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Could Low Carbon Capacity Standards be More Cost Effective at Reducing CO_2 than Renewable Portfolio Standards?

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Abstract

We examine the implications of lowering electricity sector CO_2 emissions in PJM through a Low Carbon Capacity Standard (LCCS) instead of a renewables portfolio standard (RPS). An LCCS would create a requirement for load-serving entities to procure new low carbon capacity (GW). The LCCS would provide a greater balance of energy and capacity supply than a renewable portfolio standard, which requires only the supply of energy (and excludes non-renewable low carbon generators). Approximately 25 GW of PJM generation capacity is scheduled to retire by 2019 and the RPSs currently in place in PJM will supply only 5 GW of Equivalent Load Carrying Capability (ELLC). An LCCS, providing the same amount of low carbon energy, would supply 13 to 16 GW of ELCC. We estimate the required reduction of capacity prices required to cover the investment cost premium low carbon capacity would require from consumers. For example, if the energy from an LCCS costs on average \$20/MWh more than energy from an RPS, the annual premium would be approximately \$2.2 B. In order for consumers to be better off with an LCCS in this example, capacity prices would have to decrease by \$40/MW-day. We find that if an LCCS were adopted, coal fired power plants with carbon capture, utilization, and sequestration (CCUS) would likely have the lowest cost per MW of capacity of all low carbon technologies, based on net Cost of New Entry (CONE) estimates.

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Keywords: cost effectiveness, renewable portfolio standards, restructured markets, capacity markets, carbon capture utilization and sequestration

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1. Introduction

The U.S. Environmental Protection Agency (EPA) has begun a rulemaking process to regulate greenhouse gas emissions from existing power plants through Section 111(d) of the Clean Air Act [1]. The proposed rule would establish EPA approved State Implementation Plans (SIPS) as the default mechanism for achieving federally mandated emission reductions in the electricity sector. For many states, a renewable portfolio standard could be used as the primary policy mechanism to achieve a substantial portion of reductions in the SIP. Here, we examine the implications of lowering CO_2 emissions from the electricity sector in the PJM regional transmission organization area with a Low Carbon Capacity Standard (LCCS) instead of an RPS.

Nomenclature

CCUS	Carbon Dioxide Capture, Utilization, and Sequestration
CONE	Cost of New Entry
ELCC	Equivalent Load Carrying Capability
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
LCCS	Low Carbon Capacity Standard
LSE	Load Serving Entities
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RPS	Renewable Portfolio Standard
SIPS	State Implementation Plans

Twenty nine of the United States have an RPS; 11 out of 13 PJM member states have one[1] [2]. In a restructured utility market such as PJM, an RPS serves as a requirement levied on the load-serving entities (LSEs) to annually procure a specified quantity of energy (GWh) derived from sources defined as renewable. We propose, and here evaluate in PJM, a requirement on load-serving entities to procure new low carbon capacity (GW). The LCCS would seek to provide greater balance of energy and capacity supply than an RPS, which requires only the supply of energy.

In most areas where wholesale markets exist in the United States, market clearing prices in energy markets are currently low due to low natural gas prices and demand which is below pre-recession levels. Stakeholders maintain that these low prices do not provide enough revenue to stimulate new capacity [3]. The addition of renewables tends to reduce wholesale energy prices [4], further discouraging new capacity investments. By capacity, we mean the capacity available at times of peak load, as computed by the metric equivalent load carrying capability (ELCC) [5]. Renewables are inherently variable, and the capacity they supply is generally a significantly smaller fraction of their nameplate capacity than for thermal plants. In PJM, the ELCC of wind is 13% [6] [7]; out of 100 MW of nameplate capacity, wind would qualify for only 13 MW of capacity. Electricity markets require a balanced supply of both services, energy and capacity, to meet demand with an acceptable loss of load probability (LOLP) [8].

In 2007, PJM introduced a capacity market known as the "Reliability Pricing Model" to drive investment in new capacity [9]. To date, prices have been moderate (~\$85/MW-day) and sufficient capacity has been supplied to the region. In 2013, the average total wholesale cost of energy in PJM was \$54/MWh [10]. The energy portion of this cost was \$39/MWh (73%) and the capacity portion was \$7/MWh (13%) [10].

Although the capacity market has been successful in meeting many of its stated objectives [9], it has been volatile; ranging from a price of \$16/MW-day to a price of \$174/MW-day [11]. The supply curve in the capacity market is quite steep, increasing by as much as \$300/MW-day over the last 10 GW offered [9]. Therefore, even a modest change in supply may cause large changes in capacity prices. For example, in the most recent PJM annual capacity auction, capacity prices doubled from \$60/MW-day to \$120/MW-day even as demand for supply decreased

[1]Of these 11, Ohio recently put a "freeze" on its RPS [40].

by 2 GW [11]. The price increase was "driven by supply-side effects" as imports and demand side management decreased 4.5 GW [11].

Prices in PJM's capacity market could rise significantly if more power plants retire or demand increases. New environmental regulations [12], post-Fukushima nuclear safety regulations [13], and low energy prices are accelerating coal and nuclear retirements [14] [15]. PJM estimates that 25 GW of coal capacity will retire between 2011 and 2019 with an additional 15 GW of capacity at risk of retirement [14]. Exelon has already suggested that they will be forced to close nuclear generators if energy and capacity prices remain low [16].

We examine the implications of lowering electricity sector CO_2 emissions in PJM through an LCCS. We quantify the energy and capacity produced by RPS requirements enacted by states within PJM and contrast against the energy and capacity produced by an LCCS. We gauge the required suppression of capacity prices necessary to cover the investment cost premium low carbon capacity would require from consumers. We also examine the competitiveness (on a per MW basis) of capacity offered for solar, wind, nuclear, natural gas, and coal with carbon capture, utilization, and sequestration (CCUS).

We find that if CCUS was on average \$20/MWh more expensive than wind on a levelized cost of electricity (LCOE) basis, an LCCS would be more cost effective for consumers if it lowered capacity market prices by just \$40/MW-day.

2. Methods

2.1. Quantity of Capacity Needed, Supplied by Standards

The collective RPS's in PJM states require 14% of generation to be supplied by renewable resources by 2026 [17]. To meet this collective RPS, approximately 105,000 GWh of renewable electricity per year are required [17]. If the renewable portfolio is filled exclusively with wind, it would require 40 GW of nameplate wind capacity assuming a capacity factor of 30% [14]. With an ELCC rating of 13%, this would generate approximately 5 GW of ELCC.

This 5 GW of ELCC created by the RPS is likely to be less than the capacity of units that are expected to be retired this decade. Between 2011 and 2019, 25 GW of capacity is scheduled to be retired in PJM, with an additional 15 GW of capacity at risk of retirement[2] [14]. Capacity could be further shortened if the modest growth in demand, 1% per year through 2030 [18], is realized.

Ideally, demand side management (DSM) would supply the shortfall. However, it appears likely that DSM supply in PJM may have reached a plateau. Offers peaked at 21 GW in 2015/2016 auction and dropped to 16 GW in the 2016/2017 auction and then to 13 GW in the most recent (2017/2018) auction [11].

In theory, PJM's capacity market is the financial mechanism that should procure the generators needed to satisfy the shortfall. However, for the capacity market to procure significant amounts of new build capacity, prices must rise substantially. PJM estimates that the gross Cost of New Entry (CONE) for a combined cycle[3] gas fired power plants is \$390/MW-day [19]. When profits from energy and ancillary service markets are taken into account, PJM estimates the net CONE to be \$335/MW-day[4] [20]. Net CONE is the net cost of capacity given the energy and ancillary service market value of the power plant. Essentially, capacity prices would have to increase to \$335/MW-day to incent new (gas) power plants. Historically, capacity prices have averaged ~\$85/MW-day [11].

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[2] The average capacity-weighted forced outage rate (FOR) of steam power plants in PJM is 10% [13]. The ELCC of the coal plants scheduled for retirement or at risk of retirement would be 22.5 GW, and 13.5 GW, respectively.

[3] Brattle's CONE estimates show that combined cycle units' capital costs are now only slightly more expensive than simple cycle turbines. Because of the small difference in capital costs and the revealed preference of developers to build combined cycle units [10], we focus this research on NGCC's as the default option for new generators.

[4] Energy and Ancillary Services (E&AS) estimates are based on the performance of generators for the three previous years. For the 2017/2018 auction, the years of 2011 through 2013 were used to estimate E&AS revenue [13].

If capacity prices increase from ~$85/MW-day to $335/MW-day to incent new capacity, the costs to consumers will increase by approximately $15B. This would amount to an increase of $20 per MWh delivered in the PJM region, or about a 40% increase in the total wholesale cost per MWh delivered.

2.2. Quantifying the Costs and Required Capacity Benefits of an LCCS

If generators that ran at a constant output (nuclear for example), were exclusively used to fulfill the RPS, approximately 13 GW of capacity would be supplied in addition to 105,000 GWh of carbon free electricity per year (assumed capacity factor of 90%). However, coal fired power plants with CCUS theoretically have the ability to temporarily boost output by shutting down the sequestration process [21]. This would boost peak electrical output by approximately 25% [22]. If the RPS was filled exclusively with CCUS plants, then the capacity delivered could be as high as 16 GW[5].

Estimating how this capacity supply would affect capacity markets is not straightforward. Capacity market models do not exhibit a high degree of accuracy because the market is so volatile. Instead of modeling the market, we estimate how much prices in capacity markets must decrease in order to make up for the premium paid for low carbon capacity. In Table 1 below, we show an example for quantifying the premium paid for low carbon capacity.

Table 1: Example for Costs and Capacity Supplied by RPS and LCCS

	RPS	LCCS
LCOE [$/MWh]	100	120
Energy Supplied [GWh]	105,000	105,000
Cost for Energy [2012 USD]	$ 10.5 B	$ 12.6 B
ELCC Supplied [GW]	5	13 - 16

Note: We assume the cost of wind is $100/MWh including variability and transmission costs. We assumed a cost of $120/MWh for the cost of the new low carbon source. The ELCC supplied from the low carbon source varies because of the ability of CCUS plants to temporarily pause the sequestration process and boost output. ELCC supply of the RPS was calculated assuming a 13% ELCC.

Using the assumptions in Table 1, the LCCS would cost approximately $2.1 B more but supply approximately 8 to 11 more GW of capacity than an RPS. Figure 1 below shows the supply and demand curves for the 2014/2015 auction year. To save consumers the $2.2 B from our example in Figure 1, the extra capacity supply would have to drive down capacity prices by $40/MW-day (assume 165 GW of capacity demand).

[5] Coal plants with post-combustion capture typically are designed to capture 90% of the emissions from the plant. In this research we neglect these emissions noting that the variability of wind power plants decreases the amount of carbon emissions off-set as well [41][42][43].

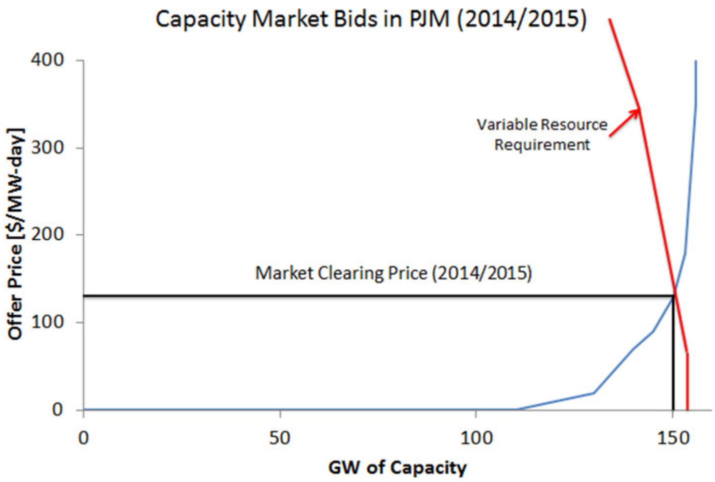

Figure 1. Supply and demand of capacity in the 2014/2015 PJM capacity auction. The Variable Resource Requirement is the downward sloping demand curve constructed by B. Hobbs [23]. The VRR is designed to reduce the volatility of capacity markets.

The costs in Table 1 above are just an example. As described well in the literature, the LCOE of renewables is dependent on the values of the analyst [24]. This is particularly true for nuclear, where LCOE is largely a function of capital cost, years needed for construction, and the discount rate assumed [25]. CCUS costs are uncertain because the first large scale plants are just now under construction [26].

Because the LCOE of low carbon energy is uncertain, we present our results as a function of the difference between and LCCS and RPS. For example, if energy from the low carbon capacity source is $20/MWh more expensive than energy from wind, how much would capacity prices have to decrease in order for technology agnostic, cost minimizing consumers to be indifferent between the two policy scenarios?

In Figure 2 below, we show how much capacity prices must decrease in order to make up for the premium paid for low carbon capacity. We assume that the cost seen by consumers for either renewables or low carbon capacity would be equivalent to the LCOE. Table 1 above is an example of these quantifications.

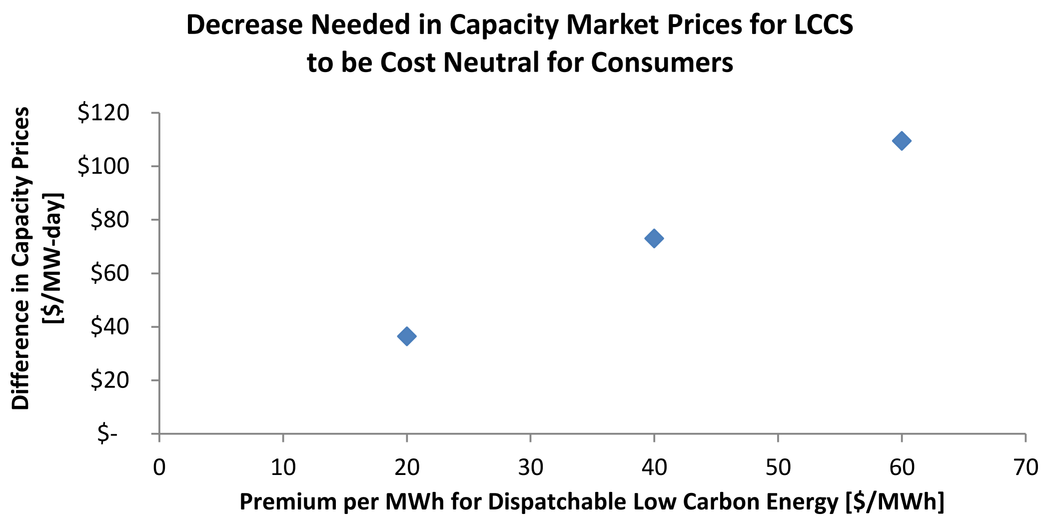

Figure 2: Savings in capacity prices that must be realized in order for consumer costs to be unaffected. An LCCS that provides the same amount of energy as the RPSs required in PJM would decrease capacity prices by supplying ≥10 GW more capacity than an RPS.

2.3. Ensuring that Low Carbon Energy is Supplied in Addition to Capacity with an LCCS

When comparing the costs of policies, we assumed that the cost of energy to consumers of both renewable energy and dispatchable energy would be equal to the LCOE. Furthermore, we assumed that power plants would be dispatched according to their technological capability (i.e. dispatchable plants would achieve a capacity factor of ~90%). In this section, we describe how low carbon capacity might be procured with an LCCS and the implied risks for the energy generated.

Typically with an RPS in restructured markets, renewable energy is procured through renewable energy certificates (REC) [27]. The REC market fosters competition to encourage the development of the lowest cost renewable energy possible. The sum of the revenue received by developers through energy markets, subsidies, and REC's should be approximately equal to the levelized cost of the energy, in the absence of a market failure.

The market mechanism we examine to directly procure capacity for an LCCS would be a new low carbon capacity market. This market would directly procure a fixed amount of low carbon capacity very much like the capacity market currently in place in PJM except that it would be limited to new low carbon generators. This market mechanism utilizes market forces to procure the lowest cost capacity given a generator's value in energy markets.

However, an issue for this market structure that directly pays only for capacity is that additional policies are needed to ensure that the LCCS plant dispatches before carbon emitting power plants. We assume in this research a gas price of $6/MMBTU, and the relatively low marginal energy costs of the low carbon generators would assure that the generator would dispatch. However, the marginal costs of CCUS plants may be higher than some existing carbon emitting power plants because the sequestration process is inherently energy intensive. If gas prices are low (~$4/MMBTU) and EOR revenue is not available, we estimate that the CCUS plant would be dispatched rarely and have a capacity factor of only 35%.

A number of policies could be used to ensure that LCCS power plants dispatch and supply low carbon energy generation regardless of market conditions. For example, some system operators consider wind power "must run" unless the wind power needs to be curtailed for grid stability reasons [28]. Also, wind plants receive energy subsidies, such as the federal production tax credit. This effectively ensures that wind energy is dispatched, even when energy market clearing prices are (slightly) negative [28].

One potential policy mechanism for ensuring LCCS plants are dispatched is the use of contracts for differences (CfD). A contract of this sort redirects some of the financial risk for the plant owner/operator onto the state which agrees to monetarily "fill in" any disparity in the wholesale price for electricity and the marginal cost of energy supply. When the converse is true and the marginal cost of energy supply is below the market clearing price, the owner/operator is obligated to pay the difference to the state. The major benefit of this arrangement is that the plant will always be dispatched and the state bears the risk to ensure low carbon energy is supplied. The risk to the state is relatively small because the marginal costs of a CCUS plant are only slightly higher than carbon emitting power plants. We find that a small EOR payment or subsidy ($10/MWh) would place CCUS plants ahead in the dispatch stack of carbon emitting power plants.

Because several mechanisms can be used to reduce the relatively small risk that LCCS plants do not dispatch, we assumed plants dispatched according to their technical capability. Furthermore, we assumed that the cost of the LCCS energy could be approximated by the LCOE. The revenue received by LCCS generators from energy market revenues, necessary energy subsidies, and capacity payments would be approximately equal to the LCOE of the energy supplied by the LCCS.

2.4. Quantifying the Competitiveness of Low Carbon Capacity Options – Net Cost of New Entry (Net CONE)

Per current practice in PJM's capacity market, the metric we will use to evaluate the economic competitiveness of a low carbon power plant's capacity is net Cost of New Entry (net CONE) [20]. We assume that capacity would be procured through an auction where low carbon generators bid their net CONE (defined below). The net CONE is quantified by fixed costs (PJM refers to these as "avoidable costs" [14]) less profits made in energy markets [14]. We estimate the net CONE on a per MW basis using the equation below.

$$CapBid = NetCONE\left[\frac{\$}{MW_{ELCC}}\right] = \frac{\text{Present Value (Owner's Fixed Costs - Energy Market Profits)}}{\text{Present Value}(MW_{ELCC})} \quad (1)$$

Owners fixed costs are a sum of construction, accrued interest, and fixed O&M. Energy market profits are a function of revenue made in energy service markets less marginal costs (variable O&M and fuel costs). We do not take into account ancillary service market revenue. We estimate costs using the financial assumptions from Brattle for PJM's official Cost of New Entry (CONE) estimates: 8% after tax weighted average cost of capital, 20 year MACRS depreciation schedule, a federal tax rate of 35%, and a state tax rate of 10% [19].

To estimate how generators would profit in energy markets, we used an hourly economic dispatch model of the generators in PJM. Marginal power plant costs (fuel and variable O&M) and carbon intensities for each region were obtained from Ventyx Velocity Suite. The dispatch model calculates marginal costs for all generators, then dispatches the least expensive generators to meet load. The dispatch model does not take into account transmission, thermal, and security constraints.

Because we are examining a plausible near future, we removed 18 GW of coal capacity from the dispatch stack. To decide which generators to remove, we relied on the PJM 40/400 rule for the power plants most at risk of retirement (over 40 years old and small than 400 MW) [12]. More information on the dispatch model for PJM is given in the previous chapter.

2.5. Assumptions for New Power Plants

Table 2 below shows our assumptions for estimating the owner's fixed costs and profits made in energy markets. The assumptions are based on the most recent data available from literature cited in the table below. Like all economic analyses, the preferences of the analyst can lead to a wide range of results [24]. Our goal is to quantify (to first order) the net cost of capacity given the market value of the energy contribution for competing technologies.

The assumptions have a mix of point estimates and a range estimates. We varied the parameter(s) which had the greatest effect on their cost per MW of capacity offered. The price of natural gas alone can dominate energy profit estimates because it sets market clearing prices in energy markets. However, we did not vary the price of gas because higher or lower market clearing prices would help or hurt all of the technologies studied. We assumed the price of natural gas was fixed at \$6/MMBTU, the EIA estimate for 2020 [29]. Of course, natural gas plants would be greatly affected by variation in natural gas prices. However, we do not show results sensitive to natural gas because it known that gas plants have the lowest cost of new entry. We show NGCC plants here for reference.

For renewables, a wide range of ELCC can be assumed. In some regions with low penetration, the ELCC of wind can be approximated by its capacity factor [5]. However, wind does not correlate well with load in the USA, and wind in PJM had an ELCC rating of 13%. We assumed a fixed cost for the capital costs of renewables because the ELCC rating has the most pronounced effect.

For CCUS, there are multiple uncertain assumptions. Capital costs are currently unknown because the first large scale plants are now under construction [26]. Our assumptions are based on estimates from the literature [30], but these are for n^{th} of a kind plants. Early examples of new pollutant control technologies tend to increase in cost after the first of a kind [31] before asymptotically approaching the n^{th} of a kind cost. Given the uncertain price of oil, it is also unknown how much revenue should be assumed for enhanced oil recovery. A rule of thumb is that the price of each MCF of CO_2 is around 2-3% of the price of a barrel oil [32] which equates to ~\$35/tonne at \$95/barrel. We assume a range from \$0 to \$60/t CO_2. We discuss the overall net emissions from CCUS after we present the results for net CONE.

Table 2: Assumptions used for (\$2012 USD)

	NGCC [20]	Wind [33]	Solar PV [34]	Nuclear [25]	Coal with CCUS [35] [36]
Capital Costs $/kW$_{Nameplate}$	1,200	1,940	3,000	5,500 – 8,500	3,600-5,500
Fixed Maintenance Costs ($/kW-year)	17	25	17	60	100
Fuel Costs ($/MWh)	40	0	0	7	27
Total Marginal Costs ($/MWh)	43	0	0	7	-25 - 30*
Financial Lifetime of Plant (Years)	20	20	20	30	30
Construction Time (Years)	3	2	2	7	4
ELCC*	.95	0.13 – .25	0.38	.975	.9 – 1.1
Energy Market Profits ($/kW-year)	$15	$108	$82	$245	$67 - $500*

Notes: *Marginal costs and energy market profits from CCUS plants vary with EOR payments. Without EOR revenue, marginal cost of CCUS would be approximately \$30/MWh. We varied EOR payments from 0 to \$60/tCO_2, which would allow CCUS plants to have a marginal cost as low as -\$25/MWh. This would substantially increase energy market profits as shown in the table. ELCC estimates were estimated.

Below in Figure 3, we show the net CONE of various low carbon technologies according to the assumptions from Table 2.

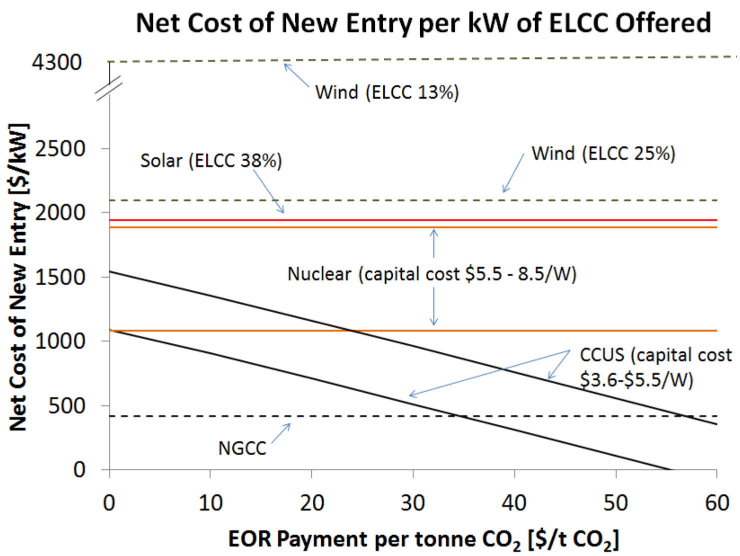

Figure 3: Net CONE of various low carbon technologies as a function of EOR revenue.

Figure 3 shows that CCUS is likely to be the most competitive technology given our assumptions. Costs of renewables are dominated by the assumed ELCC. It should be noted that ELCC of wind and solar diminishes with increasing penetrations [37].

2.6. Note on Emissions from Coal Plants with CCUS

In the analysis above, we assumed an LCCS could achieve the same emissions reductions as an RPS because eligible plants would generate substantial amounts low carbon electricity. An issue for CCUS as a carbon mitigation strategy is that CO_2-flood EOR may have greater net emissions than other low carbon power plants because it increases the overall oil supply [38]. Here, we do not account for the emissions produced by combusting the oil because we are exploring this policy as a means to meet EPA mandated emission reductions for the power sector, comparing an RPS to an LCCS. Section 111(d) regulates power plant emissions, and we assume that emissions reductions from the transportation sector are achieved through other regulations, such as Corporate Average Fuel Economy (CAFE) standards. Current U.S. policy of emissions accounting is not based on where carbon is supplied but where it is combusted [39]. Therefore, we assumed that CCUS is an eligible technology to help fulfill SIPS even though its impact on overall emissions is unclear.

3. Discussion

We examined the implications of lowering the CO_2 emissions in PJM with a Low Carbon Capacity Standard (LCCS) instead of an RPS. An LCCS requires LSE's to procure a certain amount of low carbon capacity as a means to ensure that both capacity and low carbon energy is supplied. We examined this policy as an alternative to an RPS that does not supply capacity that is commensurate with the amount of energy supplied.

We quantified the amount of capacity supplied by the RPSs in PJM and showed that capacity could become undersupplied before 2020. 25 GW of capacity are scheduled to retire by 2019 and we estimated that the RPS will supply only 5 GW of capacity. An RPS would not necessarily cause an increase in capacity prices to net CONE, but it would increase the likelihood of capacity market clearing price increases by way of undercutting profits in energy markets while supplying little capacity. If new generators are needed to supply capacity, capacity market prices will likely rise from current prices, ~$85/MW-day, to PJM's projection of net CONE, $335/MW-day. We estimate that raising capacity prices to this level would cost consumers $15 B annually and raise the wholesale cost of electricity in PJM by 40%.

An LCCS would lower dependence on capacity markets by requiring LSE's to procure capacity through "self-supply" [14]. However, energy from CCUS and nuclear plants is at present higher cost than from wind generators. We quantified the cost differences between the policies, by estimating the LCOE. If the energy from an LCCS costs on average $20/MWh more than energy from an RPS, then the annual premium would be approximately $2.2 B. In order for consumers to be better off with an LCCS in this example, capacity prices would have to decrease by $40/MW-day. The LCCS could reduce capacity prices by supplying at least ~10 GW more capacity than an RPS. Given the steepness of the supply curve for capacity, it is reasonably likely that 10 GW of capacity would lower capacity prices an appreciable amount. The supply curve for capacity in PJM typically increases by over $300/MW-day over the last 10 GW of capacity offered [9].

We then showed that if an LCCS were enacted, CCUS plants would likely have the lowest cost per MW of capacity based on net CONE estimates, if the revenue from EOR exceeds $30-45/ton of CO2. Despite uncertainty in EOR revenue, our analysis shows CCUS to be strictly dominant compared to solar and wind on both a gross and net CONE basis across the range of capital cost and EOR revenue assumptions. Net CONE estimates for CCUS were lower than for nuclear in all but those scenarios with high CCUS capital expense and low EOR revenues, and were cost-competitive with NGCC under the most favorable ($3600/kW and EOR credit >$35/t) scenarios examined.

The ability to switch off carbon capture for purposes of temporarily increasing capacity is a topic which requires further analysis to properly evaluate cost effectiveness. However, our first order analysis indicates that this ability reduces net CONE by roughly $300-400/MW-day for CCUS facilities. We also acknowledge that there are complex market dynamics of implementing a LCCS over an RPS, or vice versa, which are beyond the scope of our analysis.

Our purpose has been to highlight the potential system costs (energy and capacity) of implementing an LCCS instead of an RPS in the PJM market. We have shown that net CONE (a metric that includes the value of capacity) is more useful in evaluating the all-in system costs of policies than LCOE. We have noted throughout this work that the assumptions and values of the analyst can heavily influence the outcome of any cost estimate. However, this work suggests that, at a minimum, the costs of supplying adequate capacity to ensure acceptable loss of load should be accounted when analyzing alternative emission reduction scenarios and that the use of more comprehensive metrics such as net CONE should be preferred where data are available.

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Disclaimer

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