Utility Ownership of New Renewables in New York State

POTENTIAL BENEFITS AND RISKS FOR CUSTOMERS

PREPARED BY

Metin Celebi
Joe DeLosa III
Josh Figueroa
Sanem Sergici
Ragini Sreenath
Ethan Snyder

PREPARED AT THE REQUEST OF

Con Edison

September 20, 2024

Summary

New York State needs to add large amounts of new renewable resources (in the order of tens of thousands of MWs) over the next decade to meet the requirements of 70% of load to be met by renewable generation by 2030 and full decarbonization of electric generation by 2040 under

New York State's Climate Leadership and Community Protection Act ("CLCPA") that was signed into law in 2019.[1]

Procurement of new renewables in New York State outside Long Island is largely done through New York State Energy Research & Development Authority ("NYSERDA") contracts and New York Power Authority ("NYPA") ownership.[2] NYSERDA runs competitive solicitations for particular types of clean resources (such as offshore wind, onshore wind, and solar). While the NYSERDA contracting approach attracted offers for renewable development, New York has fallen behind its procurement targets due to various external factors such as supply chain interruptions and project cancellations.[3] As a result, only about 2.7 GW of new onshore wind and solar PV capacity has come online in New York since the end of 2020 despite New York having amongst the most aggressive power sector climate goals in the country.[4]

Utility ownership of renewables could accelerate the build-out of renewable resources necessary to achieve New York's energy and climate goals by allowing New York to access capital for renewables from utility investors, which could create benefits under certain circumstances for utility customers. Specifically, regulated utilities could offer accelerated procurement of new renewables through cost-based rates if the market is unable to offer sufficient and predictable renewable supply on a timely basis.

This white paper evaluates the potential benefits and risks for electric customers in New York State of supplementing the current private ownership model used today for bringing new renewables online with the ability for regulated utilities in New York State to own some portion of these new large-scale renewable generation plants. Specifically, we compare the future costs for customers under two ownership models for illustrative new solar PV and onshore wind generation projects: (i) utility ownership and cost recovery under regulated cost-of-service

---

[1] For example, a recent study by NYISO projects more than 20 GW of capacity from new zero-emission resources by 2030 and more than 95 GW by 2040. See NYISO, "2021-2040 System & Resource Outlook (The Outlook)," September 22, 2022, available at https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf/a6ed272a-bc16-110b-c3f8-0e0910129ade.

[2] See New York Power Authority, "New York Power Authority Renewable Energy Conferral Report Published Today," November 30, 2023.

[3] See Kinniburgh, "Missed Deadlines Pile Up As New York's Climate Law Turns Five," June 19, 2024. In a recent report, NYSERDA also pointed at the divergence between the pace of renewable development and New York's decarbonization goals. See NYSERDA, "Draft Clean Energy Standard Biennial Review," July 1, 2024, page 74, posted at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=15-E-0302.

[4] New York has a policy for a zero-emission electricity grid by 2040. New renewables additions are based on data from the Hitachi Energy Velocity Suite Generating Unit Capacity database. See Hitachi Energy, Velocity Suite: Generating Unit Capacity Database, Accessed July 2, 2024.

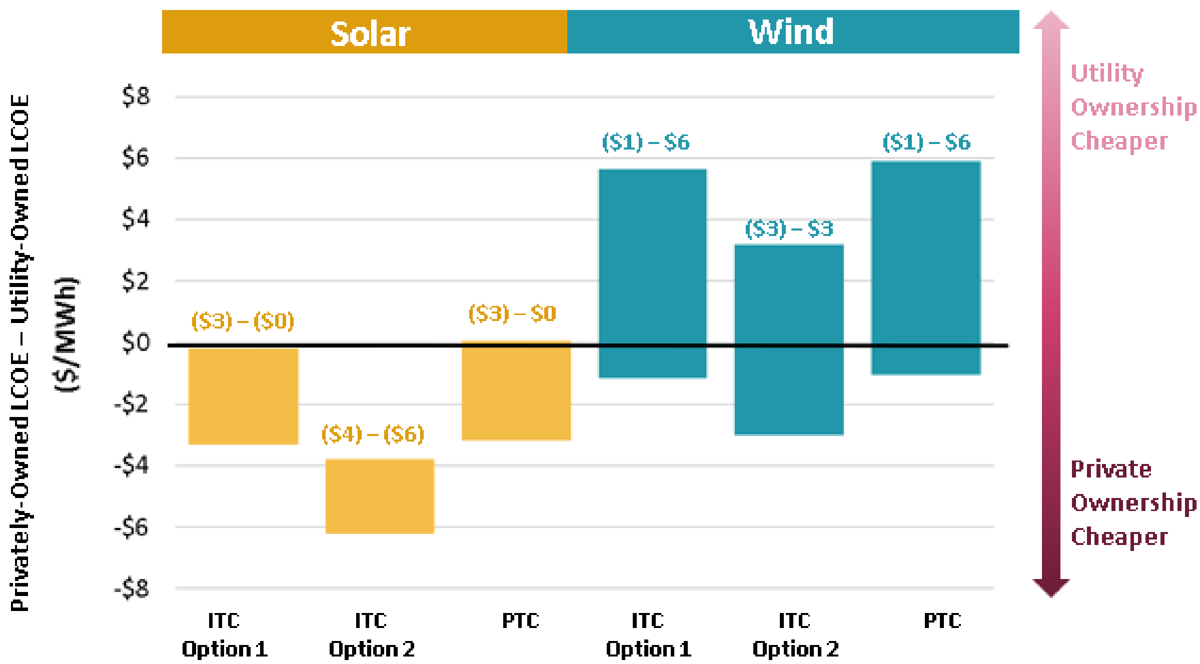
rates versus (ii) private ownership under a fixed-price long-term power purchase agreement with NYSERDA. We also provide a qualitative assessment of the pros and cons of each ownership model from the perspective of electric customers in New York State.

We find that:

- To the extent the legal and regulatory structure allows utility ownership of new renewable assets in New York State with sufficient guardrails against anticompetitive behavior, electric customers could benefit from the advantages of both the utility ownership and private ownership of assets by allowing utility suppliers to participate along with private suppliers to provide for the zero-emission supply needs of customers, i.e., new renewable resources.

- Figure 1 below shows our estimates for the range of differences in levelized costs between the private ownership model in comparison to the utility ownership model for solar and wind assets and tax credit assumptions. The range within each bar represents the impact of different inputs and assumptions based on the set of sensitivities evaluated (*i.e.*, power prices, cost of capital, contract period, etc.). As shown in the figure below, the utility ownership option could provide up to 14% customer cost savings relative to the private ownership option (positive bars), particularly in scenarios with high wholesale power prices and high cost of capital for private owners. However, the private ownership model results in up to 11% customer cost savings (negative bars) in other scenarios, including when the utility acts as an Option 2 taxpayer or there are low wholesale power costs.

FIGURE 1: CUSTOMER LIFETIME COST OF ELECTRICITY FROM RENEWABLES UNDER THE UTILITY-OWNERSHIP MODEL AS COMPARED TO THE PRIVATE DEVELOPER-OWNERSHIP MODEL



Sources and Notes: Details on the assumptions used in the financial analysis are detailed in Section II below.

- Allowing regulated utilities to own new renewables would offer several potential benefits for electricity customers in New York, including potentially accelerating the achievement of New York's clean energy goals by providing an additional source of renewable supply and offering a demonstrated history of effective project execution and risk management to provide benefits and/or cost savings for customers under certain conditions. In addition, utility ownership under cost-of-service ratemaking could provide flexibility for modifying the design and operations of the new renewables in the future, with benefits from that flexibility flowing to customers instead of being largely retained by private owners. Finally, any cost underrun in development costs would be retained by ratepayers under a cost-of-service approach, whereas these benefits would otherwise accrue to private renewable owners.

- However, utility ownership would likely shift most risks currently borne by private owners (or by developers) to electricity customers with respect to asset performance and cost overruns.[5] In addition, depending on the implementation rules, utility ownership may raise concerns about cross-subsidization of costs between the delivery

[5] To the extent that operational or cost performance does not warrant a cost recovery disallowance by the New York Public Service Commission.

services and the renewable project and assuring equal access to information on the transmission and distribution systems to all developers of renewable generation in the state. Finally, utility ownership may raise customer costs over the lifetime of the renewable asset under certain conditions, such as depending on the approach used to reflect the federal investment tax credits in customer rates.

It is important to note that the scope of this whitepaper does not include providing recommendations for specific implementation and procurement mechanisms for the utility ownership option (e.g., restrictions on the total amount of utility-owned new renewables, the types of resources for which utility ownership should be implemented, or the use or structure of competitive procurement auctions to select between ownership options). We also do not attempt to interpret or apply the NY Public Service Commission precedent, which has recently and directly addressed many of the items discussed in this paper in recent cases. Lastly, further detailed analysis with project-specific assumptions and specifications would be required to determine the relevant benefits of developing a particular renewable asset under a utility- or private-ownership structure.

The rest of the whitepaper is organized as follows. We explain the two options we evaluated for ownership of new renewables in Section I below. Section II describes our approach and findings for comparing customer costs of illustrative new renewable projects under each ownership option. In Section III, we explain the qualitative pros and cons of the utility vs. private ownership of new renewables in New York State. Section IV provides our conclusions.

I. Two Options for Ownership of New Renewables in New York State

We evaluated two options for ownership of new utility-scale renewables. The first option is ownership by a regulated utility ("utility ownership") with cost-of-service rates, and the second option is ownership by a private company ("private ownership") with a long-term contract. Key aspects of each option are as follows:

UTILITY OWNERSHIP

- Regulated utility builds (or purchases from a developer) and operates a new renewable generation facility.

- Capital costs of the generation facility are added to a utility's rate base and are recovered from electricity customers through charges for depreciation and allowed return on capital over the life of the asset as part of the revenue requirement under traditional ratemaking.[6] The revenue requirement calculation would include other costs associated with the generation facility, including operating and maintenance (O&M) costs, insurance, and income taxes.
- Utility amortizes federal investment tax credits in one of two ways. As an "Option 1" taxpayer, the utility passes through the benefits to customers through a reduction in rate base. Alternatively, as an "Option 2" taxpayer, the utility will reflect benefits from the investment tax credit ("ITC") through a reduction in the revenue requirement. Alternatively, the utility can elect to receive federal production tax credits ("PTCs"), which would be amortized, reduce tax expenses in the revenue requirement, and flow the benefits back to customers.

PRIVATE OWNERSHIP

- A private developer builds and operates a new renewable generation facility.
- The developer enters into a fixed-price contract with a state-funded entity (e.g., NYSERDA) to sell energy, capacity, and RECs over the course of an assumed contract period.[7] The contract prices (in $/MWh) reflect the developer's costs and include an appropriate level of return on investment that reflects the riskiness of the revenues during the term of the contract with NYSERDA and the riskiness of revenues during the post-contract period. The assumed return on investment during the contract period differs from the assumed return during the post-contract period to reflect the riskiness of selling energy and capacity in the market. It considers the most economically profitable and feasible option for selling RECs into New York or outside New York. For further clarification, electricity customers would pay for the price of New York Tier 1 RECs during the post-contract period (and also get the benefit of any reduction in prices under the NYSERDA contract as a result of any expectation of higher REC prices during the post-contract period in other states).

---

6 In our analysis, we assume the life of a wind or solar generation facility to be 30 years.

7 Currently, developers in New York have the option for two types of contract structures. The first option is a traditional fixed REC contract, where the developer submits a fixed bid price for RECs. The second contract option is an index REC structure where developer's contract with NYSERDA to sell RECs at prices reflecting the difference between the bid strike price and the sum of the reference prices of energy and capacity prices in the market. Our formulation of the fixed price for the combination of energy, capacity and REC products is a proxy for the index REC option. See NYSERDA, New York Tier 1 RESRFP23-1 Proposers' Webinar, December 7, 2023, at 19.

- During the course of the contract, the private company earns (and electricity customers pay for) contracted revenues.
- After the end of the contract, the private company earns market revenues for selling energy and capacity in NYISO energy and capacity markets. It also earns revenues for selling RECs at the higher of the annual Tier 1 REC prices in New York State or other states that are in the same REC trading program or other states where such renewable attributes, energy, and capacity are deliverable, whether bundled or unbundled. New York electricity customers pay for energy and capacity (that corresponds to the energy and capacity from the wind and solar plant) at the NYISO energy and capacity markets and for RECs at the New York State Tier 1 REC price.
- The developer monetizes federal tax credits in the year they are generated via an arrangement with a third-party tax equity investor, reducing the fixed-price contract rate while also generally paying a transaction fee for the tax equity arrangement.

II. Costs to Customers Under Each Ownership Option

We evaluated the all-in costs to electric utility customers to procure energy, capacity, and environmental attributes from a new utility-scale renewable asset under the utility- and private-ownership structures described in the previous section. For the purpose of this analysis, we evaluated the cost customers incur during the first 30 years of ownership for a new 100 MW onshore wind or solar PV facility in New York State. We also evaluated various scenarios related to energy market prices, financing costs, contract durations, and repowering assumptions. Together, these scenarios are designed to capture a reasonable range of potential costs to utility customers under each ownership structure.

a. Structure and Overview of Financial Model

To evaluate the customer costs of renewables under both the utility and private ownership models, we built an indicative financial model to simulate both ownership scenarios. In both scenarios, we identify reasonable assumptions to represent plausible costs of each ownership model in practice. The financial models are specific to New York State and account for recent developments and practices in renewable ownership. Our analysis is indicative and presented to show a range of plausible customer costs under each ownership structure.

In our model, the projects in the utility-ownership model and the private-ownership model are identical (*i.e.,* we do not assess the implications of potential cost overruns or underruns). The only difference between the final customer costs is based on the cost recovery mechanisms, expected rate of returns, and treatment of tax credits for the utility compared to the private developers, which we discuss next.

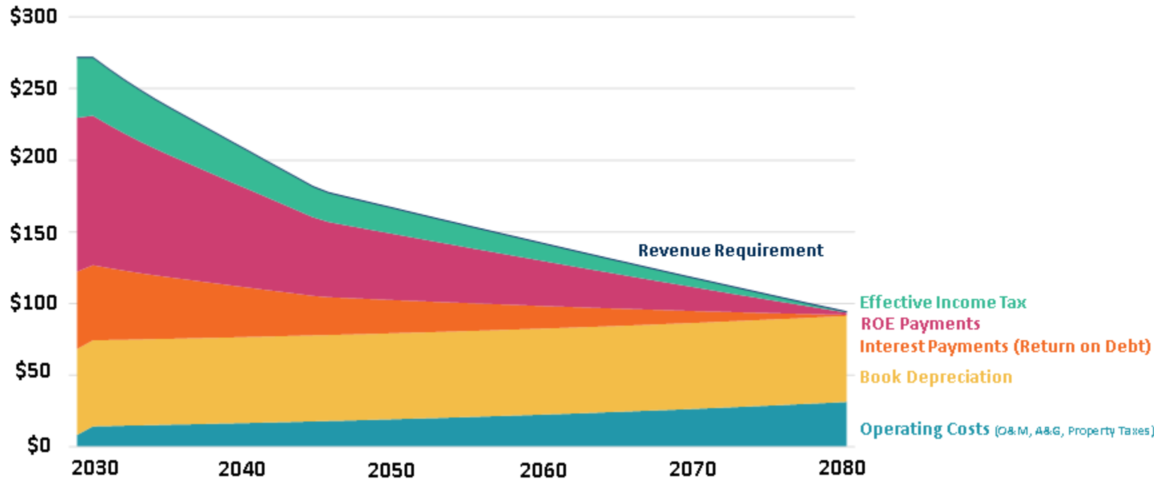
UTILITY OWNERSHIP

The financial model for utility ownership is based on a simplified revenue requirement for the renewable asset (*i.e.*, excludes other aspects of a utilities' revenue requirement), plus certain inputs and assumptions that reflect parameters for Consolidated Edison Company of New York ("CECONY").[8] As with other capital investments in rate base, the utility will recover all prudently incurred costs related to the renewable asset, and will receive a return on these capital expenses at the Commission-approved cost of capital.[9] Any non-capital costs incurred by the utility will be recovered at cost through the revenue requirement, consistent with the cost recovery procedures for other typical utility projects. Figure 2 below illustrates the basic components of the revenue requirement.

[8] Some components of revenue requirement are excluded for simplicity, such as decommissioning costs and property taxes.

[9] New York Public Service Commission Case No. 22-E-0064.

FIGURE 22: ILLUSTRATIVE REVENUE REQUIREMENT



$$\text{Revenue Requirement} = \overbrace{OC_t + TAX_t + DEP_t}^{\text{Expenses}} + \overbrace{(r_e \times P_e)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Equity}} + \overbrace{(r_d \times P_d)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Debt}}$$

OC_t	= Operating Costs
TAX_t	= Effective Income Tax
DEP_t	= Annual (Book) depreciation
Rate Base:	
K_1	= First Year Rate Base (capital cost + AFUDC)
$ADEP_t$	= Book depreciation (annual) × years in-service
r_e	= Return on Equity
r_d	= Return on Debt
Capital structure:	
P_e	= Percent Equity
P_d	= Percent Debt

Sources and Notes: J. Pfeifenberger, et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, Public Report, prepared for New Jersey Board of Public Utilities (October 26, 2022) at Appendix C.1.

The utility is assumed to be eligible to receive federal tax credits for the renewable asset either in the form of an ITC based on 30% of the total capital costs of the project or a PTC based on a $27.50/MWh tax credit multiplied by the renewable asset's energy production. We assume that the utility generates sufficient taxable income from the rest of its regulated operations to monetize the tax credits from the renewable asset. We model two ways that a utility can monetize the ITC, consistent with federal and state tax rules.[10] As an Option 1 taxpayer, the utility passes through some additional benefits of the ITC to customers by reflecting ITC benefits as a reduction in rate base. Alternatively, as an Option 2 taxpayer, utility customers see relatively fewer benefits by reflecting the ITC in the revenue requirement outside of the rate

[10] *See* ASC 980

base spread over the 30-year useful life of the asset. Instead of ITC, the utility could elect to receive PTCs, which can be monetized for the first 10 years of a project's operations per IRS guidelines.

PRIVATE OWNERSHIP

For the private owner, we developed an indicative financial model to reflect the costs incurred by a private developer in the construction and development of a solar PV or onshore wind asset in New York, and the likely bid price to be submitted into a competitive NYSERDA solicitation. In order to estimate the likely contract price bid into NYSERDA's solicitation, we developed a model to calculate the costs the private developer would need to recover, accounting for a return on investment, and net of any additional revenue streams the private developer would likely receive. Based on recent solicitations, we assumed the private developer would secure a 20-year contract with NYSERDA, which would then sell the energy, capacity, and environmental attributes to load-serving entities via NYSERDA at cost. After the contract period, we assume the private developer would compete in the wholesale electricity markets as a merchant power plant for the remaining 10 years of the asset's useful life. The present value of net revenues from this merchant period would offset the present value of total costs that the private developer would seek to recover during the contract period.

The private developer is also eligible to receive federal ITC or PTC tax credits for the renewable assets. However, we assume that the private developer does not have sufficient taxable income to fully monetize the tax credits, so it must enter into a tax equity financing relationship with a third party and incur a transaction fee. If the private developer elects to receive an ITC, then the ITC would be amortized over the first five years of operation, consistent with current industry practice, and passed onto customers as a reduction in annual costs. Whereas if the private developer elects to receive PTCs, they would be monetized for the first 10 years of a project's operations, similar to the utility.

b. Key Assumptions

To develop our customer costs for renewable energy in both ownership scenarios, we rely on a range of assumptions from publicly available sources. Many of these assumptions are consistent across both ownership scenarios; however, some are different based on the ownership structure or the type of renewable asset and drive the differences in results. Table 1 below shows the key assumptions we used in our customer cost analysis both for the 100 MW wind plant and the 100 MW solar plant.

The first subset of assumptions is the project characteristics. All of these assumptions are consistent across both ownership models but differ between the type of asset. The majority of the project characteristic assumptions rely on the National Renewable Energy Laboratory (NREL) 2023 Annual Technology Baseline (ATB) database, which provides cost and capacity factor assumptions for a range of generation technologies, including wind and solar.

The next subset of key assumptions is the electricity prices, which also only differ based on the type of asset. For these assumptions, we rely on the NREL 2023 Cambium database, which provides hourly wholesale energy price data projections out to 2050 and annual projections for capacity price and renewable energy credit (REC) price.[11] We then utilize solar and wind profile data from NREL and calculate a generation-weighted average wholesale energy price for both solar and wind resources out to 2050.

The last key subset of assumptions is the financial assumptions, which differ by ownership structure. For the utility, we assume that the cost of capital is equal to the most recently Commission-approved pre-tax cost of capital of 6.75% for CECONY.[12] For the private developer, we start with the assumption that the required rate of return is 6.99%, based on our estimate of the cost of capital for independent generation companies under current market conditions. The limited publicly reported estimates of private developer required returns indicate WACCs both above and below the allowed utility WACC of 6.75% due to various factors, including capital market conditions and how the WACC is measured. As discussed below, we perform sensitivities on the private developer's required rate of return to capture the uncertainty in this assumption.

The last financial assumption is related to how we treat customer costs. The goal of this exercise is to estimate the costs to customers under both ownership models. Therefore, we discount the annual costs charged by the utility or private developer at a societal nominal discount rate of 4.04% to compare the net present value of costs to customers.[13]

---

[11] See National Renewable Energy Laboratory, Cambium, 2023. In particular, we used the Cambium Mid Case scenario.

[12] See New York State Public Service Commission, Docket #22-E-0064 RY1, 2023. In particular, this includes 4.46% cost of debt and 9.25% cost of equity at a capital structure of 51% debt.

[13] The referenced discount rate is a nominal discount rate using a real discount rate of 2% and an assumed inflation rate of 2%.

TABLE 1: KEY ASSUMPTIONS USED IN THE FINANCIAL MODEL

Input	Units	Solar	Wind	Source
Project Characteristics				
Capital Expenditures	$/MW	$1,374	$1,619	NREL ATB
Fixed O&M	$/kW-year	$22	$29	NREL ATB
Asset Life	years	30	30	Assumption
Capacity Factor	%	22%	34%	NREL ATB
Degradation Rate	%	0.7%	0%	NREL ATB
Electricity Prices				
Average Energy Price	$/MWh	$32 in 2025 $26 in 2050	$34 in 2025 $33 in 2050	NREL Cambium
Capacity Price	$/kW-year	$27 in 2025 $148 in 2050	$27 in 2025 $148 in 2050	NREL Cambium
REC Price	$/MWh equivalent	$5 in 2025 $4 in 2050	$5 in 2025 $4 in 2050	NREL Cambium
Financial Assumptions				
Utility Pre-Tax WACC	%	6.75%	6.75%	22-E-0064, RY1
Private Developer Contract Period	years	20	20	Assumption
Private Developer Contract Period WACC	%	6.99%	6.99%	Brattle analysis
Private Developer Post Contract Period WACC	%	7.72%	7.72%	Brattle analysis
Tax Life (MACRS)	years	5	5	Assumption
Societal Discount Rate	%	4%	4%	Assumption

Many of these assumptions included in our analysis are subject to some uncertainty. For example, increases in interest rates as a result of elevated inflation levels and the Federal Reserve's monetary policy actions have resulted in a net increase in debt financing costs, which puts upward pressure on the cost of capital for both the utility and the private developer. Moreover, projecting electricity prices in the future can be heavily dependent on power sector climate policies, geopolitical risks on fossil fuel prices, and future wholesale market designs. To account for this, we test a range of values on key assumptions in order to provide a plausible range for expected customer costs of renewables under each ownership scenario. These sensitivities are outlined further below.

c. Scenarios

To account for the inherent uncertainties of our key assumptions, we developed a set of scenarios to test the elasticity of various assumptions and test the customer costs under a variety of outcomes. The sensitivities we tested are described below:

- **Wholesale Electricity Prices:** The private developer's bid price into NYSERDA competitive solicitations will reflect the cost to build and operate the generation facility net of any expected operating margins from market revenues that the private developer could receive after the contract period is over. Given the inherent uncertainty in wholesale electricity prices 20 to 30 years into the future, we analyzed the impacts on customer costs under high- and low-electricity price sensitivities. The low-price scenario is drawn from the NREL Cambium Low Renewable Energy Cost case, while the high price scenario is based on the Cambium High Renewable Energy Cost case.[14] The average nominal energy prices in the high-price scenario are 50% higher than the base case by 2050, while the low-price scenario is 35% lower than the base case by 2050.
- **Repowering:** After the 30-year useful life of a solar or wind generation facility assumed in our analysis, the owner of the facility would have the opportunity to "repower" the facility by replacing key equipment. However, the cost of replacing this equipment is likely lower than the cost of constructing a brand-new facility, which could lead to cost savings for customers. We modeled this and calculated customer costs for repowering a facility past its useful life for both the utility ownership model and private ownership model. We assumed that the costs of repowering a wind facility were 5% cheaper than the costs of developing a new facility, while we conservatively assumed there were no cost savings from repowering a solar facility past its useful life.[15]
- **Private Developer Cost of Capital:** The cost of capital for private renewable developers is uncertain, especially recently due to supply chain constraints, which have put further risk on the development of renewable energy projects in the United States and New York in

[14] National Renewable Energy Laboratory, Cambium, 2023.

[15] The cost savings from repowering an existing solar or wind facility come primarily from saved electrical wiring costs, development costs, and land acquisition costs. Literature indicates that these cost savings are higher for wind plants than solar plants because it is likely that electrical wiring costs would still be incurred at an equal level for the repowering of a solar plant compared to the wiring of a new plant, while these costs could be saved for wind plants. Moreover, there is very little empirical evidence of solar repowering costs, in part because the technology is more nascent and thus few plants have reached the end of their useful life in the United States. See NREL, Wind Power Project Repowering: Financial Feasibility, Decision Drivers, and Supply Chain Effects, December 2013.

particular.[16] To account for this uncertainty, we tested a scenario in which the private developer's cost of capital was higher than our initial assumption of 6.99%. The high value we used in the sensitivity was 7.5% for solar developers and 9.0% for wind developers based on the NREL 2023 ATB.[17]

- **Contract Period:** The majority of NYSERDA contracts for onshore wind and solar have been 20 years. However, this is less than the assumed useful life of solar and wind generation facilities. We analyzed a sensitivity in the financial model assuming the contracts signed by the private solar and wind developers were equal to the useful life of the generation facilities at 30 years. This sensitivity removes the "haircut" private developers would give in their solicitation bids based on the expected merchant net revenues that the generation facility would produce in the years after their NYSERDA contract has ended.
- **Tax Credits:** We analyzed the customer costs reflecting two tax credits that are available to utility or private developers when they construct a wind or solar project: the ITC and the PTC. The ITC provides a 30% tax credit at the time of construction for any capital costs associated with the development or construction of an applicable wind or solar project. The PTC provides $27.50/MWh of renewable energy produced over the first 10 years of the project's operation.[18]

Finally, we evaluated scenarios under different assumptions about the utility's taxpayer status. As discussed above, the impact of the ITC on customer revenue/costs is dependent on the utility's accounting method to pass on the ITC to customers under Option 1 or Option 2. Under Option 1, the utility passes through higher benefits of the ITC to customers by reflecting unamortized ITC benefits as a reduction in the rate base; whereas under Option 2, the customer sees lower benefits by reflecting the ITC in the revenue requirement outside of the rate base and spread over the 30-year useful life of the asset.[19] The scenarios described above were evaluated using both an Option 1 and Option 2 utility.

[16] See e.g., Major offshore wind projects in New York canceled in latest blow to industry - POLITICO

[17] NREL, Annual Technology Baseline: Financial Cases and Methods, 2023.

[18] The value of the tax credit is escalated over time at a 1.6% CAGR based on the average year over year escalation in the EIA AEO Fuel and Power Price Index. See Energy Information Administration, 2023 Annual Energy Outlook, 2023.

[19] In our context, Orange and Rockland would have the ability to pass on the complete benefits of the ITC to customers while Consolidated Edison Company of New York would not have that ability, as it stands now.

d. Results

We find that the customer costs are broadly comparable between the utility ownership option and the private ownership option. However, in the scenarios we analyzed, customer costs for new solar generation tend to be slightly lower under private ownership, while utility ownership tends to result in lower costs for new onshore wind generation. Customer cost differences between the utility and private ownership models are driven by the following key drivers:

- Since the utility will include the capital cost of the renewable asset in its rate base, its rate of return is tied to its cost of capital approved in its general rate case. By comparison, publicly reported developer rates of returns are generally at least as high, if not higher, than utility-allowed returns. All else equal, this increases costs under the private ownership model.
- Private developers can monetize federal tax credits (i.e., ITC or PTC) through tax-equity financing relationships, which can reduce costs for customers. Unlike a developer, utilities must utilize ITC in one of two ways. As discussed further below, if the utility elects to be an Option 1 taxpayer, it will reflect ITC benefits through a reduction in the rate base. Whereas, as an Option 2 taxpayer, the utility will reflect benefits from the ITC through reductions in revenue requirements outside the rate base. All else equal, customers of an Option 2 utility will incur higher costs relative to customers of an Option 1 utility, as well as the private ownership structure. Alternatively, the utility can elect to receive PTCs rather than ITCs, in which case the benefits of the tax credits are accrued to customers in a similar manner as the private ownership model.
- Private developers can earn revenues by selling energy, capacity, and environmental attributes into the market after the contract period. The present value of any difference between those market revenues and operating costs during the post-contract period would offset the developer's costs to recover during the contract period (hence would affect the contract price). Lower post-contract prices provide a smaller offset to the contract-period revenue requirement, but this is offset by lower customer costs for procuring and replacing energy, capacity, and environmental attributes in the market after the contract expires.
- However, in certain circumstances, the customer costs under utility ownership may be nearly equivalent to or lower than under private ownership. For example, higher discount rates for private owners reduce the cost differential between the utility ownership and private ownership models due to the higher return on capital requirements for the private developer during the contract period. Alternatively, the expectation of higher market prices

during the post-contract period provides a larger offset to the contract-period revenue requirement, but the post-contract replacement costs for customers would also be higher.

Table 2 below illustrates the range of levelized costs estimated for utility ownership versus private ownership, showing how various inputs and assumptions drive a range of potential customer cost outcomes, which impact the relative advantage or disadvantage of one structure versus another.

Ultimately, we find that both ownership models are likely to result in a similar level of customer costs, suggesting a potential role for utilities to develop renewable generation assets in New York. We recognize that it is difficult to pinpoint a “typical” set of assumptions that will describe most projects in New York, given the unique circumstances of each potential private developer, utility, and renewable asset.

TABLE 2: LCOE OF CUSTOMER COSTS FOR PRIVATELY-OWNED RENEWABLES IN COMPARISON TO UTILITY-OWNED RENEWABLES

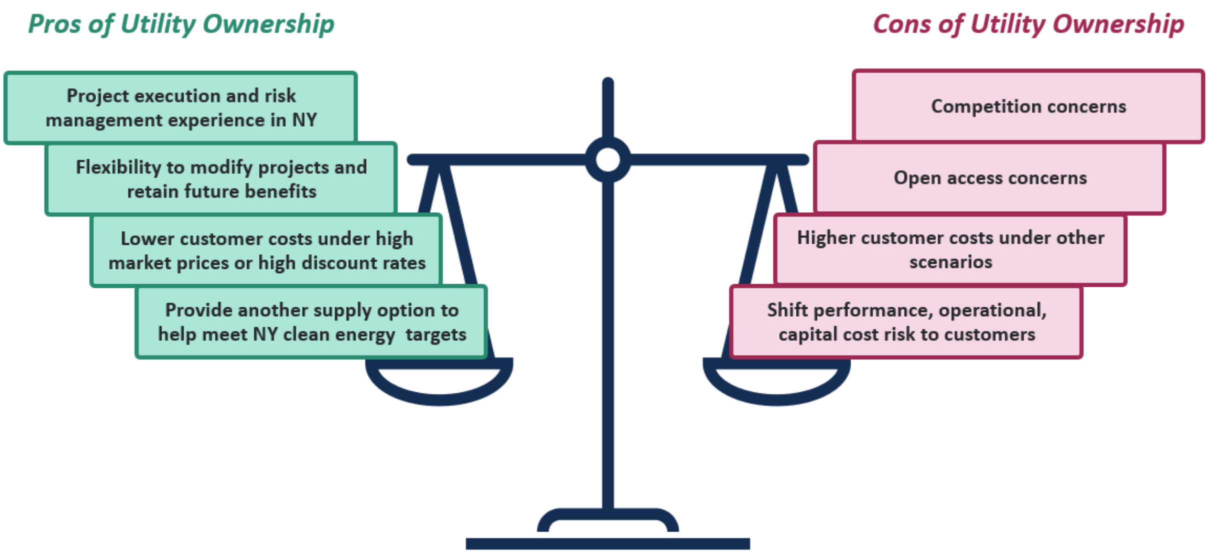
	Solar			Wind		
	Private	Utility	Private - Utility	Private	Utility	Private - Utility
ITC (Option 1 Taxpayer)						
Base	$58.43	$60.71	-$2.29	$42.12	$42.34	-$0.21
Low Electricity Prices	$58.10	$60.71	-$2.61	$42.15	$42.34	-$0.19
High Electricity Prices	$59.85	$60.71	-$0.87	$44.22	$42.34	$1.88
High Developer WACC	$60.53	$60.71	-$0.19	$47.98	$42.34	$5.64
30-year Developer Contract	$59.05	$60.71	-$1.66	$41.96	$42.34	-$0.38
Repowering	$56.33	$59.66	-$3.34	$43.41	$44.56	-$1.15
ITC (Option 2 Taxpayer)						
Base	$58.43	$64.31	-$5.88	$42.12	$44.79	-$2.66
Low Electricity Prices	$58.10	$64.31	-$6.21	$42.15	$44.79	-$2.64
High Electricity Prices	$59.85	$64.31	-$4.46	$44.22	$44.79	-$0.57
High Developer WACC	$60.53	$64.31	-$3.78	$47.98	$44.79	$3.19
30-year Developer Contract	$59.05	$64.31	-$5.25	$41.96	$44.79	-$2.83
Repowering	$56.33	$62.29	-$5.96	$43.41	$46.40	-$3.00
PTC						
Base	$55.56	$57.66	-$2.10	$36.17	$36.27	-$0.09
Low Electricity Prices	$55.24	$57.66	-$2.42	$36.20	$36.27	-$0.07
High Electricity Prices	$56.97	$57.66	-$0.68	$38.26	$36.27	$2.00
High Developer WACC	$57.70	$57.66	$0.05	$42.14	$36.27	$5.87
30-year Developer Contract	$56.22	$57.66	-$1.44	$36.03	$36.27	-$0.23
Repowering	$54.23	$57.43	-$3.20	$38.92	$39.98	-$1.06

Sources and Notes: Costs represented on the chart are equal to the LCOE of the customer costs for the private developer-owned renewable project minus the LCOE of the customer costs for the utility-owned renewable project. LCOEs are calculated using a real societal discount rate of 2%.

III. Pros and Cons of Utility Ownership of Renewable Generation

Utility ownership of new large-scale renewable generation carries an array of potential advantages and disadvantages as compared to private ownership to supply the zero-emission needs of customers and achieve New York's robust policy goals. The evaluation below assumes regulated utilities participating in renewables development alongside private entities, with utilities ultimately recovering the costs of renewable projects through utility cost-of-service rates.[20] We assess the pros and cons of utility ownership as a series of tradeoffs, with notable benefits being accompanied by material risks.

UTILITY-OWNED RENEWABLES PRESENT A NUMBER OF TRADEOFFS FOR ELECTRIC CUSTOMERS



We conclude that allowing regulated utilities to own new renewables would offer several potential benefits for electricity customers in New York, including the ability to assist in meeting New York's clean energy goals by bringing additional renewables online and by offering effective project execution and risk management to provide benefits and/or cost savings for customers under certain conditions. In addition, any cost underrun in development costs would be retained by ratepayers under a utility-owned cost-of-service approach, where these benefits would otherwise accrue to private renewable owners. Finally, utility ownership under cost-of-service ratemaking could provide flexibility for modifying the design and operations of the new renewables in the future, with benefits flowing to customers instead of being largely retained by private owners.

---

[20] This whitepaper does not provide recommendations for specific implementation or procurement mechanisms for the utility ownership option; these details are only referenced to the extent they are material for assessing benefits and risks of utility ownership. We do not attempt to interpret or apply NY Public Service Commission precedent, which has recently and directly ruled on many of the items discussed in this section in recent matters. See, e.g., State of New York Public Service Commission, Order Denying Petitions Seeking to Amend, Cases No. 15-E-0302 and 18-E-0071 (October 12, 2023) ("NYPSC Order"); State of New York Public Service Commission, Order Adopting a Clean Energy Standard, Cases 15-E-0302 and 16-E-0270, issued August 1, 2016 ("CES Order").

However, utility ownership would likely shift most risks currently borne by private owners to electricity customers with respect to asset performance and investment cost overruns. In addition, depending on the implementation rules, utility ownership may raise concerns about cross-subsidization of costs and the availability of open access to information on the transmission and distribution systems to all developers of renewable generation in the state. Depending on the structure of utility ownership and the allotment of rights to develop renewable generation in each ownership model, utility ownership may impact competition in the private developer segment over the long run. Finally, utility ownership may result in higher customer costs relative to private ownership over the lifetime of renewable assets under certain conditions, such as the approach for reflecting the federal investment tax credits in customer rates (Option 2).

2. Potential Benefits

a. Utility Ownership Could Bring Additional Renewables Online to Mitigate Any Potential Shortfalls in Meeting the State Goals

Meeting New York's 100% zero-emissions requirement by 2040 will require significant and rapid deployment of carbon-free generation resources, with the need exceeding 110 GW of nameplate capacity and 240 TWh/year of energy by 2040.[21] However, a majority of projects procured in the past five renewable solicitations by NYSERDA have been canceled, creating a projected shortfall toward meeting increasing renewable targets.[22] For example, of the 85 projects awarded by NYSERDA's large-scale renewable procurements between 2018 and 2021, all but eight have been canceled (over a 90% cancellation rate), including all 22 projects awarded as part of the 2021 solicitation.[23]

In response to these cancellations, NYSERDA opened its most recent and seventh solicitation in November 2023, drawing 68 unique proposals. Of these 68 submissions, 60 were projects previously awarded and subsequently rescinded or canceled prior Tier 1 awards from

---

[21] See, e.g., New York ISO, 2021–2040 System & Resource Outlook ("System & Resource Planning Department Slides"), October 5, 2022 at 12; New York ISO, 2021-2040 System & Resource Outlook: Appendix F, September 22, 2022, at 13.

[22] See, e.g., C. Kinniburgh, Missed Deadlines Pile Up As New York's Climate Law Turns Five, New York Focus (June 19, 2024); Draft Clean Energy Standard Biennial Review, NYSERDA, Case 15-E-0302 (July 1, 2024) at 54-59.

[23] Data from New York State, Data.NY.gov, Large-scale Renewable Projects Reported by NYSERDA, Beginning 2004.

NYSERDA.[24] Ultimately, 24 projects were awarded, representing nearly 2.4 GW of new renewable capacity.[25] Given the robust interest by developers in applying to participate in NYSERDA's 2023 solicitation, it appears New York has an active group of private suppliers willing to provide bids into NYSERDA's renewable procurement process, given NYSERDA's ability to consistently attract volumes of over 2 GW in recent competitive Tier 1 solicitations.[26] An additional data point on application interest will be available following NYSERDA's 2024 solicitation, which is currently accepting applications.[27]

Despite this continued interest from suppliers to participate in the NYSERDA competitive solicitations, a majority of these projects have been canceled or have otherwise not yet reached commercial operation. New York progress reports towards the achievement of the CES mandate show that, despite the myriad procurement activities, New York decreased its percentage of total load served by renewables in 2022 as compared to a 2014 baseline.[28] This shortfall, combined with an even greater anticipated increase in electricity consumption after 2030 as a result of continued electrification, will likely drive the desire to change procurement or development structures to accelerate progress. Should New York State identify a need to accelerate procurement volumes beyond the current pace, utilities are likely to be in a strong position to fill gaps in supplying the required procurement volumes, as discussed below.

b. Utilities Have Demonstrated History of Project and Risk Management

There have been recent instances where large-scale utility-owned generation projects have proceeded on time and on budget while similar projects by competitive suppliers have fallen short or been canceled. In particular, the Coastal Virginia Offshore Wind plant, owned and developed by Dominion Energy off the coast of Virginia, remains on time and on budget[29] in the

---

24 NYSERDA, Clean Energy Standard Annual Progress Report: 2022 Compliance Year, January 2024 at 4 ("2022 CES Compliance Report").

25 NYSERDA, 2023 Solicitation, 2023 RES Solicitation for Tier 1 RECs, November 30, 2023 ("2023 Solicitation").

26 For example, NYSERDA's 2020 solicitation procured 2,111 MW; 2021 solicitation procured 2,408 MW; and the 2022 solicitation procured 2,410 MW. New York State, Data.NY.gov, Large-scale Renewable Projects Reported by NYSERDA, Beginning 2004.

27 NYSERDA, Solicitations for Large-scale Renewables (accessed July 2, 2024).

28 2022 CES Compliance Report at Figure 3 (showing 2014, 25.3% renewable share; and 2022, 25.1% renewable share). Note that this has not impacted the RES compliance of jurisdictional utilities, which are still 99.9% compliant as of the most recent 2022 compliance report. 2022 CES Compliance Report at Table 6.

29 Dominion Energy, "Dominion Energy Achieves Another Major Milestone for Coastal Virginia Offshore Wind with Installation of the First Monopile Foundation," Press Release, May 22, 2024.

face of a suite of offshore wind project cancellations.[30] Dominion's project management team had the foresight to finance and construct a Jones Act-compliant installation vessel[31] – a need overlooked by certain competitive suppliers, leading to project abandonment.[32]

Ideally, regulated utilities' particular understanding of the regulatory and permitting environment in New York State, a direct interest in a highly reliable energy system in the state, and a long-term commitment to the state increase the likelihood of project completion. However, there is still no guarantee in this regard, given utilities' exposure to similar market forces that would also impact competitive suppliers, including financing costs, rising capital costs, and supply-chain limitations, described further below. Further, utilities are likely to face the same permitting requirements, including potential delays, in developing renewable energy as faced by private developers in New York State, as well as similar interconnection queue timing challenges. Utilities' access to a robust balance sheet and the ability to recover cost overruns subject to prudence review enables them to continue developing projects (with customers at risk for prudently incurred cost overruns, as discussed in Section II) where competitive suppliers would not. Conversely, any cost underruns would result in benefits to utility customers. Private ownership of renewables does not share these advantages.

c. Utilities Can Provide Higher Benefit or Lower Cost Development Options in Certain Scenarios

Utility participation in procurements could add additional potential suppliers, allow for access to capital from utility investors, and otherwise increase renewable development options.[33] To enable this participation, NYSERDA or other regulatory agencies could identify specific scenarios where utilities with regulated cost-of-service rates could procure large-scale renewables at a lower customer cost, greater benefits and/or lower risk for a similar renewable asset while at the same time helping New York meet its energy and climate goals. As described in more detail

---

[30] Marie J. French, "New York: Major offshore wind projects in New York canceled in latest blow to industry," *Politico*, updated April 19, 2024; State of New Jersey Board of Public Utilities, "Murphy Administration Announces Developments in Offshore Wind Industry," Press Release, May 28, 2024.

[31] Charlie Paullin, "Dominion's offshore wind construction vessel, named after Greek sea monster, moves to the water: Ship will be Jones Act Compliant," *Virginia Mercury*, April 16, 2024.

[32] Scott Disavino, "Ship shortage dealt death blow to Orsted's NJ offshore wind hopes," *Reuters*, November 3, 2023.

[33] We discuss potential long-term impacts to competition in Section II below.

in Section II above, several scenarios exist where utility ownership is likely to result in lower customer costs:

- Customer cost savings for utility-owned wind assets as compared to private ownership if the wholesale power prices are higher in the post-contract period;
- Customer cost savings for utility-owned wind assets if the private owner's cost of capital (or financial hurdle rate to accept as minimum return on capital) is at the higher end of the range of publicly reported rates.

In addition to these particular scenarios where the utility may be a lower-cost option for renewable development, customers would benefit should the utility face a reduction in capital cost compared to the projections as of the approval date, especially if the approval date coincided with a period of higher interest rates. Where private owners (with fixed-price contracts) would retain the benefits of any pre-deployment cost reductions, these benefits would accrue to ratepayers under a utility ownership model. Benefits associated with better than forecast performance in capacity factor or operating costs would also accrue to customers under utility ownership.

d. Utility Ownership Enables Future Project Modifications

Permitting the utility the opportunity to own and finance renewable generating resources in the utility rate base offers the advantage of enabling modifications to the plant (or the terms of the contract to operate and maintain the plant) more easily in the future. It also includes the ability for the utility to withstand some amount of increases in capital costs prior to plant construction in instances where a private developer may instead abandon the projects.

In the short term, utility ownership could enable modifications to the plant to reduce customer cost impacts of project implementation, should capital costs decline between the time of contract specification and construction (or between the start of construction and in-service-date through capital trackers or similar regulatory mechanisms). In an increasing cost environment, currently employed contracts are inflexible; instead of modifying contracts to reflect ongoing developmental realities, the contract structure results in project cancellation.[34] While this structure creates risk implications described below, utility-owned assets in the rate

[34] Note that NYSERDA has responded to project cancellations in the current increasing cost environment by holding "re-bid" or subsequent solicitations where cancelled projects are eligible for a new award. Aside from the seventh large-scale solicitation described above, NYSERDA has also permitted re-bid of offshore wind projects as part of their 2023 fourth offshore wind solicitation. See New York State, Offshore Wind, NYSERDA 2023 Offshore Wind Solicitation.

base enable flexibility in retaining the asset development timeline and achieving deployment by providing the Commission with the ability to approve project modification on an ongoing basis.

As such, utility ownership of renewable resources represents a trade-off for policymakers: utilities are more likely to complete awarded projects because the Commission retains the option to approve recovery of prudently incurred costs that are necessary to deliver on the project. In contrast, awarding competitively procured fixed-price contracts to private owners increases the likelihood of project cancellation (should development or operational costs increase). While the fixed-price contracts without an indexing mechanism that adjusts pricing for any future cost changes protect customers from the impact of these cost overruns, increasingly common project cancellations raise concerns about meeting New York's clean energy targets.[35]

In addition, longer-term benefits are further available from repowering utility-owned renewable assets. After the plant's initial contracted life, any modifications that would reduce cost or improve net benefits would accrue to the utilities' customers under a utility cost-of-service and ownership model. In contrast, similar benefits of repowering privately held assets would accrue to the generation developer.

3. Potential Drawbacks

a. Competition Concerns

Depending on the implementation rules, participation of transmission and distribution utilities in ownership of large-scale renewable generation projects could have an adverse effect on competition by discouraging participation from private developers of renewable assets.[36]

Appropriate participation rules and procurement mechanisms could mitigate such concerns. Where utilities have access to other facilities that may benefit certain renewable project sites, such as ownership of land, right of way, and existing facilities, mitigation measures would

[35] If desired by policymakers, this tradeoff could be minimized or eliminated by having the utility and private developers compete on a level playing field, for instance by allowing any inflation adjustments to apply to both utility-owned and private developer generation offers, by ensuring open access, and by not allowing utilities recovery of cost overruns.

[36] See, e.g., NYPSC Order at 36. ("The Commission rejected the option of utility-owned generation because it "has the potential to inhibit entry by other market participants, which can result in less competition and higher costs in the long-run.") (internal citations omitted). We should note on the other hand that entry of utilities into competitive procurements may also attract developers with other business models (e.g., build and transfer) to participate in procurements.

include the utility accurately accounting for the use of these assets in determining the costs of a renewable development project, to avoid cross-subsidization and ensure that any competition occurs on a level playing field. Such rules should ensure that all costs associated with utility-owned renewables are appropriately accounted for and accurately captured.

Further, additional code of conduct rules, particularly regarding equal access to public transmission and distribution information discussed below, may be necessary to ensure the utility does not provide additional advantages to its own projects at the expense of private companies participating in renewables development (i.e., preferential interconnection access and preferentially tailored transmission construction, or pre-queue information, as described below), whether or not competition between regulated utilities and private owners is ultimately used as the procurement mechanism.

b. Open Access Concerns

Given utilities' unique role in providing distribution and transmission service, open access concerns are inherent in a utility's participation in the ownership of renewable generation resources, particularly within its incumbent service territory. Without a specified code of conduct, i.e., the utility-owning generation under the same corporate umbrella, inherent conflict-of-interest concerns may arise, as identified in fundamental open access FERC orders.[37] These risks include a utility identifying and developing the most advantageous interconnection options to be used for their own projects using non-public information or creating new and tailored transmission and distribution plans without transparency to advantage specific utility projects (or disadvantage others seeking to develop renewables).

Without clear requirements on code of conduct for the transmission and distribution side of the utility business, these risks will need to be mitigated under the corporate structure of utility-owned (and not utility-*affiliate*-owned) generation by ensuring that the renewables development is on the basis of equal access to information available to all developers. Given the inherent similarities of corporate interests between the entity owning the generation and transmission assets, the sharing of employees within the company now providing generation and transmission services, and the requirement for the utility to provide interconnection service to (now) competitors within renewable solicitations, appropriately refined and specific

[37] Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, Final Rule, April 14, 1996. FERC Stats. & Regs. ¶ 31,036, at p. 136–137.

code of conduct restrictions would be required to retain confidence that open access would be preserved within all renewable procurements.

c. Expose Utility Customers to Investment and Performance Risks

Should utility ownership of generation extend to enabling the utilities to recover the costs of renewable assets in rate base, utility customers will be exposed to investment, performance, operational, and other risks. Despite the significant project cancellations described above, as a result of New York's competitive procurement model, which allocates risks and benefits to private companies instead of customers, customers have not borne the costs of these canceled projects. In contrast, if the costs of a canceled utility-owned project were determined to be prudently incurred, those costs would be recoverable from customers. Notably, if these costs are ultimately recovered from customers through a non-bypassable delivery surcharge, it could limit customer choice by allocating costs of utility-owned renewable resources to customers that switch to alternative energy providers (i.e., ESCOs).

Further, despite the project management advantage demonstrated at times by utilities as described above, significant risks to customers remain. Recent examples demonstrate stranded asset risks faced by customers when utilities are permitted to develop and recover from customers the prudently incurred cost of building generation assets. For example, South Carolina enacted legislation enabling utilities to construct, own, and operate the noncompleted V.C. Summer nuclear plant, leaving customers at risk for significant cost overruns for a project that was not fully completed.[38] This set of events, in part, led South Carolina to evaluate various regulatory reform options, including full and partial divestiture of supply assets from their

[38] The Brattle Group, Assessment of Potential Market Reforms for South Carolina's Electricity Sector: Final Report to the Electricity Market Reform Measures Study Committee of the South Carolina General Assembly, April 27, 2024 ("SC Reform options study") at n. 14 ("experience with the V. C. Summer nuclear plant expansion provides a vivid example of stranded asset risk. The V.C. Summer expansion construction and associated cost recoveries were approved by the Board of Directors of Santee Cooper and the South Carolina PSC under a special process enabled by the 2008 Baseload Review Act (later repealed in 2018). Though the project was never completed, approximately $9 billion in expenditures for partial construction will need to be recovered from customers over the next decades. See Thad Moore, "Santee Cooper, SCE&G pull plug on roughly $25 billion nuclear plants in South Carolina," *Post and Courier*, July 31, 2017; Gavin Bade, "Santee Cooper, SCANA abandon Summer nuclear plant construction," Dive Brief, *Utility Dive*, July 31, 2017; and Santee Cooper, Annual Report 2021, March 11, 2022.")

vertically integrated utilities.[39] New York identified these concerns in its shift away from vertical integration and towards competitive markets in 1997.[40]

d. Utility Owned Generation May Result in Higher Costs in Some Instances

In certain instances, utility ownership of renewables would result in higher costs to customers. As described in more detail in Section II, several scenarios exist where utility ownership is likely to result in higher customer costs:

- Higher costs for customers if the utility elects to utilize the ITC as an Option 2 taxpayer (by reflecting benefits from ITC through reductions in revenue requirements outside the rate base). The utility may be able to pass through higher benefits of the ITC to customers if it is an Option 1 taxpayer (by reflecting ITC benefits through reduction in rate base), or it may pass through the benefits of the tax credits similarly to private developers if it chooses to utility the PTC rather than the ITC.[41]
- While modeling shows that the utility-owned solar assets approach results in broadly comparable costs relative to privately developed ones based on current assumptions, the final customer cost is 1–11% higher under utility ownership in most cases, with the notable exception of higher developer capital cost, where the utility has the advantage.
- Customer cost increases for utility-owned wind assets as compared to private development if the wholesale power prices are lower in the post-contract period (and vice versa).

IV. Conclusions

We evaluated the potential pros and cons for electric customers in New York State of supplementing the current private ownership model used today with the ability for regulated

---

39 See ,e.g., SC Reform options study.

40 State of New York Public Service Commission In the Matter of Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service, Cases 94-E-0952 et al. (issued May 20, 1996) at 64–65. ("Divestiture of generation and energy services is a clear way to allay concerns about vertical market power and avoid anti-competitive behavior (such as cross-subsidies among affiliates in both competitive and monopoly environments and favored treatment of affiliates.")

41 Note that the majority of utilities are Option 2 taxpayers including Consolidated Edison Company of New York ("CECONY"); however, Orange and Rockland Utilities ("ORU") is an Option 1 taxpayer and therefore may be able to pass through the ITC benefits to taxpayers similarly to independent developers.

utilities in New York State to own some portion of these new large-scale renewable generation plants.

Allowing regulated utilities to own new renewables would offer several potential benefits for electricity customers in New York, including potentially accelerating the achievement of New York's clean energy goals by providing an additional source of renewable supply and offering a demonstrated history of effective project execution and risk management to provide benefits and/or cost savings for customers under certain conditions. In addition, utility ownership under cost-of-service ratemaking could provide flexibility for modifying the design and operations of the new renewables in the future, with benefits from that flexibility flowing to customers instead of being largely retained by private owners. Finally, any cost underrun in development costs would be retained by ratepayers under a cost-of-service approach, whereas these benefits would otherwise accrue to private renewable owners.

However, utility ownership would likely shift most risks currently borne by private owners to electricity customers with respect to asset performance and cost overruns. In addition, depending on the implementation rules, utility ownership may raise concerns about cross-subsidization of costs between the delivery services and the renewable project and the availability of open access to information on the transmission and distribution systems to all developers of renewable generation in the state. Finally, utility ownership may raise customer costs over the lifetime of the renewable asset under certain conditions, such as depending on future wholesale market prices and the approach for reflecting the federal investment tax credits in customer rates.