Money to Burn: Incentive Design for Carbon Capture in the US Power Sector

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Abstract

Since 2008, subsidies for carbon capture and storage (CCS) in the US have been structured to provide a per-tonne payment for stored CO_2. Using an analytical model accompanied by detailed electricity sector simulations, we compare the existing per-tonne storage subsidy with an alternative, generation-based ($/MWh) subsidy that achieves equivalent CCS generation. In doing so, we evaluate how the structure of CCS subsidies influences retrofit decisions, system and fiscal costs, and emissions outcomes in the US power sector. We find that subsidy structure strongly affects which units retrofit. Storage-based subsidies favor high heat rate units because the incentive value increases with fuel combustion, while generation-based subsidies shift retrofits toward more fuel- and cost-efficient units. The difference in incentive structures leads to a reduction in fuel use as well as system and government costs under the generation-based policy. Emissions are lower under the storage-based subsidy during the crediting period but higher afterward as the relatively inefficient units continue operating after expiration of the tax credit but without CCS enabled. Throughout, we find that CCS subsidy design plays an important role in determining both the policy cost and economic efficiency, as it pertains to the US power sector.

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1. Introduction

Federal subsidies for carbon capture and storage in the US began in 2008 with the Energy Improvement and Extension Act, which provided a per-ton credit for CO_2 captured and either stored or used in enhanced oil recovery. The credit was significantly expanded in 2018 through the Bipartisan Budget Act, which increased credit values and broadened project eligibility. The Inflation Reduction Act (IRA) of 2022 further increased the credit, extended the start of construction window, and added direct pay provisions. In 2025, the One Big Beautiful Bill Act (OBBBA) further increased the value of and expanded the eligibility for claiming the tax credit but reduced or removed most other IRA clean energy incentives. The tax credit is colloquially known as '45Q' given its section designation in the US Internal Revenue Code.

While current US policy[1] supports CCS via per-tonne subsidies for stored carbon, alternative approaches that incentivize low-emissions electricity generation directly have been available for other electricity generation technologies and have been proposed in regulatory and industry discussions. As demonstrated here, subsidizing the capture and storage of carbon versus electricity generation creates markedly different incentives for CCS investment and thus power system outcomes. Therefore, without clear understanding of these effects, well-intentioned subsidies risk inducing costly deployments.

Previous studies focus on comparing CCS deployment under carbon pricing and tax credits for carbon storage; recent work explores how technology-specific subsidies can both accelerate deployment and introduce inefficiencies if poorly aligned with firm behavior. Research has also highlighted the importance of spatial clustering and institutional feasibility in policy effectiveness. However, despite growing attention to subsidy-based approaches, no work has compared carbon storage subsidies to generation-based subsidies for CCS in the power sector. Because recent U.S. climate policy relies heavily on production- and investment-based subsidies, understanding how alternative subsidy structures affect investment and operating decisions is necessary for evaluating their fiscal and system-level consequences.

This paper addresses a policy design question: How does a subsidy for carbon stored compare with a subsidy for electricity generation? We answer this first through an analytical model then perform detailed electricity sector simulations to estimate the impacts on upgraded units' characteristics, the resulting impacts to the broader power system, and fiscal expenses across such policies. Our results highlight how subsidy-based policy structure determines the efficiency and effectiveness of CCS deployment. We show (a) subsidies based on CO_2 stored disproportionately favor fuel-inefficient units, (b) generation-based subsidies reduce both power system and fiscal costs and (c) units upgraded under generation-based subsidies remain more

[1] Although relevant to CCS, Clean Air Act 111 standards are not included in this analysis because their compliance requirements and implementation timelines remain unsettled and, at present, are under legal review. Incorporating the rules would force us to make assumptions about future judicial or administrative outcomes which are outside the purpose of this study. We leave this for future research and focus only on different incentive structures. Further, and consistent with current US policy, the simulation model assumes no performance standard after credit expiration; this implies that existing coal units may legally continue operating without CCS, so units that are uneconomic to run with CCS after 2041 are allowed to disable capture but remain active.

cost-competitive after subsidies expire. Differences in total emissions across policies are relatively small but are consistently less with CO_2-based subsidies when the subsidies are available and, after expiration, are less with generation-based subsidies.

The paper is organized as follows. First, we place ourselves within the current literature. Second, we present the theoretical logic of the subsidy designs as well as an analytical model. Third, we present an overview of the electricity capacity expansion model and policy design. Fourth, we present results with a focus on the attributes of retrofitted units, changes to system costs, as well as policy implications related to total subsidy payments and emissions. Finally, we conclude. Appendix A contains additional figures and Appendix B contains a reference table of acronyms.

2. Literature on carbon capture policy design

Effective deployment of CCS[2] depends on spatial coordination, infrastructure availability, financial incentives, and political feasibility. Regional clustering of emitters and shared CO_2 transport and storage networks can meaningfully reduce costs, particularly when supported by policies that leverage economies of scale such as the 45Q tax credit [1]. Anticipating firm responses is equally important: subsidies that overlook strategic behavior can induce inefficient retrofit choices or lead to limited emissions reductions [2]. Models that abstract away from political constraints may also misrepresent the feasibility of deep decarbonization, highlighting the need for policy realism in long term planning [3]. Together, these findings emphasize that CCS policy design must be grounded not only in economic efficiency but also in spatial and institutional realities.

A broad literature evaluates how the structure of energy policy subsidies shapes the adoption of low-carbon technologies. Studies comparing technology neutral approaches, such as carbon pricing, with technology specific subsidies identify tradeoffs among cost effectiveness, political durability, and deployment speed [4, 5]. Technology-specific subsidies, including production tax credits and direct deployment incentives, can accelerate adoption but may distort market signals or crowd out lower cost alternatives [6]. These concerns are especially relevant in sectors with large sunk costs and long asset lifetimes, such as electricity generation. Understanding firm behavior under alternative incentives is therefore important for designing policies that deliver emissions reductions without unnecessary fiscal or economic burdens [7].

A growing set of studies examines the impacts of the Inflation Reduction Act (IRA) on emissions, energy markets, and technology deployment [8, 9, 10, 11]. Parallel work evaluates the role of CCS across decarbonization pathways for power generation, fuels, and negative emissions technologies such as direct air capture (DAC) and biopower with CCS (BECCS) [12, 13, 14]. These studies, however, nearly always assume that CCS deployment is driven by per-tonne subsidies for stored CO_2, command and control regulations, or Pigouvian carbon

[2]For simplicity, we defer to the CCS acronym and recognize the distinction among carbon capture and storage (CCS), carbon capture, utilization, and storage (CCUS), and carbon transport, utilization, and storage (CTUS); we do not consider utilization in this work.

pricing. To our knowledge, no prior work compares per-tonne storage subsidies with per-MWh generation subsidies for CCS retrofits. These are the two policy structures that now exist in some form in the US. This paper addresses that gap by evaluating how subsidy structure shapes retrofit decisions, power system outcomes, and fiscal expenditures.

3. Theory and analysis

Assume a price taking electricity generator whose objective is to maximize profit. Using the parameters and variables defined in Table 1, baseline profit for an existing unit without CCS is

$$\max_{Q_i} \pi_i = (p - c_i^v - c^f H_i)\, Q_i, \tag{1}$$

where p is the market price of electricity, c_i^v represents variable operating costs, c^f is the fuel price, and H_i is the unit's heat rate. Profit is therefore proportional to generation Q_i net of variable and fuel expenses.

Symbol	Units	Description
i	–	Generating unit index
π_i	\$	Profit without retrofit
π_i^c	\$	Profit with retrofit and CO_2-stored-based credit
π_i^g	\$	Profit with retrofit and generation-based credit
p	\$ / MWh	Price for electricity
c_i^v	\$ / MWh	Variable and operating costs
c^f	\$ / mmBTU	Fuel cost
H_i	mmBTU / MWh	Unit heat rate
Q_i	MWh	Generation
η	\$ / tonne CO_2	Storage subsidy (net of storage costs)
β_i	%	Capture rate
θ	tonnes CO_2 / mmBTU	Fuel emissions rate
c_i^u	\$ / MW	Present value of CCS installation
R_i	MW	CCS retrofit investment
γ_i	\$ / MWh	Generation subsidy

Table 1: Analytical model symbols and descriptions

When a subsidy for carbon storage is introduced, profit includes an additional revenue term equal to the subsidy value times captured emissions. The unit also incurs capital costs associated with CCS installation. Profit with CCS and a carbon storage subsidy is therefore:

$$\max_{Q_i, R_i} \pi_i^c = \left(p - c_i^v + (\eta\beta_i\theta - c^f)H_i\right) Q_i - c_i^r R_i. \tag{2}$$

The retrofit decision depends on the difference in profit between the CCS and non-CCS configurations. Thus, CCS adoption is profitable when the difference is positive:

$$\pi_i^c - \pi_i > 0 \quad \rightarrow \quad p\,\Delta Q + \eta\beta_i\theta H_i Q_i > \Delta c^v Q + c^f \Delta H Q + c_i^r R_i, \tag{3}$$

where Δ indicates the difference between post-retrofit and pre-retrofit values. This expression highlights a central tradeoff in that a higher heat rate increases both fuel expenses and subsidy revenue. To further explore this relationship, we take the derivative of the profit difference with respect to fuel combustion ($H_i Q_i$):

$$\frac{\partial(\pi_i^c - \pi_i)}{\partial(H_i Q_i)} = \eta\beta_i\theta - c^f. \tag{4}$$

Thus, if the per-tonne subsidy exceeds the fuel cost, then units with higher heat rates, that is less fuel-efficient units, receive a larger net benefit from installing CCS. This is a structural feature of per-tonne storage subsidies in that generator revenue increases with fuel combustion.

The advantage for higher heat rate units under storage-based subsidies follows directly from the analytical expression in the previous equation; that is, the marginal incentive increases with fuel combustion whenever $\eta\beta_i\theta > c_f$. Note, this relationship holds independently of any particular retrofit cost assumptions or heat-rate distribution in the generator fleet. While the exact magnitude of the effect varies with market conditions, the direction of the incentive favors higher heat rates under a per-tonne storage subsidy.

For comparison, a generation-based subsidy provides a constant payment per-MWh, independent of fuel use:

$$\max_{Q_i, R_i} \pi_i^g = (p + \gamma_i - c_i^v - c^f H_i)Q_i - c_i^r R_i. \tag{5}$$

and the retrofit condition becomes:

$$\pi_i^g - \pi_i > 0 \quad \rightarrow \quad p\,\Delta Q + \gamma_i Q_i > \Delta c^v Q + c^f \Delta H Q + c_i^r R_i. \tag{6}$$

Unlike the carbon storage subsidy, the revenue term under a generation subsidy does not scale with heat rate. As a result, a generation subsidy favors units with lower heat rates, minimizing fuel cost per-MWh. This distinction explains the difference in retrofit patterns across the two policy designs and serves as the analytical foundation for the simulation results.

The relationship between heat rate and subsidy value can be illustrated using a levelized cost of electricity (LCOE) framework. Figure 1 shows LCOE and revenue components for a representative coal unit with CCS across a range of heat rates, fuel prices, retrofit costs, and assumed financing periods. Parameter values are drawn from Brown et al. [13]. The figure demonstrates that the storage subsidy increases with heat rate because captured emissions increase linearly with fuel combustion. In contrast, O&M and fuel costs also rise with heat rate. When the subsidy exceeds the incremental fuel cost, subsidized LCOE can become negative, meaning the retrofitted unit generates net profit even without electricity revenue. These combinations occur across multiple cost assumptions and heat rate ranges, illustrating the strong incentive that per-tonne subsidies create for retrofitting inefficient units.

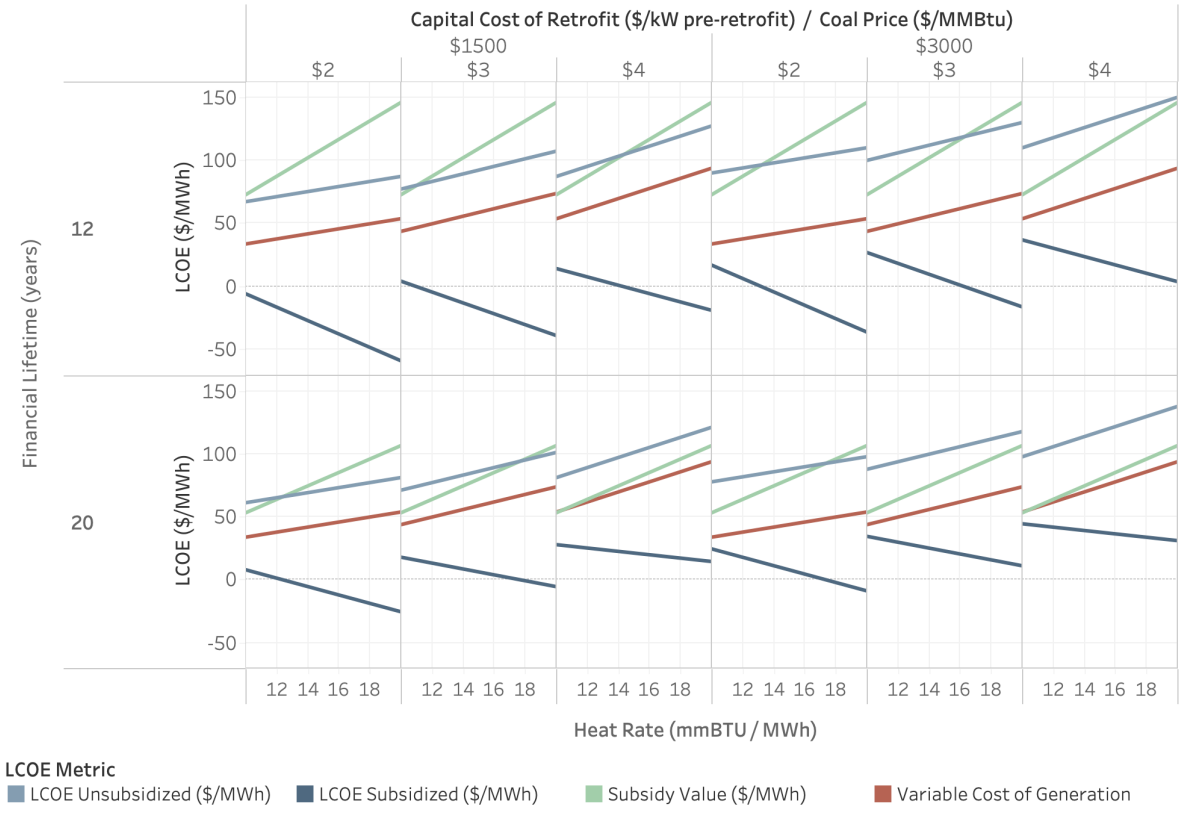


Figure 1: Levelized costs and revenues as a function of unit heat for a representative coal unit retrofit by cost component (color), capital cost of retrofit (primary column), coal price (secondary column), and financial lifetime (row)

4. Simulation methodology

We further divide this section into an overview of the ReEDS model, the modifications introduced for this study, and the policy design framework used in the simulation analysis.

4.1. ReEDS

To perform this analysis, we rely on the open source version of the Regional Energy Deployment System (ReEDS)[3] [15, 16]. ReEDS is a long term capacity expansion model developed by the National Laboratory of the Rockies (NLR) to simulate the evolution of the US electricity sector. The model provides detailed spatial and temporal resolution and is designed to evaluate long term changes in the US electricity system under alternative cost and policy assumptions. System investments in generation, storage, and transmission infrastructure are selected by minimizing system cost subject to technical, operational, and policy constraints.

As summarized in Table 2, we modify ReEDS to reflect the specific needs of this analysis. First, we enable detailed CCS transport and storage network modeling following the methods

[3]Version used in this study corresponds to commit b69551d; the code used in this study is publicly available via GitHub.

in Brown et al. [13]. This allows the model to capture spatial differentiation in CO_2 transport distances, injection costs, reservoir availability, and regional infrastructure constraints that materially affect the cost and siting of CCS retrofits.

Second, generator representation is refined from heat rate clusters (the default in ReEDS) to the individual generating unit level. This allows ReEDS to identify low-cost retrofit opportunities with greater fidelity and to represent heat rate-driven differences in retrofit decisions consistent with the theoretical results presented earlier. Unit-level resolution also allows the model to identify which units are economic retrofit candidates under each policy. Differences in heat rate across the fleet are substantial, and aggregating units into clusters can mask the variation that determines retrofit profitability. Moving to a unit-level representation therefore prevents averaging effects that would dilute the influences identified in the analytical model.

To limit computational burden, we disable several non-essential technologies for this analysis, including concentrated solar power (CSP), advanced geothermal, as well as hydrogen-based electricity generation and production technologies. These exclusions do not materially affect CCS deployment decisions under the policy scenarios examined.

We limit our analysis to coal-fired CCS retrofits. Combined-cycle gas (Gas-CC) units do not achieve emissions rates high enough for the 45Q storage credit or the generation subsidy to materially affect retrofit decisions. Even with high capture rates, the remaining emissions intensity of gas-CCS units typically produces insufficient credit revenue to offset retrofit and operating costs. As a result, gas-CCS retrofits are economically unattractive under all policy designs considered here and generally do not appear as viable candidates in the simulation model. Focusing on coal-CCS therefore isolates the portion of the generatin fleet where subsidy structure affects retrofit incentives and system outcomes.

To represent the spatial and cost complexity of CO_2 transport and storage, we embed a detailed infrastructure module following Brown et al. [13]. This module includes both inter-regional CO_2 pipeline corridors and direct connections from emitting units to saline aquifers, mapped across 134 balancing areas. Pipeline capital and operating costs are derived from the National Energy Technology Laboratory CO_2 Transport Cost Model (CO2_T_COM) and incorporate pipeline length, elevation gain, mass flow rate, and booster pump requirements.

For geologic storage, cost and capacity assumptions draw from the National Energy Technology Laboratory Saline Storage Cost Model (CO2_S_COM) and the National Carbon Sequestration Database. Storage costs are represented as levelized per-tonne values over a 30 year project lifetime, accounting for planning, permitting, injection operations, monitoring, and closure. Consistent with current large scale CCS development pathways, the model assumes storage exclusively via injection of refrigerated liquid CO_2 into saline aquifers, which remains a scalable and cost effective sequestration pathway at present.

Several limitations of this analysis should be acknowledged. The modeling relies on a detailed but still stylized representation of retrofit decisions and does not capture the full range of operational, regulatory, and engineering constraints that real projects may face. We have attempted to find robust results over key driving assumptions such as natural gas price and RE

Modification	Reasoning
Enable detailed CCS networks, consistent with Brown et al. [13]	Regional details and costs influence buildouts [1]
Unit level generator parameterization	Increased resolution relative to heat rate clusters
Disabled CSP, H_2-based electricity generation, and advanced geothermal	Reduce model dimensions and solution time

Table 2: Modifications from default ReEDS settings

costs but there remain several other facets left unexplored. The analysis also abstracts from risk appetites and financing constraints as well as the strategic behavior of plant owners which could influence real-world responses to subsidy design. In addition, the policy environment may evolve, particularly with respect to performance standards or post-credit operating requirements that affect whether units continue to use capture equipment. Although these simplifications allow us to focus on the mechanisms by which subsidy structures shape retrofit decisions, they also imply that quantitative results should be interpreted as directional rather than precise forecasts.

Future work could extend this analysis in several directions. One valuable extension would be to evaluate policy interactions, such as how subsidy structure performs when combined with emissions standards, firm- and/or state-level clean portfolio requirements, or carbon pricing. Applying the same framework to emerging decarbonization technologies or to sectors beyond the power system could indicate whether the mechanisms identified here generalize to other contexts where heterogeneous assets face technology-specific incentives.

We are able to combine the logic from the analytical model with the ReEDS data on the 2024 electricity generation fleet (not including units with announced retirements by 2030) to evaluate the $ / MWh-equivalent incentive level from 45Q for retrofited, coal-fired electricity generation units. Figure 2 presents such a metric on the horizontal axis with (log-scaled) capacity on the vertical axis and the color representing post-retrofit heat rate. Towards the top-left, there are several newer and more-efficient coal combustion units of larger capacity. As the incentive increases, so does the unit heat rates. There is a clustering around the $80 / MWh range and still some units with $90-100 / MWh incentive levels.

4.2. Policy design and scenario framework

To conduct this analysis, we begin with the current 45Q tax credit for carbon storage. The credit provides a per-tonne subsidy for CO_2 captured from electricity generation, direct air capture, and other stationary sources, with the value depending on whether the CO_2 is permanently stored or utilized. Under the Inflation Reduction Act and carried forward in the OBBBA, power plants are eligible for up to $85 per-tonne[4] for CO_2 stored in geologic formations and $60 per-tonne for CO_2 used in approved applications, provided that projects capture at least 75% of

[4]All US dollar values in this paper are presented as $2024

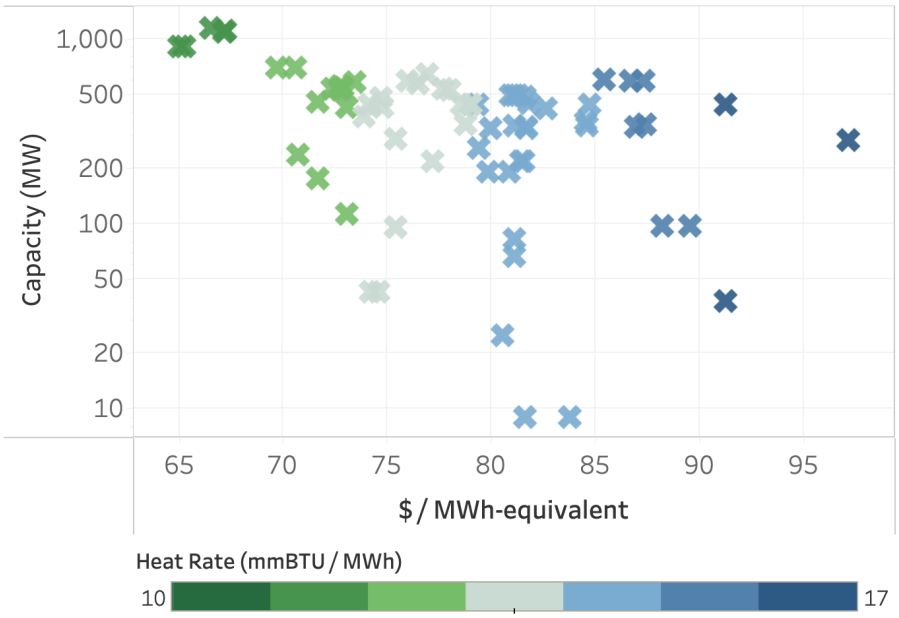


Figure 2: Post-retrofit generation capacity (vertical axis) by $ / MWh-equivalent incentive level resulting from 45Q (horizontal axis), distinguished by heat rate (color)

Setting	**Variations**
Natural gas price	*Ref* (AEO 2025 Reference Case), *High* (AEO 2025 Low O&G Resource), *Low* (AEO 2025 High O&G Resource)
RE cost	*Ref* (ATB Mid Case), *High* (ATB Conservative Case), *Low* (ATB Advanced Case)

Policy label	**Description**
CO2	Subsidy for carbon stored at $85 per-tonne, available for 12 years for units constructed or retrofitted before December 31, 2032
Gen	Generation-based subsidy determined endogenously to match CCS deployment levels observed in the assumption-equivalent CO2 scenario

Table 3: Scenario settings and policy descriptions

emissions and begin construction by 2033. The credit is available for 12 years and includes transferability and, for qualifying entities, five years of direct pay.

To test the robustness of our findings to underlying fuel and technology cost conditions, we evaluate sensitivity to alternative assumptions about natural gas supply and renewable energy costs. Natural gas price trajectories are taken from the 2025 Annual Energy Outlook [17], which includes three resource cases: Reference (Ref), High O&G Resource (HOG, corresponding to lower gas prices), and Low O&G Resource (LOG, corresponding to higher gas prices). These cases reflect uncertainty in upstream supply costs that directly influence the competitiveness of CCS retrofits relative to other generation technologies. Renewable energy cost assumptions follow the NREL Annual Technology Baseline and include a Mid case (“Base”), an Advanced (“Low”) cost trajectory, and a Conservative (“High”) cost trajectory.

To ensure parity across policy designs, we construct a generation-based subsidy that yields

the same total CCS generation as the carbon storage subsidy. We first solve the 45Q enabled scenarios and record generation from retrofitted units. We then impose the following constraint, with complementary dual variable λ, requiring that total generation from coal-CCS meets or exceeds the corresponding level observed in the carbon storage case:

$$\sum_i Q_i \geq \bar{q} \;\perp\; \lambda \tag{7}$$

By setting the generation subsidy equal to the dual value λ, the model applies the market-consistent per-MWh payment that produces the same incentive to acheive CCS generation at the same level as the carbon storage case. This ensures comparable retrofit and dispatch behavior without forcing identical unit-level outcomes. Because ReEDS assumes a 20-year capital recovery period while 45Q is available for only 12 years, we scale the resulting λ values by the ratio of the 20-year to 12-year capital recovery factors. The resulting generation subsidy values (in \$/MWh) should therefore be interpreted as having an equivalent effective incentive duration to 45Q. Finally, we include the product of the endogenous CCS-enabled generation and the static, resulting value of λ in the objective function in order to (a) acquire the appropriate shadow values with incentives as opposed to a technology-specific generation mandate and (b) ensure our resulting CCS-enabled generation matches those from the CO2-based incentive equivalent simulations.

5. Results

Figure 3 presents the distribution in 2035 of CCS-based generation by units' post-retrofit heat rates, differentiated by policy (CO2 in blue, Gen in orange), natural gas price (rows), and RE cost assumptions (columns); Figure 5 in Appendix A presents the same information but by level values (TWh) and for individual units. Consistent with the analytical results, retrofit decisions under the Gen policy shift toward lower heat rate units across all scenarios. The peak of each distribution reflects the concentration of available coal units near 14.5 mmBTU/MWh (post-retrofit), but the tails differ significantly by policy. Under the CO_2 subsidy, the incentive to maximize captured emissions leads to retrofits on higher heat rate units, whereas Gen consistently favors the more efficient portion of the fleet. The resulting generation-weighted average heat rates are 13.2 mmBTU/MWh under the generation-based subsidy compared to 15.8 mmBTU/MWh under the CO2 scenario.

Differences in coal CCS retrofit heat rates vary with underlying market assumptions. When gas prices or RE costs are high, which makes CCS comparatively more competitive, the distribution compresses toward the mean because a larger portion of the available units are economically viable retrofit candidates. Under less favorable conditions, with low gas prices or low RE costs, only units at the edges of the heat rate distribution retrofit, which widens the differences between the two policies. In all cases, the Gen policy systematically selects more efficient units, while the CO_2 policy incentive structure pushes retrofits toward less fuel-efficient units.

Figure 4 summarizes the discounted (using a 5% discount rate) difference in electricity

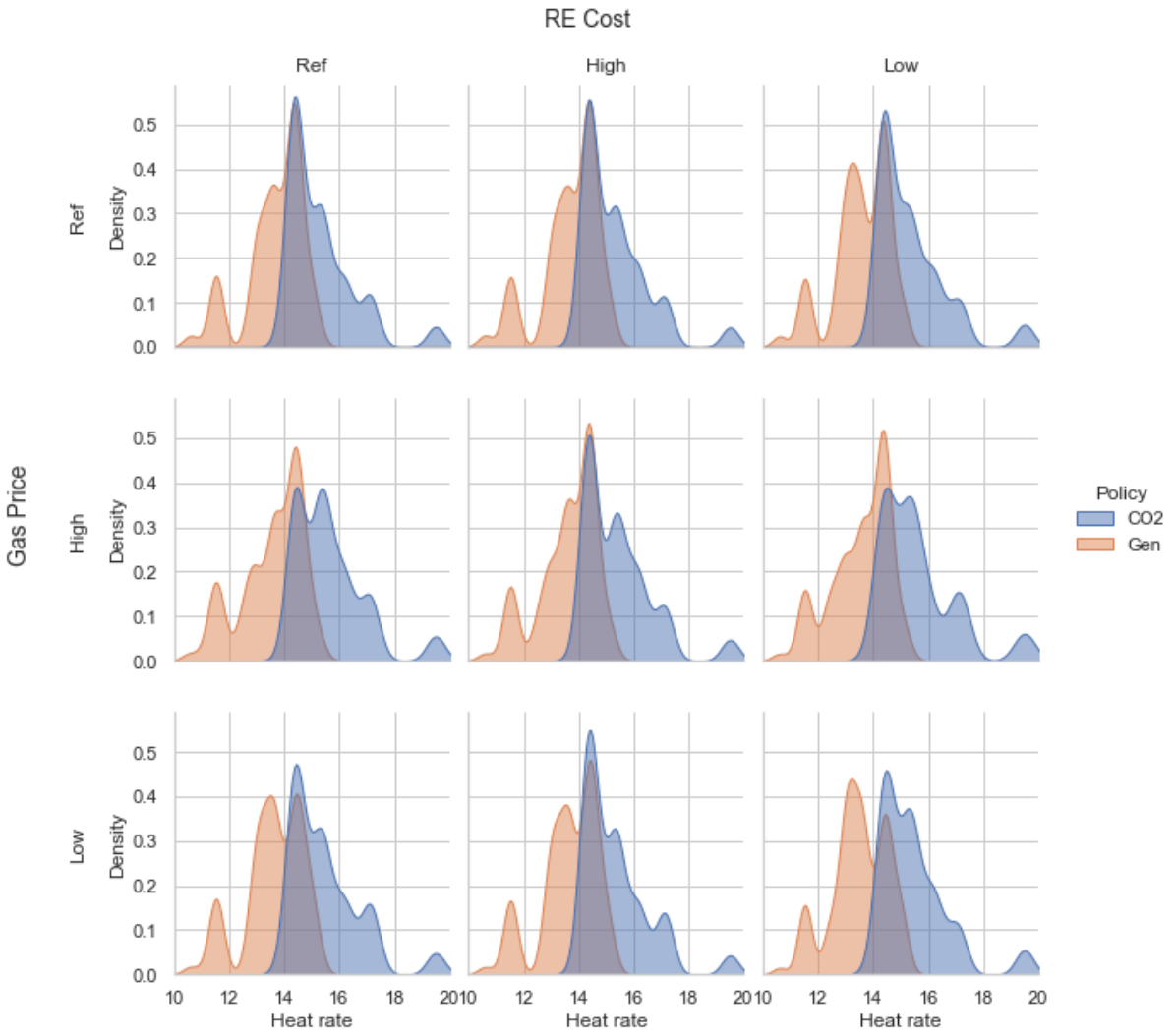


Figure 3: Distribution of generation in 2035 by unit heat rate (horizontal axis) and policy (color); columns vary RE cost assumptions while rows vary natural gas price assumptions

system costs between the two policies, with values reported as Gen [minus] CO2. Negative values therefore indicate lower costs under the Gen policy. Across all gas price and RE cost combinations, system costs are lower under the Gen policy. The magnitude of savings increases in scenarios where CCS deployment is higher, specifically when gas prices or RE costs are increased. Said differently, there is a direct and monotonic relationship between total CCS deployment and the increase in system and fiscal costs between a CO_2-based and a generation-based incentive.

Fuel cost reductions are the largest contributor to the system level differences. Under the CO_2 subsidy, retrofits occur at higher heat rates, increasing fuel combustion and fuel expenditures relative to Gen. Capital costs for generation and storage form the second largest cost category difference. Higher heat rate units often require more expensive CCS retrofits; the Gen policy avoids these installations by favoring low cost, lower heat rate units. A smaller but notable contributor is the difference in long-run capacity needs: because the Gen policy retrofits lower cost units that remain competitive after the incentive expires, fewer new resources are

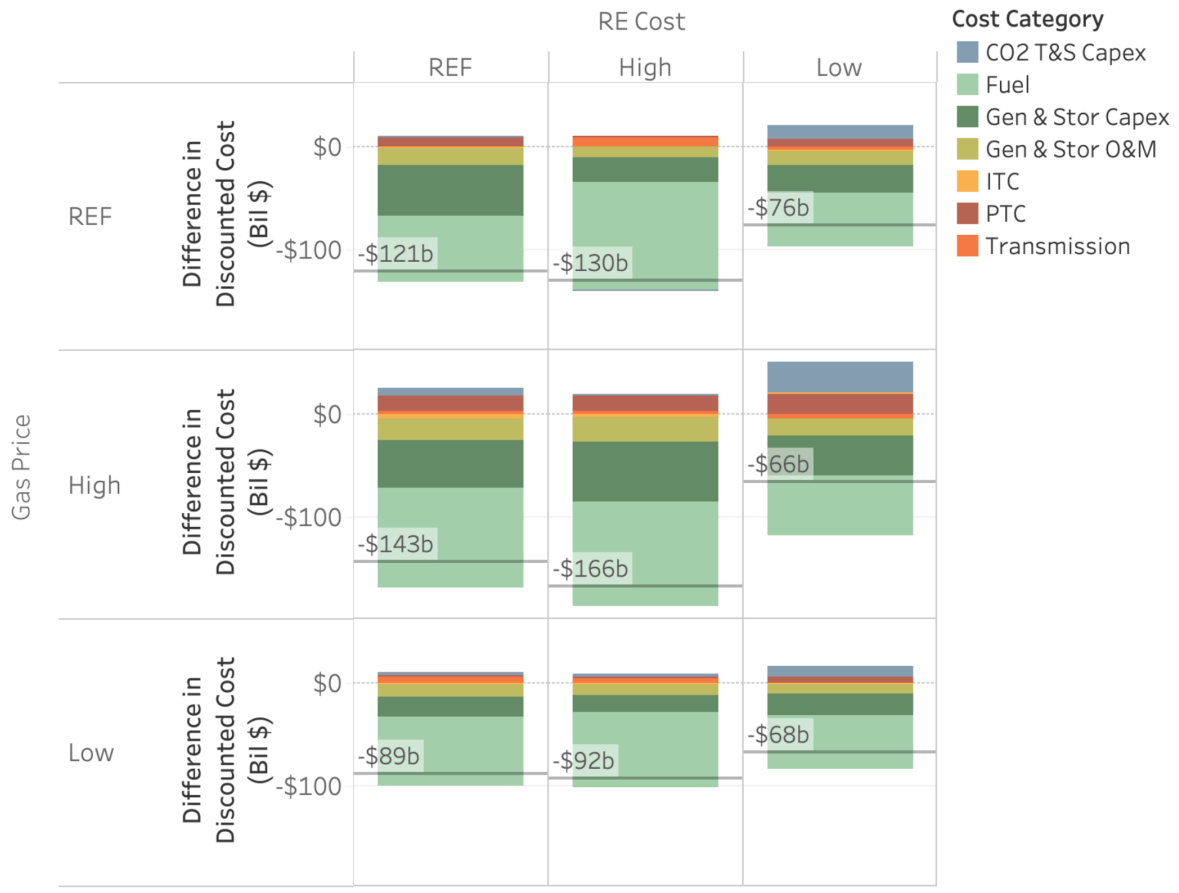


Figure 4: Difference in discounted system cost (5% discount rate) between policy scenarios (Gen [minus] CO_2) for various natural gas price (rows) and RE cost (columns) assumptions, by cost category (color)

built later in the planning horizon. An exception arises under low RE costs, where CO_2 transport and storage costs increase under Gen because the selected retrofit units are geographically more dispersed[5], increasing average pipeline distance and injection costs.

Next, we compare fiscal and environmental outcomes. Table 4 reports the generation subsidy required in each scenario to match CCS deployment in the CO_2 case (akin to λ from the previous section), along with the discounted difference in government expenditures. Required Gen subsidy values range from \$72/MWh to \$84/MWh depending on scenario conditions. These values track with both the underlying market environment (i.e. the cost-competitiveness of coal-CCS technologies relative to other potential investments) as well as aggregate deployment levels being matched.

Consistent with the system cost results, discounted government expenditures are lower in all cases under the Gen policy. On average, fiscal costs fall by 28% relative to the CO_2 subsidy, corresponding to an average reduction of \$9.2 billion. The magnitude of savings scales with CCS deployment: scenarios with higher overall retrofit levels show larger fiscal differences.

Emissions trends are consistent across scenarios. During the period when subsidies are

[5]See Figure 8 in the Appendix for a map of the CCS system buildout under both reference scenarios

Generation Subsidy ($/MWh)			
		RE Cost	
Gas Price	Ref	High	Low
Ref	$73.39	$74.70	$79.33
High	$73.48	$72.01	$75.32
Low	$83.90	$79.90	$81.12

Change in Government Expenditures (Discounted $ billion)			
		RE Cost	
Gas Price	Ref	High	Low
Ref	$-9.83	$-10.46	$-7.18
High	$-11.08	$-11.15	$-9.96
Low	$-8.52	$-8.94	$-5.66

Table 4: Generation subsidy values (12-year duration from start of construction) and change in government expenditures (Gen [minus] CO2)

active (2029–2041), total emissions[6] are roughly 4% lower under the CO_2 policy because that policy retrofits some high emitting units that would otherwise retire. After the credit expires, however, these same units disable CCS operation and continue generating as high emitting units, causing post-2041 emissions to be approximately 9% higher than in the Gen policy. Under Gen, retrofitted units are more efficient and remain cost competitive after the incentive ends, leading to lower long-run and cumulative emissions.

6. Conclusions

This paper evaluates two policy approaches for encouraging carbon capture and storage in the US power sector: payments for stored CO_2 and payments for electricity generation from units equipped with capture technology. Although either approach can support similar levels of deployment, they lead to different investment choices and long-run system outcomes.

The policy mechanisms underlying these differences are straightforward. A payment tied to stored CO_2 increases with units' fuel combustion rates, which makes higher heat rate units more financially-attractive candidates for retrofit. A payment tied to generation does not vary with fuel combustion, so lower heat rate units receive the stronger incentive. When deployment is held constant across policies, the generation-based structure consistently shifts retrofits toward more efficient units.

These choices carry substantial implications for system performance and policy efficiency. Favoring efficient units reduces fuel combustion, avoids costlier retrofits, and leads to lower total system and fiscal costs. In addition, because the selected units remain competitive after the credit period, emissions are reduced in the years following incentive expiration. The storage-based approach produces slightly lower emissions during the credit window but results in a less efficient remaining fleet once capture equipment is no longer operated.

[6]Figure 9 in the appendix shows power sector emissions across all policy and scenario combinations.

Overall, the form of financial support for CCS generation plays a considerable role in shaping economic and environmental outcomes. Aligning incentives with units that use less fuel and require lower capital outlays can reduce government expenditures and improve long-run emissions performance. These findings underscore the importance of considering the structure of subsidy design when developing policy to support carbon capture in the electric power sector.

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7. Appendix A: Additional figures and tables

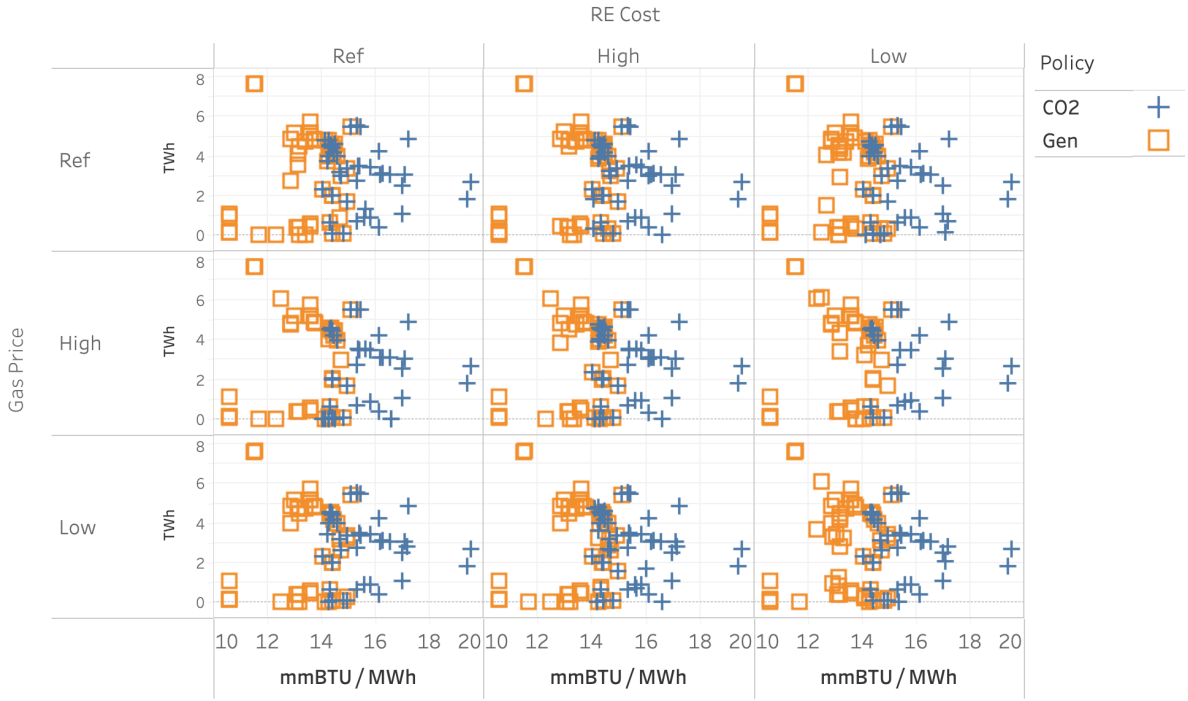


Figure 5: Electricity generation (vertical axis) by heat rate (horizontal axis) for electricity generating units (individual symbols) by policy (color and shape)

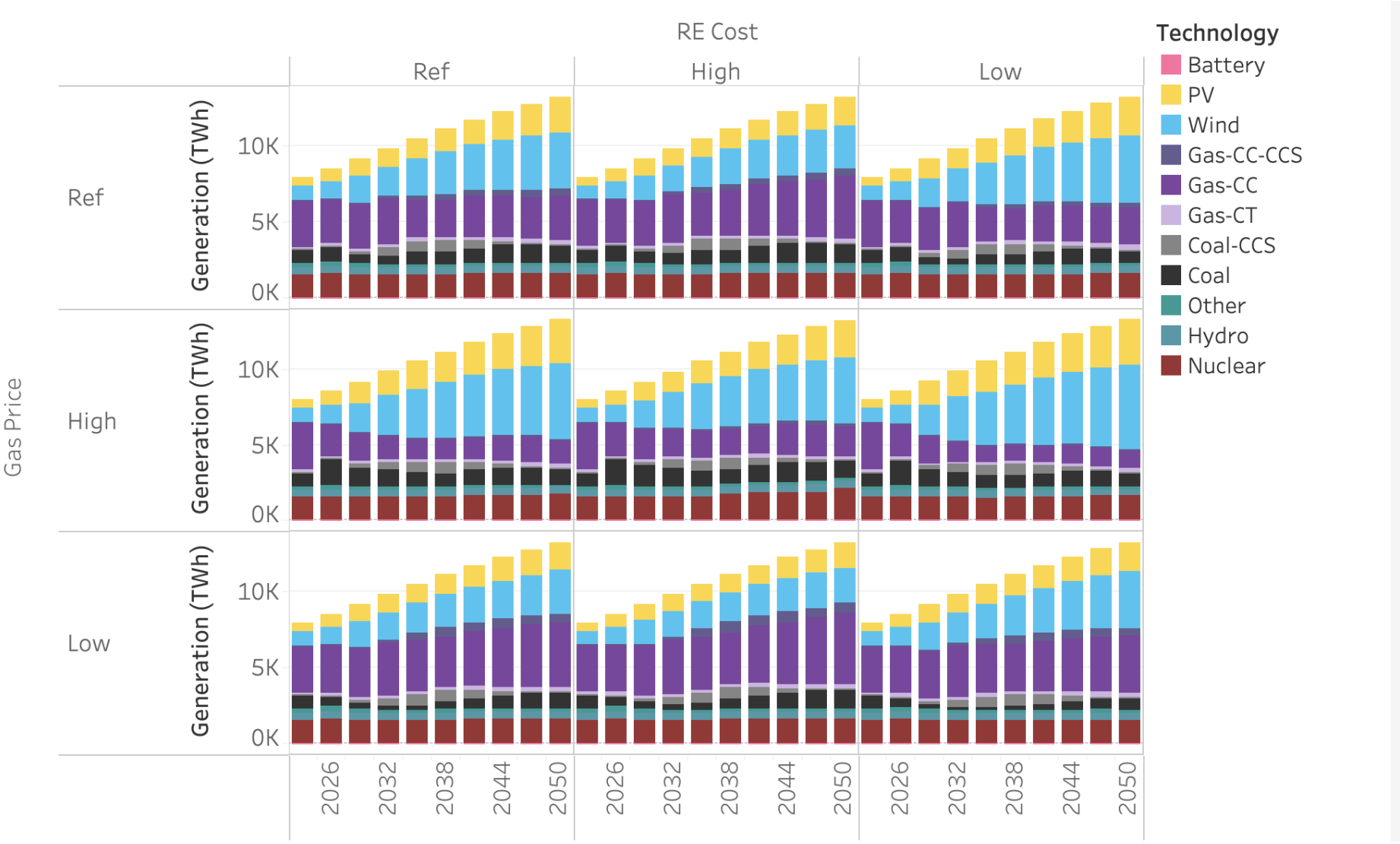


Figure 6: Generation by technology (color) and year (horizontal axis) for various gas price (rows) and RE cost (columns) assumptions

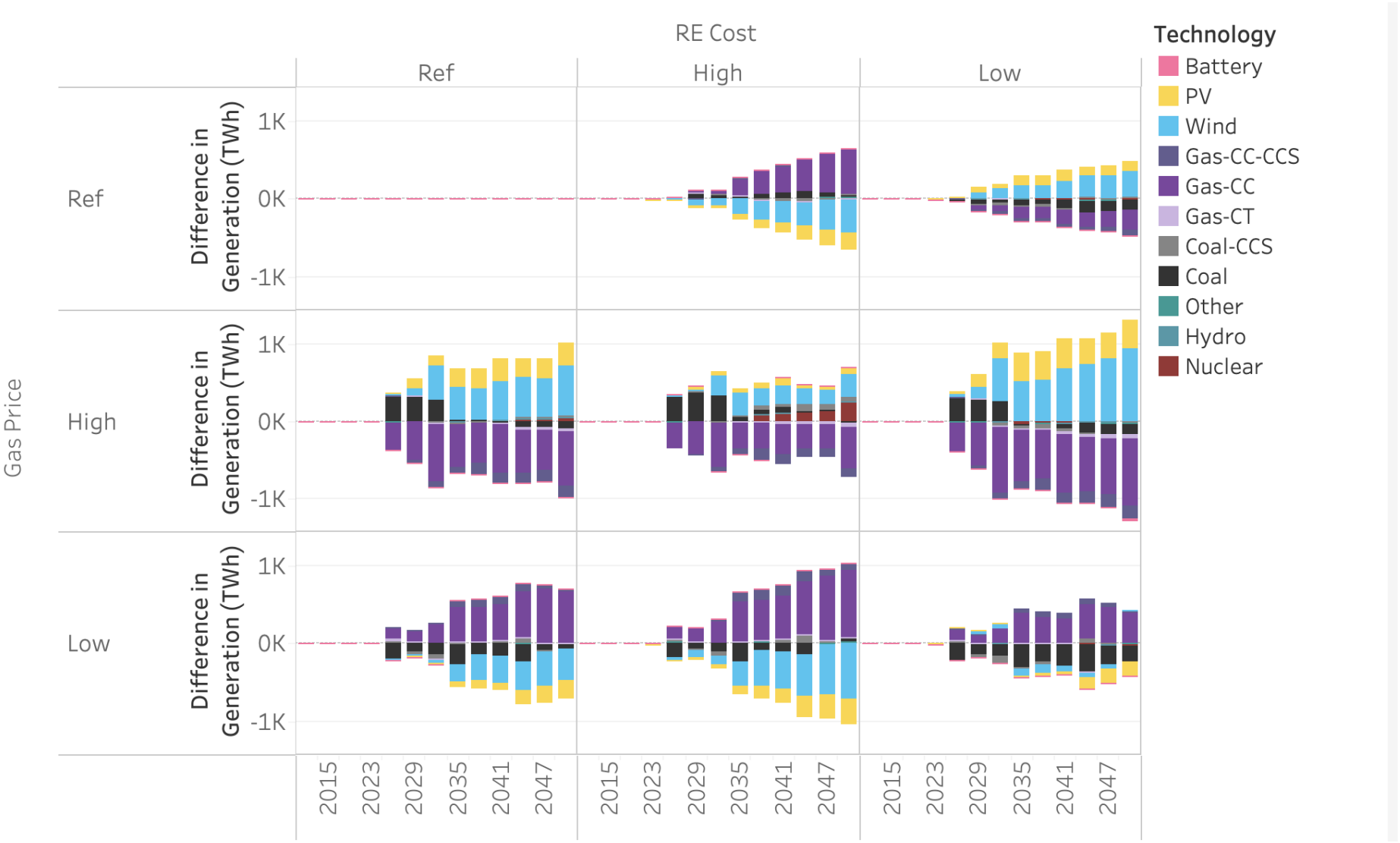


Figure 7: Difference from Ref gas price and RE cost scenario of generation by technology (color) and year (horizontal axis) for various gas price (rows) and RE cost (columns) assumptions

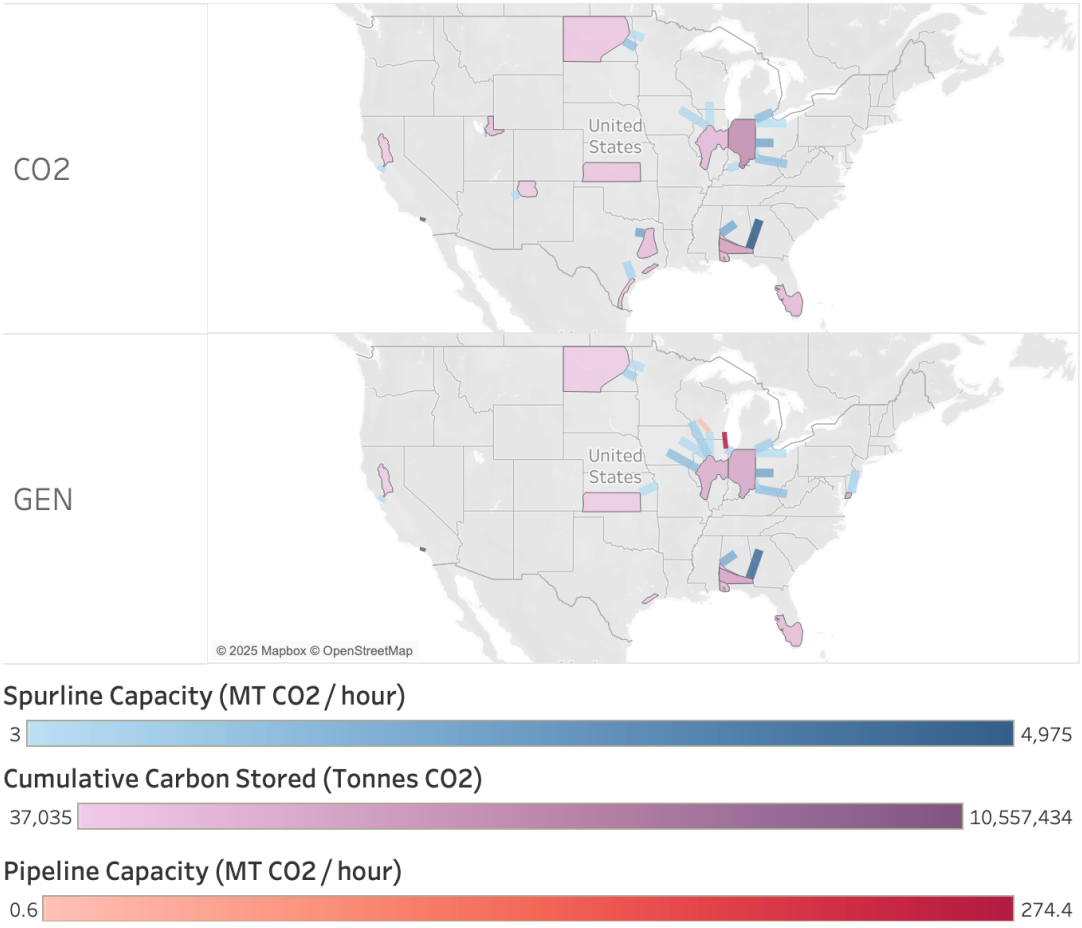


Figure 8: System CCS buildout in 2040 under Ref gas price and RE cost scenarios by policy (row)

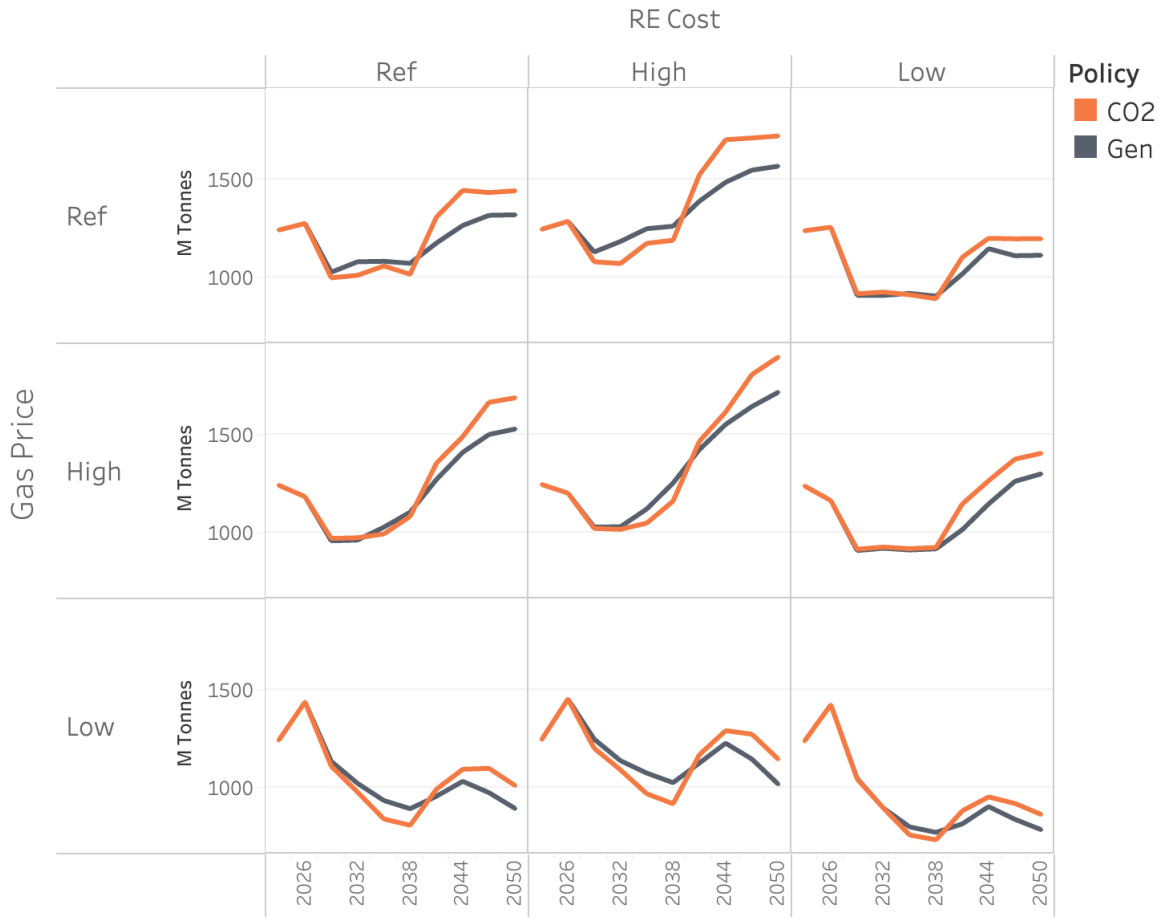


Figure 9: Power sector emissions by gas price (row), RE cost (column), and policy (color)

8. Appendix B: Acronyms

Acronym	Meaning
45Q	Section 45Q tax credit for carbon oxide sequestration
BECCS	Bioenergy with carbon capture and storage
CAA	Clean Air Act
CCS	Carbon capture and storage
CCS T&S	Carbon dioxide transport and storage
CCUS	Carbon capture, utilization, and storage
CO2_S_COM	NETL CO_2 Saline Storage Cost Model
CO2_T_COM	NETL CO_2 Transport Cost Model
CSP	Concentrated solar power
CTUS	Carbon transport, utilization, and storage
DAC	Direct air capture
Gas-CC	Combined cycle, natural-gas fired electricity generators
HOG	High oil and gas resource case (low gas price)
IRA	Inflation Reduction Act
LCOE	Levelized cost of electricity
LOG	Low oil and gas resource case (high gas price)
MW	Megawatt
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
O&G	Oil and gas
O&M	Operations and maintenance
OBBBA	One Big Beautiful Bill Act
RE	Renewable energy
ReEDS	Regional Energy Deployment System model
mmBTU	Million British thermal units

Table 5: Acronyms and their meanings