholesale energy markets; encouraging bilateral (or co-located) agreements; improving load forecasting; enacting statutory permitting and siting reform; and recognizing that the drivers of recent increases in retail electricity rates – spending on investment other than generation – is regulated at the state level.

I. A COMMITMENT TO WELL-FUNCTIONING COMPETITIVE WHOLESALE ENERGY MARKETS IS THE MOST CONSEQUENTIAL AND IMPACTFUL WAY TO PROMOTE ESSENTIAL INVESTMENT IN GENERATION WHILE PROTECTING RATEPAYERS FROM INEFFICIENT INVESTMENT

Over the last 25 years, competitive markets administered by ISOs/RTOs have definitively proven to be the most efficient and transparent way to meet our nation's electricity needs at the lowest cost while protecting electricity customers from inefficient investment. Well-functioning competitive markets support a reliable power system, foster competition, reward innovation and efficiency, and drive emissions reductions.[4]

However, competitive markets offer more than electric grid reliability. When investors in power plants – like EPSA members – choose to build new assets or upgrade existing facilities, they do so without a guaranteed rate of return or cost recovery for their investment. Competitive power suppliers rely on markets to send efficient price signals for when and where investment in capacity is required (or not required) and compete for the opportunity to recover their costs through those markets. Competitive markets do not offer a negotiated, guaranteed return on equity (ROE) or rate of return for asset owners. If competitive power suppliers make investments that prove to be inefficient or unnecessary, the investors bear the cost of that mistake. The risk of investing in generation remains on the developers and owners of power plants – *not the ratepayer*.

Of course, investment in power plants is a multi-decadal decision. As is true of all state or regional long-term planning efforts relating to the bulk power system, competitive power suppliers make assumptions about future demand and predictions about how regulatory and political environments will prefer to meet expected demand. However, when incorrect assumptions are made, preferences change, or unpredictable macroeconomic events arise to affect the supply/demand of electricity, competitive power suppliers shoulder the financial burden. One need only think back over the last 25 years to consider the unforeseeable events of significant consequence – including the shale gas revolution, the pace of technology change, the rise of accelerated large load additions to the system, and the ever-evolving political landscape – to recognize the folly in assuming that there is a perfect foresight in the electricity supply industry over the next few decades. That guaranteed uncertainty is why EPSA so strongly advocates for markets that immunize electricity customers from the risk inherent in multi-billion-dollar decisions made about investments in power plants.

[4] https://epsa.org/getting-to-the-truth-on-competitive-electricity-markets/

In short, competitive markets keep the cost of inefficient investment on investors' balance sheets and not on retail electricity bills. For brevity's sake, I will briefly highlight a few other issues regarding EPSA's support for competitive wholesale markets.

- Much attention has been paid to clearing prices in the last three Base Residual Auctions (BRAs) in the PJM Interconnection region. PJM is perhaps the epicenter of the national challenge over the effect of data center development on electricity customers and ensuring that the affected states have sufficient capacity to meet rising demand for electricity.[5] PJM is in the midst of an intensive stakeholder process to arrive at both short- and long-term solutions to this challenge, and competitive power suppliers are intently engaged in those discussions.

  What has received far less attention is the response from competitive power suppliers to higher clearing prices in the BRA. For three capacity auctions prior to the 2025/2026 delivery year, capacity prices in PJM were at record low prices – clearing at or below $50/MW-day.[6] However, the auction covering the '25/'26 delivery year (and in the subsequent two BRAs) sent a dramatically different message – PJM needs additional capacity to power the system. I'm proud to say that competitive power suppliers not only heard that message but responded with vigor. Since the '25/'26 BRA results were announced in July 2024, competitive power suppliers have announced over 12 *gigawatts* of new capacity through new investment, uprates, or delayed retirements.[7] The market is responding as quickly as practicable to a dramatic reversal in price signals.

  PJM is grappling with a substantial forecasted increase in demand for electricity, and there is much work yet to be done. But as PJM, stakeholders, and regulators are challenged to find and implement appropriate solutions, we should continue to financially protect ratepayers by ensuring that unnecessary investments or investments that run over budget don't find their way into retail electricity rates.

- While often referred to as "deregulated," competitive markets are, in fact, subject to significant regulation and are better described as "restructured." While *states* (noting the caveat of Texas) *do not* have jurisdiction over wholesale markets, markets are subject to multiple and ever-present layers of thorough regulatory oversight. ISOs/RTOs may have independent market monitors internal to their organization working concurrently with separate independent external market monitors, both of which are backed up by the federal regulator – FERC – to constantly monitor and oversee the appropriateness of bids and clearing prices in competitive markets. Electricity customers can be assured that whether wholesale markets are sending an hour-long signal for short-term electricity generation, or offering a year-long commitment for capacity, there is a "cop on the beat" closely watching wholesale market outcomes. Further, ratepayers also should be mindful that *state* regulators oversee and approve their *retail* electricity rates, which include the cost of wholesale generation.

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[5] PJM was also perhaps the epicenter of Winter Storm Fern, bearing the brunt of bitter cold temperatures throughout the Eastern United States in late January, and operating the grid at near peak demand for one of the longest durations in PJM's history. The experience underscores the importance of a well-prepared fleet of dispatchable resources, and as Senator King is fond of saying, "building the church for Christmas Eve Mass" (relating to the importance of meeting peak demand).

[6] In the three PJM BRAs prior to the '25/'26 delivery year, resources clearing prices were $28.92 ('24/'25), $34.13 ('23/'24), and $50 ('22/'23).

[7] https://epsa.org/wp-content/uploads/2025/12/P3-New-Generation_One-Pager.pdf

- Competitive markets have enabled significant emissions reductions from generation fleets in ISO/RTO regions over the last 25 years. Nationwide, emissions from the overall U.S. power generation sector have fallen dramatically since the advent of competitive markets. Markets administered by ISOs/RTOs reward efficiency and innovation, and in regions where fuel costs and efficiency are significant drivers of competitiveness, the least-cost, most efficient resources will be rewarded. A commitment to wholesale markets has driven emissions and wholesale energy costs down, while improving electric grid reliability.

- EPSA acknowledges that the effect of increased U.S. exports of liquified natural gas on retail electricity rates is a hotly debated topic. It is notable that despite dramatic increases in LNG exports over the past decade, on balance domestic natural gas prices have remained remarkably stable. However, "affordability" advocates should be mindful that no matter how much LNG is shipped from the U.S., inadequate domestic fuel supply *infrastructure* can have a far greater impact on ratepayers in regions that are unwilling to ensure that a sufficient supply of deliverable fuel can benefit electricity customers.

  New England offers a cautionary tale. On the coldest days of the year, New England does not have the necessary supply infrastructure to ensure sufficient levels of natural gas to adequately supply needs for home heating and power generation, requiring the grid operator to lean heavily on older, less efficient oil-fired generators to ensure reliability. January brought bitter cold temperatures to supply-constrained New England, and as a result, natural gas – and wholesale energy – prices increased substantially. The average price of natural gas in New England exceeded $24/MMBtu for the month – up nearly 63% from December 2025.[8] Wholesale energy prices in January were 19% higher than December and 14.5% higher than January 2025. When considering the "affordability" of retail rates, it is important to ensure that insufficient fuel supply infrastructure does not adversely raise fuel prices (and thus electricity prices).

II. VOLUNTARY BILATERAL AGREEMENTS, INCLUDING PHYSICALLY "CO-LOCATED" PARTNERSHIPS – WHICH ISOLATE INVESTMENT RISK BETWEEN COUNTERPARTIES – SHOULD BE ENCOURAGED AS A VEHICLE TO PROTECT RATEPAYERS

The growing interest in voluntary bilateral partnerships between power plants (both existing and new) and large demand customers (like data centers) embody the competitive characteristics and ratepayer protection that wholesale markets encourage. Bilateral financial contracts are not new to competitive markets. Both the supply and demand sides of competitive markets have entered into bilateral agreements for years. However, discussions have recently broadened to include physically co-locating large loads with generation that in some cases may be behind-the-meter entirely. Whether limited to bilateral contracts, or including physical co-location, data centers and generators can drive a more rapid buildout of new infrastructure that *isolates the investment risk to the contracting parties and protects ratepayers from shouldering the cost of any inefficient investment*.

EPSA supports allowing large demand customers to procure their own new generation to provide certainty over their supply cost. For an investor like a hyperscaler, the benefit is a hedge against possible long-term price volatility. For a generator, the upside is certainty of revenue over a given period – a benefit that is rare for competitive power suppliers over a multi-year period. EPSA believes that co-location has the potential to accelerate development of new resources and is consistent with the long-standing use of bilateral agreements.

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[8] https://isonewswire.com/2026/02/25/monthly-wholesale-electricity-prices-and-demand-in-new-england-january-2026/

When considering bilateral agreements and/or co-location, it is important to keep in mind timelines for development. Regarding *dispatchable* generation, it takes four or more years to build a new natural gas power plant, while data centers can be built in a fraction of that time.[9] "Bring your own generation" (BYOG) discussions should be mindful of the practical implication that – in the short-term – BYOG is likely a pairing with an existing generator if the timeframe for data center development is before the end of this decade.

EPSA appreciates and acknowledges all the work that FERC has done – and continues to do – to determine the best way to interconnect large loads while addressing the responsibilities of data centers to shoulder the cost of their energy development and interconnection. There are few blueprints or precedents for FERC to reference, and this issue does not have a single, silver bullet solution. However, a regulatory *and statutory* environment that encourages and incentivizes voluntary bilateral/co-location agreements could be transformative in sparking a wave of innovative investment that can bolster overall electric grid reliability while isolating ratepayers from bearing the cost of inefficient or unnecessary buildout.

III. BOTH COMPETITIVE MARKETS AND TRADITIONALLY REGULATED UTILITIES USE DEMAND FORECASTS AS THE FOUNDATION ON WHICH TO BUILD NEW GENERATION – BLOATED, ASPIRATIONAL, OR IRRATIONAL FORECASTS LEAD TO INEFFICIENCIES AND UNNECESSARY INVESTMENT

The investments required to ensure U.S. dominance over the development of AI and a domestic manufacturing renaissance begin with answers to several important questions. As I mentioned above, the energy industry is tasked with diagnosing how much additional electricity demand is coming, when it will materialize, and where it will be located. These are difficult questions to answer, and the consequences of inaccuracies include both reliability shortfalls and investors left with stranded generation assets, which in some (non-ISO/RTO) regions are backstopped by captive electricity customers.

Thus, we should not rush headlong into potentially trillions of dollars of energy infrastructure investments without a calculated and realistic projection for what infrastructure is needed. In short, accurate load forecasting is foundational – and at the very core – of whether our nation will sufficiently and affordably meet future demand for electricity.

For an example of how rapidly (and significantly) demand forecasts evolve, in early October 2025, it was reported that an investor-owned utility (IOU) in Ohio reduced its previous demand forecast from data centers from 30 gigawatts to 13 gigawatts and has since been further reduced to 5.7 gigawatts – a meaningful reduction resulting from a tariff change that set out the requirement of a financial commitment from data center developers to address their electricity needs.[10]

Accurate load forecasting is critical to ensure that we neither fail to meet the needs of the nation nor spend billions of dollars in capital on what may become stranded assets should load fall short of expectations. Thoughtful load forecasts take time and require more than basing projections on mere inquiries, and EPSA understands that the nation must move quickly to encourage and provide an adequate electricity grid for these investments. But allowing unrealistic or speculative projects to skew demand assumptions – instead of demanding disciplined forecasting – will only harm ratepayers by increasing costs and adding resources that may or may not be needed. EPSA remains engaged with regional grid

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[9] The pressures affecting the building of new dispatchable generation are not unique to competitive power suppliers – rather these challenges are affecting *all* generation developers equally. There is no region in the United States, restructured or vertically integrated, where new dispatchable generation can sidestep the time-consuming processes and supply chain challenges also affecting competitive power suppliers.

[10] https://www.datacenterdynamics.com/en/news/aep-ohio-slashes-data-center-pipeline-by-more-than-half-report/

operators and regulators to identify ways to ensure more realistic, accurate, and verifiable forecasts for this growing demand.

IV. PERMITTING REFORM IS PERHAPS THE MOST IMPACTFUL BENEFIT THAT CONGRESS CAN PROVIDE THE ENERGY INDUSTRY TO IMPROVE RELIABILITY AND ASSIST IN "AFFORDABILITY" EFFORTS

For years, generators were often frustrated by prolonged waits in regional interconnection queues to receive interconnection agreements (IAs). However, due to recent efforts in virtually all markets, queue processes continue to deliver meaningful improvements and faster processing times. The current dilemma, however, is energy generators are now experiencing a glut of proposed investments that have received IAs yet continue to be stymied when trying to navigate the permitting process. For example, there are more than 71 gigawatts of resources through the queue in the PJM Interconnection that are not yet adding electrons to the system or under active construction and development.[11] In March, the Midcontinent ISO (through its Commercial Operations Date Report) indicated that it had cleared over 75 gigawatts of proposed investment through its queue that now have interconnection agreements that have not yet been constructed, with over 40 gigawatts of that generation "delayed" having run into various hurdles to completion and operation.

EPSA appreciates the broad support for statutory permitting reform in Congress. Permitting reform will minimize development costs and lead to the more efficient construction and interconnection of new generation. However, EPSA recognizes that "permitting reform" can be a nebulous, undefined concept, and would like to highlight several specific examples of excellent work already done on permitting reform (recognizing that the Senate Environment & Public Works Committee also has a key role to play in Senate discussions).

- H.R. 4776,[12] the Standardizing Permitting and Expediting Economic Development (SPEED) Act includes bipartisan language that attempts to provide permitting certainty to protect projects across administrations. Power plants are multi-decade assets – investors value certainty and now is the time to reverse the precedent of permitting whiplash (affecting both dispatchable and intermittent generation) and provide stability to investors.

- In September 2024, EPSA joined an amicus brief[13] at the U.S. Supreme Court in *Seven County Infrastructure Coalition v. Eagle County, Colorado*, supporting the petitioner's challenge to what has become an expansive approach to the effects assessed by federal agencies in their National Environmental Policy Act (NEPA) environmental reviews of new infrastructure projects. The SPEED Act provides valuable codification of the NEPA reforms outlined in the Court's *Seven County* ruling.

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[11] https://epsa.org/pjm-interconnection-reform-permitting-barriers/

[12] https://www.congress.gov/bill/119th-congress/house-bill/4776

[13] https://epsa.org/wp-content/uploads/2024/09/Supreme-Court-23-975-Seven-County-Merits-INGAA-et-al-Amius.pdf

- In the prior Congress, this committee passed the Energy Permitting Reform Act.[14] Title I of the bill includes prudent and responsible guardrails on the legal process for awards and review of key federal permits. EPSA appreciates the inclusion of reasonable timelines for the legal process to unfold and to prevent drawn out, undefined delays in federal permitting. Title V of the bill would wisely create a process for FERC to harness the expertise of the North American Electric Reliability Corporation (NERC) when considering possible adverse impacts on electric grid reliability of proposed federal rules. The language does not appear to put a significant onus on FERC, as its role appears to be limited to directing NERC to conduct reliability analyses and to make those studies public.

As permitting reform negotiations have now restarted in earnest, Senators need not reinvent the wheel when valuable work on impactful reforms has already been done; instead, the Senate can utilize the existing work product to more expeditiously address these crucial issues and deliver development wins for the nation.

V. RECENT STUDIES HAVE CONCLUSIVELY SHOWN THAT INCREASES IN RETAIL ELECTRICITY RATES HAVE BEEN DRIVEN BY SPENDING ON TRANSMISSION & DISTRIBUTION – NOT FROM GENERATION.

In 2025, both the Lawrence Berkeley National Laboratory[15] (LBNL) and Energy Tariff Experts[16] (ETE, in conjunction with EPSA) released findings from separate studies identifying drivers of retail rates. Both studies – conducted independent of one another – returned remarkably similar conclusions. Increases in retail electricity rates in the last few years *are not* the result of investment in new generation – rather, spending on transmission & distribution (T&D) infrastructure has resulted in higher costs.

LBNL summarized its findings by noting that "Distribution (and transmission) expenditures have contributed to retail price increases, whereas direct generation costs have declined nationally… Over the last two decades, aggregate investor-owned utility (IOU) spending on distribution and transmission increased in real, inflation-adjusted terms, whereas expenditures on generation generally declined." LBNL identified several drivers of this T&D spending, including replacing aging equipment, hardening and resilience upgrades, and supply chain challenges. While these upgrades may be necessary, captive electricity customers incur the cost directly.

Regarding the ETE study, which focused specifically on the PJM Interconnection region, the analysis examined "average residential retail electric bills over the past decade to evaluate the costs of generation from the PJM Interconnection market along with other costs such as distribution, transmission, and public policy programs that make up the total bill." The study clearly found that the cost of wholesale generation in the PJM region — as a percentage of a customer's retail bill — had held relatively steady, or in some cases even declined in the last decade. However, the study found that the cost of building electric transmission & distribution infrastructure has driven retail rate increases along with costs associated with state policy choices.

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[14] https://www.congress.gov/bill/118th-congress/senate-bill/4753
[15] https://eta-publications.lbl.gov/sites/default/files/2025-10/presentation_retail_price_trends_drivers.pdf
[16] https://epsa.org/wp-content/uploads/2025/05/EPSA-ETE-Study_2025.5.14-FINAL.pdf

To be clear, this is not a criticism of utility investments in distribution and transmission assets. Our nation is coming out of a prolonged period of minimal increases in electricity demand, marked by lower wholesale energy prices. There will be an investment cost to not only build new generation, but for the poles and wires to improve and strengthen the transmission and distribution system. For instance, in late 2025, the Edison Electric Institute, which represents U.S. investor owned utilities, estimated that its members will spend over $1.1 trillion on grid enhancements in the next five years.[17] While these investments are valuable to reliability and grid efficiency, relative to the "affordability" discussion, it is important to identify the economic drivers impacting retail energy bills, and where regulators choose to place the investment risk.

VI. REVERSING COURSE TO ALLOW UTILITY OWNED GENERATION IN RESTRUCTURED MARKETS TURNS A BLIND EYE TO WHY COMPETITIVE MARKETS WERE CREATED, DOESN'T SOLVE THE UNDERLYING CHALLENGES TO INTERCONNECTING NEW GENERATION, AND PUTS RATEPAYERS BACK ON THE FINANCIAL HOOK FOR ILL-ADVISED INVESTMENTS

Rapid demand growth in the PJM Interconnection has led to concerns about whether sufficient capacity will be developed in the coming years to meet that demand. Some have seized on this discussion to advocate for allowing investor-owned utilities to once again build and operate power plants, reversing nearly 30 years of restructured experience. Of course, this proposition is rooted in the requirement that the cost of investing in this new generation would be paid for – with an agreed-upon guaranteed rate of return – through retail electricity rates. As noted above, should unpredictable events render the capacity unnecessary before the end of its useful life, or the technology itself obsolete, ratepayers still foot the bill plus the return on equity. Advocates for this radical change in approach argue that somehow IOUs have a much clearer line of sight into formulating *multi-decadal* projections into the long-term needs of their state/region.

Of course, even with the guaranteed profit through a captive ratebase, no generation developer has a silver bullet for navigating permitting and siting challenges. While improvements have been made, every generation developer faces the same interconnection and permitting processes, regardless of the regulatory framework. Similarly, chronic workforce and supply chain shortages (particularly for natural gas turbines and substation equipment) pose the same challenges to *all* developers and are not somehow overcome with a guaranteed ROE. So, reversing course to allow monopolies that haven't built generation in decades to suddenly put ratepayers back on the hook for new assets overlooks the core reliability and affordability tenants that prompted the creation of competitive markets nearly thirty years ago.

Thank you again for the opportunity to participate in today's hearing, and I look forward to EPSA's continued engagement with the committee on issues affecting electric grid reliability and affordability.

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[17] https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Energy-Grid/Fact-Sheet-Grid-Resilience.pdf