ELECTIVE PAY
FINANCING AND CAPITAL

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center *for* public enterprise

Contents

Introduction

The elective pay provision of the Inflation Reduction Act stands to transform public power. Tax-exempt entities—including state instrumentalities and nonprofits—can now claim tax credits for investment in or production by clean power facilities and receive tax credit disbursements directly from the Internal Revenue Service (IRS). Applicable entities include existing public power organizations, rural cooperatives, economic development corporations, departments of energy, or housing authorities. Tax credit eligibility puts public power on a more even footing with private developers and allows states and localities to seriously consider owning and operating their own facilities rather than defaulting to procurement via power purchase agreements (PPAs) with private providers. Elective pay directly from the IRS not only promises to reshape the landscape of energy financing by providing public entities with comparable investment advantages to those of private counterparts, but cuts out tax equity investors, allowing public entities to capture the full value of their tax credits.

Utilizing elective pay for public power beckons states, municipalities, and agencies to re-imagine their roles in leading and facilitating project development. Public actors must develop the capabilities to plan capital projects, procure financing, operate complex energy systems, and manage project portfolios.

The Center for Public Enterprise's new financing model (referred to herein as the model or CPE model) is designed to help such entities think through their options by assessing illustrative examples of elective pay projects . The customizable model is not restricted to any particular markets or regions; users can easily alter its assumptions as needed to meet their needs.

This is the first freely available model assessing the impact of elective pay on both large- and small-scale public energy generation[1], and its accompanying Net Present Value calculator is the first public-facing evaluation of the circumstances in which ITC or PTC is advantaged that focuses on public energy projects and elective pay in particular.[2]

This paper describes the operations of the model by detailing the assumptions behind its inputs and outputs. It grounds users in the ways that elective pay tax credits change the financing landscape for the public development of energy and how to interpret the specific financial metrics which it generates.

[1] This model is illustrative. The assumptions (outlined below) are generalizable to a variety of regions and market conditions. Inputs can be altered and selected by the user. More specific models for particular projects, specific regions, or other energy resource types—, or reflecting requested market conditions, more disaggregated data, or business models can be constructed by CPE upon request.

[2] Many such calculations exist for tax credit choices faced by private developers. For a comparison of the ITC and PTC for solar projects, see: Batra et al. 2022. *Solar economics: The PTC vs. ITC decision*. ICF. Available at: https://www.icf.com/insights/energy/solar-economics-ptc-vs-itc.

In addition to describing the operation and output of the model, this paper uses it to make several conclusions about public energy development in the context of a direct pay tax credit regime. Under the model's baseline assumptions, CPE concludes that:

1. **Elective pay increases the viability of public energy generation**—even with the penalty on tax-exempt debt.[3] Without elective pay, publicly owned and operated generation would require significantly higher revenues and debt service expenditures, placing it at permanent disadvantage relative to private projects capable of accessing tax credits.
2. **Public power can survive under hard-budget constraints** (i.e., any expenditures by the state can be repaid in full) if given the flexibility to set its own prices and negotiate purchase arrangements with potential customers.
3. **Public power can build significant cash reserves to undertake future investment**, to stabilize rates, and/or to cross-subsidize the operation of other public power projects in the state's broader energy mix.
4. **Public power faces qualitatively different "hurdle rates" than private projects do, limiting the utility of apples-to-apples comparisons between public and private development**. Public power projects need assurances that the investment can be carried out and produce the results (capacity, revenue, etc.) necessary to ensure the project can meet operations requirements, such as: a specific rate of return, revenues sufficient to meet debt service or cost, and/or the delivery of a particular service (e.g., spare capacity for local grids).
5. **The Inflation Reduction Act creates opportunities for public power to expand rapidly** using a combination of municipal debt and tax credit equity to seed a "revolving fund" that could quickly and sustainably finance new generation assets.

This report outlines the model, develops these conclusions, and examines their implications for public power policy. Section I details and justifies the initial assumptions about the kind of public energy projects being modeled. Section II lists the model's inputs, describes how the model calculates project costs and revenues, and illustrates the model's key outputs, such as hurdle rates and the calculation of levelized costs of energy. Section III places these results in financial and policymaking context, surveying the model's implications for the viability of individual projects, the impacts of choices between the Clean Electricity Investment Tax Credit (ITC) and the Clean Energy Production Tax Credit (PTC) on project finances, and the methods by which elective pay disbursement can seed subsequent capital development—allowing a public developer to rapidly expand their portfolio.

[3] When elective pay tax credits are combined with tax exempt municipal debt, the IRS will take a ten percent penalty from payments.

Section IV concludes the report by listing anticipated model expansions and highlighting the implications of the CPE model for energy policy and local public financing strategies.

Section I: Initial Assumptions

What is a Public Developer?

The CPE model concerns itself with projects by public developers—publicly owned entities with their own budgets, autonomous decision-making authority, and a large degree of independence from government appropriations (*see Box 2 for examples*).[4] Public developers are best thought of as publicly owned corporations, similar to private (tax-liable) developers, but without the same cash flow, profitability, or return constraints (i.e., public developers have to meet some standard of cash flow neutrality whereby they earn enough to sustain operations, expansion targets, or other public purposes set by their founding statutes, but not necessarily a return beyond that). If the developer is operating in competitive electricity markets, it may face other regulations in order to sell electricity, ones that impact its rate structure or impose limits on the types of entities that can purchase its power.[5] CPE also presumes that these public developers are created under state, local, or tribal law; are not federal entities (exclusive of the Tennessee Valley Authority); and are eligible for elective pay.[6]

The CPE model presumes public developers can use a combination of state or municipal green bank, tax-exempt, and market debt financing to fund capital expenditures in renewable energy capacity. The public developer—either an agency which isolates its activities from its other responsibilities or a state instrumentality created specifically for purpose—builds, operates, and maintains the renewable capacity. Generation from that capacity is sold to customers on the grid, such as distribution utilities, large-scale customers like factories or cities, or community aggregators, via power purchase agreements (PPAs) (*see Box 1*). The CPE model presumes these sale arrangements to be "physical PPAs" whereby the developer signs a long-term contract[7] with a purchaser that pays an agreed-upon price.[8]

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[4] Lala, C. 2023. *Direct pay: an uncapped promise of the Inflation Reduction Act.* Center for Public Enterprise. Available at: https://static1.squarespace.com/static/622cca56a2f5926affd807c6/t/64257e7047150f31bf02e7cf/1680178800773/Direct+Pay+101+-+Center+for+Public+Enterprise.pdf.

[5] EPA. "Physical PPA." Available at: https://www.epa.gov/green-power-markets/physical-ppa.

[6] CPE's comments to the IRS on August 15, 2023 called on the IRS to recognize federal entities as applicable entities for elective pay. Source: Gordon, J., C. Lala. 2023. *Comments to the Internal Revenue Service on the administration of sections 6417 and 6418 of the Inflation Reduction Act: elective pay and transferability.* Center for Public Enterprise. Available at: https://www.publicenterprise.org/reports/6417-6418-nprm-comments. The model's assumptions may change if rulemaking clarifies that federal entities (such as federal power marketing administrations) are eligible for elective pay.

[7] This may not be the arrangement used in every jurisdiction, particularly if the developer is subject to rate regulation or cannot participate in a competitive electricity market. In that case, the model inputs for price can be treated as a yearly average price applied to the public developer's generation.

[8] EPA. "Physical PPA." Available at: https://www.epa.gov/green-power-markets/physical-ppa. PPAs will often feature a price escalator tied to a benchmark of costs and spot electricity prices.

Box 1. The different types of energy entities.

Energy sources are built by **private and public developers**, described below:

- **Private Developers**: A private (for-profit or tax-liable) firm investing in the construction of new energy projects. The investments are recouped either through power purchase agreements or through sale into wholesale energy markets.

- **Public Developers**: A publicly owned and operated entity with its own budget and autonomous decision-making authority separated from day-to-day political appropriations processes, and separation from day-to-day appropriations. Public developers can be spun off from an existing government agency, operate within agencies, function as independent power producers, or exist as an unaffiliated public enterprise. They invest in the construction of new energy projects for the purposes of making a return that can be channeled into additional investments, subsidies to consumers, or other public purposes (*see Box 2*).

These developers build energy generation capacity to serve **utilities**, which actually deliver electricity to customers. Utilities own and operate facilities for generation, transmission, and/or distribution of electricity[9], and their investments, rate of return, and consumer rates are subject to regulation by a commission or analogous public authority. Utilities are organized differently across the country:

- **Vertically integrated utility**. This type of utility company owns generation, transmission, and distribution resources and does not exclusively rely on regional electricity markets or PPAs for electricity to serve customers. As such, the utility is also the developer. An example of a private vertically integrated utility is Portland General Electric Co. An example of a public vertically integrated utility is the Tennessee Valley Authority.
- **Distribution utility**. Distribution utilities (also known as "deregulated" or "restructured" entities) deliver electricity to customers within a bounded geographical area, such as a city or county. They do not own generation and usually buy it from the regional electricity market and/or through PPAs. An example of a private distribution

[9] "Electric utility company." From 42 USC § 16451(5). Text available at: https://www.law.cornell.edu/definitions/uscode.php?width=840&height=800&iframe=true&def_id=42-USC-1021651770-834541452&term_occur=1&term_src=title:42:chapter:149:subchapter:XII:part:D:section:16451

utility is Chicago's ComEd. An example of a public distribution utility is the Long Island Power Authority.

Private vertically integrated utilities and distribution utilities are given the status of legal monopolies by regulators: in return for monopoly control of electricity supply over a given region, these private utilities submit to local and state price regulations and oversight. They are also known as "**investor-owned utilities**" (IOUs) when they are financially accountable to shareholders.

Other power entities or arrangements include:

- **Municipal utilities**. Municipal utilities, or "muni utilities" are either city or municipality government-owned utility companies or investor-owned regulated monopolies. They are mostly distribution utilities but many also own and operate distributed energy resources including rooftop solar. One prominent example of a private distribution utility with its own generation assets is Pepco in Washington, DC. City of Aspen Electric System in Aspen, CO is an example of the same model in a publicly owned context.
- **Electric cooperatives**—often **rural electric cooperatives**—are not-for-profit power suppliers owned and operated by their customers. They can own their own generation and develop their own projects, but do not always. One prominent example is the Nebraska Public Power District.
- **Community choice aggregators**. Similar to a cooperative, community choice aggregators (CCAs) involve governments or communities pooling their resources together to purchase electricity through PPAs or, less often, to finance their own energy generation sources. One prominent example is East Bay Community Energy, co-owned by cities across California's Bay Area. CCAs are less prevalent than muni utilities or cooperatives.

The model captures an important characteristic of public developers, which can make financing decisions that private entities cannot. While public developers may be subject to balance sheet and nominal cash flow constraints like any other private entity, they do not face private entities' profitability constraints, higher hurdle rates, or their sole reliance on market debt and equity finance. Still, public developers likely face a harder budget constraint than typically imagined for state enterprises: any utilization of direct state funding must be repaid, thereby requiring the developer to at least bring in sufficient revenue to meet costs and service debt.[10] But, in turn, these entities have more autonomy in their decision making than other state agencies or instrumentalities. The result is that the

[10] For any public developer, the precise financial conditions on their portfolios or projects will be set out in state or local law.

public developer can act as a "regular" market participant—but one with considerable leeway to select investments in line with holistic grid priorities, allowing it to influence price-setting, investment, and demand in the broader electricity market.

Modeling a Public Developer

The model only examines project-level finances and ascribes all cash inflows, outflows, and the capital costs to that specific project. This constraint means that the model does not rely on the existence of either a portfolio of pre-existing public projects, or even on a balance sheet with which the public developer can support the projects in years of negative net cash flow. All periods of negative cash flow are presumed either to be paid out of a pre-existing cash reserve built from generation revenues or to be borrowed (likely by taking out an overdraft loan from the state or the developer itself) and paid back in the first available period with positive cash flow. Section III of this report describes how relaxing this constraint enables developers to build a self-funding project portfolio.

Box 2. What are public developers?

The United States already has multiple prominent public energy developers. Some examples include (but are not limited to):

- **The Tennessee Valley Authority (TVA)**. TVA, chartered by the federal government during the New Deal, is a federally owned energy developer that builds and maintains energy resources for much of the Southeast US.
- **New York Power Authority (NYPA)**. NYPA, a New York state-owned power developer, has built, owned, and maintained various energy resources—primarily hydropower and nuclear—and transmission projects across New York state for the last 70 years. New York state recently passed the Build Public Renewables Act (BPRA) to accelerate NYPA's ability to build and operate renewable energy sources.
- **Los Angeles Department of Water and Power (LADWP)**. LADWP, the largest municipal utility in the country, has both built energy resources (and water infrastructure) across the Los Angeles metropolitan area and distributed it to customers for over a century.

Smaller public developers, community choice aggregators, and municipal utilities can build energy resources, too. Two examples include:

- **East Bay Community Energy** is a community choice aggregator (CCA) co-owned by city governments in Alameda County, California, that buys and builds its own renewable energy sources to pass on lower power costs to customers.
- **Nebraska Public Power District** is a public power utility run by the state of Nebraska that builds and maintains energy generation sources to provide electricity to local municipal utilities and cooperatives.

Modeling the finances of individual projects imposes stricter budget constraints than most public projects will likely face. However, it also usefully illustrates the viability of standalone projects and proxies for other possible strictures state authorities may place on one-off projects, constraints which will characterize much of the initial elective pay-driven project development undertaken by entities without recent histories of public ownership and operation.

This model determines project viability on a project-by-project basis, an assumption that would not hold if a public developer invests in and operates multiple projects and can aggregate their cash inflows and outflows. This model also assumes that the project's capital stack is entirely debt-based and is used to finance 100 percent of capital expenditures prior to the receipt of elective pay disbursements.[11] Elective pay disbursements are marked as free cash flow which the entity can either use to reduce debt or save in a cash reserve for future use. The model allows a user to toggle between these alternatives.

The CPE model is a purely financial model that represents the costs and profits of a project in cash terms from the point of view of each energy technology. It does not capture the value of the project to its region's energy mix and thus should not be thought of as a way of fully capturing the social or environmental benefits and broader price effects of a given technology in a public developer's broader generation portfolio. CPE plans to work with public developers to develop this model further in order to capture these tradeoffs and broader effects of different generation technologies in a portfolio.

The Role of Elective Pay in Project Development

<u>Development without elective pay:</u> Prior to the IRA, only private developers could access the ITC and PTC. Public entities and non-profits were excluded from eligibility for these tax credits. But private developers, in turn, require significant tax liabilities to receive the full value of their tax credits.

[11] The model assumes that the public developer does not partner with other entities to construct or operate this project. Future modeling will incorporate viable joint investment and operating arrangements as well as any partnership structures that future rulemaking may make available to public entities.

In the absence of full refundability or direct payments from the Treasury Department, private developers must turn to tax equity markets. A tax equity investor (typically large banks) has a tax bill or liability large enough to claim the full value of the developer's expected tax credit. So the investor provides cash for the project (treated as equity, specifically tax equity) and, when the project enters operation, the investor receives the tax credit disbursement. Tax equity transactions allow developers to monetize the tax credits for their project upfront, but at a discount relative to the money they would have received if the Treasury had sent them funds directly.[12] A Credit Suisse report estimates that this discount can be as steep as 15 cents on the dollar.[13] Moreover, the tax equity market is itself fundamentally constrained: banks can only monetize credits commensurate with their available tax liabilities, and their willingness to enter tax equity transactions in the first place will be further curtailed if they deem a project especially risky. The complexity of tax credit equity markets makes it difficult for smaller or high-risk projects to access financing.[14] Though the IRA's transferability provisions are expected to lower these barriers,[15] the aggregate tax base of potential buyers is still expected to constrain the monetization of tax credits by private developers. Elective pay-eligible entities do not face this problem and can receive the full value of elective pay without turning to tax equity markets.[16]

Figure 1 illustrates how private developers can use tax equity markets to monetize their tax credits.

[12] For example, a private developer might receive $850,000 from tax equity markets to monetize a tax credit worth $1,000,000. The discount of $150,000 accounts for administrative costs of financing, a return to tax equity investors for providing the cash upfront and using their balance sheet space to do so, and the tax equity investors' stronger bargaining position on account of both the demand for monetization from developers and the limited aggregate balance sheet space in tax equity markets.

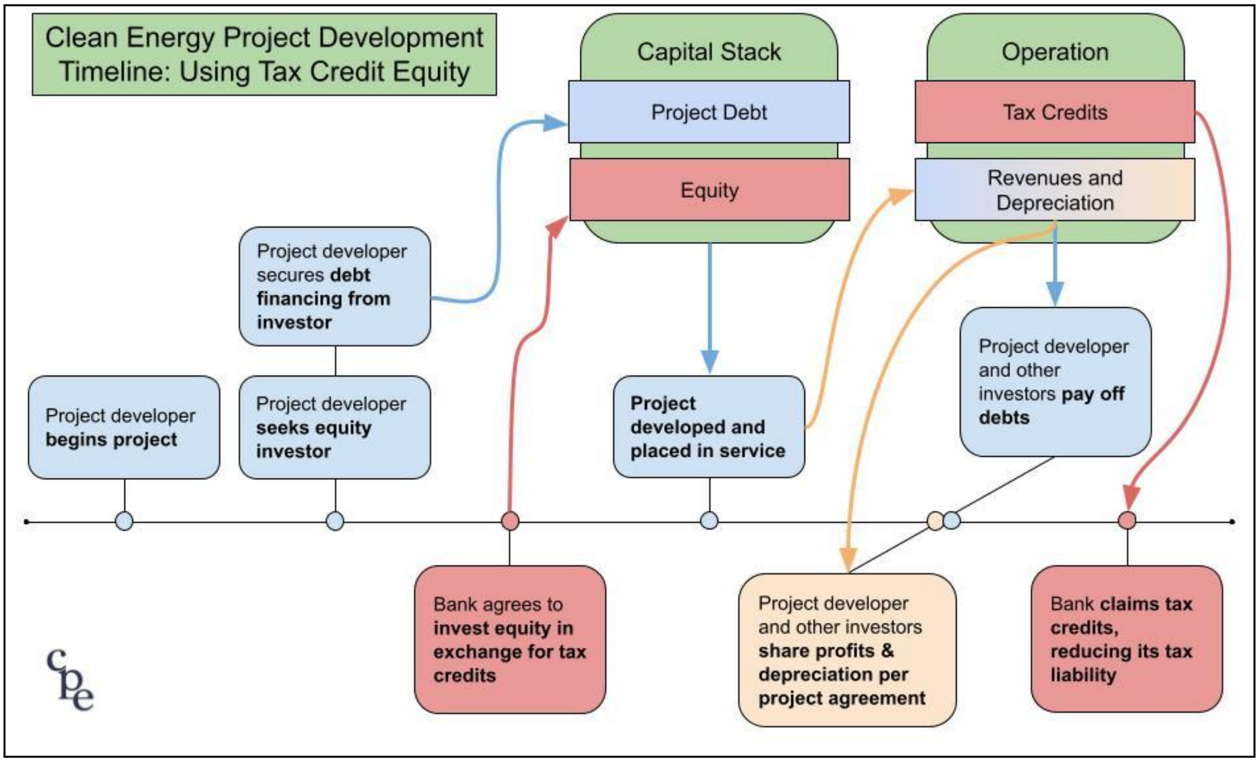
[13] Jiang et al. 2022. *US Inflation Reduction Act: A Tipping Point in Climate Action*.Credit Suisse. p.19-20.

[14] "Tax Equity Financing: An Introduction and Policy Consideration"*Congressional Research Service,* no. R45693, April 17, 2019, https://www.everycrsreport.com/reports/R45693.html#fn25, accessed 09/4/24.

[15] Transferability allows tax liable entities (i.e., those not eligible for elective pay) to transfer their credit to other taxpayers. This expands the pool of eligible taxpayers but ultimately still limits how much can be monetized based on the total tax base of potential buyers, and allows buyers to provide a discount so long as demand for monetization exceeds supply. Credit Suisse forecasted that the monetization discount would drop to 10 percent of which 5 percent covered administrative costs and the other 5 percent covered the actual monetization. The standardization of transferability contracts could see the total discount fall further. Sources: 1) IRS. 2023. "Elective Pay and Transferability." Available at: https://www.irs.gov/credits-deductions/elective-pay-and-transferability; 2) Chang, R. 2023. Understanding Direct Pay and Transferability for Tax Credits in the Inflation Reduction Act. Center for American Progress. Available at: https://www.americanprogress.org/article/understanding-direct-pay-and-transferability-for-tax-credits-in-the-inflation-reduction-act/; 3) Jiang et al. 2022. US Inflation Reduction Act: A Tipping Point in Climate Action.Credit Suisse. p.20.

[16] Further rulemaking will determine whether or not entities eligible for elective pay can be the recipients in a transferability transaction.

Figure 1.



Note. Actions of developers to change the debt or equity on their balance sheets or make debt payments are represented by blue boxes and arrows. Tax credit actions and flows are represented by red boxes and arrows. The flow of revenues from energy sales is represented by orange boxes and arrows.

<u>Public development with elective pay:</u> Elective pay is disbursed directly from the Treasury Department as cash payment equal to the tax credit that an eligible entity would receive if it had a tax liability. Once received, elective pay payments can immediately offset other cash flow requirements or be used to pay down debt. Elective pay also allows eligible entities to directly monetize their tax credits, thereby cutting out the middleman of tax equity markets.

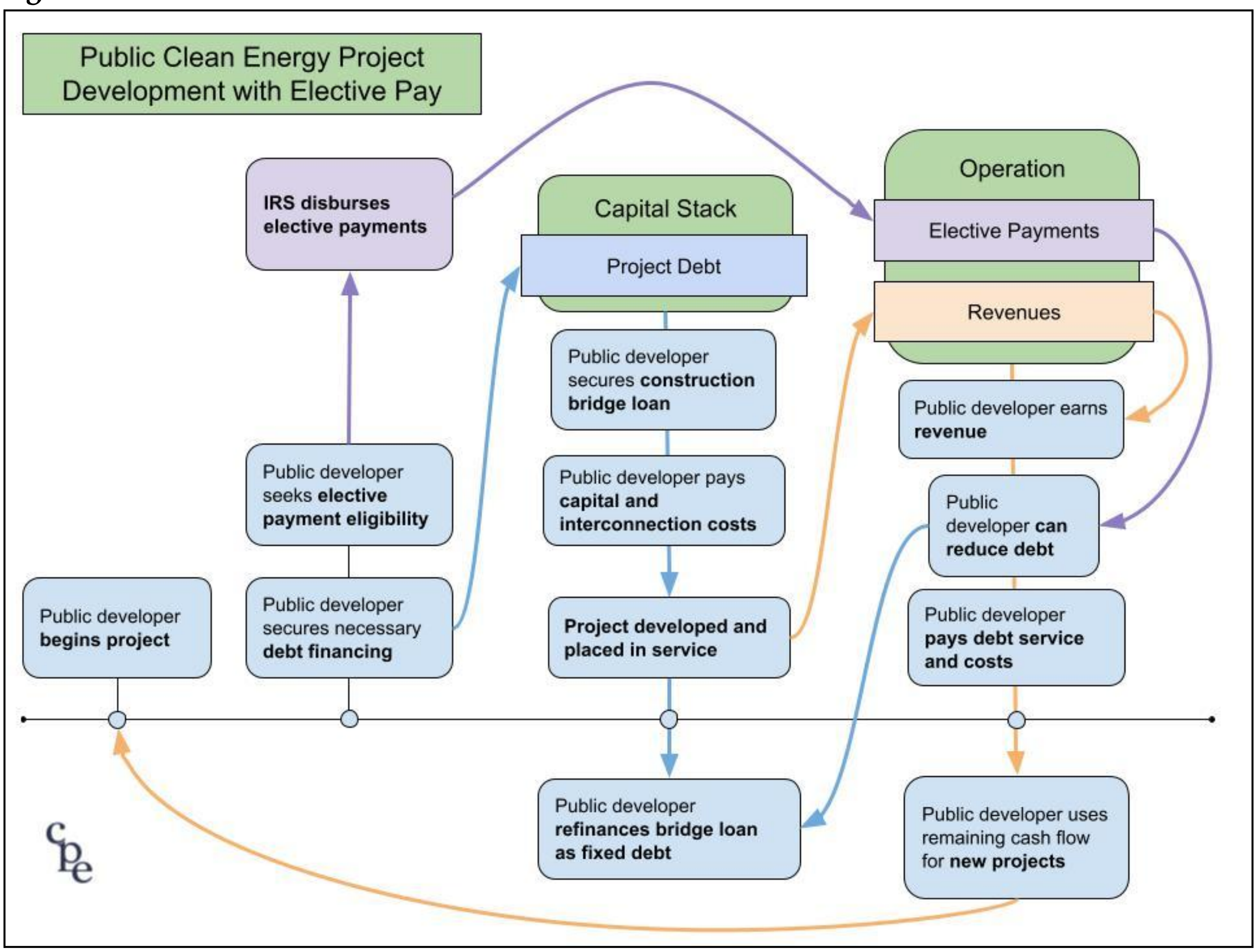
While elective pay corrects for the above disadvantages of tax equity financing, it raises different challenges. The obstacles faced by public developers relative to their private counterparts include the penalty on cheaper tax-exempt debt, the inability to claim depreciation in asset values, and the uncertainties associated with the elective pay pre-registration, application, and disbursement processes (*see "Elective Pay Goes Far—But Not Always Far Enough" in Section III for more context*).[17]

[17] CPE's comments from August 15, 2023 emphasized the need for the pre-registration, application, and disbursement processes to be as simple and predictable as possible to avoid negative repercussions for capital development processes among public entities. Source: Gordon, J., C. Lala. 2023. *Comments to the Internal Revenue Service on the administration of sections 6417 and 6418 of the Inflation Reduction Act: elective pay and transferability.* Center for Public Enterprise. Available at: https://www.publicenterprise.org/reports/6417-6418-nprm-comments.

Some public utilities and community choice aggregators will face issues integrating elective pay into their existing approaches to energy development. For example, many public utilities will only invest in projects brought to them by private energy developers and arrange PPAs in advance of operation to finance the plant. However, elective pay may allow or encourage such utilities to take a more proactive role in development using in-house expertise to determine the projects that they could own and operate directly. They would not have to wait for private developers to offer projects, which may or may not face difficult-to-overcome constraints, not meet certain requirements, or let the conditions of external entities limit the financial viability of energy projects.

Figure 2 illustrates how a public developer would use the elective pay process to monetize tax credits.

Figure 2.



Note. Actions of developers to change the debt or equity on their balance sheets or make debt payments are represented by blue boxes and arrows. Elective payment-related actions and flows are represented by purple boxes and arrows. The flow of revenues from energy sales is represented by orange boxes and arrows.

Barriers to capital development: Both Figures 1 and 2 illustrate the project development processes—how an institution (private or public) goes from planning the installation of equipment that can generate an income to actually installing that equipment and, finally, earning the income. For a specific instance of capital development to be successful, the entire process must occur. An interruption at any point in this process may result in the project failing to be completed or in significant cost overruns.

A financial model such as this one cannot capture and model every barrier. These include potential or existing construction delays; the availability of materials, tools, or skilled labor to execute key tasks; grid interconnection problems; the threat of output curtailment due to grid conditions; permitting; or the complexity of processes used to claim tax benefits like elective pay. It is important to emphasize that these factors affect both public and private projects.

Public developers are buttressed against some of these risks due to their lower minimum returns on investment. This makes it possible for public developers to take on projects their private counterparts would not. But this is not a panacea for all barriers to investment. If a public entity cannot interconnect a project, site it in advantageous areas, expect to deliver power consistently without curtailment, find customers who will consistently use its output, or face unpredictable delays on their construction and operation, it will face constraints similar to any other developer.

The discussions that follow will highlight how the model accounts for some of these barriers and how model users should interpret model results in response. However, it cannot always capture many systemic-level barriers to investment, a constraint that users should keep in mind.

Section II: The CPE Model

This section walks through how the CPE model works. First, it is important to note that the model uses default values for certain inputs including the capacity factor, technology-specific overnight costs of capital, and interest rates. Default values are drawn from a variety of standard data sources, such as those published by the U.S. government via the Energy Information Administration or the National Renewable Energy Laboratory. They are not meant to be authoritative statements of the characteristics or costs of renewable energy systems. Rather, they are guides for those needing reference values. As such, the model allows users to set "alternate" values if they do not wish to use the defaults.

Second, the model aims to determine whether a particular project can earn enough revenue to cover its costs and debt service. The viability of a project is ascertained through the average debt service coverage ratio (DSCR) which is defined as the principal and interest payments in a given period divided by net income. Viable projects will have a DSCR greater than 1.0 over the project's lifetime. Net income incorporates elective pay, fixed operations and maintenance expenditures (O&M), variable O&M, gross revenues, and renewable energy certificate (REC) sales (*see "Model Inputs" below for further definitions*). The model presumes that project lifetimes for both solar and wind are 30 years after construction is complete, and that the debt used to finance the project is paid back fully over the life of the project through a combination of revenues, REC sales, and elective payments on tax credits.

Third, the model aggregates annually. Each developer is presumed to undertake project planning and pay capital expenditure costs in its first year (2023). Solar projects are given 2 additional years for construction (2024 and 2025) while wind projects are given 3 additional years (2024 to 2026). The model then calculates output, costs, and revenues in each construction and operation year alongside with debt service and the cash buffer the project builds over time.

The model also produces other results, including the project's lifetime electricity output (in MWh), the net present value of elective payments, unsubsidized and subsidized simple levelized costs, a subsidized overnight cost of capital, a capital recovery factor, and a minimum DSCR over the project period. This section will define major components of the calculations, beginning with the costing of chosen systems, describe other relevant inputs, and discuss how the model calculates its results under these parameters.

Model Inputs

Model inputs are determined by the technology the developer chooses to invest in. The model allows the selection of the following technologies:[18]

- Utility-scale solar (Solar)
- Hybrid solar and storage
- Distributed generation
- Standalone battery storage
- Onshore wind (Wind)
- Offshore wind

Costs

Capital expenditure: Each technology has capital costs that can be encapsulated by an overnight cost of capital (OCC), a measure that aggregates various capital cost components, normalizes them by system capacity, and excludes interest accrued during construction and development.[19] Capital cost components include (but are not limited to) site preparation, equipment installation costs, engineering

[18] Further elaborations of the model are planned which will include other eligible technologies such as geothermal, nuclear, and pumped hydro storage.

[19] EIA. 2023. *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023.* Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

costs, development costs, labor costs, as well as the studies necessary to secure regulatory approval.[20] By using OCC as the input for capital costs, the CPE model presumes that capital expenditure is paid upfront even if the work may last several years. OCC is measured in dollars per kilowatt ($/kW), or the dollar cost per unit of electricity generation capacity installed.

The total capital expenditure of a project is the OCC multiplied by the project's generation capacity.

Default input values for the OCC, capacity factor, and system size are drawn from the EIA and the NREL's Annual Technology Baseline data. Users have the option to choose their own input values based on their own research or project needs.

<u>O&M costs:</u> Default fixed and variable O&M costs are taken from the EIA.[21] These are calculated on an annual basis either based on the capacity itself (fixed O&M) or calculated based on generation (variable O&M). Fixed O&M can include staffing, annual maintenance, telecommunication and sewer connections, maintenance, decommissioning, other forms of overhead and (for private entities) property taxation; these costs will be incurred even if the facility does not produce power.[22] Variable O&M costs vary with operation and often include start/stop costs.[23] However, these costs are generally zero for solar and wind systems. For users who want to simulate exogenous cost growth over time, the model provides an adjustable cost escalator.

<u>Interconnection costs:</u> The interconnection process requires projects to go through an approval process before they can connect to the grid.[24] Interconnection processes across the country (in the context of state, ISO/RTO, and FERC rules) have come under immense pressure from the scale of clean resources attempting to interconnect. Interconnection queues have grown sharply (nationally, they surpass the size of existing capacity altogether) because the interconnection process does not conduct anticipatory planning for new capacity, excludes key stakeholders from sharing cost burdens of new hosting capacity, and does not or cannot account for the realistic operating profiles of storage

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[20] EIA. 2013. *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Available at: https://www.eia.gov/outlooks/capitalcost/.

[21] EIA. 2023. *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023.* Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

[22] To the extent the default inputs of fixed O&M data provided by the CPE model account for taxation, they may overstate fixed O&M costs. Source: 1) Ferrari, J. "Long-term capacity expansion planning." Electric Utility Resource Planning (2021): 139-172. Available at: https://www.sciencedirect.com/science/article/abs/pii/B9780128198735000058. 2) Agar, Amritpal Singh, and Giorgio Locatelli. "Economics of nuclear power plants." In Nuclear Reactor Technology Development and Utilization, pp. 161-186. Woodhead Publishing, 2020. Available at: https://www.sciencedirect.com/science/article/abs/pii/B9780128184837000044.

[23] Agar, Amritpal Singh, and Giorgio Locatelli. "Economics of nuclear power plants." In Nuclear Reactor Technology Development and Utilization, pp. 161-186. Woodhead Publishing, 2020. Available at: https://www.sciencedirect.com/science/article/abs/pii/B9780128184837000044.

[24] Berkeley Lab. "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection." Available at: https://emp.lbl.gov/queues.

projects.[25] The result is jockeying between process managers and applicants, delays, and increasing costs.[26] This inefficient process increases interconnection costs (represented by an adjustable average cost per kW), which the model also covers for through its adjustable cost escalator.

Revenues

Gross revenue: The revenues of the modeled public developer are provided by the sale of power generated from the project via a physical PPA. The model presumes a fixed capacity factor for the life of a project, but also derates the power annually at a rate of 0.5 percent per year (this input, labeled "derat," is adjustable) to incorporate diminishing power from reasons such as wear and tear. Users can incorporate and customize annual fixed price escalation—a standard PPA condition—into the model.

REC sales: Renewable energy credits (RECs) are financial instruments created by states to track and provide cash flows to renewable electricity.[27] They are components of renewable portfolio standards that greenhouse gas emitters can buy from renewable or carbon-neutral energy generators. Physical PPAs usually denote which party takes ownership of RECs generated by a clean energy project.[28] Users can determine the revenue to the project from sale of RECs if the terms of the project PPA allow the public developer to retain some or all of the RECs. This model presumes that the public developer can earn a constant average price (allowing for either an administrative price or for a market price whose volatility has been smoothed out) on the share of RECs it is able to sell. The model also provides an adjustable REC price escalator.

Financing

Capital stack and the weighted average cost of capital (WACC): The capital stack refers to the mix of debt and equity financing used by a project to pay for its capital expenditures. The CPE model presumes that the entirety of a public energy project is financed by a mixture of green bank debt, other forms of state and local (municipal or "muni") debt, and various kinds of fixed-term market debt. An option remains for the modeler to incorporate equity into the project capital stack if they so choose. The components of the capital stack are used to calculate a weighted average cost of capital (WACC), an average interest rate reflecting both the rates of return on and component sizes of the different components of the capital stack. All debt products in the stack are presumed to have a 30-year maturity. The cost of project financing is modeled as a fixed-rate loan with the WACC as its interest

[25] Lala, C., J. Burt, S. Peddada. 2023. *The Interconnection Bottleneck: Why Most Energy Storage Projects Never Get Built.* Applied Economics Clinic. Available at: https://aeclinic.org/publicationpages/2023/5/17/the-interconnection-bottleneck-why-most-energy-storage-projects-never-get-built-48nct.

[26] Ibid.

[27] EPA. "Renewable Energy Certificates (RECs)" Available at: https://www.epa.gov/green-power-markets/renewable-energy-certificates-recs.

[28] EPA. "Physical PPAs." Available at: https://www.epa.gov/green-power-markets/physical-ppa.

rate. The model assumes that this loan is taken out once a project begins operation (the year when the project begins to generate power) and paid back over the life of the project.

Bridge loan debt: Until the project begins operation and starts earning revenue, it is presumed to use a construction bridge loan with an interest rate higher than the fixed-term WACC to cover upfront capital expenditures and interconnection costs. The project must pay interest on that loan, but nothing more. Most construction bridge loans require a balloon payment of remaining loan principal once the construction period ends. But the CPE model presumes that the public developer refinances the entire principal amount of the construction loan with the fixed-term debt described above. Note that the interest payments on the construction loan are the first instance in which the project records a cash flow. If the bridge loan has a rate above zero, this will be recorded as negative cash flow (see "Cash buffer" below to determine how this is recorded).

Elective pay and debt: As noted above, elective pay can be paid out as either an ITC or PTC. The ITC payment is sufficiently large relative to the capital expenditure that the modelers are allowed to decide whether they wish to use some or all of it to reduce project debt during the first year of operation. This would amount to paying off a large portion of the construction loan at once and refinancing the rest. CPE presumes that the elective pay disbursements and refinancing timelines in the first year of operation line up accordingly. **This presumption may change contingent on forthcoming IRS guidance on elective pay disbursement timelines.**

Cash buffer: Once a project begins operations, it must also start paying fixed and variable costs as well as full debt service (principal and interest payments) on its debt. The model calculates net income (revenues minus costs plus REC revenues and elective pay). It then subtracts debt service to calculate a net cash flow. As mentioned above, the project starts with negative cash flow to cover the interest payments on the construction bridge loan. Normally, these payments would be shouldered either by the state or, more likely, by the public developer itself. But, as we model the finances of a specific energy project rather than the broader the state or public developer's overall balance sheet, negative payments are attributed to borrowing by the individual project and must be paid back. Absent an existing cash buffer from years of positive net cash flows, all "overdrafts" are presumed to be borrowed from the state or public developer.[29] If negative cash flows persist, this overdraft debt to the state increases (if the "overdraft rate" is greater than zero). Once the project begins earning revenue and generating positive net cash flows, the overdraft debt is repaid out of the net cash flows remaining (i.e., it is subordinate to the project debt used for calculating the WACC). When the overdraft debt is repaid, positive cash flows continue to build up in a cash buffer which is presumed to earn an annual rate comparable to those on standard cash reserve accounts. These cash flows can be accumulated, used to offset or stabilize

[29] If the "overdraft rate" is set to zero, then the model is effectively saying that an external entity covers the project's negative cash flow until that entity can be paid back out of future positive cash flow.

electricity costs, re-invested, or used to support the operation of other existing public energy projects. Note that there is a fixed tradeoff for the use of the cash buffer between those three purposes.

Box 3. What are green banks?

The CPE model allows for debt issued by a "green bank." A **green bank** is a financial institution established by a state, tribal, or municipal government—or a non-profit institution—dedicated to lending to renewable energy and carbon emissions mitigation investments. Green banks are thus typically a public or public-serving financial enterprise. Prominent examples of green banks—or infrastructure banks that can undertake green lending—include:

- The Connecticut Green Bank
- The New York State Green Bank
- Michigan Saves
- The Nevada Clean Energy Fund
- The California State Infrastructure and Investment Bank
- Hawai'i Green Infrastructure Authority
- Minnesota Climate Innovation Finance Authority (passed in legislature)
- New Mexico Climate Investment Center (proposed)

Green banks typically act as revolving funds (*see Box 5*) and lend alongside private investors to take on subordinated debt positions in projects, thus lowering their overall costs of capital. The CPE model gives green bank debt a lower interest rate than market rate debt by default, but users can customize this input. (In the absence of an official green bank, other state- and local- level financial institutions can play the role of one.) That being said, if green bank debt is tax-exempt, any project with that debt in its capital stack would still incur the IRS's penalty on their elective payment earnings.

The IRA, which upgraded the Environmental Protection Agency (EPA)'s Greenhouse Gas Reduction Fund (GGRF) into a seed fund for various public and non-profit green lenders, has the potential to expand green banking nationwide. The GGRF can fund both state-based institutions and national non-profits.

There are various ways for green banks to make use of elective pay. Pending federal rulemaking, green banks can potentially purchase investment and production tax credits from private and public developers and monetize them in a procedure referred to as "chaining." CPE is monitoring regulatory guidance on the eligibility of green banks to engage in chaining transactions and has recommended allowing such practices be taken in conjunction with other elective pay tax credit entities to maximize the uptake of elective pay wherever possible.

CPE has previously submitted comments* to the EPA advocating for using GGRF funds to capitalize green banks around the country.

*Lala, C. et al. 2023. "Comments on Guidance for Green Bank Implementation." Center for Public Enterprise. Available at: https://www.publicenterprise.org/reports/comments-on-guidance-for-green-bank.

Model Outputs

Total Output

The model calculates a project's total output by adding together the yearly energy generated by the project defined as installed capacity multiplied by the capacity factor and discounted by an annual derate of 0.5% to represent wear and tear. The derate can be adjusted in the model inputs.

Net Present Value (NPV) of Tax Credits

The value of elective pay tax credits to the project is calculated via the net present value (NPV) of payments made from the Treasury Department to the developer. The model allows the user to select between ITC and PTC tax credits, a choice which changes the disbursement timing and yearly value of credits and therefore affects the tax credits' NPV—the value of present and future payments measured in the value of today's money. The discount rate applied to the NPV is the WACC taken from the model's sample capital stack. Section III introduces a calculator based on the CPE model to help inform public developers of the tradeoffs between the ITC and PTC as measured by their NPVs.

Levelized Cost of Energy (LCOE)

The levelized cost of energy represents an average lifetime cost of electricity (in dollars per unit of generation) from a particular energy system. It accounts for capacity factors, fixed O&M operation and maintenance costs, and discount rates (in the model's case, the WACC). The result is a measure that allows different resource types, with their different construction and operating periods, to be compared with a common financial metric.[30] Users can also use LCOE to observe the immediate impact of key energy system and financial changes: higher discount rates increase the LCOE; higher capacity factors and longer periods of project operation lower it, as do longer periods of project operation.[31]

[30] DOE Office of Indian Energy. *Levelized cost of energy.* Available at: https://www.energy.gov/sites/prod/files/2015/08/f25/LCOE.pdf.
[31] Ibid.

The CPE mode uses a simplified LCOE formula provided by NREL:[32]

$$sLCOE = \frac{overnight\ capital\ cost * capital\ recovery\ factor + fixed\ O\&M}{8760 * capacity\ factor} + (Fuel\ Costs\ * Heat\ Rate)$$

The renewable technologies modeled do not have fuel costs or heat rates, setting their value to zero. Fixed and variable O&M costs and capacity factors are model inputs and 8760 is the number of hours in a year.[33]

The model presents a subsidized and unsubsidized LCOE. The former uses a reduced base overnight cost of capital which accounts for the present value of elective pay disbursements; the latter does not. This allows modelers to compare the immediate effect of elective pay across resource types as well.

That being said, modelers should be cautious using the LCOE for more than these basic comparisons between resources. For instance, NREL's simplified LCOE does not incorporate the cost of degradation. Nor does it capture avoided costs which represent the benefits a particular project might have for the resilience and stability of the broader electrical grid.[34]

Capital Recovery Factor (CRF)

The capital recovery factor (CRF) is the ratio of loan payments over the lifetime of the project to the net present value of the payments expressed as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

The model uses the WACC as the interest rate i and a project lifetime of 30 years as the period n, and expresses CRF as a percent.

Debt Service Coverage Ratio (DSCR):

The project's debt service coverage ratio (DSCR) for a given year is the ratio of net income in that year to the debt service costs (principal and interest) incurred that same year.[35] The viability condition this model imposes on the public project is the project's *average* debt service coverage ratio (DSCR), the average of all annual DSCR values—which must be greater than 1 over the duration of the project.

[32] NREL. "Simple Levelized Cost of Energy (LCOE) Calculator Documentation." Available at: https://www.nrel.gov/analysis/tech-lcoe-documentation.html.

[33] Some years may have a different number of hours. We think 8760 is a good approximation for most time horizons, but users may customize this formula as they see fit.

[34] Ibid. Also see: Green, M. 2023. "The Case for Grid Thought." *Center for Public Enterprise*. Available at: https://www.publicenterprise.org/blog/case-for-grid-thought.

[35] The model defines net income as gross revenue minus total costs (variable and fixed costs). The user can choose to include elective pay and REC It does not include debt service.

The model also provides a minimum DSCR, which is the lowest ratio of annual earnings to debt service achieved over the project's lifetime. A minimum DSCR above 1 means the project earns sufficient cash flow to cover debt service in every year of its operation.

Section III. Results and Discussion

Interpreting Project Viability Conditions

Viability in the Context of a Public Developer

The model presumes that the state or developer will require some sort of financial viability criteria on the project: likely that the project be able to "pay for itself" and provide power "at cost." The model represents this condition as a DSCR which is greater or equal to one.

This metric should be interpreted in the context of a public developer's specific mission and local conditions. Generally, the goal of public power development is to increase and maintain renewable capacity rather than generating above average returns. Thus, using the DSCR as a measure of project financial viability focuses users' attention on the threshold financial conditions for beginning and sustaining the operations of a specific energy generation project. For a public developer, those conditions do not require any additional variables such as market defined opportunity costs.It will likely have neither equity returns nor profit requirements (except any imposed in statute). We thus assume that the minimum financial target of a project is to break even while its output serves other goals such as grid resiliency, decarbonization, or bill savings. Users of this model can impose stricter or looser financial requirements if they so choose.

The average DSCR represents an implicit hurdle rate—a minimum return that projects must be able to anticipate earning with some confidence in order for their developers to secure financing and proceed with capital expenditure. There are a few caveats to this calculation, however. Recall that this model functions on a per-project basis. Running projects "at cost" will mean something different if multiple public projects are contributing to the balance sheet of a single public developer. A more profitable project could "cross-subsidize" a project whose average DSCR happens to be less than 1 but that is crucial to build for different reasons (perhaps as a virtual power plant or as an emergency reserve). In that case, the hurdle rate should be calculated on the balance sheet of the developer itself. If the state itself oversees multiple developers, then calculating viability could be done at the level of the consolidated statewide balance sheet. While this model does not allow users to calculate hurdle rates on any balance sheet except that of the individual project, it can be used as part of a broader procedure for portfolio construction.

The Impact of Elective Pay on Project Viability

The model's average DSCR output illustrates how elective pay makes public energy development financially viable even under hard budget constraints. Turning elective pay off in the model produces an immediate and sharp drop in all projects' average DSCR *at any price of energy*, because public projects do not have any other way to access tax credits—and no other IRA program matches elective pay's generosity or its uncapped availability for such a wide class of renewable projects. Elective pay sharply reduces the amount of capital expenditure that is subject to *any* kind of payback. Elective pay thus directly enables the public sector to begin entering the clean energy space on an even footing with—or better than—private developers. Moreover, it enables creative financing of higher-risk projects by combining the public sector's lower hurdle rate with a federally subsidized cost of capital.

Thus, states, municipalities, and public developers should view elective tax credits and federal direct pay as an uncapped subsidy or grant for projects that meet qualifications. Tax credits for private projects are already an implicit federal subsidy, since they lower private developers' financing costs by providing a guaranteed stream of income. (Private projects which use tax equity markets simply sell those subsidies to other private entities to monetize them upfront.) Elective pay does precisely the same for public projects of all kinds, but without the need for developers to navigate financial markets to secure the benefits.

Elective pay's uncapped and relatively stable funding rules[36] let public developers build their own cash reserve from which they can expand their investments as they see fit, independent of political cycles,patronage, or funding sources that impose impractical or counterproductive conditionalities and

[36] CPE's report, *Direct pay: an uncapped promise of the Inflation Reduction Act,* noted that [elective] pay is effectively a fiscal window. We draw on Nathan Tankus' definition of a fiscal window as an uncapped program whose benefits are legally entitled to those with qualifying projects. Any investment program meeting specified criteria can claim the ITC, PTC, or other elective pay-eligible tax credits regardless of the fact that their parent organizations do not pay taxes. The Treasury will spend more or less money on elective pay credits depending on takeup—not on fixed caps set in appropriations, nor based on constraints imposed by the aggregate tax liabilities of financial institutions or potential credit buyers. Rather, the various investment barriers and state capacity issues faced by public projects (see Section I) will likely be the binding constraint on how much is disbursed to elective pay projects. For further discussion see Tankus, N. 2020."The Coronavirus Depression Requires A New Approach to Budgeting." Notes on the Crisis. Available at: https://nathantankus.substack.com/p/the-coronavirus-depression-requires. 2) Lala, C. 2023. *Direct pay: an uncapped promise of the Inflation Reduction Act.* Center for Public Enterprise. Available at: https://www.publicenterprise.org/reports/direct-pay-uncapped-ira. p. 11.

uncertainties on the disbursement of funds.[37] In elective pay's absence, projects would have to rely either on additional debt or more expensive project equity.[38]

Box 4. A tale of two projects.

The private sector has led solar and wind energy resource development across the United States. What would it look like for a public developer to do what private firms are doing—this time with the benefit of elective pay? This box takes two recent newsworthy private renewable energy projects and uses the CPE Model to reimagine them as public projects.

1. **Solar in Missouri**. Ameren Corp, a gas and electric utility, announced in June that it plans to build 100 MW of solar energy (and purchase 450 MW more from other owners) in Missouri, specifically in Vandalia and Bowling Green. Lawrence Berkeley National Laboratory (LBL) data on solar efficiency in Missouri suggests that this solar installation would have a capacity factor around 20.5%.

   Simulating this project's finances as if a public developer were undertaking it requires making certain assumptions: first, that the public developer pays prevailing wages and secures an exemption to domestic content requirements; second, that this project is located in an energy community and a low-income census tract: Bowling Green is an energy community and Vandalia's city limits border one, and both are in low-income census tracts; third, that the public developer secures tax-exempt financing; fourth, that an energy price of $45/MWh is realistic given solar PPA data from LBL; fifth, that the model's default capital stack, which has a WACC of 4.65%, is appropriate. Toggle the model's "Inputs" tab to reflect these assumptions.

   EIA data suggest that utility-scale solar in Missouri has an overnight cost of $1,497/kW. Plug in this installation cost and the 20.5% capacity factor on the model's "Solar" tab and to see the results.

[37] This is not to say public developers should avoid other state grant funding or capitalization. Rather, the design of public appropriations to energy projects matters and will affect takeup depending on the specific conditions of a public project. States and municipalities can and should consider supplementing elective pay with reliable and periodic capitalization grants if they so choose, while setting fixed, clear, and transparent eligibility criteria that are easier to monitor.

[38] This is not to say projects using elective pay cannot or will not utilize equity for the remainder of the capital stack, merely that public developers do not have to if they can use municipal or green bank debt. Elective pay credits can thus be thought of as an "equity" entry in the capital stack that requires zero dividends or returns–hence the term "tax equity."

Under these conditions, a public developer using the ITC would receive a one-time elective payment of $63.6 million in the first year of operation (NPV $55.5 million) and, if it used this credit to immediately pay down debt, the project's average debt service coverage ratio (DSCR) would be 1.11—meeting the model's financial viability threshold.

A public developer using the PTC would receive no benefit from the fact that these projects are in low-income census tracts. It would receive elective payments over the first 10 years of operation with an NPV of $37.4 million. But the project's average DSCR would be 0.85—failing to meet the model's financial viability threshold. The lowest viable price at which this project is viable using the PTC is $52/MWh.

2. **Wind in Maine**. Patriot Renewables, LLC, a renewable energy generation developer, is building a 59 MW onshore wind turbine installation in Moscow, Maine with financing from Greenbacker Capital, which submitted an order to Vestas for 14 turbines on its behalf in July. CPE assumes that this project has a 48% capacity factor based on average annual wind speeds around Moscow at given turbine heights, and NREL classifications of turbines.

   Simulating this project's finances as if a public developer were undertaking it requires making certain assumptions: first, that the public developer pays prevailing wages and secures an exemption to domestic content requirements; second, that, while Moscow, ME, is not an energy community, energy projects there qualify for a low-income tax credit; third, that the public developer secures tax-exempt financing; fourth, that an energy price of $45/MWh is realistic given wind PPA data from LBL; fifth, that the model's default capital stack, which has a WACC of 4.65%, is appropriate. Toggle the model's "Inputs" tab to reflect these assumptions.

   EIA data suggests that onshore wind in Maine has an overnight cost of $2,075/kW. Plug in this installation cost and the 48% capacity factor on the model's "Wind" tab and to see the results.

   Under these conditions, a public developer using the ITC would receive a one-time elective payment of $41.6 million in the first year of operation (NPV $34.7 million) and, if it used this credit to immediately pay down debt, the project's average debt service coverage ratio (DSCR) would be 1.04—meeting the model's financial viability threshold.

   A public developer using the PTC would receive no benefit from the fact that Moscow, ME, is a low-income census tract. But it would receive elective payments over the first 10 years of operation with an NPV of $45.8 million. The project's average DSCR would be 1.01—again meeting the model's financial viability threshold.

(Both conclusions here rest on the assumption of a 48% capacity factor. Lower capacity factors—even those in the 30 - 35 percent range—would prevent the Moscow, ME, project from being financially viable.)

Why are the results of both examples different when developers choose the PTC over the ITC? The PTC is a credit earned based on the quantity of energy that a project generates annually, and is disbursed for the project's first 10 years. The ITC, meanwhile, is a credit earned based on the total capital investment sunk into the project, and is disbursed just once at the start of the project. It stands to reason that more expensive projects may receive more from an ITC, while projects that generate more may receive more from a PTC. But there is nuance to this generalization: to learn more about the tradeoffs between the ITC and PTC, see the next subsection, "Choosing Between ITC and PTC," and interact with the NPV Simulator attached to this model.

The Ameren Corp solar project in Missouri was announced in June. Swiantek, Valerie. 2023. "Ameren Missouri Adding 550 MW of Solar to Portfolio." *Solar Industry*. Available at: https://solarindustrymag.com/ameren-missouri-adding-550-mw-of-solar-energy-to-its-portfolio.

The Patriot Renewables, LLC, wind project in Maine was announced in July. Vestas. 2023. "Vestats secures 59 MW order from Greenbacker Capital Management in the USA."
Vestas. Available at:
https://www.vestas.com/en/media/company-news/2023/vestas-secures-59-mw-order-from-greenbacker-capital-man-c3798375#.
Patriot Renewables. 2023. "About the Western Maine Renewable Energy Project." Patriot Renewables. Available at: https://www.patriotrenewables.com/projects/western-maine-renewable-energy/. Turbine data in particular can be found at: https://storymaps.arcgis.com/stories/8d6f67995d494e4d8953b561fef9b10a.

Wind turbine classes and capacity factor information can be found in multiple places. Wind turbine class definitions were sourced from LM Wind Power. Available at: https://www.lmwindpower.com/en/stories-and-press/stories/learn-about-wind/what-is-a-wind-class. NREL has data on average wind speeds in Maine, which were used to identify the probable wind turbine class for the Patriot Renewables project. Available at: https://windexchange.energy.gov/maps-data/339.

Capacity factor and PPA price data for utility-scale solar and onshore wind turbines are sourced from Lawrence Berkeley National Laboratory's Energy Markets & Policy practice and from NREL. Available at: https://emp.lbl.gov/ and https://atb.nrel.gov/electricity/2023/index. Region-specific overnight cost of capital data are sourced from the EIA's most recent "assumptions" document. Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

Viability is More Than a Number

The DSCR metric allows governments and public developers to ensure that they have adequate financial capacity to carry out their planned projects. However, the model cannot judge the many other reasons for or against building these projects. Indeed, governments may have reasons to want capacity of their own that cannot easily be quantified: they might wish to increase renewable supply faster than the private sector or other public power providers are able to do alone, build resiliency options under their own control for emergency situations or particular jurisdictional needs, or stabilize their respective power markets by having a "public option" available to prevent price spikes in stressed periods. Of course, there are costs to the government from acting as an investor and operator. But it may be harder for governments to achieve these goals simply as power purchasers or if additional financial constraints (a higher average DSCR threshold, equity returns, or profit requirements) are imposed beyond those of basic at-cost operation mandates, net of elective pay and other grants.

A direct comparison between the price of publicly generated power and the price from a private-market PPA or other kinds of wholesale market prices results in an incomplete assessment of public power because the government or public developer can use its income from these operations more flexibly than other providers can. Governments can reinvest the project's cash flow into further projects, offset price hikes for vulnerable groups, or support the operation of systemically important public assets on the developer's balance sheet with volatile cash flows (such as publicly-owned storage projects specifically designated for periods of high energy demand).[39] The model's quantitative outputs cannot provide insight into these tradeoffs.

The model provides users a few options for incorporating cost overruns driven by known risk factors: there is an entry for interconnection costs and an entry allowing for an exogenous increase in capital costs. However, not all investment barriers can or should be represented as predictable increases in costs.[40] Investment barriers will not always represent a monetary "cost"; instead, they might render future projections less reliable or impossible to make. For instance, revenue forecasts immediately become less reliable if a project can never enter operation. Much of the prevailing anxiety about elective pay implementation, for one, concerns the possibility that the IRS administers it in ways that make payments difficult or impossible to access. Projects should be able to rely on elective payments' massive and vital boosts to their capital stacks. It is crucial that governments address these barriers precisely so

[39] It is not out of the question that the government could consider providing cash flow or grants to public developers or to solve specific problems. Another way of saying this is that the state could deem certain projects important enough to provide them with continuous cash flow subsidies or provide funds to further reduce the capital expenditure subject to payback; this choice is common with public institutions of all kinds.

[40] Duke Energy, for example, added a 20% "cost risk premium" to its calculations "as a proxy for unknown market conditions" in a recent regional resource plan document. Source: Duke Energy. 2023. *2023 Carolinas Resource Plan*. "Appendix C: Quantitative Analysis" p. 86. Available at: https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-c-quantitative-analysis.pdf.

that project developers can maintain sufficient confidence in anticipated costs and revenues to actually proceed with their promised projects.

Elective Pay Goes Far—But Not Always Far Enough

Unlike private developers, elective pay-eligible projects cannot access the benefits of claiming accelerated depreciation[41] on their tax forms. Moreover, public projects using tax-exempt debt face a penalty on their tax credit disbursement. For smaller projects or projects with extraordinarily high capital costs, these disadvantages may either prevent takeup of elective pay entirely or see the project developers utilize tax equity markets to monetize tax credits.[42]

But elective pay offers significant advantages especially for public energy development. States, municipalities, and public developers can access much cheaper debt than private sector actors or even some nonprofits. This debt—encompassing various kinds of municipal or "muni" debt as well as green bank debt (*see Box 3*)—can be cheap enough to allow the entire project's capital stack to avoid both more expensive market-rate debt and equity.[43] In those circumstances, the project can still be viable even with the tax-exempt penalty.

The municipal financing landscape represents a significant opportunity for utility-scale solar, storage, and onshore wind generation. These types of projects (pending interconnection costs) see sufficiently high lifetime output and manageable capital costs. In most cases, they can produce enough at recognizable prices to meet the expected debt payments. But CPE's initial modeling suggests that distributed generation, offshore wind, and other projects seeing insufficient output or excessive capital costs will require additional state support, industrial policies, energy market reforms, or various other policy changes to meet the model's DSCR-based viability condition. As discussed above, that does *not* mean these projects are undesirable. But CPE's model does not suggest that elective pay will always provide them with sufficient financial support.

Choosing Between ITC and PTC

For clean generation projects beginning in 2025 and afterwards, projects can choose between the Clean Electricity Investment Tax Credit (ITC) and the Clean Electricity Production Tax Credit (PTC). Both

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[41] Depreciation refers to the degradation of capital equipment over time due to ordinary use, wear and tear, etc. It is treated as an expense on tax forms, and allowing developers to claim more depreciation in the early years of a project reduces their overall tax liability. Source: DOE. 2023. Federal Solar Tax Credits for Businesses. Available at: https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses.
[42] This may be especially likely for nonprofits undertaking project development.
[43] To the extent that municipal debt markets can issue more standardized forms of debt, debt at longer maturities, or see the future revival of a federal reserve facility dedicated to backstopping municipal securities (e.g., the Federal Reserve's Municipal Liquidity Facility), public developers could further cement their debt-financing advantages.

are disbursed at the start of the project's operation. The ITC reimburses the project for a set percentage of the total capital investment. The PTC pays a set amount per kilowatt-hour (kWh) generated.

The value of each credit (the ITC percentage, or PTC dollar per kWh) depends on the bonuses the project is eligible for, such as meeting prevailing wage and domestic content requirements, whether it utilizes tax-exempt financing, and if it is located in an energy community.

The model can be used to compare the value of ITC and PTC credits for an individual project. To assist public developers with choosing the appropriate credit, CPE used the financial model to create an interactive app—**the CPE Elective Pay NPV Simulator**[44]—depicting the difference between the ITC and PTC across different bonus credit "scenarios" for a sample utility-scale solar project. Users can choose a bonus credit scenario and select from a range of overnight costs of capital, capacity factors, and three different discount rates. In response, the Simulator will display different bar charts illustrating how the PTC and ITC compare against each other across users' selected ranges. The NPV values themselves are calculated using the CPE model's projected tax credit values for utility-scale solar. The range of capacity factors is selected from the model's extraction of NREL Annual Technology baseline[45] tab, and the overnight cost of capital ranges incorporate the default utility-scale solar OCC values from EIA's power market module values for clean generation.[46]

A "positive" bar on the charts represents a PTC advantage over ITC (measured as NPV, in millions of dollars) at the user's selected scenario, overnight cost, capacity factor, and discount rate.[47] A "negative" bar shows an ITC advantage over PTC (measured as NPV, in millions of dollars).

Users can choose among three probable credit scenarios:

- Scenario 1 compares the credit values for projects meeting prevailing wage requirements, securing an exemption to domestic content requirements, and facing a 15 percent penalty for using tax-exempt bond financing.
- Scenario 2 compares credit values for projects meeting prevailing wage requirements, securing an exemption to domestic content requirements, facing a 15 percent penalty for using tax-exempt bond financing, and earning the energy community bonus.

[44] If the link changes after this particular document is uploaded, please refer to the CPE Energy Program website for more recent iterations of the app and model. https://www.publicenterprise.org/reports/financial-model-for-elective-pay.
[45] NREL. 2023. Annual Technology Baseline. Available at: https://atb.nrel.gov/electricity/2023/index.
[46] EIA. 2023. *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023.* Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.
[47] Specifically, the bars depict the net present value of the credit in millions of dollars for the utility-scale solar project. Net present value discounting allows one to adjust the PTC and ITC values based on the time between their disbursements and the start of the project. More time passing before a disbursement diminishes the value of the amount disbursed in terms of today's money. In other words, $1 today is worth more than $1 in the future.

- Scenario 3 compares credit values for projects meeting prevailing wage requirements, earning the domestic content bonus, facing a 15 percent penalty for using tax-exempt bond financing, and earning the energy credit bonus.

Example bar graphs for these three scenarios are available below (see Figures 3.1 – 3.3). The bar graph for Scenario 1 illustrates that the PTC is more advantageous (in NPV terms) than the ITC except at the lowest capacity factors. Scenario 2 illustrates that the PTC's advantage diminishes faster with higher discount rates and capital costs if one adds an energy community bonus. Scenario 3 further cements this finding: when the domestic content exemption becomes a domestic content bonus, the tax credit advantage tilts further towards the ITC.

Figures 3.1 – 3.3 illustrate tax credit advantages at multiple overnight costs. A snapshot of tax credit values for a single overnight capital cost ($1,500 per kW) is available in Figure 4.[48] It confirms the following findings (also visible in the first three bar graphs):

- The more production a project can expect at a given discount rate and capital cost, the more financially advantageous it will be for developers to select PTC disbursements. (Increased production can be proxied for via a higher capacity factor, which is the ratio of power produced in a given period of time by an energy system relative to the power it could have produced if it had run at maximum potential capability.) By contrast, a higher capital cost for a given amount of production will advantage the ITC.

- Higher discount rates at a given capital cost and capacity factor advantage the ITC because the entire ITC is dependent on the cost of investment and is disbursed at once at the start of the project. The PTC is disbursed over the project's first ten years based on the project's production in those years—and, as such, PTC payments are discounted many more times than the ITC's disbursement.

- Adding tax credit bonuses generally advantages the ITC for two reasons. First, they increase the amount of the tax credit money that is disbursed upfront (and hence discounted less often). Second, ITC bonuses are valued in *percentage points* added to the ITC's base percent of project capital costs (with the exception of the tax-exempt financing penalty, which is measured in *percent* and not percentage points). However, the PTC receives the same bonuses as a *percent* of the PTC's dollars paid per kWh produced. So a base ITC covering 30 percent of project costs receiving either domestic content or energy community bonuses will increase in value by

[48] CPE chose this $1,500/kW value for the snapshot because it comes closest to the EIA's $1,448/kW base overnight capital cost for utility solar, which the CPE model uses as a default overnight capital cost value. See: EIA. 2023. "Table 3. Cost and performance characteristics of new central station electricity generating technologies." In Assumptions to the Annual Energy Outlook 2023: Electricity Market Module. Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

10 percentage *points* to 40%, equivalent to a 33 *percent* increase in ITC value. As the figure indicates, this may not be enough to swing the total tax credit NPV advantage away from PTC in all instances—especially if the project can expect high system generation. But bonuses significantly shift tax credit advantages towards ITC across all project profiles.

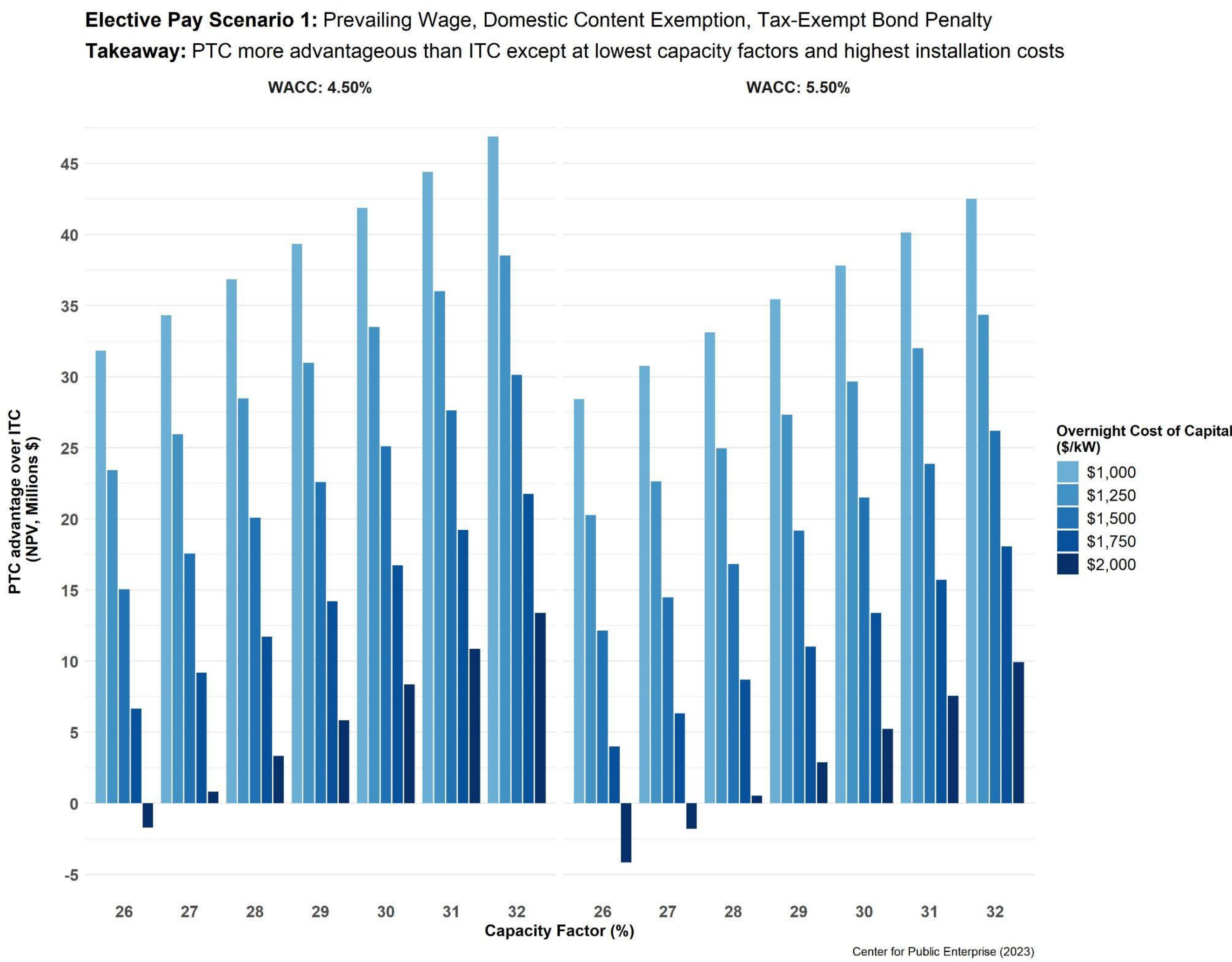
It is vital for public developers to assess the circumstances under which a particular credit might be more financially advantageous to claim for elective pay. **However, it is equally vital to note that public developers and their governments need not choose a particular credit just because the credit is financially advantageous in net present value terms.[49] The disbursement profile—receiving an ITC payment up front or a PTC payment over time—may be as or more important depending on what the public developer intends to do with the received funds.**

For instance, a state government setting up a utility scale solar system while meeting the energy community bonus would see modest to large advantages to selecting the PTC (analogous to scenario 2; *see Figures 3.2 and 4*). However, the developer may still opt for the ITC, which would immediately reimburse 40 percent of capital costs in this scenario, to reduce the project's outstanding debt load. For this reason, the CPE model allows the user to decide whether some or all of the ITC is taken as cash or is used to immediately pay down debt. Model users can also observe how this decision affects a project's lifetime average DSCR.[50] Not only can using the ITC to reduce project debt in the first period of operation increase the average DSCR, but it can also result in a DSCR above that of the PTC by lowering overall debt service payments over the life of the project.

[49] Note that just because a particular credit's NPV is higher, does not mean that the project's average DSCR will be higher—especially if credit monies are used to reduce project debt.

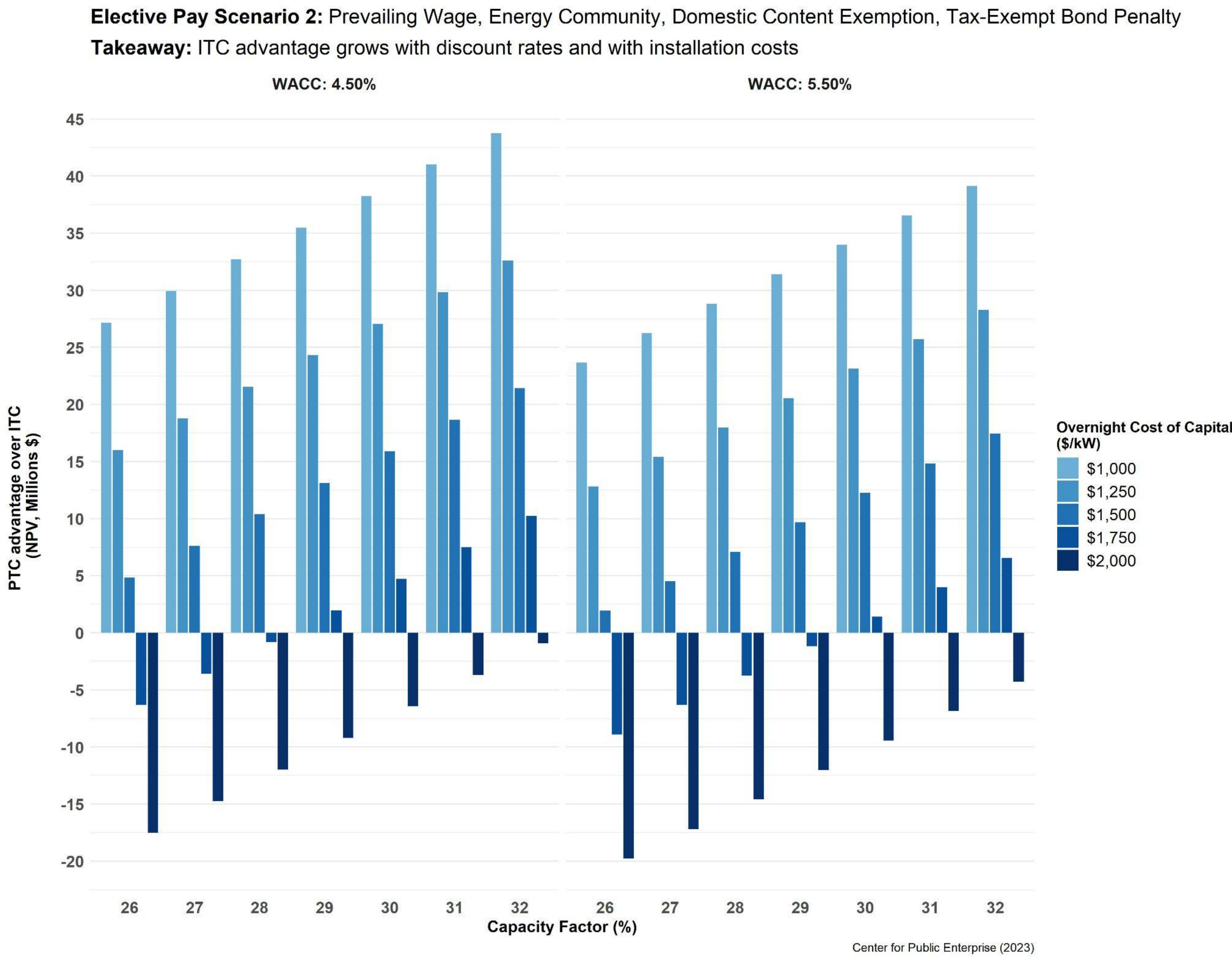
[50] The PTC can also be used to pay down debt. This report focuses on the ITC because it is a much larger up-front disbursement relative to the 10 annual PTC payments. But, in principle, a public developer can opt to use either, in which case the timing would also matter in instances where both NPVs are relatively similar.

Figure 3.1



Note. Under elective pay scenario 1 (paying prevailing wages, exempt from domestic content requirements, financed by a tax-exempt bond), the PTC is more advantageous than the ITC except at the lowest capacity factors and highest installation costs. Readers can replicate this chart on the NPV simulator attached to this model.

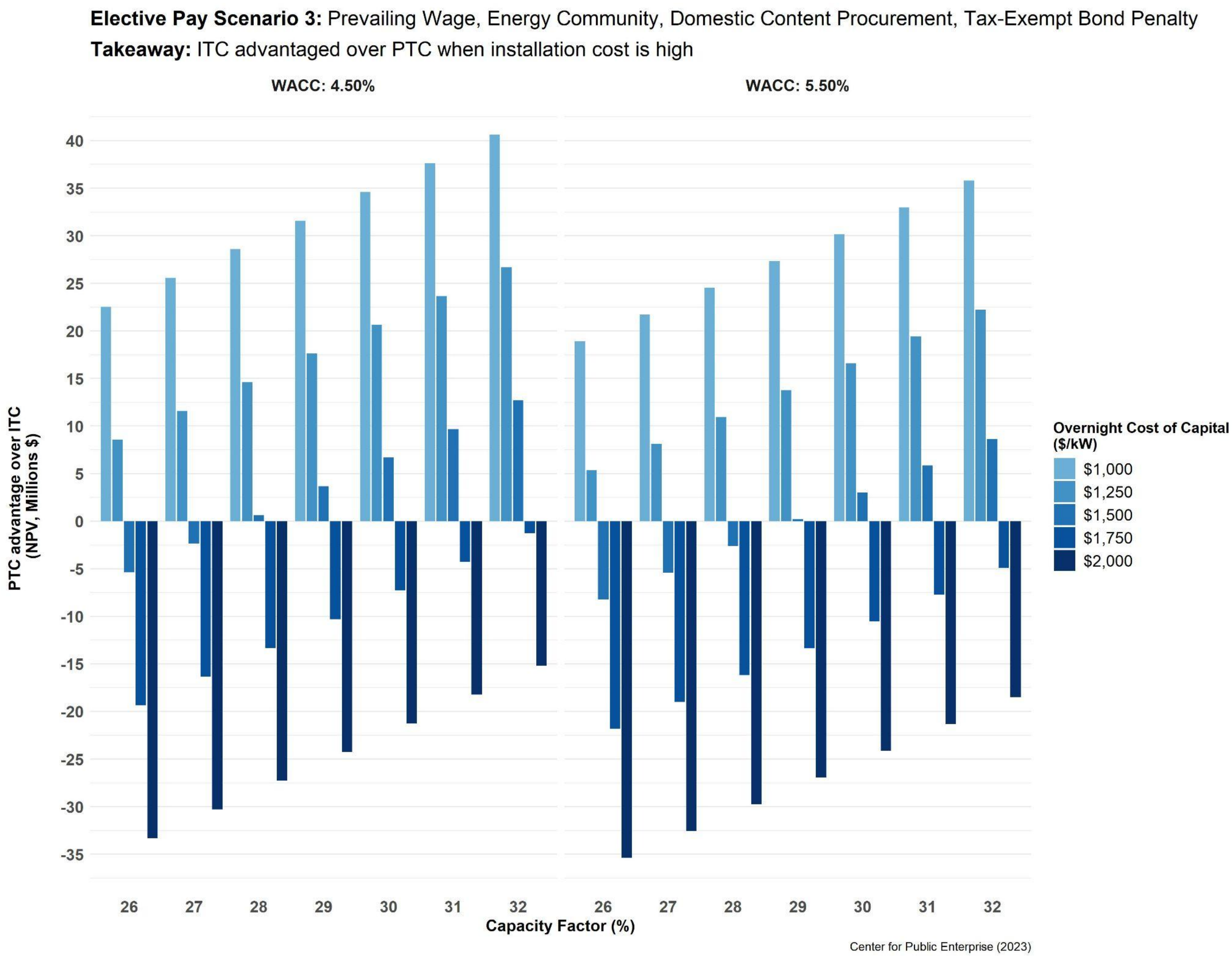
Figure 3.2



Note. Under elective pay scenario 2 (paying prevailing wages, in an energy community, exempt from domestic content requirements, financed by a tax-exempt bond), the ITC's advantage grows with discount rates and with installation costs. Readers can replicate this chart on the NPV simulator attached to this model.

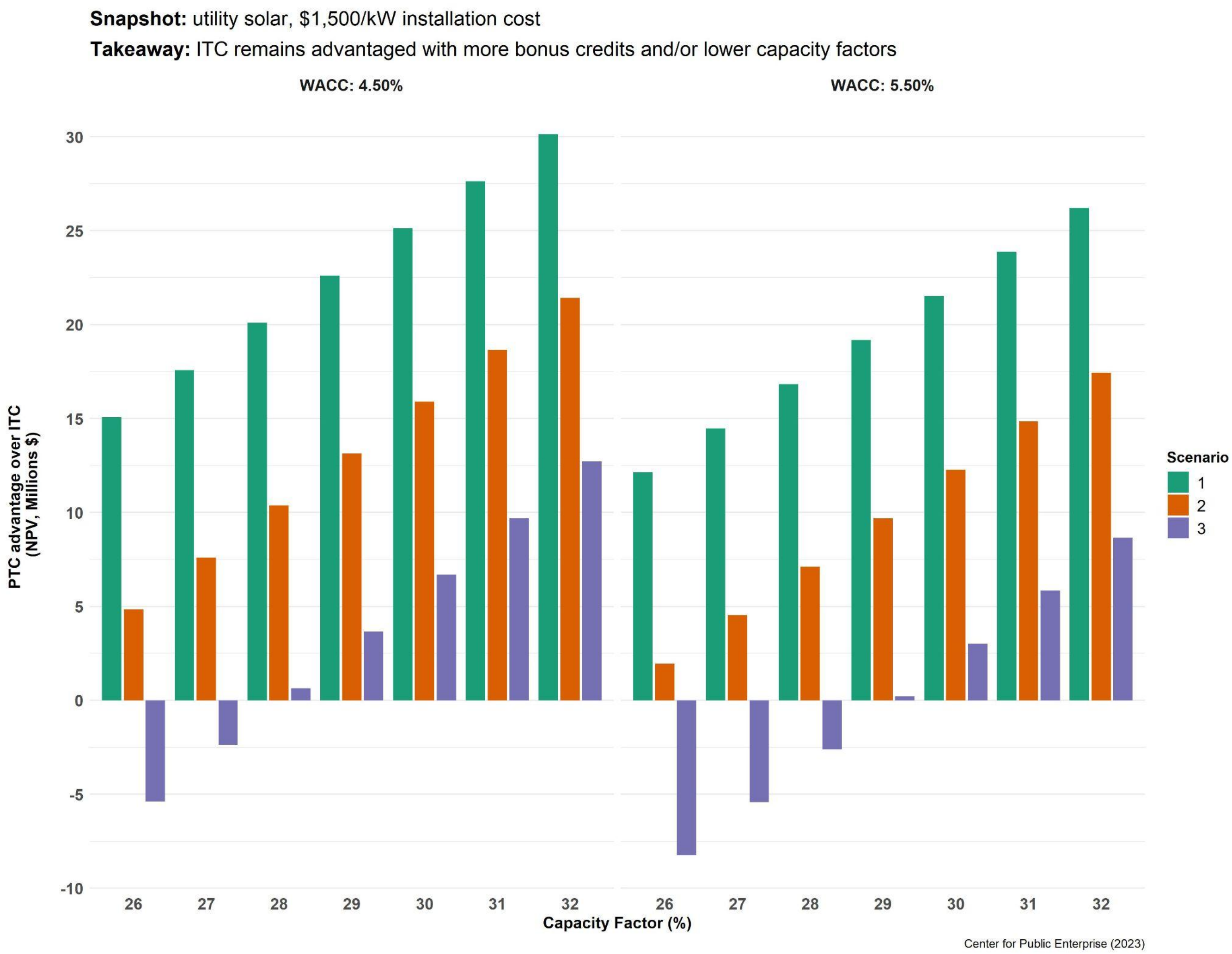
![cpe logo]

Figure 3.3



Note. Under elective pay scenario 3 (paying prevailing wages, in an energy community, meeting domestic content requirements, financed by a tax-exempt bond), the ITC is advantaged over PTC when installation cost is high. Readers can replicate this chart on the NPV simulator attached to this model.

Figure 4.



Note. This snapshot of a potential utility solar project with an installation cost of $1,500/kW demonstrates that the ITC remains advantaged with more bonus credits (Scenarios 2 and 3) and/or lower capacity factors. Readers can replicate this chart on the [NPV simulator]() attached to this model.

Extending the CPE Model to Create a Public Power Portfolio

The baseline model is designed to evaluate an individual publicly developed energy generation project eligible for the IRA's elective pay tax credits. However, a public developer typically holds a portfolio of generation projects. By loosening the CPE model's constraints we can simulate the balance sheet of a revolving fund, which enables a developer to use elective pay and project revenues from one project to seed financing for future projects, or to cross-subsidize lower-profit projects with revenues from higher-profit projects (*see Box 5*). A revolving fund allows the public developer to gain more financial flexibility to reach its social, economic and environmental goals.

A developer need not use an ITC payment to pay down debt. ITC payments to one project can be transferred to new developments, thus seeding another or multiple energy projects of comparable size. Since the model assumes that each individual public project is entirely paid for by debt, the ITC can be recycled into new developments so long as expected revenues are sufficient to meet debt service. Still, the public developer would have to be sufficiently assured that the original project which generated the ITC credit can earn enough to meet its viability threshold and overcome particular investment barriers.[51]

To reinvest its ITC credits, the public utility would:

1. Select the ITC as its chosen elective pay credit and not utilize ITC to reduce the original project's (Solar 1's) fixed debt.

2. Apply the elective pay payment on the ITC to pay the capital and interconnection expenditures necessary for one or more additional generation and storage projects (Solar 2). Committing revenues from Solar 1's ITC payment to Solar 2 reduces the size and servicing costs of the new project's initial construction bridge loan and the subsequent fixed term debt once Solar 2 enters operation.

3. Collect an ITC on Solar 2 and potentially repeat the process.

In this scenario, the ITC acts as a revolving fund which finances future renewable project development (*see Box 5*).[52] This allows a developer, if it so chooses, to loosen the financial

[51] Depending on the circumstances, specific financial products such as a credit default swap or other kinds of insurance may mitigate the fallout from some investment barriers, though not all. Depending on their charters, green banks may be able to offer these insurance products to public projects if they are so inclined.

[52] In its example, CPE uses the ITC in a revolving fund. But in principle, annual PTC payments can be recycled into new capital expenditure as well; it just takes longer to collect the full value of elective pay as PTC is paid out over 10 years relative to ITC which is disbursed with a lump sum payment.

constraints that are in the CPE model for individual projects by changing the rate paid on overdrafts on the cash reserve.[53]

Several factors condition how much new investment an ITC revolving fund can spark:

- The timing of Solar 2 and subsequent projects. Depending on when ITC funds from Solar 1 are applied to Solar 2, there are positive or negative implications for Solar 2's average DSCR. Applying funds later will mean Solar 2 will have to pay higher costs upfront before having its future debt costs reduced. This timing decision depends on the confidence a public developer has in its revenue and cost projections for these two projects (as well as the state of other investment barriers with respect to Solar 2).

- The state or public developer's capability or willingness to take on further debt to pay for projects. Such a constraint could exist regardless of the potential revenue from Solar 2, 3, etc., if the public developer faces some kind of statutory debt limit. The type of debt limit may also matter: a strict nominal debt limit would bind more harshly than one that restricts liabilities to a certain percentage of a different variable such as asset value.[54]

- The period of time left for elective pay provisions. IRA only makes elective pay available through 2032. Each solar project has significant lead times before it comes online. The CPE model presumes a full year of project development and two full years of construction for utility scale solar. Wind projects are given an additional year for construction. Elective pay can only be disbursed once the project is near or at operation (year 1 of operation in the model). Without more public funds for capitalization or a larger debt appetite on the part of the developer, those lead times will only allow this recapitalization cycle to happen a handful of times before IRA's elective pay provisions lapse.[55]

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[53] Setting a 0% overdraft rate in the model allows the user to simulate the scenario that either the state or public developer covers the project's negative cash flows. Even though the debt is paid off by the receipt of positive cash flows, this transaction could just as easily be represented on the state or public developer's balance sheets.

[54] Credit growth rates are difficult to speak of in this context because capital investment by any developer is incredibly "lumpy"—i.e., it happens periodically and all at once (or not at all) as opposed to smoothly over time. A decision to re-invest ITC money or money from Solar 1's cash buffer in Year 1 or Year 2 will significantly affect the rate of "investment growth" between two fixed years. But it is still true that a strictly nominal debt limit (i.e., debt capped strictly at $25 million) will bind more harshly than debt normalized by a variable that also grows with time, presuming both types of limits were comparable in scale initially.

[55] This is not intended as a comment on the feasibility or viability of additional projects using the ITC mechanism. If the developer is able to take on the debt, then it is entirely possible for those projects to proceed. It is only to say that further capital injections from the state (which presumably are at lower cost than the various debt products in the standard public capital stack or at a zero rate) will facilitate further investment. This is the same mechanism by which elective pay increases public investment.

- The amount of other federal, state, or local funds available to capitalize new projects. This is true of a single public power project or an entire public project portfolio. More public funds for capitalization or bridge financing will facilitate lower project construction costs. Additional public financing will also ease the timing constraints mentioned above. If the state provides subordinate debt that is paid out of Solar 2's subsequent income or the Public Power Portfolio's cash reserves, then it can possibly shift Solar 2's development and construction periods forward relative to Solar 1's ITC disbursement. If the state provides capitalization funding in addition to the ITC for Solar 2, it will further reduce reliance on more expensive market debt.

- The state of investment barriers. As mentioned before, various investment barriers can prevent the full development (from planning to operation) of Solar 2. Multiple barriers may combine to make Solar 2 impossible or delay it to such an extent that the public developer either uses ITC to pay down Solar 1's debt or just keeps the money in its growing cash buffer. As before, both projects can be modeled and planned in complete isolation from one another (except for strict cases such as the utilization of Solar 1 ITC money for Solar 2). However, the more the project balance sheets are integrated into a single public developer's portfolio, the more likely it is for investment barriers on one project to influence other or subsequent projects. The revolving fund will not revolve if Solar 2 cannot enter operation and sell its generation (*see Box 5*).

- State capacity. Suffice to say, developing even one public project will require specialized staffing, resources, and capabilities on the part of governments. Managing and coordinating several will require more, particularly to ensure that the projects whose financing or operation depend on one another can be coordinated effectively.

- Assessed needs of local, state, or national grids. The state—and any conditions on external funding or capitalization—will ultimately shape the mission and scope of the public developer. Capital development plans will grow larger to the extent the state wishes to utilize public development to tackle regional or national grid issues.

Box 5. How do revolving loan funds work?

A **revolving loan fund** (RLF) is a pool of capital that makes loans to projects which, at a later date, return the capital to the fund. Returned funds are then used to make loans to other projects. A public developer or other financial entity, such as a green bank, could deploy a revolving fund to quickly and repeatedly finance capital expenditure over longer periods of time. As the Department of Energy notes*, as long as defaults remain low, "RLFs can be 'evergreen' sources of capital that are recycled over and over again to fund projects well into the future."

Some RLFs, such as those which issue longer term debt, "revolve" very slowly. An RLF used to offer bridge or gap financing to elective pay projects, however, could revolve quickly—in the case of an ITC project, as soon as the IRS issues a tax credit or elective payment refund to the project sponsor.

A revolving fund structure for an elective pay project might work like this:

- A financial entity, such as a state investment authority, green bank, or a public developer itself, provides bridge financing from an RLF for the construction of a clean energy-generating asset.
- The project developer builds the asset, makes an elective pay election, and receives a refund from the IRS.
- The refund in effect "buys out" the bridge debt and the funds are returned to the RLF, which makes further loans to new projects.

Public authorities could use their balance sheets as the revolving fund—channeling asset income into new loans—or, in more complex arrangements, set up an external, off-balance-sheet financial entity, likely a special purpose vehicle (SPV), to do the same. Seed funding from government grants or bond issuances could capitalize RLFs.

*Department of Energy. 2023. "Revolving Loan Funds." Available at: https://www.energy.gov/scep/slsc/revolving-loan-funds.

Section IV: Implications for Policy Research and Public Energy Development

While the CPE model requires project-specific data to speak to more particular circumstances, it allows users to undertake a generalizable investigation of the new financial landscape for public energy generation. CPE will continue to modify and expand the model to augment its capabilities. Planned future modifications include but are not limited to:

- Assessing additional generation, storage, or grid resources that public developers could own and operate;
- Modeling public power and grid management in specific circumstances, e.g., as reserve or excess capacity, public storage during peak periods, etc.;
- Conducting scenario-based modeling for a scalable public-power portfolio facing various investment barriers;
- Including more complex debt and equity liabilities with varying maturities in the capital stack;
- Modifying the model to account for potential joint operating or investment arrangements;
- Incorporating measures of avoided cost to allow assessments of consumer and developer benefits from industrial policies tackling investment barriers or bottlenecks;

CPE also stands open to discuss the model with any interested organization, and can create customized versions of it for specific projects or entities.

One important takeaway from every iteration of this model is that public power is more than a system for delivering cheaper power than prevailing market alternatives: public power, which is financially viable at recognizable energy prices, represents an avenue for states and localities to shape their local energy infrastructure more directly to the benefit of local consumers, towards decarbonization, and to meet grid resiliency needs. These goals require the state to participate in the energy system more directly through ownership and operation; to actively undertake policies to coordinate all applicable stakeholders to identify and mitigate investment barriers; and to build their own capacity for rapid capital stock development. The model can illustrate those challenges for different project designs states might contemplate, as well as for different evaluative criteria the state might use to set project or portfolio "hurdle rates." But it is on policymakers to follow up, to address those challenges once identified. CPE stands ready to assist with technical support, with policy research, and in connecting interested parties to fellow practitioners.