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Issue Brief

The Hidden Tax on Your Power Bill: Construction Work in Progress

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Introduction

Construction Work in Progress, or CWIP, is the most influential energy policy term that never appears on a household utility bill. It shows up only on a regulated company's ledgers; yet the way regulators treat this line item can add real dollars to what families pay every month.

Ordinarily, large utility projects are financed the same way as most private investments. A company raises debt and equity, builds the facility, and only after it is operational does it begin earning revenue. Investors shoulder the risk that costs may rise, schedules may slip, or demand may fall short. Customers start paying only once they receive the service.

CWIP turns that typical business sequence on its head. State commissions as well as the Federal Energy Regulatory Commission (FERC) have allowed utilities to move CWIP into the "rate base." The rate base is the pool of assets on which a utility earns a guaranteed rate of return. As such, when CWIP is approved, households are no longer just consumers of energy; they also become financiers, covering the carrying costs of projects still under construction. The policy was pitched as a practical tool to encourage construction. Initially, it kept investor-owned utilities solvent while they tackled expensive long-term projects, such as nuclear plants or extra-high voltage lines. In practice, it has produced inflated budgets through undisciplined spending and pushed risk from investors onto ratepayers.

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The Manhattan Institute is a community of scholars, journalists, activists, and civic leaders committed to advancing economic opportunity, individual liberty, and the rule of law in America and its great cities.

Policymakers today face a choice. They can: 1) end CWIP entirely, forcing utilities to return to traditional debt/equity financing; 2) allow CWIP only under strict budget caps set at the outset of construction, with no change orders; or 3) make CWIP rates of return performance-based, rewarding projects that finish on time and on budget while penalizing overruns.

Given the anticipated increase in electricity demand from new data centers needed to power AI, federal and state officials need to ensure that ratepayers are not financing the costs of increased energy infrastructure through premature CWIP charges.

Policy Problems

Economists have a name for the bias that underlies cost explosions in regulated industries: the Averch-Johnson effect.[1] First described in the early 1960s, the theory predicts that when a regulated monopoly is guaranteed a fixed-percentage return on every dollar of capital it owns, the firm has an incentive to own more capital than is economically efficient. In competitive markets, investors curb that instinct because each unnecessary dollar erodes profits. Under cost-of-service regulation, by contrast, the utility passes its costs to customers, so "gold-plating" (adding unnecessary features to a project) can raise shareholder earnings.[2] Including CWIP in the rate base amplifies this timing distortion because, instead of earning a return only after an asset is in service, the utility begins earning during construction. CWIP also incentivizes lengthening construction timelines. With conventional regulation, a project must be completed before it begins earning a return; and long delays hurt the bottom line. CWIP lets the clock start ticking the very day that ground is broken. Every change order, schedule slip, or "futureproofing" upgrade is not simply absorbed—it expands the capital base and extends the period over which the utility earns its guaranteed return.

CWIP changes the incentive structure for utilities. Utilities undertaking large infrastructure projects, such as grid expansion, must choose how to account for construction costs, and that choice has direct consequences for customer rates. The decision of how to approach large infrastructure projects depends upon FERC and state commission policy and approvals. Broadly speaking, utilities have two common accounting approaches for capitalizing major outlays:[3] CWIP and Allowance for Funds Used During Construction (AFUDC). Both options include some level of capitalization of the outlays for the project.[4] However, each approach brings differing implications for service fees assessed to existing customers. The effects on the rate base used to determine customer charges depend on the accounting approach implemented. **Table 1** provides a quick reference for the major differences between these two approaches.

Under CWIP, the utility provider may implement an approach whereby costs of construction (materials, labor, land development, etc.) are recorded as an asset immediately. From an accounting perspective, rather than debiting current expense for outlays as they occur, the debit is applied to an accumulating asset. Only when the project is complete, and the asset is fully developed and placed into service, will depreciation begin. Under this approach, construction costs are capitalized (meaning that the cost is recorded as a long-term asset rather than expensing it immediately, allowing the cost to be spread over the asset's useful life), but interest costs from borrowings associated with the project are not capitalized and are reported as an expense.

Under CWIP, the accumulating asset is included in the rate base. Accordingly, customer-service fees reflect the accumulated value of the incomplete (not in use) asset still under construction. I.e., the customer is paying for the new asset before it provides any service. To the extent that the new project is an expansion of the power grid to a new set of customers, the existing customer pool is paying for the construction of a grid-expanding asset for which they will not be the beneficiary. Simply put: existing customers are paying for an asset that will benefit future customers.

Under the alternative, AFUDC, the asset is not included in the rate base until it is fully completed and in use. One criticism of this approach is that it often results in the rapid increase in customer-service fees during the period in which the assets become operational. The associated "rate shock" is attributable to the sudden inclusion of the asset into the rate base. Clearly, an advantage of this approach is that existing customers do not bear the financing costs (via service fees) for an under-construction project. But, importantly, it creates a different incentive structure for the utility.

Table 1

Comparison of CWIP vs. AFUDC[5]

	CWIP	AFUDC
Financing costs	Financing costs of the project are expensed as incurred and recovered immediately via service rates charged to customers.	Financing costs are separately capitalized as an asset. That asset is depreciated over its useful life, beginning after the new facility becomes operational.
Rate base	The rate base increases as the CWIP asset accretes.	The rate base is unaffected until the capitalized asset becomes operational. At that time, the capitalized asset becomes part of the rate base.
Customer impact	Customer rates increase immediately during construction because CWIP is included in the rate base.	No immediate cost to customers; rates increase when the capitalized asset is placed in service.
Trade-offs and characteristics	The entity is not able to capitalize interest costs; cash inflow during construction (pending regulatory approval). The increase in customer fees can be viewed as customers paying to service the debt burden. CWIP shifts the financial burden of construction from utilities to consumers. The sharing of the financial burden may result in an accelerated initiation of development of critical energy infrastructure. There are little risk-avoidance and cash constraints on the part of the utility because, at least in part, the project is funded with nonutility resources. However, because the utility can charge as it builds (rather than having to complete the project before assessing an increase in fees), the completion of the project may not be as timely. I.e., because the utility can assess fees on an incomplete project, its impetus for completing the project is not as strong. The increase in fees is gradual over the period of construction.	Existing customers do not "pay ahead" for provider assets not yet in service; no cash inflow during construction. The fee adjustment once the asset becomes operational is immediate (i.e., rate shock).

These different accounting treatments create fundamentally different incentive structures for utilities. Under CWIP, utilities face little pressure to control costs or timelines because every additional dollar spent and every month of delay expands their rate base and increases their guaranteed returns. Cost overruns become profit opportunities rather than financial penalties. By contrast, under AFUDC, utilities have strong incentives to complete projects quickly and efficiently because they earn no cash returns during construction—delays and cost overruns reduce overall project profitability. This difference in timing of cash flows creates opposite incentives: CWIP encourages spending and delays, and AFUDC rewards efficiency and speed.

The Widespread Adoption of CWIP

The regulatory treatment of CWIP has evolved significantly over the past century, shaped by shifting energy demands, infrastructure needs, and economic pressures. The inclusion of construction costs in utility rate bases began modestly in the early 20th century, gaining momentum only in response to acute energy crises and the rise of capital-intensive generation projects.

Maryland became the first state to authorize CWIP inclusion in the rate base in 1923, followed by Louisiana in 1924. No additional states permitted the practice from 1924 to 1947. After those two decades, the pace accelerated modestly, with eight states and the District of Columbia approving CWIP between 1947 and 1969, bringing the total to 11 jurisdictions by 1969.

This pattern changed dramatically during the 1970s energy crisis. Rising energy demand and a boom in nuclear power projects—95 GW of nuclear capacity came online between 1970 and 1990—created new financial pressures.[6] The Arab oil embargo of 1973 further exacerbated energy concerns, leading to concentrated efforts for energy independence and security. These conditions prompted a massive expansion in CWIP authorization: between 1970 and 1976, 21 additional states adopted CWIP policies, bringing the total to 31 states plus the District of Columbia—32 jurisdictions in total.[7] By 1979, 33 state public utility commissions were permitting privately owned electric utility companies to include CWIP in the rate base.[8] These policies resulted in $45 billion (in 2025 dollars) being included in the rate base in 1978.[9]

Despite the widespread adoption of CWIP during the 1970s energy crisis, growing public resistance and financial uncertainty led several states to reverse course in the years that followed. Even as CWIP expanded, a handful of states began disallowing CWIP in rate-base calculations because of voter and lawmaker concerns over increased prices, prolonged construction delays, and abandoned projects.

In 1976, Missouri voters, upset with rate hikes from the construction of a nuclear power plant (Callaway Plant), reversed course and banned the use of CWIP by ballot initiative.[10] Construction of the Callaway Plant began in 1975, with two units originally planned. However, the first unit failed to reach "full-power" operation until 1984, three years later than scheduled and with significant cost overruns.[11] The second unit, previously scheduled for production in 1990, was instead canceled in 1981.[12] Union Electric Co. Chairman Charles J. Dougherty stated, "We regret having to make the decision to cancel this unit, but we cannot expose our investors and customers to the financial risks and uncertainties inherent in its construction."[13]

Like Missouri, New Hampshire outlawed CWIP in the rate base in 1979.[14] The Public Service Company of New Hampshire (PSNH) had struggled to build the Seabrook nuclear power plant and suffered construction delays and cost overruns. Nevertheless, the public utility commission approved a CWIP for PSNH. In response, the state legislature, pushed by ratepayers, passed the 1979 anti-CWIP bill because of concerns that the plant that might never be completed.

The law was challenged in court, and in 1988, the case reached the New Hampshire Supreme Court, which ruled that PSNH could not include CWIP in the rate base before providing any service.[15] Two days after this ruling, PSNH filed for bankruptcy and later merged into Northeast Utilities,[16] marking the first bankruptcy by an investor-owned utility since the Great Depression. The Seabrook nuclear power plant did not provide service until 1990.

CWIP was changing at the federal level as well. By 1980, FERC, which was established in 1977 to replace the Federal Power Commission, had restricted CWIP in the rate base to capital invested only in pollution control and fuel conversion projects. This is a policy that FERC inherited from its predecessor, which first began allowing limited CWIP inclusion under Order No. 555 in late 1976.[17] Meanwhile, utilities began to face financial strain, which was exacerbated by a significant slowdown in the demand for energy.

Electricity demand grew annually by over 5% in the 1950s, 1960s, and 1970s; that rate slowed dramatically to 2%–3% in the 1980s and 1990s, before falling to less than 1% in the first decade of the 2000s. This demand slowdown created financial pressure on utilities that had built excess generating capacity based on earlier high-growth projections, leaving them with expensive assets that generated less revenue than anticipated and created challenges in recovering their substantial capital investments.[18]

Estimates from the National Regulatory Research Institute show that CWIP use nationwide rose continuously from 8% of net electric utility plants in 1967 to a staggering 36% in 1983, meaning that over one-third of the industry's net plant value was tied up in ongoing construction.[19] That scale of capital encouraged overleveraging because utilities could finance larger portions of projects with debt while relying on CWIP funds to pay for the interest, reducing the market pressure to maintain conservative capital structures.

With utilities on the brink of bankruptcy, Congress passed legislation, such as the Construction Work in Progress Policy Act of 1983, which sought to authorize FERC to include CWIP in the rate base for utilities facing "severe financial difficulty."[20] The Congressional Budget Office later noted that while the industry had broadly improved by 1985, many firms still remained under significant financial stress as they attempted to recover from the large costs of recently completed or canceled power plants.[21] The trajectory of CWIP policy reveals a recurring tension between infrastructure ambition and financial accountability. As utilities pursued increasingly complex and capital-intensive projects, the regulatory safeguards around CWIP proved fragile, often failing to protect ratepayers from the risks of delay, cancellation, and cost escalation. The resulting financial strain, bankruptcies, and public backlash forced a reckoning not only with CWIP itself but with the broader regulatory model that enabled it. This decade of financial and regulatory turmoil, driven by failed megaprojects, reduced demand; and rising costs laid the groundwork for the restructuring efforts of the 1990s, which sought to realign incentives, reduce ratepayer exposure, and reimagine how infrastructure would be financed in a more competitive environment.

CWIP Today

Despite decades of hard-earned lessons, the incentive distortions that fueled CWIP crises of the past continue to shape modern utility planning. Take the Shoreham Nuclear Power Station on Long Island, New York. By 1983, the New York Public Service Commission had allowed the Long Island Lighting Company (LILCO) to include about $355 million of CWIP in the rate base, even though the plant was unfinished. Later cost disputes led to large disallowances.[22] The plant itself was completed and test-run, yet never entered commercial service because of sustained public-safety and environmental opposition,[23] leaving ratepayers paying for financing tied to an asset that was never useful.[24]

The Pacific Northwest nuclear program offers a broader cautionary tale. Pre-service cost-shifting to customers combined with massive overruns helped produce the 1983 bond default.[25] At the time, it constituted the largest municipal bond default in U.S. history.[26] Together, these episodes show how early recovery weakens cost discipline, encourages overexpansion, and transfers financing risk from investors to customers.

Though jurisdictions have attempted to use restructuring efforts to curb these risks, some jurisdictions have kept or modified CWIP instead of eliminating it. In the 1970s and 1980s, many commissions approved CWIP subject to refund, placed collections in escrow, and required true-ups (a process to adjust financial figures for accuracy) after prudence reviews so that disallowed costs would be returned with interest. Federal policy moved in the same direction by capping the share of CWIP eligible for the rate base, by requiring detailed construction progress reporting, and by prohibiting double recovery when AFUDC had been recorded. Several states created independent construction monitors and milestone reporting, and some conditioned CWIP on firm schedules, capped categories such as pollution control and fuel conversion, or reduced the allowed carrying charge when projects slipped.[27] These guardrails tempered, but did not remove, the capital-bias incentive.

One of the most prominent recent examples is the construction of Georgia's Plant Vogtle Units 3 and 4, which reveals what happens when the traditional, ratepayer-funded model for capital projects runs unchecked in a modern context. Approved in 2009 at a supposed capitalization of roughly $14 billion, the twin nuclear reactors began full commercial service only in 2023 and 2024, after costs swelled to about $37 billion.[28] A 2009 Georgia law designed to encourage nuclear construction allowed Georgia Power to roll CWIP into monthly bills as soon as concrete was poured. Customers effectively financed the project for 13 years before receiving a single kilowatt-hour of new nuclear electricity.

Plant Vogtle's trajectory makes the problems with CWIP vivid. Mounting construction setbacks from component redesigns, contractor bankruptcies, and pandemic-related labor shortages led to an explosion in the total price tag. Rather than face punishment, Georgia Power was entitled to earn over 10% return on that growing sum each year because CWIP was already in the rate base. For management and shareholders, the mushrooming budget did not threaten the project's profitability; it enhanced it.

Mississippi Power's Kemper County "clean coal" plant shows that CWIP problems are not limited to nuclear technology. Promised in 2009 as a $2.9 billion gasifier that would turn local lignite into low-emission electricity,[29] the project relied on CWIP surcharges and a hybrid accounting mechanism called "mirror CWIP," which treats construction balances as though they were already in the rate base, allowing the utility to earn a carrying charge during construction even though the assets had not yet been placed in service. These accounting decisions allowed the company to collect over $600 million from customers while construction dragged on. Technical failures eventually forced regulators to abandon the gasification section and order refunds—but only after ratepayers had prepaid for equipment that will never operate.[30]

Clean-coal experiments demonstrate that the Averch-Johnson effect is technology-agnostic. Mississippi's Kemper plant kept adding complexity (e.g., carbon-capture loop, additional gasifier) while the utility was earning a live return on each new bolt and beam. Technical realities eventually rendered the design unworkable; but by then, hundreds of millions of dollars had already been collected from customers. Giant battery farms and hydrogen hubs currently in the planning stages risk the same trap: if regulators guarantee generous returns and allow CWIP charges years before the first electron or kilowatt is delivered, utilities have every reason to oversize and overspend.

Contrast those outcomes with the Mountain Valley Pipeline (MVP), a 303-mile interstate gas line from West Virginia to Virginia. Federal pipeline rules generally bar cash recovery until gas actually flows; as such, MVP's partners carried over $7 billion of spending as CWIP on their own books, recording only noncash AFUDC income.[31] I.e., they booked an accounting accrual that increases the construction account and is treated as imputed income but did not send invoices or collect any cash from pipeline customers until gas began to flow. Delays and court challenges have been painful for investors, but household budgets in the region have not been tapped. The MVP example proves that megaprojects can still attract financing without early rate-base treatment when the rules demand genuine market discipline.

Current federal policy does not make development easy on future customers. The Energy Policy Act of 2005 directed FERC to encourage transmission investment through incentive-based rate treatments. To implement this mandate, FERC issued Order No. 679 (2006). This order created a menu of potential incentives available on a case-by-case basis. These include allowing prudently incurred CWIP in the rate base; recovery of 100% of prudently incurred costs if a transmission project is abandoned for reasons beyond the utility's control; return-on-equity adders (within the zone of reasonableness); and, in certain circumstances, the use of hypothetical capital structures (i.e., an imputed debt-to-equity mix such as 50/50 or 60/40) used for rate-making purposes, regardless of the utility's actual balance sheet.[32] These tools were intended to spur transmission expansion amid concerns that grid bottlenecks threatened reliability and competitive wholesale markets. FERC's goal was to lower the cost of capital and encourage transmission companies to take on long-lead projects.

What seemed pragmatic in 2006 looks far more controversial today. FERC Commissioner Mark Christie has been one of the most consistent dissenters, warning that CWIP and abandonment recovery together "make consumers the bank for transmission developers" and "the insurer of last resort."[33] His concern is that these mechanisms shift both financing risk (CWIP) and failure risk (abandonment recovery) away from shareholders and entirely onto customers, who begin paying returns on billions in capital outlays before a line delivers a single kilowatt-hour.

The Problem Persists with Renewable Energy

Modern renewable energy generation has far lower spatial power density than compact thermal plants such as nuclear or natural gas. This means that less power is generated or delivered per unit area and that more space is required to produce the same amount of power. Therefore, renewable projects require more extensive collector systems and longer-haul transmission corridors.

Peer-reviewed estimates of life-cycle "surface power density" place utility-scale photovoltaic solar generation at 6–7 watts per square meter (W/m^2) and utility-scale wind generation at 1–2 W/m^2. By comparison, nuclear power has a surface power density of 200–500 W/m^2, while natural gas combined-cycle plants average 500–1,000 W/m^2. This mismatch means that replacing a single 1,000-megawatt (MW) coal-fired generating unit operating at a 70% capacity factor (CF)—which would produce about 6.1 terawatt-hours (TWh) of electricity per year—would require about 2,800 MW of photovoltaic solar capacity operating at a 25% CF, or 2,000–2,300 MW of wind capacity operating at a 33%–36% CF, depending on site performance.[34]

Building at that scale in remote windy or sunny areas entails new high-voltage lines; today, 765-kilovolt (kV) alternating-current (AC) transmission line segments routinely cost $5–$6 million per mile even before stations are built to receive them, with CWIP eligibility subject to FERC approval.[35] The result is a swelling number of grid megaprojects whose economics depends on speculative generation forecasts but whose financing costs are front-loaded onto ratepayers.

The following case studies show a consistent pattern: whenever CWIP allows early recovery, costs expand and risks shift to customers. Consider the Potomac–Appalachian Transmission Highline (PATH). Proposed as a 765-kV line to carry West Virginia coal power into the regional grid operator PJM's load centers, PATH entered PJM's regional plan and obtained federal incentive approvals but never received state certificates in any of the three jurisdictions that it crossed. Opposition from landowners and environmental groups was fierce; by 2012, load forecasts had fallen to the extent that PJM canceled the project. Yet PJM ratepayers nevertheless paid $250 million in development costs. Commissioner Christie summarized it as "not a single ounce of steel in the ground"; yet hundreds of millions of dollars were recovered from customers, and he attributed the bill directly to the commission's granting of CWIP and other incentives.[36]

Dominion's Coastal Virginia Offshore Wind (CVOW) project serves as another example. The Virginia State Corporation Commission noted that Rider OSW—Dominion Energy Virginia's Offshore Wind rate-adjustment clause that recovers the revenue requirement for the CVOW project—is "largely a return on construction work in progress" until the project enters commercial operation.[37] CVOW is a 2.6-GW offshore wind development, currently about 50% complete, with Dominion projecting completion by the end of 2026, at an estimated cost of $10.7 billion.[38] The expected cost reflects ongoing PJM network upgrade requirements, which remain one of the largest unfixed inputs into the project. A wind farm of this scale involves extensive inter-array and export cabling—hundreds of miles of subsea feeder lines and supporting infrastructure that can be placed in the rate base and that can earn a return during construction through Rider OSW. Beyond the project footprint itself, additional long-haul transmission is often required to integrate new generation into the grid.

Florida Power & Light's Port Everglades Next Generation Clean Energy Center, on the other hand, was capitalized with financing costs under AFUDC and did not recover carrying costs from customers until the plant entered service. The project was commissioned in April 2016 (matching the publicly stated 2016 in-service timeline), at which point AFUDC capitalization stopped and costs moved into the rate base through normal post-COD treatment. Thus, any pre-service charges to customers were avoided. The plant's efficiency improvements were expected to lower fuel burn and produce lifetime customer savings, illustrating AFUDC's discipline relative to CWIP's early-recovery model.[39]

Limiting or eliminating CWIP's early-recovery privileges would not halt the construction of bona fide infrastructure development; it would simply ensure that the next generation of energy investment is driven by efficiency and prudence rather than by an accounting rule that rewards spending for its own sake. The savings to be had are significant. Some consumer advocacy groups estimate that the construction of nuclear power plants overrun costs by an average of 100%, costing roughly twice their initial estimate.[40]

Reform Options

The choice between CWIP and AFUDC represents only the most basic policy decision. A range of reforms could restore market discipline and consumer protection. FERC could make CWIP approvals conditional; i.e., make CWIP rates of return performance-based. Utilities meeting schedule and budget benchmarks would earn their full authorized return, while those experiencing delays or overruns would face automatic reductions in the CWIP return rate. Cost escalation beyond approved baselines would trigger immediate refund mechanisms, ensuring that ratepayers do not subsidize poor project management.

Another commonsense approach would be to include automatic clawback provisions that would create enforceable mechanisms to recover customer payments when projects are abandoned or costs exceed predetermined thresholds. Rather than using the current system where customers bear stranded investment risk, utilities would face meaningful financial consequences for project failures.

Restricted change orders under CWIP could lock the scope of a project and the cost before approval. Relevant commissions would preauthorize a "not to exceed CWIP amount" based on the project and required costs. Any variance exceeding a certain threshold would suspend CWIP accruals until the project is reauthorized. Limited exceptions may be allowed for regulatory compliance of unforeseen circumstances. All other cost increases would be excluded from CWIP recovery and thereby absorbed by owners or shareholders.

For load pockets driven by data and AI campuses, an option is to move the load off the regulated grid entirely. Authorizing truly off-grid providers channels private capital into self-contained microgrids and on-site generation. This avoids CWIP in the rate base. New Hampshire's HB 672-FN provides a template by creating a category for off-grid electricity providers that generate, transmit, distribute, and sell power at retail to on-site customers while remaining independent of the state's transmission and distribution systems.[41] An off-grid supplier that does not use public rights-of-way or interconnect with the grid is not treated as a public utility and is exempt from most utility statutes, while still complying with siting and other generally applicable laws. If an off-grid project later interconnects or uses public corridors, it immediately becomes fully regulated, which preserves consumer protections and keeps risk with investors until broadly available service begins.

The complete elimination of CWIP in the rate base probably represents the best reform. Eliminating CWIP would force utilities to finance construction through traditional debt and equity markets, earning returns only after projects deliver service. The interstate MVP's financing structure shows that major infrastructure projects can attract private capital without early rate recovery, provided that investors face genuine market discipline. These reform options are not mutually exclusive. The key principle underlying all these alternatives is the realignment of risk and reward so that the incentives are aligned in such a way that those who benefit from project success should also bear the consequences of project failure.

Conclusion

CWIP is a cautionary tale about how well-intentioned financial tools can distort incentives and shift risks when applied without safeguards. Originally promoted as a way to help utilities weather the capital strain of large, long-lead projects, CWIP has repeatedly weakened cost discipline, encouraged oversizing, and transferred the financial burden of speculation onto households and businesses.

Historical episodes in Missouri and New Hampshire during the nuclear build-out of the 1970s and 1980s revealed these risks vividly: ratepayers paid billions for reactors that never delivered power, and utilities stumbled into bankruptcy despite early cost recovery. Those lessons appeared to set limits, but the Energy Policy Act of 2005 and FERC's Order 679 reopened the door by extending CWIP to transmission, again transferring risk to consumers in the name of grid modernization. Georgia's Plant Vogtle demonstrates how CWIP can sustain multi-decade construction programs even as costs more than double, with families paying surcharges for years before receiving electricity. Mississippi's Kemper "clean coal" project and Dominion's offshore wind build show that CWIP's distortions are not limited to any one technology; the common thread is that once cash recovery begins, every delay and change order expands the rate base and makes the utility less affordable for the customer.

Transmission megaprojects such as PATH reveal the same flaw on a regional scale: customers in several states paid hundreds of millions for a line that never received state approval or entered service. Taken together, these examples validate the concerns of the critics. CWIP, especially when coupled with abandonment recovery, makes consumers both the lender and the insurer for speculative infrastructure. The Averch-Johnson effect, the incentive to over-invest capital under cost-of-service regulation, is magnified when utilities can earn a guaranteed return before an asset is even in service. The result is a feedback loop of larger projects, longer timelines, and higher costs, all of which still generate guaranteed returns for shareholders while ratepayers shoulder the risk.

A broader return to AFUDC would require federal and state actions in tandem. FERC should withdraw CWIP-in-rate-base incentives under its transmission incentive policies, and states (through legislatures, public service commissions, or voter initiatives, where applicable) should repeal or revise statutes and orders that authorize CWIP recovery in retail rates.

Endnotes

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4 Capitalization for large projects requiring extensive outlays to build long-term assets is common to Generally Accepted Accounting Principles in the U.S.

5 The terms CWIP and AFUDC have specific definitions and implementations in the Accounting Standards Codification (ASC). The ASC is produced by the Financial Accounting Standards Board (FASB) for the purposes of public financial reporting. While the terms used here are the same, the implementation and use of those terms by the Federal Energy Regulatory Commission (FERC) differs from the specific use in the ASC. FERC uses these terms to delineate methods of fee determination. Our discussion is not centered on the ASC and public reporting but rather focused on the fee determination approaches permitted by FERC.

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