For a Nuclear-Free, Carbon-Free World
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Via Federal Register Online Submission For
Office of Associate Chief Counsel (Passthroughs & Special Industries)
Internal Revenue Service
CC:PA:LPD:PR (REG–117631–23)
Room 5203
P.O. Box 7604
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Washington, DC 20044

Re: Request for Comments on Proposed Rule (REG-117631-23) – Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property

Dear Associate Chief Counsel:

Thank you for the opportunity to provide the Internal Revenue Service (IRS) with input on the regulations governing provisions of the Inflation Reduction Act (IRA) relating to clean hydrogen production: Section 45V Credit for Production of Clean Hydrogen; and Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property.

These regulations will play an important role in shaping our country's energy supplies and infrastructure, energy costs, greenhouse gas (GHG) emissions, and other environmental impacts of energy production and consumption. The Nuclear Information and Resource Service ("NIRS") hereby provides our comments, which focus, in particular, on the importance of IRS's proposed requirements for qualifying Energy Attribute Certificates (EAC), i.e., incrementality, temporal matching, and deliverability; and the questions posed in the Federal Register Notice about exceptions to the incrementality requirements for electricity generated by nuclear power plants that do not meet the proposed commercial operations date (COD) criterion.

Alignment with the National Hydrogen Strategy

There is a high risk for both dramatic cost escalation and emissions impacts of the 45V hydrogen production credit (H2PTC) if the regulations are not closely aligned with the *U.S. National Clean Hydrogen Strategy and Roadmap (NCHSR),* published by DOE in June 2023 as required by the Infrastructure Investment and Jobs Act of 2021 (IIJA).[1] The EAC qualification criteria for

[1] U.S. Department of Energy. *U.S. National Clean Hydrogen Strategy and Roadmap.* June 2023. https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf

incrementality, temporal matching, and deliverability are essential to assuring that H2PTC claims comply with the statutory greenhouse gas (GHG) emissions standards of the authorizing legislation. As the IRS has recognized in the proposed rule, if existing low-/zero-GHG-emitting generation is diverted to supply hydrogen production, then it must be "replaced" to meet remaining electricity loads on the grid. A recent study examined the emissions impact of using electricity from existing power plants, including a hydrogen demonstration project at an existing nuclear power plant. It finds that the electricity supply diverted to hydrogen production "has to be made up by generation elsewhere, which includes both fossil fuel and zero-emission generation":

> Thus, the net impact on New York State's GHG emissions would be that non-zero emissions electricity replaces zero emissions electricity. The actual impact depends on the assumptions about the emissions profile of the replacement electricity. If it is the average of electricity sales in New York – which includes a large amount of in-state generation as well as imported hydropower, the net emissions in [sic] amount to about 18 kg CO2-eq/kg hydrogen; this is considerably worse than the 14.6 kg CO2-eq emissions for grey hydrogen at the current 2.7% methane leak rate. If natural gas plants that now operate at a low capacity factor supply the electricity, the emissions would rise to more than 40 kg CO2-eq per kg hydrogen.
>
> The same reasoning would apply if existing wind, solar geothermal, or hydropower were diverted to make hydrogen; the specific impact per unit of hydrogen would be worse than New York in most places because New York has more zero-emission electricity in its usage profile than most other states. … The example above illustrates the concept of 'additionality':[2] green/pink hydrogen are only truly zero-emissions if new electricity generation capacity is installed to produce the hydrogen. If additionality is ignored, then producing hydrogen would take clean electricity away from other applications, causing fossil-based electricity to ramp up elsewhere in the grid.[3]

In practical terms, for hydrogen to be produced at scale, it would take thousands of megawatts of generation capacity to power electrolysis systems that produce the volumes of clean hydrogen targeted by the NCHSR (10 million metric tonnes per year (MMT/year) in 2030). In a given region, this may amount to hundreds of megawatts of generation capacity. For instance, a key

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[2] Similar principles to those encompassed by the incrementality requirement in the proposed rule are described, in other contexts, as "additionality"—that the new electricity loads required for clean hydrogen production must be supplied by new "additions"/"increments" of low-/zero-emissions generation. There may be definitional differences in how energy sources qualify, but the terms characterize requirements with broadly similar principles.

[3] Makhijani, Arjun, and Thom Hersbach. "Hydrogen: What good is it? A technical exploration of the potential of hydrogen to contribute to a decarbonized energy system." Just Solutions Collective. January 2024. https://justsolutionscollective.org/wp-content/uploads/2024/02/Hydrogen-What-Good-is-it-by-IEER-r2.pdf

element of one project receiving an award under DOE's Regional Hydrogen Hub Demonstration Program (RHHDP), is the installation of a 250 MW electrolysis system at the LaSalle Nuclear Power Plant.[4] As there is no incrementality requirement under the RHHDP, the LaSalle reactors' generation that will power electrolysis may be replaced, in real time, by ramping up generation from other sources in the PJM market. The advantage of the incrementality requirement is that it guarantees, as much as possible, that electrolysis equipment is powered, in real time, by new zero-emissions electricity sources.

Additionally, the proposed EAC requirements will best support one of the key elements of the NCHSR, i.e., to reduce the levelized cost of clean hydrogen production by 80% by 2030. In that regard, the role of the H2PTC is not to serve as an electricity generation subsidy for unprofitable power plants; but, rather, to reduce the sale price of clean hydrogen to make its wide adoption affordable to end users in sectors where it can have the highest impact in reducing GHG emissions. As explained further herein, the NCHSR seeks to reduce the cost of clean hydrogen, in part, by reducing the amount of electricity required to produce it. Permitting exemptions to EAC criteria that would apply the H2PTC as an electric generation subsidy would be ineffective, and possibly counterproductive, by increasing the sale price of clean hydrogen and, thereby, impeding its adoption at the scale required to reduce GHG emissions in the high-impact economic sectors targeted by the NCHSR.

We also find that the rationales considered for granting exemptions for existing nuclear and renewable generation sources are unavailing. Regions of the country where electricity sector emissions are low, and an existing nuclear or renewable generation source is unprofitable, are generally those with robust renewable energy growth, making EAC exemptions unnecessary and uneconomic. Also, formulaic approaches to allowing H2PTC claims would be ineffective at preventing retirements of unprofitable generation sources, and would be exceedingly wasteful. Unprofitable facilities that might be retired would not receive enough support to make their continued operation economical, except as an incentive for uneconomic generation to secure market share against more affordable new generation sources.

Further, the formulaic approach under consideration would disconnect H2PTC claims from the actual production and end use of qualified clean hydrogen, at great taxpayer expense and without advancing the adoption of clean hydrogen in the high-impact sectors targeted by the NCHSR. Applying the H2PTC formulaically to all existing nuclear and/or renewable sources would provide awards at levels that would be marginal to each facility: not enough to make ends meet for some, and completely unnecessary for many more, but incurring a large cost to taxpayers nonetheless. We find there is no convincing reason to veer from the proposed EAC requirements

[4] Good, Allison. "Constellation to build $900M green hydrogen production facility." S&P Global Market Intelligence. February 16, 2023. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/constellation-to-build-900m-green-hydrogen-production-facility-74372628

by creating exemptions that would apply the H2PTC as an electricity subsidy. There are other financial supports for nuclear and renewable generation sources, including the clean electricity production and investment credits (CEPTC and CEITC), the nuclear production credit (Nuclear PTC), and the Civil Nuclear Credit program.

The NCHSR includes "three key strategies to ensure that clean hydrogen is developed and adopted as an effective decarbonization tool for maximum benefit to the United States."

The first strategy of the NCHSR is, "Target strategic, high-impact uses for clean hydrogen." Those uses include "the industrial sector (e.g., chemicals, steel and refining), heavy-duty transportation, and long-duration energy storage to enable a clean grid." Targeting hydrogen production to high-impact end uses is essential, because producing clean hydrogen is a highly inefficient use of electricity. Electrolyzers require up to 52.5 kilowatt-hours (kWh) of electricity to produce 1 kilogram (kg) of hydrogen, yet the energy content of hydrogen is only 39.4 kWh/kg – 25% less potential energy than the electricity used by the electrolyzer.[5]

Researchers have recently reported achieving technological improvements that may make it possible to achieve efficiencies in electrolysis of up to 95%, reducing the electricity required to produce 1 kg of hydrogen with only 41.5 kWh of electricity. Such technological advances would support the NCHSR's cost reduction pathway. However decreasing the amount of electricity required for clean hydrogen production would further reduce the share of H2PTC claims that could pass through to providers of the electricity input to the process.

Converting hydrogen to electricity entails substantial energy losses: hydrogen fuel cells have an efficiency of about 60%, and combustion turbines are about 40.3% efficient, resulting in further energy losses of 40% to 59.7%. If hydrogen combustion is used in a cogeneration system, through which waste heat is recaptured and used for space heating or industrial processes, combustion efficiency can be increased to 90%, still resulting in a net loss of 32.5% of the electricity used to produce clean hydrogen. Thus, depending on the end use, clean hydrogen results in an electricity loss of nearly one-third for the most efficient applications; and losses of 55%-70% when used in the most common electricity generation applications (fuel cells and combustion turbines).

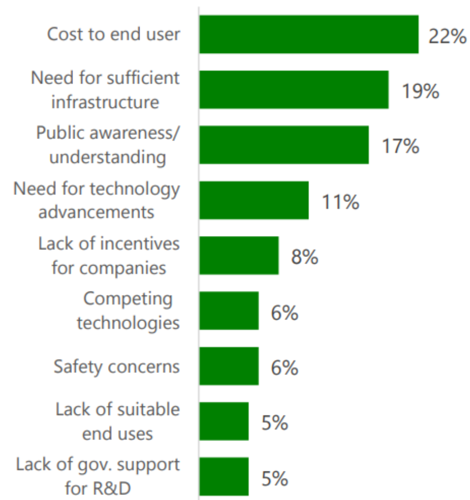
As IRS has recognized in promulgating the incrementality requirement for EACs, diverting low-/zero-emissions electricity generation to clean hydrogen production would have a self-defeating effect of increasing GHG emissions, if zero-emissions generation were replaced on the grid with electricity produced by fossil fuel sources. For that reason, the first and best use of renewables and low-/zero-emissions generation is for grid power. Furthermore, if new low-/zero-emissions

[5] Blain, Loz. "Record-breaking hydrogen electrolyzer claims 95% efficiency." New Atlas. March 16, 2022. https://newatlas.com/energy/hysata-efficient-hydrogen-electrolysis/

generation can be brought online rapidly enough to prevent existing nuclear or renewable generation from being replaced on the grid with fossil fuel sources, then an exemption from the incrementality requirement would be unnecessary. The incrementality criterion is, therefore, essential to assuring that clean hydrogen production satisfies the emissions standards of the IRA and does not simply shift GHG emissions from other sectors to the electricity sector.

The NCHSR's second strategy is to "Reduce the cost of clean hydrogen." According to DOE (emphasis added):

> <ins>Stakeholder input continuously identifies the cost of clean hydrogen as a key challenge for achieving economic scale.</ins> … As shown in Figure 15, cost was the most widely selected barrier, but the lack of infrastructure and the need for public awareness and acceptance were also identified as major challenges. Incentives in the BIL and IRA are expected to drive meaningful progress down the cost curve within the decade.



> <ins>The levelized cost of hydrogen must be reduced significantly.</ins> For example, based on analysis in 2020, the cost of clean hydrogen using proton exchange (or polymer electrolyte) membrane (PEM) electrolysis can be over $5/kg when using renewable electricity. <ins>Furthermore, the cost of electrolysis depends heavily on the cost of electricity used.</ins> Hydrogen from low-volume PEM electrolysis requires an 80 percent reduction in cost to achieve the Hydrogen Shot goals and to be competitive. While advanced and high-temperature electrolyzers are progressing, challenges to market adoption include the cost, durability, and scale of manufacturing capacity.

Through the Hydrogen Energy Earthshot (Hydrogen Earthshot) program it launched in 2021, DOE set a goal of reducing the cost of clean hydrogen from $5.00/kg to $2.00/kg in 2026 and $1.00/kg in 2031, in order "to unlock the market potential for clean hydrogen." The NCHSR has since incorporated the Hydrogen Energy Earthshot's strategy and targets. The H2PTC can play a key role in achieving these cost reductions, if the regulations direct the credits toward helping achieve economies of scale in production of clean hydrogen. The value of the subsidy will be greatest if it enables cost reductions through scaling up manufacturing of electrolysis systems. In the hydrogen production chain, electricity is a key input. As such, the cost of qualified EACs to power electrolyzers must be as low as possible. But if the value of the H2PTC is used to subsidize higher-cost sources of electricity, that will be reflected in higher sale prices of the hydrogen that is produced. Higher prices of clean hydrogen will result in lower demand. That will, in turn, result in slower deployment of hydrogen infrastructure, lower economies of scale in manufacturing, and a slower rate of cost-reductions.

Postulated Energy Attribute Credit Exemptions

As detailed below, the Nuclear PTC has effectively established a sort of revenue floor for existing nuclear power plants, of $40.00/MWh. If a nuclear reactor's operating costs are higher than that, and the combination of revenues, the Nuclear PTC, and/or state subsidies are insufficient to cover its operating costs, it would nevertheless be counterproductive to create an exemption for the H2PTC to further subsidize that reactor's costs of operation. Doing so would increase the cost of clean hydrogen, thereby also reducing demand for clean hydrogen and undermining the national hydrogen strategy:

- The $3/kg value of the H2PTC would play a key role in meeting DOE's targets for clean hydrogen cost reductions. At DOE's estimated $5/kg average cost of production for clean hydrogen, the tax credits would enable current technology to achieve DOE's mid-range (2026) target price of $2/kg.
    - The NCHSR's mid-range cost target ($2/kg) relies upon achieving early cost reductions in a range of clean hydrogen inputs: electricity, capital, and fixed operation and maintenance (O&M).
        - In DOE's modeling, capital and O&M costs of electrolysis are reduced by $1.75/kg, from about $2.25/kg to around $0.50/kg.
        - Electricity costs are reduced by about $1.25/kg, from around $2.75/kg to $1.50/kg. Electricity cost savings are expected from two factors: improving the energy efficiency of electrolyzers, so less electricity is required to produce 1 kg of hydrogen; and by operating electrolyzers intermittently, primarily when electricity costs are low.
            - At $1.50/kg, that would imply an electricity cost of $28.15/MWh to $36.14/MWh, depending on the efficiency of the electrolysis equipment. In any case, utilizing electricity from reactors that operate at more than $40.00/MWh would be uneconomic for meeting the goals of the NCHSR.
    - The H2PTC stands to jumpstart these cost reductions by subsidizing a reduction in the sale price of clean hydrogen, spurring demand for clean hydrogen and further buildout of production capacity. Reductions in capital cost and technological improvements rely on increasing the scale of manufacturing electrolysis equipment. As production scales up, innovation-learning curves would drive further technological and process improvements.
- Exempting unprofitable reactors so that the H2PTC becomes an electricity subsidy would short-circuit that virtuous cycle, by increasing the cost of clean hydrogen, making it more difficult if not impossible to meet DOE's target prices.

    - Per the analysis below, doing so could require allocating between \$2.02/kg and \$2.56/kg of the H2PTC toward electricity costs, consuming 67% to 85% of the value of the H2PTC for one input into the cost of clean hydrogen, and leaving only a fraction to defray the cost of other inputs, for which the majority of mid-range cost reductions are required.
- The higher the price for clean hydrogen, the lower will be the demand for it, because the cost proposition of adopting clean hydrogen as a fuel or energy carrier will be less cost-effective for end users. Lower demand will undermine the potential for scaling of manufacturing capacity and technological innovation to achieve the \$1/kg production cost target.
    - Slowing deployment of high-impact applications for clean hydrogen will compromise the country's ability to realize emissions reductions, which is the ultimate rationale for the H2PTC and the goal of the NCHSR and the Hydrogen Energy Earthshot program.

Higher electricity input costs will increase the cost of hydrogen to end users. For every \$10/MWh the H2PTC is applied to subsidize the cost of nuclear generation, the cost of hydrogen would increase by \$0.415 to \$0.526 per kg, depending on the efficiency of the electrolyis equipment.

- If only a portion of the reactor's generation capacity is used to produce hydrogen, the portion of the H2PTC that would have to be applied as an electricity subsidy would be proportionally greater, in order to meet the reactor's operating costs.
    - For instance, if an 800 MW reactor's operating costs were \$48.75/MWh, it could require a subsidy of at least \$5/MWh, after the combination of sales revenue, the Nuclear PTC, and/or other subsidies. But if only 200 MW of its capacity were used for hydrogen production, then it would require the equivalent of \$20/MWh in subsidies from the H2PTC to meet its operating cost, in addition to the cost of the "market value" of the electricity used for clean hydrogen production.
- Assuming the \$15/MWh value of the Nuclear PTC were applied to the share of electricity used for hydrogen production, the cost to be covered by hydrogen sales and the H2PTC would be at least \$48.75/MWh, or \$5.058/kg to \$6.411/kg.
    - At a generation cost of \$48.75/MWh, and with the Nuclear PTC and H2PTC providing revenue equivalent to \$15/MWh and \$5/MWh respectively, the remaining cost of nuclear generation to be covered from other revenue sources would be \$28.75/MWh. If only 25% of the reactor's generation were allocated to clean hydrogen production, the effective amount of the H2PTC that must be applied to electricity costs would be four times greater than \$5/MWh.
    - The hydrogen production cost would then have to internalize the electricity revenue price (\$28.75/MWh) and the equivalent of \$20/MWh from the H2PTC. At conventional electrolyzer efficiency rates of 52.5 kWh/kg of hydrogen,

$48.75/MWh is equivalent to $6.411/kg, more than DOE's projection of the total production cost of clean hydrogen today.

        - At significantly higher efficiencies of 95% (41.5 kWh/kg) recently achieved in laboratory tests of new electrolysis technologies, $48.75/MWh in electricity cost would still be $5.058/kg.
    - With current capital and O&M costs of $2.25/kg, the total cost of hydrogen would be $7.308/kg to $8.661/kg, or $4.308 to $5.661/kg after the H2PTC were applied. Even if all of the capital and O&M cost reductions that DOE has modeled were still achieved by 2030, the $2/kg in additional savings would still result in a price of hydrogen of $2.308 to $3.661/kg in 2030, 130% to 266% greater than the Hydrogen Energy Earthshot target of $1/kg.
- Increasing the cost of electricity inputs to clean hydrogen production would introduce a new obstacle to achieving the $1/kg target.
    - Using the H2PTC to subsidize higher cost electricity from uneconomical nuclear reactors would run counter to the strategy for reducing clean hydrogen production. As described above, nuclear reactors operate most cost-efficiently at full capacity, and they function as "price-takers" in the electricity market–selling all of their output at whatever the hourly wholesale clearing price is. For a nuclear reactor to produce hydrogen intermittently and still realize a significant amount of revenue from the H2PTC, it would need to power a much larger electrolyzer.
        - For instance, using the example above, a reactor owner would either have to build a 200 MW electrolyzer and run it constantly, or it would have to build 800 MW of electrolysis capacity and operate it 25% of the time, primarily at times when electricity prices are low.
        - The capital cost of a larger electrolysis system would be greater than the smaller system, but that cost would be recovered over the same volume of hydrogen produced, significantly increasing its contribution to the unit cost of the final product.

Costs and Economics of Existing Nuclear Generation

Nuclear power plant economics are dominated by fixed-cost expenses, with low-/minimal variable costs. This is due to a number of factors, the combination of which is unique to the nuclear industry:

- High capital cost for construction and maintenance.
- Large staffing requirements, resulting in high employment costs. Workforce size varies from plant to plant, but not in direct proportion to the generation capacity of the reactor. The dominant factor is whether the site contains one or multiple reactors. Single-reactor sites typically have a permanent workforce of 600 or more. Two-reactor sites typically have a workforce of 800 or more. Merchant reactors tend to have smaller workforces than utility reactors, through cost-reduction measures.

- Fixed fuel costs. While fuel accounts for a relatively small share of total operating costs,[6] it is treated as a fixed capital expense, "because it is a long-lived tangible asset that meets the definition of property, plant, and equipment."[7] Nuclear fuel assemblies are used for power generation for staggered periods of 4.5 to 6 years. Reactors shut down to replace one-third of the fuel assemblies on regular intervals, every 18 to 24 months. The frequency or amount of fuel purchased generally does not vary based on the power output of the reactor: if a reactor endures an unplanned outage and does not generate as much electricity as anticipated, it usually does not change the refueling schedule.

Because of this high fixed-cost structure, nuclear reactors are typically only economical to operate at full-power, generating and selling as much electricity as possible to reduce the unit-cost of operations. Technical features also limit nuclear reactors' ability to vary their output in response to market prices or electricity demand. For these reasons, merchant nuclear reactors operate as "price-takers" in wholesale power markets, benefiting during periods when market prices are high and taking losses when prices are low.

Reactor-Specific Factors affecting Operating Costs and Retirements

The operating cost of any given reactor is shaped by fixed characteristics, primarily the generation capacity of the reactor and whether it is the sole operating reactor or part of a multi-reactor power plant. There is wide variation in generation capacity of individual reactors and nuclear power plants: from the single-reactor R.E. Ginna Nuclear Power Plant, with 582 MW of generation capacity, to the three-reactor Palo Verde Nuclear Generating Station with 4,200 MW of capacity. Staffing and other fixed costs are not proportionally greater for larger reactors, so smaller reactors must recover similar costs from a smaller volume of electricity sales, raising their unit cost of operations. Older reactors also tend to be smaller than younger reactors, because of the way the industry scaled up generation capacity in the 1960s-1970s to achieve cost efficiencies, compounding adverse economies as the reactor ages.

Nuclear reactors' operating costs also vary over their operational histories. Capital costs remain high in the first 10-20 years of operation, due to high construction costs. Many reactors encounter large capital expenditures in mid-life for major maintenance projects, such as replacement of steam generators or extended power uprates. Costs begin trending upward between 20-30 years of operation, due to relicensing expenses and rising maintenance costs as large numbers of components, structures, and systems begin wearing out.

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[6] Nuclear Energy Institute. "Nuclear Costs in Context." December 2023.
https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context

[7] "14.3 Accounting for nuclear fuel." PwC. January 19, 2024.
https://viewpoint.pwc.com/dt/us/en/pwc/accounting_guides/utilities_and_power_/utilities_and_power__US/chapter_14_nuclear_p_US/143_accounting_for_n_US.html#pwc-topic.dita_1605044308166270

Due to these combinations of factors, smaller, older, reactors in single-unit power plants tend to face higher operating costs that can make them uncompetitive; while larger, mid-life reactors in multi-unit power plants tend to have the lowest operating costs. Of the thirteen reactors that retired from 2013 to 2022, nine had generation capacities below the industry average (1,013 megawatts in 2013), nine were at single-unit nuclear power plants, and nine operated in merchant power markets. The four retired reactors that operated under cost-of-service ratemaking faced extenuating circumstances: three encountered extraordinary maintenance costs due to extended outages arising from mismanaged steam generator replacement projects, which state regulators deemed imprudent and would not allow cost recovery; the fourth was the smallest nuclear reactor in the country at the time (476 MW), and one of the oldest (43 years old in 2016), leading the utility to retire it in favor of generation sources that would be more affordable for its customers.

The U.S. nuclear fleet is substantially older than the world average of 31.4 years. Originally licensed and expected to operate for 40 years, the average age of the 93 reactors in the U.S. was 42.1 years in mid-2023; more than half (49 of 93) were over 40 years old, of which 10 were over 50 years. While under 25% of operating reactors worldwide are in the U.S., 53% of reactors over 40 years old and 77% of reactors over 50 are in the U.S. From 2002-2012, average operating costs for nuclear power plants rose by 50%, or about 4.5% per year, on average. Cost increases were largely driven by higher maintenance and capital costs and an industry-wide wave of applications to the Nuclear Regulatory Commission (NRC) for extensions of the original 40-year operating licenses, indicators of the advancing age of the reactor fleet. At the end of that period, nuclear generation companies announced the retirements of five reactors in a ten-month period--the first reactor closures in the U.S. since the late 1990s.

Historical and Industry Trends affecting Nuclear Power Plant Economics

The 15-year period in which no U.S. reactors retired (1998-2013) spanned three fundamental shifts in the power generation sector:[8]

- **The "deregulation" (or "restructuring") of electricity markets.** Nearly half of the states in the U.S. transitioned to competitive markets for pricing and sales of electricity generation and ancillary grid resources. Approximately half of the reactors in the U.S. became merchant power plants, earning revenue through wholesale markets and/or bilateral power contracts with utility companies; the remainder of nuclear generation continued to be owned and operated by vertically-integrated utility companies, which recover their capital and operating costs and a regulated amount of profits through "cost-of-service" rates approved by state utility regulators.
- **The "shale revolution"** in fossil gas extraction. Legislation enacted in 2005 allowed for widespread deployment of high-pressure horizontal hydraulic fracturing technologies.

[8] Wind Energy Technologies Office. "Wind Is Changing Pricing Patterns in Wholesale Power Markets." U.S. Department of Energy. June 1, 2020. https://www.energy.gov/eere/wind/articles/wind-changing-pricing-patterns-wholesale-power-markets

This resulted in massive expansions of fossil gas supplies within a few years, and persistent downward trends in wholesale prices for electricity throughout much of the country, but particularly in states that had deregulated.
- **The "green energy revolution."** Since 2000, many states have established programs to promote renewable energy and energy efficiency, leading to stagnant or declining growth in electricity demand and declining costs for wind and solar photovoltaics (PV). These trends placed further downward pressure on electricity market prices after 2010. The introduction of new technologies and generation sources have placed intense competitive pressures on legacy/incumbent generation sources. Federal energy efficiency standards and tax credits, and global expansions of wind and solar and supply chains, further amplified the trends, resulting in wind and solar costs declining by 70% and 90%, respectively, between 2012 and 2022.

Amid these shifting conditions, the transition of a significant portion of the nuclear industry into the merchant generation sector spurred a number of trends within the nuclear industry, which have had long-term implications:
- In the 1990s transition to wholesale power markets, states awarded approximately $130 billion (2016 dollars) in bailouts of nuclear utilities' stranded costs for reactor construction, in the transition. This allowed merchant reactors to enter wholesale markets, largely without legacy capital cost burdens.
- Consolidation of reactor ownership through utility mergers and sales of reactors, enabling cost efficiencies through workforce reductions, vendor and materials procurement, outage planning, etc.[9]
- Surging electricity prices linked to natural gas prices in the early 2000s through 2008, delivering sustained high profit margins for several years.
- Lightened regulations and enforcement, requiring fewer shutdowns for maintenance, shorter refueling outages, and reduced or deferred maintenance costs.
- Investments in generation capacity increases of existing reactors ("power uprates"). Between 1996 and 2014, the industry implemented 127 power uprates, adding approximately 6,000 MW of generation capacity. Power uprate projects frequently encountered cost overruns, which did not improve the overall operating costs of reactors. After 2014, companies shelved or canceled several proposed power uprates, because they found them uneconomical in the face of lower market prices for electricity.

[9] During the first decade of deregulation, utility companies sold 19 reactors to merchant generation companies; and utility holding companies transferred ownership of 29 reactors from utility subsidiaries to merchant generation subsidiaries. Mergers and acquisitions have further concentrated reactor ownership. Since 2015, four holding companies have divested their nuclear power plants by spinning off their merchant generation businesses to newly formed, separate corporations; and two have exited the merchant nuclear generation business by retiring and/or selling all of the reactors they owned.

Recent State and Federal Subsidies for Existing Reactors

Between 2015 and 2019, corporations announced their intent to retire thirteen other merchant reactors with similar cost profiles (older, smaller, and/or single-units in merchant power markets with persistently low prices), but have continued operating them after state-level policy decisions that promised financial assistance. Currently, there are 18 merchant reactors operating with some form of state-mandated, ratepayer-funded financial assistance. For twelve of those reactors, state subsidies range from $9.70 per megawatt-hour (MWh) to $18.26/MWh; the remaining six receive a more modest subsidy enacted in Illinois in 2021, which averages approximately $2.60/MWh. Not all reactors receiving state subsidies were subject to retirement notices, nor were all of them unprofitable prior to receiving the subsidies. Owners had announced plans to retire two of four now-subsidized reactors in New York, and seven of nine in Illinois. New Jersey authorized subsidies for three reactors, although their majority owner (the utility holding company, PSEG) stated that, while they operated at a net profit, a subsidy was necessary to justify their continued operation, by assuring an 18% rate of return.[10]

By contrast, utility-owned reactors do not require subsidies and are not at risk of retirement due to wholesale market conditions, because their operating costs are covered through cost-of-service electricity rates approved by state utility commissions. As explained above, the four utility-owned reactors that have retired in the previous decade did so, either because they faced large, unrecoverable costs due to mismanaged maintenance projects, or because the utility company determined that the reactor's continued operation was not economically justifiable relative to replacement with more cost-effective energy efficiency and new generation sources.

Thus, proposals to subsidize existing nuclear power plants have arisen only in deregulated states, and have been driven by the declining economic viability of certain segments of merchant reactors; specifically, those that have higher operating costs and are located in regions where market forecasts project average hourly prices will remain low for several years. Those conditions have prevailed in regions where conditions favor low wholesale clearing prices: abundant generation capacity, stagnant electricity demand, and/or rapid growth of renewable energy sources. In such local markets, some reactors' operating costs are uncompetitive, especially where the growth of wind and solar is sufficient to displace incumbent generation and reduce average market clearing prices. For instance, in some regions and years, long-term power purchase agreements for wind generation have included prices under $20/MWh,[11] less than the reported operating costs of all but a few nuclear power plants.[12]

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[10] Nash, James, and Nicholas Pugliese. "Nuclear plants are profitable. Should NJ electric customers be asked to pay more?" *Bergen Record.* February 21, 2018. https://www.northjersey.com/story/news/watchdog/2018/02/21/nuclear-plants-profitable-should-nj-electric-customers-asked-pay-more/336011002/

[11] Energy Technologies Area, Berkeley Lab. "Wind Power Purchase Agreement (PPA) Prices." Lawrence-Berkeley National Laboratory. https://emp.lbl.gov/wind-power-purchase-agreement-ppa-prices

[12] Nuclear Energy Institute. "Nuclear Costs in Context." December 2023. https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context

The Nuclear Production Credit and Changing Conditions for Merchant Reactors

The advent of the Inflation Reduction Act has, effectively, established a new cost environment for merchant nuclear generation. Existing nuclear reactors can qualify for the 45U Nuclear PTC, up to a certain threshold of revenue from electricity sales, other market revenues, and subsidies from state and federal government programs. The value of the credit starts at $15.00/MWh for reactors with annual revenue of up to $25.00/MWh (and satisfy the Nuclear PTC's workforce qualifications). Under the Nuclear PTC formula in the IRA, the value of the credit reduces to $0/MWh when a reactor's revenue averages $43.75/MWh in a given year. A reactor's owner(s) may still claim the credit if state subsidies raise the revenue rate higher than that, as long as the state program requires that the Nuclear PTC be applied toward reducing or refunding the state's subsidy cost.

The Energy Information Administration projects average electricity prices to be greater than $30.00/MWh in every region of the country in 2024.[13] Some reactors may still earn less than that, because there is variation between clearing prices in submarkets in each region. However, wherever average annual market revenues are at least $25.00/MWh, the Nuclear PTC now sets a revenue floor for merchant reactors of $40.00/MWh. If a merchant reactor's operating cost projections significantly exceed that level, and its revenues are otherwise insufficient to cover those costs, then its owner(s) may consider retiring the reactor. However, it would still be more cost-effective to source hydrogen production with renewable energy, because the subsidized costs of electricity generated by utility-scale wind and solar photovoltaics (PV) were less than $40.00/MWh in most parts of the country in 2023. The low-end cost range for both wind and solar PV was $0/MWh, and the median range cost was $33/MWh for wind and $38.50/MWh for solar.[14] Because of the $0/MWh variable cost of wind and solar, regions of the country with sustained low electricity prices tend to be those where renewable energy growth is robust, and there would be no need for exemptions to the incrementality requirement.[15]

Conclusion

The EAC requirements in the proposed rule are essential for assuring that producers of clean hydrogen who file H2PTC claims meet the statutory emissions standards under the Inflation Reduction Act of 2022; and, further, they are aligned with and support the goals of the U.S. National Clean Hydrogen Strategy and Roadmap (NCHSR), developed pursuant to the Infrastructure Investment and Jobs Act of 2021.

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[13] Energy Information Administration. "In most U.S. regions, 2024 wholesale electricity prices will be similar to 2023."January 18, 2024.https://www.eia.gov/todayinenergy/detail.php?id=61244

[14] Lazard. "Lazard's LCOE+ (April 2023)." *See PDF page 6, "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies."* April 2023. https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf

[15] Joachim Seel, et al. "Plentiful electricity turns wholesale prices negative." *Advances in Applied Energy*, Volume 4, 2021, 100073, ISSN 2666-7924. https://doi.org/10.1016/j.adapen.2021.100073

Exemptions from the EAC requirements for existing nuclear and renewable generation sources are not warranted, as the purpose of the H2PTC is to reduce the price of clean hydrogen for end users, not to subsidize electricity generation facilities. Nuclear and renewable energy generation are already supported by a number of policies and programs, including production tax credits and, in the case of unprofitable nuclear power plants, the DOE's Civil Nuclear Credit program established by the IIJA. Furthermore, diverting substantial amounts of existing generation—especially power plants with high operating costs, that might remain unprofitable even with the support of the Nuclear PTC—could increase the cost of clean hydrogen through misdirecting the H2PTC as an electricity subsidy.

The GHG emissions impacts of doing so could be greater than emissions from the production of hydrogen with fossil fuel feedstocks using methane steam reforming processes ("gray hydrogen"). The factors that are leading some nuclear power plants to become unprofitable cannot be ameliorated by the H2PTC without compromising the tax credit's purpose. However, the market conditions that largely contribute to low electricity prices and low power sector emissions levels correlate with robust renewable energy growth. This further supports the effectiveness of the EAC requirements in the proposed rule, without exemptions for existing nuclear and renewable generation facilities.

Sincerely,

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