What does carbon pricing mean for electricity markets?

Research Question

What are the technical challenges that arise from integrating carbon pricing into wholesale electricity markets and what are current approaches to integrate them in the U.S.?

Key Points

- Carbon pricing is an efficient way to to reduce emissions in a technology neutral way; however, there are implementation issues, including coordination with other policies.
- Carbon pricing may not lower emissions within a region if some states or areas do not participate.
- Contract shuffling and leakage are complications that can impact the efficacy of a carbon price.
- While no ISO or RTO market has yet implemented a carbon tax, some have integrated cap-and-trade market prices. There are many proposed methods to manage electricity imports and exports and emission leakage.
- Implementations of a carbon price should consider other carbon programs in the same region to appropriately value carbon.

The carbon pricing landscape

Electricity markets have decades of experience with pricing environmental emissions, as SO2 and NOx emissions markets existed when many of the regional markets in the U.S. were created. After a period of time around 2010 when it appeared that carbon pricing would be the central approach in Federal efforts to reduce electric sector carbon emissions and a period thereafter when it appeared to be a non-starter, discussions of carbon pricing have re-emerged as states are beginning to turn to carbon pricing to implement reduction strategies.

Assigning a price to carbon usually falls into two general categories: a carbon tax and cap-and-trade programs.

- Carbon tax: A price on the amount of carbon emitted, usually in $/ton of carbon or greenhouse gas emissions. The tax rate is generally set to a politically acceptable rate, or could be set at a rate that balances marginal emissions reduction benefits and costs, or at a rate that attempts to internalize the external/societal costs of emissions in a specific market.
- Cap-and-trade: A program that limits the total quantity of carbon emissions through a cap and issues allowances that can be traded. In this case, the quantity of emissions is constant and an implicit price is creates that varies depending on the difficulty of achieving the cap, with caps commonly tightening (shrinking) over time.

There is extensive literature on both policies (see Additional Reading), and implementation requires detailed plans to define the participants and to assess the potential impacts on society. As of 2021, there is no US federal or state policy that requires the use of a carbon tax in an electricity market, although New York has developed extensive plans for possibly implementing a modified social cost of carbon in electric sector generation dispatch decision making (see the next section).

There are two major cap-and-trade programs in the U.S. today that impact wholesale electricity markets: the California Air Resource Board (CARB)[1] program and the Regional Greenhouse Gas Initiative[2] (RGGI,

[1] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program

[2] https://www.rggi.org/

pronounced Reggie), see Figure 1 and 2. The CARB program began auctions in 2012, with goals set initially by CA Assembly Bill 32 to bring emissions down to 1990 levels by 2020 (achieved) and down to 80% below 1990 by 2050. Since inception, $12.5 billion has been raised through the auction of permits to fund California's Greenhouse Gas Reduction Fund. The most recent auction settlement price in August 2021 was $23.30. On the east coast, RGGI covers electric sector emissions in 10 states and began auctions in 2009. The auction price was most recently $9.30 in September 2021, and the total funds raised through the auction to support state consumer benefit programs is $4.35 billion. While the RGGI footprint overlaps with existing markets, the CARB program has an explicit import provision, extending its reach beyond California's borders. This impacts CAISO's regional Energy Imbalance market, a real-time wholesale market for energy in California, that includes 10 neighboring utilities in other states.

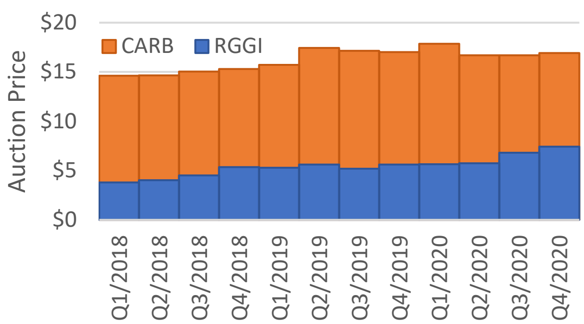

Figure 1: CARB and RGGI Auction prices 2018-2020

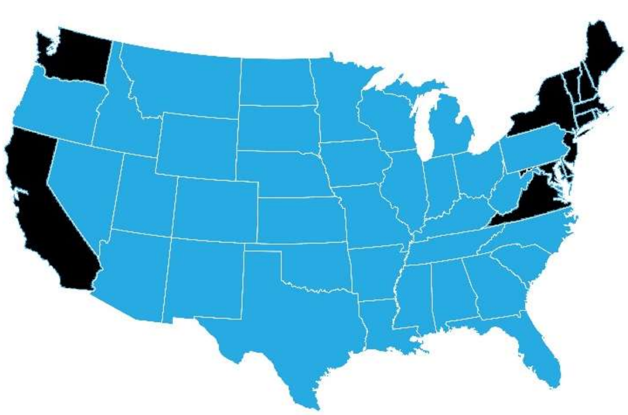

Figure 2: Map of U.S. states with cap-and-trade polices

In addition to specific programs that price carbon, there are many other policies that encourage investment in zero-carbon resources through different mechanisms. The policies vary in efficacy, duration, incentive structure, and geographic scope, and there will likely be new or modified policies in the future. These include renewable portfolio standards, production tax credits for specific technologies, state subsidies, and zero-emissions credits. While these policies have similar goals, the incentives differ. The carbon pricing programs directly cap or tax the amount of carbon emissions that are expelled. The other policies mentioned provide incentives for low or zero-carbon investments or continued operation of low-carbon assets, but are often not agnostic to the technology or do much to influence the emissions of the existing fleet. Further information can be found in the Additional Reading section.

Continuing conversations on carbon pricing have also been sparked by FERC, who held a technical conference on carbon pricing in fall 2020 seeking comment on policy, jurisdictional, and technical questions. The conference was followed by a policy statement welcoming ISOs and RTOs to submit proposals for implementing a carbon pricing design in their region, implying that FERC would have jurisdiction to rule on an ISO/RTO proposal if it came to them. Presenters offered a number of views concerning the technical aspects of carbon pricing, including the following bullet points:

- There is not likely to be a uniform carbon policy that fits every market region. Each region has a unique market design and generation characteristics that make the creation of a single carbon pricing design difficult.
- There are few changes needed to implement a basic carbon price in electricity markets today. Several markets already incorporate cap-and-trade policies through changes to a generator's variable cost offers. Challenges arise when there are different methods of implementation across regions.
- Different carbon prices or policies in states

within an ISO (or imbalance market) would cause challenges and could potentially increase operating costs or emissions.

- Incentives for investments in new resource might not be as strong in some regions where new resource entry is primarily determined by state-administrated utility planning and existing subsidies exist.

How can a carbon price be implemented in electricity markets?

Once a social cost of carbon is determined, whether through a cap-and-trade program or a tax, this value can be incorporated into electricity markets. For example from a technical perspective, if a federal cost for carbon were implemented that would create a price for all carbon emissions from power plants across the U.S., the challenges in including this value in markets would be minimal. Decisions about the value, point of collection, use of collected revenues, and logistics would take agreement, but technical implementation is more widely agreed upon among academics and researchers. This design would be ideal and the likely most efficient and less complex implementation. However, without a federal price assigned to carbon, any implementation will be more challenging (and second-best) and require modifications to ensure it does not place undue burden on any one participant. Several ISOs/RTOs have already investigated these implementations and had to address the technical challenges, discussed in the next section.

Implementing a value in electricity markets generally follows several broad steps, described below and shown in Figure 3.

Offer modification: Emitting resources will either have to relinquish emission allowances or pay a tax to be allowed to generate. This price can be used to modify supply offers into the day-ahead and real-time markets. If the value is initially determined in $/MMBTU, a conversion can be made based on the heat rate of the plant to create a $/MWh cost to be added to the resources variable cost offer. Most markets allow participants to offer a piecewise linear energy cost offer with multiple steps to approximate a quadratic, non-linear incremental heat rate curve.

Changing supply curve: Once emitting resources have modified offers in the market, the supply curve will change. Emitting resources will move further up the supply curve appearing more costly to the market operator. The greater the emissions from a plant, the higher the cost adder, the higher up the curve the resource will appear. When the market clears supply and demand, the marginal resource might either

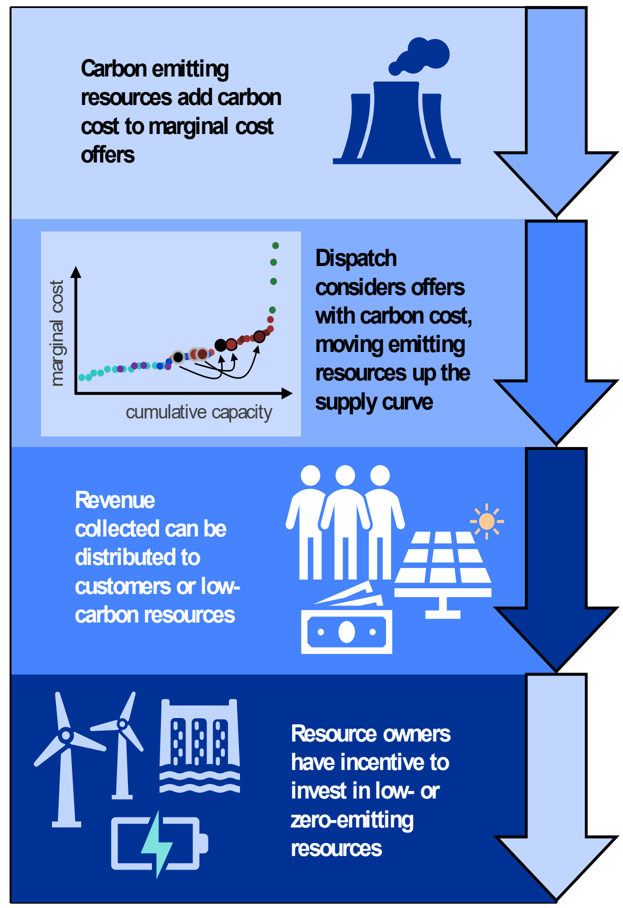

Figure 3: Process of incorporating a carbon price in electricity markets

become a lower-emitting resource than it would otherwise be without carbon pricing, or the price might be higher reflecting the new offer of emitting resources. This will depend on the resource mix in each region, the carbon price, locational impacts, and other characteristics. All cleared generation will receive the potentially higher price, including non-emitting resources. Emitting resources would then pay a carbon charge for their emissions, collected by the operator or some other entity such as state organizations.

Revenue collection and allocation: The additional costs from the modified offers will likely change the clearing prices of electricity, which will now charge demand for carbon emissions. The revenue collected can be used in several ways depending on the type of carbon price implemented. A state can set up a fund to further incentivize research or investment in low carbon resources, or redistribute some of the revenue back to customers to offset the increased prices they need to pay. States can also set up programs to incentivize customers to reduce energy use, such as energy efficiency programs.

Resulting market incentives: Once a carbon price has been incorporated into wholesale markets, existing and potential market participants see a new incentive to invest in low carbon-emitting resources. With no or low carbon adders, a resource will be more competitive in the market and earn more revenue from higher energy rents. However, there can also be unintended consequences that need to be considered, as discussed in the next section.

Technical challenges and regional implementations

Several major challenges accompany carbon pricing in electricity markets including but not limited to: contract shuffling and leakage, multi-state implementations, and counting carbon multiple times. This section will explain these challenges while describing how some markets have implemented or proposed to implement carbon pricing and efforts to address these challenges.

Contract shuffling and leakage

When a state within a region unilaterally implements a restriction on carbon emissions, but surrounding states do not, the carbon implications of electricity trade between states become important. For example, if a load serving entity in Region A had a bilateral contract with a coal plant in Region C, it might opt to buy power from a hydro facility in Region B instead. The entity in Region A would then be reducing emissions of purchased power. Load in Region B that previously got power from this hydro facility now needs a new generation source, which can be fulfilled by the coal plant in Region C since neither region has a cap on emissions. This process of shifting contracts to support the carbon goals of the state with a restriction on carbon is referred to as contract shuffling, see in Figure 4. Some instances can

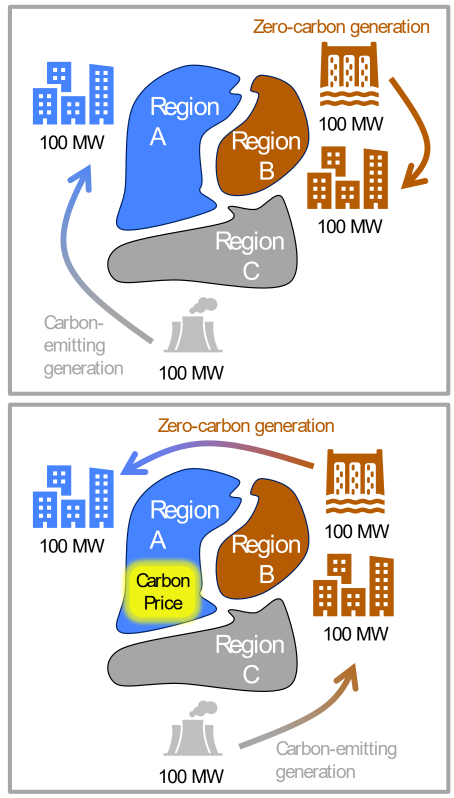

Figure 4: Simplistic representation of contract shuffling

result in maintaining emissions in an area, but this shift does not always have negative implications.. In some instances, contract shuffling can lower overall emissions even though a higher emitting plant is still generating power.

Leakage is a term used to describe the shift in carbon emissions from the area pricing carbon to its neighbors, leading to a reduction in the state with a carbon policy, but a corresponding increase in emissions in states without carbon policy. A different simple example can be seen in Figure 54. Region A implemented a carbon price on generators within its footprint, whereas Region B has no price on emissions. Without a carbon price, emissions across all regions total 9600 tons. If the generator in Region A adds a $4/MWh carbon cost to its variable cost offer, Region A would then import more energy from the cheaper generator in Region B. Emissions in Region A reduce by 2000 tons, and total emissions reduce to 9400 tons. However, some emissions have "leaked" out, since Region B's emissions have increased by 1800 tons. In this simple example, total emissions decreased. However, there can be cases where total emissions in the combined regions increase. Detailed studies on leakage have been performed for many regions throughout the U.S. The study found positive leakage (i.e., reduced net emissions reductions) in scenarios with higher carbon prices; see Additional Reading, Bisline and Rose, 2018, for further information.

California ISO (CAISO), New York ISO (NYISO), and PJM have considered these challenges in their carbon pricing proposals, described in the following section.

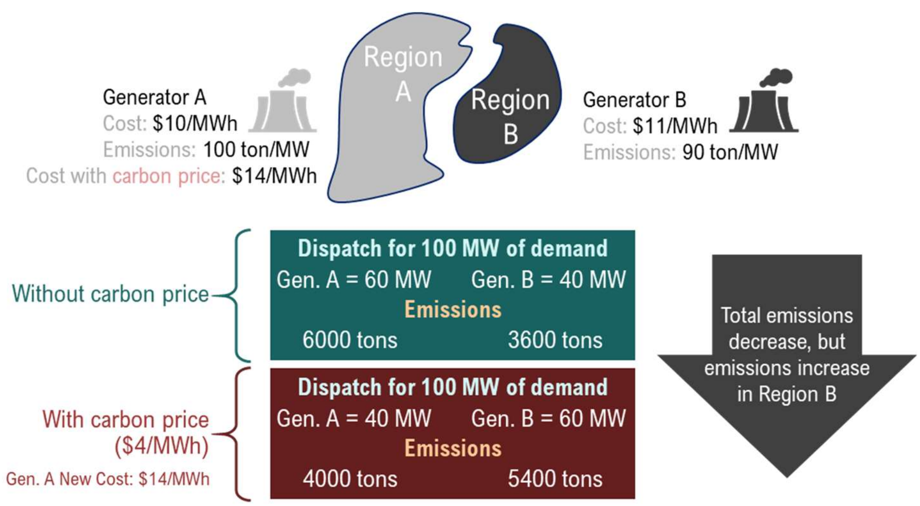

Figure 5: Simplistic representation of carbon leakage

Multi-state and single-state implementations

Carbon pricing causes challenges at the seams, where a region pricing carbon meets a region that does not price carbon. This can be an issue for a single-state market when interacting with neighbors and a multi-state market where some states have implemented a price on carbon and others have not. The use of broder adjustments in the market can be used to manage leakeage, but can also impact dispatch and regional emissions. For those markets that have implemented or studied carbon pricing, all have made decisions on how to handle imports, exports, and intraregional flow.

CAISO is a single state ISO but operates a real-time Energy Imbalance Market (EIM) with utilities in many neighboring states. Since California has a cap-and-trade system, all generators within the state must account for emissions value in their bids. To sell power for consumption within California, out-of-state resources must account for emissions and include a greenhouse gas adder on their bids. Several challenges arise, including how to account for imported emissions when a single source is not apparent. Another challenge arises for prices and dispatch within the EIM region but outside of California because those prices and dispatch should not reflect additional costs imposed by California's regulations. To manage this, CAISO developed several proposals and ultimately decided on a single-pass optimization that considers the greenhouse gas adder for imports to California but not for dispatch outside the state. To reduce the chance of leakage, CAISO caps the MW quantity bid to serve California load to the unit's maximum operating limit less the basepoint dispatch for the unit. If the EIM were to extend to the day-ahead market, this process would require adjustment since previous basepoints might not be available.

NYISO is also a single state ISO where imports and exports needed to be managed under the proposed carbon price administered by New York State. To avoid leakage, they propose that imports earn the border price without the carbon adder (this component is called the LBMPc in NYISO), and exports would sell energy outside the state without the carbon price added. This would maintain a status quo for imports and exports, maintaining the current practice. While this method is simple to implement, it does not allow for incentives to reduce emissions outside the state. However. This may not be a significant shortcoming; studies performed[3]did not show significant opportunity for alternative methods to decrease emissions outside New York.

Lastly, PJM conducted a series of carbon pricing studies to examine possible methodologies if states opted to implement a carbon price beyond RGGI. Since not all states within the PJM footprint might implement a price, intra-ISO but inter-state energy exchange posed a challenge. The different studies suggested methods to handle leakage: regional carbon pricing, one- or two-way state border adjustments, modifying allowance caps from RGGI using imported emissions, and incentivizing energy efficiency and in-state generation through allocation of RGGI allowances and revenue investments. NYISO and CAISO use versions of one- and two-way border adjustments, referring to modifications to imports and exports. Since no carbon pricing proposal has been approved in PJM states (other than RGGI), no changes to existing practices have been implemented.

Multiple pricing of carbon emissions

A critical issue for potential electricity pricing of carbon emissions is whether the carbon has already been priced—was it priced explicitly or implicitly? With many greenhouse gas emissions reduction policies and incentives being considered and implemented across state and federal agencies and jurisdictions, including state utility regulators, there is the potential for pricing the same molecule of carbon more than once. Pricing the carbon multiple times is costly for society. EPRI's research has highlighted that multiple policies pricing the same emissions raises the societal costs of reducing emissions without additional emissions reduction benefits, see Figure 6. While this research was in the context of using the social cost of carbon and other greenhouse gases, it is a general issue. Multiple pricing is already occuring with the same carbon being priced (or proposed to be priced) in, for example, mineral extraction, emissions caps, clean energy standards, social cost of carbon externalities pricing, and implicitly via technology standards and subsidies. This carbon pricing overlap is occurring across federal policies, state policies, and across jurisdicational levels (federal, state, and local). Pricing carbon in ISO/RTO electricity markets where generators already face these explicit or implicit carbon prices would be pricing the carbon yet again and increasing the cost of compliance without

[3] S. Newell, B. Tsuchida, M. Hagerty, R. Lueken, and T. Lee, "Revenue Allocation and Seams Options," Brattle Group report for NYISO IPPTF Stakeholders, 2018, https://www.nyiso.com/documents/20142/2625121/2018_09_20%20Zonal%20and%20Seams%20Issues.pdf/17f965c7-bcda-3b9f-9b1e-19958d2c6574.

emissions reduction benefits, which is still true even if the market operator adjusts the carbon price to account for other emissions policies (e.g., see proposal for NYISO).

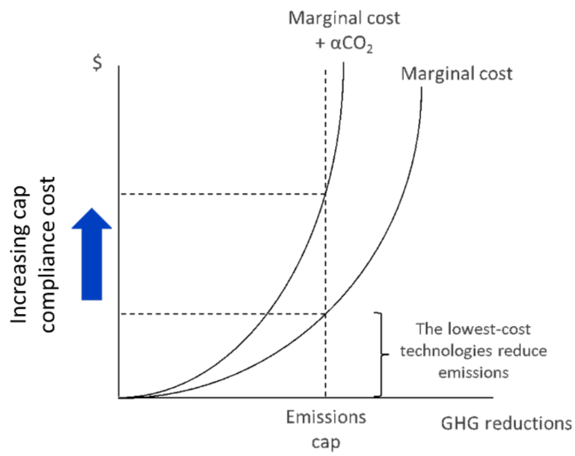

Figure 6: Example graph demonstrating that valuing CO_2 more than once, in this case pricing CO_2 ($\alpha > 0$) on top of an emissions cap, is economically inefficient, increasing compliance cost without emissions reduction benefits (Source: EPRI Report ID 3002020523)

Conclusion

Integrating carbon pricing in electricity markets can be complex due to the regulatory, legal, and implementation challenges that exist within the US. While implementation of a Federal carbon price within an existing ISO market would not be difficult and require only minor adjustments to existing software, many challenges arise when states have differing carbon policies and trade electricity within an existing ISO or imbalance market. Additional challenges arise when attempting to account for regional emissions; both contract shuffling and leakage can create complex accounting rules and affect net emissions reductions, as well as affordability. Lastly, the economic efficiency of a carbon price within the electricity market is dependent upon other policies that may already be pricing the carbon. Adding a carbon price to electricity markets could be an effective means to price and reduce carbon emissions in a technology-neutral way that incentivizes innovation; however, if other emissions reduction policies are in place or forthcoming, such as clean energy standards, renewable portfolio standards, or emissions cap-and-trade programs, a carbon price on electricity could be ineffective—increasing emissions reduction costs without reduction benefits.

Related EPRI Work

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Carbon Price Impacts on Electricity Prices. EPRI, Palo Alto, CA: 2020. 3002019005.

How does a carbon price impact electricity prices? Program 201 Back Pocket Insights. EPRI, Palo Alto: CA 2021.

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Additional Reading

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NREL, “Renewable Portfolio Standards,” https://www.nrel.gov/state-local-tribal/basics-portfolio-standards.html

NYISO, “Carbon Pricing,” https://www.nyiso.com/carbonpricing; specifically two reports: (1) S. Tierney and P. Hibbard, “Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO’s Wholesale Electricity Markets,” Oct. 2019 and (2) S.A. Newell, R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee, “Pricing Carbon into NYISO’s Wholesale Energy Market to Support New York’s Decarbonization Goals,” 2017.

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