State of Oregon Department of Environmental Quality

Written Comments

Greenhouse Gas Emissions Program 2021 Rulemaking: Advisory Committee Meeting 3 Held March 18, 2021

This document is a compilation of written comments received related to the third meeting of the advisory committee for the Greenhouse Gas Emissions Program 2021 Rulemaking to develop a new Climate Protection Program. Comments related to this meeting received after the cutoff will be included with comments from the next advisory committee meeting.

Comments

DEQ RAC 3 Comments for Cap and Reduce

Date February 20, 2021

By: Diane Hodiak, 350Deschutes, dhodiak@350deschutes.org, 206-498-5887

Guidance for these comments, in some cases, has been taken from the ***EPA Tools of the Trade, A Guide to Designing and Implementing Cap and Trade Program for Pollution Control, 2003***

Thank you *for the opportunity to provide these comments. I remain concerned about the exemptions given to Oregon's top polluters and the message this gives to other polluters in terms of fairness, as well as the weakening of the ability to reach science based emission reductions.*

In addition to a weak cap and reduce, I do not believe that DEQ has adequately accounted for the additional emissions that will be generated from electricity. Your estimates are inconsistent with PGE and PacPower projections.

ACI

No ACI should be allowed to fossil fuel plants and electricity generation until they have made significant reductions in criterion pollutants. (NOX, CO2, Sulphur Dioxide, Lead, Methane) Research has shown that communities as far away as 200 miles can experience health issues. (Study of coal generation at 4 corners, CO, NM, AZ) Any ACI should prioritize deployment in communities closest to source of pollution. The EPA has a methane reduction program and BACT, Best Available Control Technology. Purveyors of Natural Gas have many options to clean up methane emissions. Being under the cap would encourage this rather than give them permission to pollute.

- Make sure that if allowance is given, that it has proof of full operation for the time period given and that it meets the recommended requirements: (I believe you are hiring someone for this work?)
- Real: **offsets** must represent real emission reductions that are:
- Additional:
- Permanent:

- Verifiable:
- Quantifiable

Allowances must have value, care must be taken to price them accordingly and issue them in a way that supports upholding their value. Handing them out to everyone early on does not do that. Reserve some of these "carrots" to use when you need to incentivize a polluter.

There should be a lot of entities under the cap. This creates more allowances and increases options for trading, thereby strengthening the program and giving polluters more flexibility.

Every Polluter Possible Should be Under the Cap With Stopgaps to Prevent Gaming of the System.

DEQ could design an "easy exemption form" for polluters with smaller, less regular emissions. This could be similar to the IRS tax forms for individuals and businesses. Entities could opt in if they felt they would receive better treatment with a simplified reporting form.

Businesses will find gaps, and guide fuels to "exempt" entities, thereby gaming the system.

Those what wish to be qualified as EITE should not receive an exemption, but an allowance up to a certain limit ……but not until they have proven they actually incurred additional cost. This is how Massachusetts regulates its electricity sector.

Enforcement

Must have strict guidelines for how emissions will be counted. Will it include lifecycle analysis, combustion, transport, storage, and more? This is the preferred system

There should be consistency and transparency. Certain polluters should not receive preferential treatment, as is proposed now with exemption of aircraft and fossil fuel and electricity generation plants.

There must be a clear, enforceable mechanism for penalties such as misrepresentation of emissions.

Measurement mechanisms must be consistent and accurate, so that parties feel there is fairness in establishing a baseline, in system implementation and in allowance pricing.

Determining the threshold. Close to zero This treats nearly everyone the same.

A set price on carbon/ghg emissions is often requested by fuel entities who request certainty that they can count on. Including everyone at a zero threshold provides that certainty.

AWEC
ALLIANCE OF WESTERN ENERGY CONSUMERS

MEMORANDUM

To: Richard Whitman, Director, Oregon Department of Environmental Quality

From: Alliance of Western Energy Consumers

Edward Finklea Natural Gas Director

Date: March 26, 2021

Re: Feedback on Oregon Climate Protection Rulemaking Advisory Committee Meeting 3

Thank you for the opportunity to provide written feedback to the questions posed by the Oregon Department of Environmental Quality ("DEQ") at the third meeting of the Oregon Climate Protection Program: Rulemaking Advisory Committee. The Alliance of Western Energy Consumers (AWEC) is a non-profit association of more than forty businesses that consume electricity and natural gas in the States of Oregon, Washington and Idaho. As we noted in our January 21, and February 26, 2021 comments, AWEC brings to this proceeding the concerns of natural gas consumers, especially Energy Intensive, Trade Exposed Entities (EITEs), for whom most have no alternative to using natural gas in their manufacturing processes and still make products in Oregon that can be sold into competitive markets.

AWEC is very concerned with the direction of the agency's efforts to design a cap and reduce rule that appears to put severe limitation on the use of alternative compliance instruments. Options for reducing the use of natural gas for many of Oregon's industrial and commercial firms are limited. If Oregon is going to impose caps on natural gas emissions through this rule covered industrial and commercial entities will need the flexibility to access domestic and global supplies of affordable compliance instruments. A greenhouse gas (GHG) emission anywhere in the world has the same impact on Oregon as a greenhouse gas emission from an in-state source. Oregon is proposing to embark on a greenhouse gas emission reduction effort knowing that the only way to effectively mitigate the impacts of climate change is for every US State and every other country to join Oregon in regulating GHG emissions and requiring the same levels of reductions as being proposed by the agency.

If Oregon natural gas consumers are going to be covered under Oregon's cap and reduce rule, those consumers must be afforded access to domestic and global GHG emissions reduction instruments, including allowances from the Western Climate Initiative, the Regional Greenhouse Gas Initiative and offsets from the voluntary and compliance offset markets. Climate change is a non-localized problem. Greenhouse gases mix throughout the atmosphere, so reducing them anywhere contributes to overall climate protection. There is no justification on the basis of climate science to arbitrarily limit the percentage of alternative compliance instruments, or to limit the eligible sources of GHG emission reduction instruments to only in-state and local sources.

The breadth of available alternative compliance instruments will be critical to the ability of natural gas consumers to meet their regulatory obligations at a reasonable cost. Natural gas consumers should be allowed to meet their compliance obligation each reporting period with alternative compliance instruments. As long as the compliance instrument results in a GHG reduction or offset, there is no difference from a climate change protection perspective or from a GHG accounting standpoint. To put any limit on the source or the percentage of alternative compliance instruments being used to meet the regulatory obligation imposed by the reduction program is simply arbitrary and, in all likelihood, counterproductive if the agency seeks to implement a successful program.

At page 37 of the Meeting 3 handout, DEQ identifies three major drivers for reductions of natural gas combustion: energy efficiency; fuel switching/electrification; and renewable natural gas. AWEC concurs that efficiency gains and sourcing renewable natural gas are feasible options natural gas consumers have to reduce GHG emissions. Electrification would lower natural gas consumption, but not necessarily GHG emissions. DEQ has been less than forthcoming on the question of whether electrification, especially of space heating of buildings currently accomplished with natural gas, would truly lessens the global and the local environmental impacts of that necessary energy consumption.

Industrial and commercial businesses will continue to invest in energy efficiency measures to reduce natural gas use and improve productivity. Oregon regulators, however, cannot control the timing or extent of technical advances that would enable efficiency measures alone to meet a significant portion of the compliance obligations being proposed by DEQ. This is especially true in the early years of the cap and reduce program.

Fuel switching to electric end uses is set forth as an option to reduce GHG emissions at page 37 of the handouts from the RAC 3 meeting. DEQ has not developed any factual record to support a finding that fuel switching to electricity will necessarily reduce GHG emissions during the timeframe of the program. DEQ does not know what the carbon content of the electric grid serving a particular customer will be in Oregon in a particular year in the future. If the only way to reduce natural gas consumption is to electrify the end use, such fuel switch could drive up Oregon GHG emissions. Direct use of natural gas is far more efficient than generating electricity with natural gas and then using the electricity as a heat source. The generating capacity needed to serve the space heating loads of Oregon natural gas utilities has not been studied by DEQ. Neither have the reliability issues on the electric grid that would be caused by rapid growth of electric space heating load in the next 10 to 15 years. DEQ has not explored any of the unintended consequences of electrifying significant quantities of current natural gas use as a de facto energy policy or the environmental externalities associated with the construction of needed generation, transmission and distribution resources that would be needed to meet the energy required for space heat in Oregon to be "all electric". Thus, the agency can not rely to a significant degree on electrification of natural gas end uses as a GHG reduction strategy for current uses of natural gas for space heating in Oregon.

Renewable natural gas is noted by DEQ as another one of the compliance tools. AWEC agrees that renewable natural gas and renewable hydrogen are alternatives to traditional natural gas as sources of heat for building and some industrial applications. The Oregon legislature has already recognized the contribution renewable natural gas can play in Oregon's energy future through enactment of SB 98. ORS 757.390-398. That legislation allows Oregon local distribution companies to pursue renewable natural gas projects anywhere in the United States, not just locally-sourced natural gas. One of the first projects under the new law is NW Natural's Tyson Fresh Meat Renewable Natural Gas project in Nebraska. Oregon Public Utility Commission Proceeding UM 2145. The legislature's policy choice makes sense, especially given that Oregon natural gas customers use natural gas almost exclusively sourced from outside Oregon. Natural gas consumed in Oregon is produced almost exclusively in British Columbia and Alberta in Canada and domestically from the US Rockies region, primarily Wyoming.

SB 98 recognized that as long as an Oregon program secures renewable natural gas from anywhere, the acquisition avoids traditional natural gas being sourced from somewhere. Had SB 98 limited the eligible sources of renewable natural gas to Oregon, our consumers would have less renewable natural gas to pursue, thus holding down the percentage contribution from renewable gas that can realistically be achieved and driving up prices because sources of supply would be arbitrarily limited to our state. DEQ should apply the SB 98 policy directive and precedent established by the Oregon legislature for renewable natural gas to alternative compliance instruments; i.e. allow natural gas consumers to seek affordable GHG emission reductions associated with alternative compliance instruments wherever they can be found.

There should be no percentage caps or geographic limitations of alternative compliance instruments in the program being designed in this proceeding. By suggesting that alternative compliance instruments must be locally sourced and capped at 25%, DEQ has raised the spectrum of designing a program that offers only extremely limited, Oregon-developed, and very expensive alternative compliance instruments. These design elements will make it nearly impossible for covered entities to economically comply with the GHG emissions reduction requirements and the cap and reduce rule. Surely the agency's objective is not to build a program it knows the regulated community will struggle to stay in compliance with in the years ahead.

Measurable, verifiable and permanent GHG emission reductions in the form of allowances and offsets are available from many credible trading planforms and registries in the United States and in many other countries that offer compliance instruments. Auction settlement prices for allowances in the joint California-Quebec auction and Regional Greenhouse Gas Initiative are currently \$17.80 and \$7.60 per metric ton, respectively. The weighted average price of offsets supplied by the California Compliance Offset Program in 2019 was \$14.13 per metric ton. In contrast, DEQ at page 37 of its RAC 3 meeting materials projects a "CCI price of \$200 per metric ton in 2020 dollars." \$200 per metric ton converts to \$10.60 per MMBtu of natural gas consumed, as every \$10 carbon price equals \$0.53 per MMBtu given the carbon content of natural gas emissions.

For the last several years, natural gas as a commodity has been priced between approximately $2.50 and $4.00 per MMBtu. See Attachment 1 for 2021 Projected Prices at the primary trading hubs that serve Oregon, and the national NYMEX index, which is based on the Henry Hub price in Louisiana. Instead of facing a compliance price of $.75 per MMBtu to $0.94 per MMBtu, (recent California prices) the Oregon-only approach could cost more than ten times that price for the same global GHG reductions. DEQ has offered no justifiable reason for limiting the market for compliance instruments so tightly that it causes compliance cost to be as much as ten times what they would need to be to achieve the same GHG reductions by relying on alternative compliance instruments generated by programs outside Oregon.

DEQ has yet to address issues raised previously by AWEC regarding how entities are to achieve compliance when they have no feasible alternative to using natural gas or how energy intensive, trade exposed businesses will be treated under the proposed regulatory program. AWEC is extremely concerned that the agency is building a program that leaves natural gas consumers with no reasonable and prudent way to comply with the program. By arbitrarily proposing to limit alternative compliance instruments to Oregon-only programs and cap alternative compliance instruments at 25%, DEQ has deepened AWEC's concern that the cap and reduce regulations will severely limit the ability to use natural gas in Oregon and have negative economic impacts on businesses, consumers and the Oregon economy. At a minimum, the ICF economic modeling should run a policy scenario or sensitivity that assumes alternative compliance instruments could be used by covered entities to meet 75% - 100% of their compliance obligations in the first 10 years of the cap and reduce program.

Energy intensive, trade exposed businesses are likely to struggle to comply with a program that takes a punitive and unnecessarily costly approach to compliance. If such a program is adopted by DEQ, many businesses could be left with no choice but to shift manufacturing that relies on natural gas use elsewhere. Such an outcome will likely lead to significant leakage of GHG emissions to other jurisdictions that don't have the GHG emissions advantage Oregon's relatively clean electric grid possesses in a carbon constrained world. DEQ's regulations must anticipate and be designed to mitigate against leakage. This is the only way Oregon can achieve a net reduction in GHG emissions and potentially contribute towards meaningful climate protection with its one-state GHG reduction program.

AWEC urges DEQ to expand the number of eligible sources of alternative compliance instruments to any certifiable program in the world and not adopt any percentage cap on such instruments. We appreciate the opportunity to provide input into this proceeding.

		NYMEX	Sumas (NW Pipeline)	Rockies (NW Pipeline)	
					Source
	1/1/2021	2.467	$ 3.23	3.23	Monthly I
	2/1/2021	2.76	$ 2.75	2.75	Monthly I
	3/1/2021	2.854	$ 3.04	3.04	Monthly I
	4/1/2021	2.508	$ 2.37	2.323	ICE Quote
	5/1/2021	2.554	$ 2.20	2.2915	ICE Quote
	6/1/2021	2.615	$ 2.22	2.395	ICE Quote
	7/1/2021	2.674	$ 2.59	2.619	ICE Quote
	8/1/2021	2.692	$ 2.72	2.7195	ICE Quote
	9/1/2021	2.683	$ 2.72	2.6705	ICE Quote
	10/1/2021	2.698	$ 2.83	2.5705	ICE Quote
	11/1/2021	2.77	$ 3.48	3.075	ICE Quote
	12/1/2021	2.904	$ 4.13	3.494	ICE Quote

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arauco

To: Richard Whitman, Director, Oregon Department of Environmental Quality
Sent via email: GHGCR2021@deq.state.or.us

From: Arauco North America, Inc.

Date: March 26, 2021

Re: Feedback on Oregon Climate Protection Program: Rulemaking Advisory Committee Meeting 3

Thank you for the opportunity to provide feedback on the topics presented by the Oregon Department of Environmental Quality ("DEQ") at the third meeting of the Oregon Climate Protection Program: Rulemaking Advisory Committee ("RAC").

As a reference, Arauco North America, Inc. is a wholly owned subsidiary of Celulosa Arauco y Constitución and operates a particleboard plant located in Albany, Oregon. Arauco supports efforts to reduce GHG emissions. Arauco is third party certified Carbon Neutral and has established corporate CO2 emissions reduction through Science Based Targets.

Arauco is very concerned with the direction of the DEQ's policy proposals regarding alternative compliance instruments. We are troubled to see DEQ move away from the concept of a "cap and reduce" program with flexible compliance pathways. The new direction is to now develop a program that generates revenue to fund projects in Oregon only **with the stated goal of reducing co-pollutants**. This proposal is the highest cost pathway to compliance shared to date and will result in leakage. Energy Intensive, Trade Exposed ("EITE") entities, such as Arauco, must be provided with affordable compliance pathways under the proposed Climate Protection Program ("CPP") and the scope of CPP must be to reduce GHG emissions only. We expand on our concerns below with answers to the proposed questions from the RAC #3 meeting:

(1) What are your thoughts about integrating potential community climate investments in the CPP?

Arauco does not support the agency's proposal of community climate investments ("CCI") as the sole pathway for alternative compliance with the proposed CPP. It is clear the agency intends to raise revenue from regulated entities through the sale of CCIs and subsequently direct those funds to projects intended to reduce co-pollutants in Oregon communities, as opposed to reductions in greenhouse gas emissions generally. Greenhouse gases are non-toxic global pollutants and do not remain local in any way. Any reduction in greenhouse gas therefore benefits Oregon communities, regardless of where that reduction occurs. As such, we disagree with DEQ's proposal of CCIs as the sole mechanism for alternative compliance.

DEQ should focus policy proposals on greenhouse gas reductions, not revenue generation or the reduction of other air pollutants.

Limiting alternative compliance options to those generated Oregon will limit the effectiveness of this compliance tool as there likely are not sufficient opportunities for in-state projects, nor are they likely to be cost effective. As long as the compliance instrument results in a greenhouse gas reduction, there is no difference from global emissions or a greenhouse gas accounting standpoint. Any limit on alternative compliance instruments to meet an entity's compliance obligation would be arbitrary. Before advancing the concept of CCIs, DEQ must study the availability of qualified in-state projects to ensure that there are adequate options available to control costs throughout the life of the program. Arauco urges DEQ to revisit the proposed CCI model and to provide an affordable and flexible compliance pathway for regulated entities in order to avoid the very real threat of leakage.

Further, DEQ proposes a CCI price of $200/ metric ton of carbon for the purposes of modeling the three policy scenarios and has not offered any justifiable reason for limiting the market for compliance instruments to those that cost $200 (or even $50)/ metric ton of carbon. Certifiable offsets and allowances are available in the U.S. and around the world that correlate to an actual reduction in greenhouse gas emissions. These programs range in price from $15 to $20/ metric ton of carbon,[1] not $200 as the agency proposes on slide 37. **DEQ's proposed CCI price will subject regulated entities to compliance costs that are 10 times the price of those currently available for the same carbon reduction in the global marketplace.** DEQ's proposal of $200 CCIs provides no feasible alternative for EITE businesses to comply with the proposed regulatory program. By setting its own CCI price far above that of the global offset and allowance market, this policy proposal will ultimately result in the leakage of emissions to jurisdictions with a less favorable electricity profile than Oregon's relatively clean electric grid.

(2) *Should there be a limit on how much regulated entities are allowed to use community climate investments?*

Arauco does not support limiting the use of alternative compliance options to a percentage of regulated entities' compliance obligation. For many regulated entities, these tools may provide the only cost-effective means to achieve compliance with a cap and reduce program. Alternative compliance options provide a verified reduction in global greenhouse gases. As that is the stated goal of the CPP, DEQ should not limit the use of alternative compliance mechanisms, as currently proposed in the agency's modeling scenarios.

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[1] California Carbon.info. 2030 WCI Emissions and Price Forecast file:///C:/Users/JDresler/Downloads/2030%20Emissions%20and%20Price%20Forecast%20Excerpt.pdf

Regarding the regulation of non-natural gas fuels, Arauco is concerned about the indirect costs associated with transportation fuels and the potential for dual regulation under the CPP. DEQ cannot view sectors independently from one another when analyzing impacts or the feasibility of the CPP. Local manufacturers, for example, will be impacted through the direct regulation of facilities, but could also realize significant indirect cost impacts related to transportation or the upstream regulation of natural gas.

Thank you for the opportunity to provide agency feedback.

Sincerely,

John Bird
North America EHS&S Manager

Jason Young
Duraflake/Albany Environmental Manager

bp

Tom Wolf
Senior Government Affairs Manager
US West Coast

bp America Inc.
Cherry Point Refinery
4519 Grandview Road
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March 26, 2021

Oregon Department of Environment Quality
VIA Email Transmission
GHGCR2021@DEQ.STATE.OR.US

Re: **Climate Protection Program: Rulemaking Advisory Committee (RAC) Meeting #3**

Dear Department of Environmental Quality Staff:

On behalf of bp America (bp), thank you for the opportunity to participate in the Oregon Department of Environmental Quality's (DEQ) RAC meeting on March 18th.

Our comments are focused on the recent RAC discussion of key elements for regulation of non-natural gas fuel suppliers. During this conversation, different stakeholder positions were aired with respect to the most appropriate threshold above which an entity is regulated under the Climate Protection Program (CPP).

As we have stated in our previous comments, bp supports a threshold of 5,000 MT CO_2e as an appropriate and fair value to adopt. This threshold closely equates to Oregon's Clean Fuels Program threshold for a fully regulated entity when converted to gasoline / diesel volume. In addition, this value is reasonably proportional to the California Cap & Trade threshold of 25,000 MT CO_2e, given that Oregon's market is approximately an eighth the size of California's when applying the lens of motor gasoline and on-road diesel demand.[i]

Setting the threshold at a higher value risks setting a ceiling to which unregulated entities may grow while enjoying the competitive advantage of not bearing the cost burden for CPP compliance. We believe this hinders meeting GHG reduction targets due to program leakage and it is not equitable for entities that are covered by the CPP.

To the latter point, combustion emissions require simple math and an EPA emission factor[ii] to calculate the cost per gallon that relates to carbon price. By taking a California Cap & Trade value of $15 / MT as an example, this would result in an E10 gasoline cost of 12 cents per gallon and a B5 diesel cost of 14.5 cents per gallon that are associated with the carbon price. This clearly shows that entities not covered in the program will have a significant cost advantage over covered entities. Therefore, the universe of those uncovered entities should be small.

With respect to a claim of disproportional administrative burden to smaller entities that was made during the RAC discussion, we should recognize that, for the most part, these are the same entities already covered under the existing Clean Fuels Program and they have proven their sophistication in benefiting from the carbon intensity reduction incentives that are offered. That being said, all regulated entities should be open to finding ways to streamline CPP administrative processes.

Please do not hesitate to reach out to me at thomas.wolf@bp.com or 360-483-7438 if you have any questions or need additional context.

Sincerely,

Tom Wolf
bp America

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[i] EIA data (2019) https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_a.htm, https://www.eia.gov/dnav/pet/pet_cons_821dst_dcu_nus_a.htm

[ii] EPA https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf

Alyn Spector
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Representing Cascade and Avista as Oregon's Rural Service Providers

March 29th, 2021

Nicole Singh, Senior Climate Policy Advisor
Singh.Nicole@deq.state.or.us
Department of Environmental Quality
Office of Greenhouse Gas Programs
700 NE Multnomah St.
Portland, OR 97232

Submitted to: GHGCR2021@deq.state.or.us;

Dear Ms. Singh,

Thank you again for the opportunity to represent the perspective of Cascade Natural Gas and Avista (Rural Service Providers) through my position on the Department of Environmental Quality's (DEQ) Regulatory Advisory Committee (RAC). We appreciated the conversations that took place during the DEQ's March 18th meeting regarding the development of a Community Climate Investment (CCI) fund that could support additional pathways to GHG reductions and improve flexibility for regulated entities.

As stated previously, **it is critical for regulated entities to have as many pathways to compliance as possible to achieve maximum carbon reductions at minimal cost for our utility customers.** The CCI fund discussed on March 18 could serve as an important tool for supporting sustainability in our communities through quantifiable carbon reduction activities in low income, rural, and traditionally underserved communities. As currently proposed, however, it is unclear how the CCI will provide a lower cost flexible alternative for compliance, how it will be operated, and how much it will cost.

The Rural Service Providers remain concerned about transparency in DEQ's scenario modeling and the risk of unintended consequences such as incentivizing migration from regulated emissions (such as those from the natural gas sector) to unregulated fuel sources (such as the electric sector) which would result in limited carbon reductions.

In preparation for RAC-4, the Rural Service Providers reiterate our request to review the details behind the analysis performed by ICF via a dedicated breakout session provided to RAC members and the public. DEQ needs to make available the spreadsheets, data inputs, and assumptions that are used in the modeling for RAC members to assist DEQ in providing subject matter expertise for model parameters. In particular, we would like to better understand how the CCI price range of $50 to $200 per metric ton was developed, and why slide 37 of the meeting slides for RAC 3[1] appears to assume costs will be in the highest end of the range. We are also uncertain how the discrete scenario packages were developed. We acknowledge that DEQ has asserted the scenarios modeled do not represent final or complete program design models. However, we need to better understand why multiple variables were modeled within certain scenarios or switched from one scenario to another as the models were refined. We look forward to further opportunities to develop a shared understanding of the program's emerging framework and mechanics. We would also like to see further discussions on protections for low-income customers.

We appreciate the opportunity to have our voices heard in this proceeding, and we look forward to continued engagement in the areas outlined in our comments.

Executive Summary

Natural gas LDCs play, and should continue to play, an important role in supplying Oregonians with clean, reliable, and affordable energy. Today, our utilities operate extensive infrastructure to deliver gaseous fuels to end users at affordable rates as required by our regulators; in the future this infrastructure should be leveraged to deliver a blend of low-carbon fuels such as renewable natural gas and hydrogen. Our infrastructure also serves an essential role in addressing reliability challenges associated with intermittent renewable resources, and in the resilience of the overall energy system amid increasingly extreme weather events. It's important to keep considerations such as energy affordability and resource adequacy in mind as a cap-and-reduce program structure is developed. It's also important to ensure that program discussion and design remain a collaborative, public process that isn't commandeered by pre-packaged solutions introduced outside the RAC process.

To this end, we focused our comments into two key themes that address **flexibility and feasibility** and **transparency and accuracy in modeling**, with respect to both program structure and the rulemaking process.

Flexibility & Feasibility

Natural gas consumption varies with economic and weather cycles, and emissions-reducing projects may require years of planning and development. A cap-and-reduce program that provides flexible, but qualifiable pathways to GHG reductions will allow regulated entities to pursue emissions reductions in a cost-effective manner.

1. The cap-and-reduce program should take an all-of-the-above approach to reducing GHG emissions regardless of where those reductions take place or what technology solutions are utilized.

[1] Available at: https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/ghgcr2021m3Slides.pdf

2. Compliance mechanisms should not be limited to Community Climate Investments (CCI). Additional out-of-state GHG reduction instruments such as interstate carbon registries should also be allowed.

3. Alternative compliance options must be cost-accessible to regulated entities and CCI projects must be affordable relative to other compliance options.

4. The CCI must be designed with input from regulated entities in a manner that is transparent, and the design should result in verifiable outcomes with oversight by a state regulatory body.

5. We expect that a CCI program would promote flexibility and should be available to regulated entities to the greatest extent possible, especially in the early years of the cap and reduce program.

6. GHG reductions should remain a fundamental goal of CCI investments. Investments should have quantifiable savings and should designed with rigorous methodology to ensure that projects lead to verifiable outcomes.

7. The funds distributed by a CCI program should be allocated via a fair and transparent process to support a range of efforts similar to those funded through the California Air Resources Board's Climate Investment Program. These include woodsmoke reduction programs, emissions reductions associated with agricultural equipment, low carbon transportation, and affordable housing.

8. CCIs should be administered in a manner which avoids leakage to unregulated sectors or double-counting of GHG emission reductions. For example, a CCI project that includes electrification must be tied to investment in renewable generation or other source of energy that demonstrates a lower carbon intensity than the displaced energy source. Resource adequacy must also be demonstrated to ensure the electric grid is able to handle increased electric load paired with intermittent renewable generation.

9. CCI projects should not include measures that lead to significant increases in energy costs for utility customers.

10. CCI projects should be focused on delivering equity in Oregon's energy transition with a focus on delivering impact in traditionally underserved communities, including rural and low-income communities.

Transparency & Accuracy in Modeling

Public engagement and open communication are the cornerstones of a well-designed and vetted program that serves the public good. Without a clear understanding of how decisions are made, or transparency in modeling, it is difficult for the stakeholders tasked with reviewing and supporting program design to provide meaningful input.

1. All aspects of the cap-and-reduce rulemaking, including the CCI program, should be developed and refined with maximum transparency and collaboration with the full RAC.

2. The inputs from the three modeling scenarios continue to fluctuate without a clear understanding of the learning objectives informing each scenario. Further discussion on the specific questions driving the modeling scenarios as designed is essential.

3. Modeling results should describe emissions from sectors DEQ proposes not to regulate under the rule (e.g., electric generation), and should clearly identify any new emissions from unregulated entities that result from rule-related activities.

4. The initial CCI concept was designed outside the RAC process and shared with DEQ before being presented to the RAC for further development. Moving forward, the CCI should be developed within the parameters of the RAC and its design should be subject to public feedback and comment.

5. The price of compliance instruments offered through a CCI program should be determined using a transparent methodology as part of the public RAC process, informed by best practices for carbon offset programs, and presented during RAC proceedings by DEQ and ICF.

Comment Details

As stated in our Executive Summary, the Rural Service Providers have identified two core themes with respect to program structure and the rulemaking process.

Flexibility and Feasibility

Our comments relating to flexibility and feasibility address fundamental prerequisites for the success of any cap-and-reduce effort, as well as compliance flexibility as it pertains to the Community Climate Investment fund proposed during the RAC 3 meeting.

1. **Prerequisite #1 (Flexibility): CCI projects must not be the only alternative compliance pathway available to regulated entities.**

   If the purpose of Oregon's cap-and-reduce program is to help reduce global GHG emissions, the state should take an all-of-the-above approach to reducing emissions regardless of where those reductions take place. The CCI has the potential to provide a pathway to local GHG reductions with regional benefits for undeserved communities. This is a laudable goal that should be encouraged. However, the CCI should not be approached as a primary goal of EO 20-04, but rather as an *additional* pathway to compliance with ancillary benefits. It does not serve, and should not be misconstrued as, the entire goal of this program. Instead, regulated entities should be allowed to achieve compliance through both domestic and global GHG emissions reduction instruments including allowances from the American Carbon Registry, Western Climate Initiative, and Regional Greenhouse Gas Initiative.

Further, compliance mechanisms should be available in sufficient volume to support regulated entities in achieving their GHG reduction targets. Limitations on the use of alternative compliance options that achieve GHG reductions is counterintuitive and risks raising costs to Oregon's ratepayers with no demonstratable carbon GHG reduction value. If DEQ limited compliance projects to only Oregon in the scenario modeling, this would partly explain the significant cost per ton value assigned by DEQ in modeling those offsets.

2. **Prerequisite #2 (Feasibility): Alternative compliance options must be cost-accessible to regulated entities, and CCI projects must be affordable relative to other compliance options.**

As previously stated, an all-of-the-above approach to GHG reduction is essential. If a compliance pathway is offered by the program, it should be available to be utilized by regulated entities as necessary for program compliance. All alternative pathways should be considered to be of equal merit and therefore not designed in a way that artificially drives regulated entities towards one set of options. The Rural Service Providers are concerned that the DEQ's scenario modeling assumes a $200 per metric ton CCI price. This seems significantly high, and risks discouraging investments in this pathway. When paired with the general limitations faced by local distribution companies in driving customer energy usage reductions, unvetted costs built into program modeling are particularly concerning. We grow increasingly concerned that limited and inaccessible compliance mechanisms developed without transparency will significantly limit the success of this effort.

The Rural Service Providers maintain that a successful cap-and-reduce effort must offer regulated entities as many realistic avenues of compliance as possible. These avenues should be based from an understanding of the opportunities and limitations unique to each regulated entity, and they should bridge the gap between the GHG reductions that can be achieved independently under existing legal, economic, and regulatory parameters, and any remaining compliance obligation.

We believe the Community Climate Investment (CCI) fund introduced during RAC 3 has the potential to promote flexibility and support GHG reductions that would otherwise be costly or difficult for a regulated entity to achieve on its own. The following factors are key to the success of a CCI fund:

- The fund's structure must be designed in a manner that is transparent and results in verifiable outcomes.
- Regulated entities funding the program should have the opportunity to help develop the criteria for allocating funds, and at minimum, should play an advisory role similar to the

role played by the investor owned utilities funding energy efficiency efforts through the Energy Trust of Oregon.

- The CCI fund should be subject to rigorous oversight and reporting. Monitoring of CCI operation and finance should be provided by a state agency familiar with this type of oversight role, such as the Oregon Public Utility Commission (OPUC).

As stated earlier, we believe that compliance flexibility tools should not be limited to a CCI and that this pathway should supplement, but not supplant, additional instruments for GHG reduction such as the use of verified compliance instruments through independent carbon offset registries. To ensure successful achievement of GHG reduction goals, we encourage the DEQ to allow unlimited use of a CCI program and the use of at least 25% alternative compliance instruments other than CCI as part of this program.

We have outlined additional thoughts on CCI and other pathways that promote flexibility below and in the Responses to Discussion Questions section of this document:

The Rural Service Providers believe that investments through a CCI program should be as varied as the needs of the communities they're designed to benefit. This means developing project guidelines that ensure the intent of the program is met without inhibiting flexibility or innovation. From our perspective, projects should concurrently reduce or sequester GHG emissions while providing value to communities that face environmental and economic impacts. GHG reductions should be a fundamental goal of climate investments. These reductions should be quantifiable and designed with rigorous methodology to ensure that climate funds are invested in projects that lead to verifiable outcomes.

The funds distributed by a CCI program should be allocated via a fair and transparent process to entities with demonstrated potential to serve traditionally underserved and economically vulnerable communities. This could include low-income weatherization agencies and non-governmental organizations for whole home conservation retrofits and net zero energy housing construction, and to organizations with experience in climate adaptation that result in sequestration of carbon. The CCI could also support a range of efforts similar to those funded through the California Air Resources Board's Climate Investment Program.[2] These include woodsmoke reduction programs, emissions reductions associated with agricultural equipment, low carbon transportation, and affordable housing.

Ultimately, CCIs should be administered in a manner which avoids leakage to unregulated sectors or double-counting of GHG emission reductions. This means looking at the GHG intensity of both the emissions the project is slated to offset, and any emission associated with the project itself, including inadvertent migration to more carbon intensive energy sources. There is a significant risk of GHG emissions leakage associated with electrification of building heating and vehicles. The CCI should not consider measures that simply shift emissions from vehicles and buildings to the power sector. Any electrification measures must be tied to investment in

[2] California Climate Investments Funded Programs | California Air Resources Board. Available at: https://ww2.arb.ca.gov/our-work/programs/california-climate-investments/california-climate-investments-funded-programs

low-carbon generation sufficient to supply the newly-electrified load. Additionally, resource adequacy must be demonstrated to avoid the risk of grid instability associated with intermittent generation sources. Project selection should also be designed in a way that expands opportunities for emissions reductions and avoids competition between the fund and regulated entities to engage in a limited set of activities. Any CCI design should also be mindful to avoid projects that inadvertently harm the communities they are designed to support, such as significant increases in energy costs for utility customers, or GHG leakage from one sector of the economy to another.

Transparency & Accuracy in Modeling

Public engagement and open communication are the cornerstones of a well-designed and vetted program that serves the public good. Without a clear understanding of how decisions are made, or transparency in modeling, it is difficult for the stakeholders tasked with reviewing and supporting program design to provide meaningful input. To date, modeling demonstrations and discussions have not provided adequate transparency of assumptions and inputs.

In particular, the inputs in the three overall modeling scenarios provided to date continue to fluctuate without a clear understanding of the learning objectives informing each scenario. Without a strong foundation of transparent data informing modeling, we are concerned that GHG emissions reduction opportunities may be left on the table. It will be essential that modeling results describe emissions from sectors not regulated under the CPP (e.g., electric generation), and their interactions with regulated sectors. This will help avoid unintended migration of GHG emissions from one sector to another.

We would also like to better understand the origins and data that have and will inform the ongoing design of the Community Climate Investment fund. The Rural Service Providers understand that the CCI was designed and vetted by a group of RAC members and affiliated entities outside the RAC process, and was shared with DEQ before being presented to the RAC for further exploration and development. Because of its origins outside of ICF, DEQ, or the collective Regulatory Advisory Group, it is essential that RAC members and the public are given full disclosure regarding which stakeholders were involved in the development of the draft CCI concept. While the CCI has conceptual merit, significant further development is required to ensure that it meets the intended purpose of achieving GHG reductions for regulated entities. It is therefore essential moving forward that all elements of cap-and-reduce program design be developed within the parameters of the RAC, and therefore be subject to public feedback and comment.

We seek a fuller understanding of the origin of the cost estimates of the CCI compliance instruments used in modeling. We ask that the price of compliance instruments offered through a CCI program be determined using a transparent methodology informed by best practices for carbon offset programs. And it should be done as part of the public RAC process and presented during RAC proceedings by DEQ and ICF.

We would like to provide some initial feedback on the modeling results presented during RAC 3 and pose some questions for DEQ's and ICF's consideration. The three modeling scenarios presented to the RAC continue to lack transparency and are insufficient for meaningful review. Even if the scenarios are not program designs, but simply meant to test design concepts, as suggested by DEQ, the lack of underlying information regarding how the inputs informing these scenarios is concerning. However, based on the limited data available, we have several observations.

Policy Scenario 1, having the most flexibility[3] of all three scenarios was stated by DEQ as the only policy scenario to meet the GHG emissions target in 2050. Based on the "Policy Scenario 1 Results" graph shown on slide 39 of RAC 3[4], we interpret that the cap is met in all years, with the net emissions inclusive of CCIs, banking and trading being well below the trajectory from about 2025 to about 2040 at which point the difference between emissions and the cap are reduced until emissions match the cap in 2050. In each scenario, a similar emissions reduction trend occurs between 2025 and about 2030. It is unclear what drives these earlier emission reductions and request DEQ provide more detail on what is assumed to occur over time. Notably, the scenario with the most flexibility was the only one to solve for the emission reduction objective while the other scenarios modeled with more stringent GHG reduction obligations and additional restrictions, did not solve. This would support that more flexibility, beyond what was modeled in Policy Scenario 1, is required to ensure an emissions reduction cap can be successfully met cost-effectively.

Also, we believe the $200 per ton CCI offset cost applied steadily throughout the trajectory would have a significant impact on the ultimate cost and economic viability of Oregon businesses that must comply with the program. Has DEQ determined whether the ultimate compliance cost for industrial and large commercial businesses from Policy Scenario 1 would result in leakage of emissions from those businesses to outside of Oregon? How is DEQ determining what cost can be borne by Oregon businesses and natural gas customers to achieve GHG emission reductions? Allowing a lower CCI cost would yield a more cost-effective emission reduction outcome while continuing to maintain a vibrant Oregon economy. We welcome more detail from DEQ to understand the changes in emission levels that occur over time in the scenarios as that will help RAC members provide valuable input to DEQ.

Responses to Discussion Questions

The DEQ posed the following questions regarding a potential CCI program:

- *What types of projects should be funded by community climate investments?*

  As stated under Flexibility and Feasibility, the Rural Service Providers believe the CCI should fund cost-effective projects with a demonstrable impact in GHG reductions. Funds should be allocated through a fair and transparent distribution process. CCI funds could be applied to support efforts such as weatherization, affordable energy efficient housing, clean transportation and other purposes related to the sector from which the funds are collected. Care should be taken to avoid incentivizing leakage of GHG emissions to unregulated sectors.

[3] Policy scenario 1 was defined as having no limits to trading of compliance instruments, regulating large stationary sources separate from natural gas utilities, allowing alternative compliance options up to 25% of the compliance obligation, and having a less stringent GHG emissions target of 80% reduction by 2050
[4] Id 2.

- *How could DEQ incorporate community input throughout this process?*

  Public input and transparency are essential components of a successful CCI effort. The program should be developed through a breakout workshop comprised of interested RAC members, as well as representatives of impacted communities across a demographically, economically, and geographically diverse range of stakeholders. A third party tasked with operating the CCI could be steered by a board representing these communities.

  Regardless of whether the program is developed through the RAC or concurrent with the RAC, it is essential that further program design take place under the public eye and with maximum opportunities for feedback and comment. Discussions regarding the design and operation of the CCI should be made "at the table" in the context of the public process.

- *How could DEQ ensure and prioritize investments in environmental justice and other impacted communities?*

  The CCI could follow the example of California's Greenhouse Gas Reduction Fund, which requires that 25% of funds be spent in EJ communities, and that 25% of funds be spent on projects that benefit EJ communities.[5] New York is considering similar requirements for their Community Climate and Investment Act.[6]

  However, if such provisions were put in place, EJ should be defined in a manner that serves a broad range of economically vulnerable and traditionally underserved populations across different demographic, economic, and geographic backgrounds. It would also be essential that no cap or limitation was placed on the total amount of projects that regulated entities could support to achieve climate investment credits in a given compliance period, including via other alternative compliance mechanisms.

- *Should there be a limit on how much regulated entities are allowed to use community climate investment credits?*

  We believe there should not be a limit on the number of climate investment credits regulated entities are allowed to use in a given compliance period. Maximizing flexibility and opportunities for achieving GHG reductions is an important part of ensuring the program meets its purpose.

The DEQ posed the following discussion question regarding non-natural gas fuel suppliers:

- *What other concerns might the annual variation present for regulated businesses? For consumers?*

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[5] SB 535 Disadvantaged Communities | OEHHA (ca.gov)
California Climate Investments to Benefit Disadvantaged Communities | CalEPA
[6] CCIA-Bill-Summary-12.7.20.pdf (zmm.org)

As with gas utility sales, the sales of delivered fuels vary from year to year based on climate and economic cycles. Any initial cap or baseline for the sector should be determined based on several years of data, to avoid undue influence from COVID and climate.

Conclusion

Cascade Natural Gas and Avista appreciate the opportunity to participate as members of the RAC. We look forward to continuing to engage in this process to help support the achievement of meaningful carbon reductions for natural gas customers with the greatest benefit lowest cost for our communities.

We thank you for the opportunity to participate in this process to ensure the best possible outcome for our environment, economy, and equity for all Oregonians.

Respectfully Submitted,

Alyn Spector

Alyn Spector
Energy Efficiency Policy Manager
Representing Cascade and Avista as
Oregon’s Rural Service Providers

From: Peter Brandom <Peter.Brandom@hillsboro-oregon.gov>
Sent: Friday, March 26, 2021 9:14 AM
To: GHGCR2021 * DEQ
Cc: Peter Brandom; Andy Smith; Jenna Jones; Tracy Rutten
Subject: Cap and Reduce RAC Comments Post Meeting #3

Good Morning,

Please consider the following comments and questions following the last RAC meeting.

- Regarding the Community Climate Investments
    - Provide clarity on process for assessing whether and how projects meet their intended GHG reductions. Consequences and response for projects that fail to meet their reductions should be clearly defined at the outset of the program
    - Similarly, timelines for project implementation and outcomes should be established and formally agreed prior to project approval
    - How will project recipients/implementers be required to demonstrate project outcomes long term?
    - Limits (or cap) for how much of required GHG emissions reductions may be met with CCIs should be clearly established, and there should be limits. We feel that no more than 25% should be allowed for CCIs
    - Who might the third party recipients of CCI funds be? This should be clarified at the outset of the program
    - What is meant by 'regional structure' in how allocations of CCIs might be made?
    - Specialized GHG reduction technical expertise, above and beyond the DEQ and approved by the DEQ, should be required for assessing potential reductions from CCIs before they are considered
    - Understanding that the example project types listed on slide 18 of the meeting presentation are illustrative; consideration should be made for natural resources projects that sequester or otherwise benefit GHG emissions
    - In the examples, please clarify 'heat pumps' for heating and cooling, distinct from 'heat pump water heaters' that are much more energy efficient than traditional electric water heaters
    - Please consider for CCIs existing programs in communities that have proven effective at reducing GHGs. We agree that augmenting existing efforts should not replace existing funding with CCI funds, CCI funds should be required to augment/expand efforts and grow reductions
    - Local governments are a key resource to connect with and leverage relationships with community-based groups that advocate for environmental justice and

historically marginalized community members, and local governments can play a role in identifying both community partners and CCI projects with an equity focus
    - Local governments should play a role in facilitating community input for the CCI process
- Regarding point of regulation of natural gas in program
    - Given the variability in the industry, and potential for entities to 'game' the system, and considering the amount of GHG emissions that would be excluded in a higher threshold scenario (per DEQ at 300,000 $MTC0^2e$, would be roughly 2,000,000 tons of emissions, equivalent to over 230,000 homes' energy use for one year) we urge regulation of natural gas at any amount greater than or equal to 0

Finally, we ask to please understand as soon as is possible, specific entities that will be regulated under the rules in different scenarios.

Thank you,
Peter

Peter Brandom (he/him/his) |*Senior Project Manager*
City of Hillsboro, Oregon
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email peter.brandom@hillsboro-oregon.gov
web www.hillsboro-oregon.gov|Twitter @cityofhillsboro

March 26, 2021

Office of Greenhouse Gas Programs
Department of Environmental Quality
700 NE Multnomah St.
Suite 600
Portland, OR 97232

RE: Climate Protection Program - RAC Meeting #3

DEQ's Office of Greenhouse Gas Programs,

Thank you for the opportunity to provide comments after the third Climate Protection Program Rulemaking Advisory Committee meeting. Based on the materials and conversation, we are concerned that DEQ is considering exempting a substantial portion of non-natural gas fuel supplier emissions. We also want to make sure DEQ is considering both equity and environmental integrity as it considers how to move forward on alternative compliance. Finally, we have many questions on the initial modeling results and hope that DEQ will provide the more detailed data and assumptions that the results are based on as soon as possible. Our specific comments are detailed further below.

Non-Natural Gas Fuel Suppliers

DEQ's brief on non-natural gas fuel suppliers (referred to in shorthand as "oil companies" throughout our comments as those make up the majority) tees up two main issues for discussion: the threshold for regulation and distribution of compliance instruments. Those were also key topics of discussion during the RAC meeting. Our comments are broken up into those two topics below, but to summarize, **we want DEQ to hold oil companies responsible for their pollution.**

Set the Threshold at Zero or Near Zero

DEQ appears to be considering anywhere from no threshold (i.e. zero) to a 300,000 MT threshold, although it appeared DEQ was leaning towards the higher threshold. Wherever the threshold is set, those companies above the threshold would be regulated, while those below would be given a free pass. At 300,000 MT, only 86% of emissions would be covered and 6 companies. At zero, about 90 companies would be regulated and 100% of emissions. **Placing the threshold at zero or near zero would ensure oil companies are not let off the hook for their pollution.**

It was extremely disappointing to see DEQ dismiss an exemption of 14% of fuel supplier emissions (by setting the threshold at 300,000) as "relatively small" and "relatively little."[1] Particularly when DEQ is already planning to exempt a significant portion of emissions from the program by not regulating gas-fired power plants and considering other exemptions for industry.

If this is truly a Climate Protection Program, DEQ should seek to cover as many emissions as possible. In the non-natural gas fuel supplier case, we're talking about many entities that are collectively responsible for the largest and growing share of Oregon's greenhouse gas emissions - transportation emissions. Just knowing that information, DEQ should be looking to cover as many emissions with a zero or near zero threshold. When you add on the fact that these entities are also responsible for emitting harmful co-pollutants that disproportionately burden and harm Black, Indigenous, people of color, and low income communities, it makes it even more important to cover these entities and emissions.

Setting a zero or near zero threshold would also address many of the issues around volatility in the market and prevent gaming of the system. DEQ described at length in its brief the potential for entities to fall in and out of regulation depending on where the threshold is set. Setting the threshold at 300,000 provides a lot of room for entities to fall in and out of regulation either due to the market or gaming of the system. A zero threshold is cleaner and can avoid the potential gaming of the system that would be more likely to occur at higher thresholds to skirt regulation. For these and other reasons, other jurisdictions have also recognized the wisdom of setting a zero or near zero threshold (e.g. the Transportation Climate Initiative draft model rule for the RGGI states).

100% Free Allocation is Concerning

In addition to where the regulatory threshold is set, how DEQ distributes compliance instruments to oil companies is critical. Generally, DEQ has been operating from the idea that it will directly distribute compliance instruments to each regulated entity – essentially free allowances. And those compliance instruments would then likely decline each year with the cap. **We have concerns with direct distribution to oil companies, and if that is how DEQ proceeds, there at least need to be safeguards in place.**

There is a potential for oil companies to profit from direct distribution of compliance instruments. Compliance instruments are things of value – and DEQ could essentially be giving these away to oil companies for free. Oil companies are not subject to the same regulations as other entities (e.g. utilities are regulated under the PUC) so there is less oversight of how compliance instruments are used/value spent. In addition, if DEQ provides an over-allocation of compliance instruments, oil companies could not only see windfall profits, but also not need to reduce their emissions at the pace and scale necessary.

As a result, at the very least, safeguards are needed:

[1] See page 3 of the DEQ RAC Meeting #3 brief titled "Considerations for Non-Natural Gas Fuel Suppliers" and Slide 26 of the slides for RAC Meeting #3..

- The initial allocation of compliance instruments should be substantially less than the baseline emissions calculation for the entity so oil companies do not receive 100% free allowances and would have to reduce emissions from day one. And, the compliance instruments allocation should decline substantially every year thereafter.
- Ideally, DEQ would also put conditions on the distribution of compliance instruments – e.g. oil companies would need to have an emissions reduction plan in place to receive direct distribution and/or demonstrate emissions reductions to receive compliance instruments.

Community Climate Investments

While we continue to be interested in the potential benefits of Community Climate Investment projects, the details of how they would work and the effect they would have on the program are still not clear. Big questions such as whether the projects would be required to reduce emissions and how to deal with double counting still seem unsettled. **As DEQ considers whether and how to move forward on CCIs, it must ensure both equity and environmental integrity**.

At baseline, all of the projects should reduce or remove emissions to ensure the environmental integrity of the program and there should be a 1:1 reduction of emissions for each alternative compliance instrument. Options must then be considered to ensure alternative compliance does not allow pollution to occur above the cap or persist unabated in communities. These could include:

- Reducing the number of compliance instruments proportionate with the amount of alternative compliance instruments
- Limiting the amount of alternative compliance instruments
- Building in monitoring, tracking, and adjustments over time to course correct
- Phasing out the use of alternative compliance instruments
- Setting a price for the alternative compliance instruments that reflects the social cost of carbon or higher
- Applying specific conditions on the use of alternative compliance instruments:
    - Require reductions on-site first for stationary sources/use of lowest emissions achievable rate technology
    - Limits on/or no use by stationary sources if they are in violation of air quality permits or if the stationary source is in a nonattainment area and the stationary source contributes to or causes the nonattainment of air quality standards
    - Emissions reductions plans in place as a prerequisite to use of alternative compliance

While it is challenging to provide a specific prescription with many questions still outstanding about how the program would work, If DEQ chooses to utilize alternative compliance options, we would strongly urge the agency to ensure that the program: requires onsite emissions reductions first; incorporates air quality impacts and considerations; and requires that investments happen in and directly benefit Oregon communities, prioritizing investments in frontline/impacted communities. Furthermore, if DEQ plans to utilize alternative compliance options, it needs to demonstrate how it will ensure the cap will still be met in the near term and over the life of the program.

In terms of specific projects, there was much discussion at the RAC meeting about the types of projects that could be funded through CCIs, and particularly the merits of electrification projects. Deep decarbonization studies consistently find prioritizing building electrification to be a least cost and necessary step to achieve climate targets.[2] As a result, we strongly support the inclusion of electrification projects if DEQ moves forward with the CCI concept.

Furthermore, it was mentioned that there might possibly need to be an advisory body that would help oversee implementation of the CCI concept and projects. That advisory body should include full and fair representation of Black, Indigenous, people of color and other frontline communities as well as environmental, public health, and labor interests.

Initial Modeling Results

It continues to be tough to follow the initial modeling scenario results as they were presented in real time and the underlying data was not provided. **We urge DEQ to provide the underlying data including sector-by-sector data as soon as possible so that we can further understand and study the modeling results.** We also look forward to the more complete modeling results to come as we understand that these were only partial results focusing on greenhouse gas reductions. With that said, we've outlined below a few of the questions we were left with as well as some initial observations.

Some Initial Questions

Having the data may help answer some of the questions below, but these were some of the questions we were left with:

- What exactly were the assumptions that were included? The summary chart of assumptions for each scenario only provides a high level sense of what the assumptions were, but not the specifics.
    - In particular, it was not clear what the assumptions included were for the Community Climate Investments which were a main subject of conversation at RAC Meeting #3. For example, did the models assume that all of the CCI's would reduce emissions and that they would be a ton for ton reduction?
    - What were the specific assumptions around RNG? There is a note in Slide 45 that RNG use assumptions go beyond SB 98. How far beyond and based on what data?
    - What are the specific technology assumptions being relied on in the different scenarios, particularly around electrification?

[2] See E3 report commissioned by California Energy Commission on The Challenge of Retail Gas in California's Low Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use - https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf; Regional Deep Decarbonization Study by Clean Energy Transition Institute - https://www.cleanenergytransition.org/meeting-the-challenge; Washington State Energy Strategy - https://www.commerce.wa.gov/wp-content/uploads/2020/11/WA-2021-State-Energy-Strategy-FIRST-DRAFT-2.pdf; and Rocky Mountain Institute's Building Electrification: A Key to a Safe Climate Future - https://rmi.org/building-electrification-a-key-to-a-safe-climate-future.

- Is the cap and the commensurate reductions in each Scenario reflecting emissions below 1990 levels, emissions below 2022 levels, or some other baseline? For example, when DEQ is talking about the target of 50% below by 2035 and 90% below in 2050 in Scenario 3, are those numbers below 1990 levels or some other baseline? Our assumption was that those would be tied to below 1990 levels consistent with the baseline for the overall state goals.
- What are the program design elements that made a difference or not (e.g. trading was noted as not making much of a difference) and what are the relative impacts of making adjustments to them? This type of information will be particularly important for conversations around designing the fourth scenario.
- What are the results for each individual sector under each scenario - e.g. is one sector using more CCI's than others?

Some Initial Observations
While it is challenging to provide observations without a full picture of the assumptions and data as discussed above, here are some of our initial observations:

- DEQ appears to be leaving a lot of potential emissions reductions on the table. The total regulated emissions appears to be less than 36 million MT in all of the scenarios. Total emissions that DEQ has the authority to regulate are much higher although an exact accounting from DEQ has still yet to be provided.[3] We asked for this accounting to determine how much the exemptions were leaving on the table in our comments after the first RAC meeting and would still very much like to see it. We offered up our best calculations at the time in those comments showing that DEQ could potentially be exempting almost a quarter of the emissions it could regulate. For an economy-wide program that is supposed to serve as the backstop to meeting our state goals, this is very concerning.

- Scenario 3 appears to demonstrate that targets that go above and beyond the targets in the Executive Order and are more consistent with the best available science are largely achievable, particularly in the earlier years when the reductions matter the most. There are just a few years at the end of the timeline where it appears emissions might exceed the long-term target and we would like to better understand what program design elements are causing that and how things might be adjusted to ensure the long-term target is also met.

Reflecting on the initial observations above, we want to continue to lift up some of the points that we have been raising in our previous comments and hope will drive discussions on the next scenario and ultimate design of the program:

[3] DEQ GHG Reporting Program 2019 Preliminary data shows total state emissions at 65 million MTCO2e. Seven million of that is from agriculture which DEQ says it does not have the authority to regulate. That leaves 58 million (with some of that being from landfills to be regulated under another program and from imported electricity which DEQ also says it does not have the authority to regulate).

- DEQ should work to design a program that reflects best available science and the closest proposed so far are the targets in Scenario 3 (50% below by 2035 and 90% below by 2050).
- No exemptions. DEQ has been modeling a number of exemptions in the scenarios – the biggest ones being electricity generators and a 300,000 ton threshold for non-natural gas fuel suppliers. There is no room for exemptions in a strong Climate Protection Program.

Thank you for your consideration of our comments and we certainly look forward to continuing the conversation once we see the fuller picture of modeling results, including the benefits of the program.

Sincerely,

Zachariah Baker
Oregon Policy Manager
Climate Solutions

Nora Apter
Climate Program Director
Oregon Environmental Council

Mr. Collin McConnaha
Manager, GHG Programs
Oregon DEQ

March 20, 2021

Dear Collin:

We write to share our support for the Community Climate Investment (CCI) Program suggested at the March 18 meeting of the DEQ and Rules Making Meeting (RAC). We are Cultivate Oregon, a woman-led non-profit that advocates for an equitable and sustainable food system that champions an environmental justice and scientifically supported approach to economic vitality for sustainable food, farms, families, and communities.

The CCI program is a perfect vehicle to support climate change adaptation and mitigation quality of life improvements in disproportionately impacted OREGON communities. But, there is an important caveat in our support for the proposed community climate investments program. We believe this mechanism is perfect for use as an "Alternative Compliance Instrument" concept for the <u>third-party nonprofits to be able to incentivize a healthy soils program</u>. We also strongly advocate that nonprofits must achieve a balance with supporting projects that represent **both** environmental justice needs as well as emission reduction/carbon capture projects <u>that result in healthy soils</u>.

Here is a list of why Cultivate Oregon agrees with the DEQ suggested approach to the community climate investments program, which would involve Oregon nonprofits.

1. Regionally located nonprofits can best identify, recommend, and manage a pass through mechanism to fund various climate adaptation and mitigation projects in their locale that supports both environmental justice needs as well as carbon sequestration programs that support healthy soil ecosystems.
2. Rural Farming communities characteristically have higher illness rates, poor environmental quality, limited access to adequate health care, and areclassified by the USDA as under-resourced and under-served.. 25% of Oregon land mass consists of farm land and 25% is privately owned forests that typically/often border these disproportionately impacted communities.
3. Regional coalition partnering nonprofits know their impacted communities, the local farmers, and some also have the expertise to understand how to develop, monitor, and achieve healthy soil practices, thus covering all sides of any community climate investment project.
4. An Alternative Compliance Instrument would allow the third-party non-profits you mention to financially incentivize soil carbon sequestration and healthy soil practices on working lands located in areas also targeted for environmental justice gains within impacted, rural communities.
5. Healthy soils programs reduce co-pollutants, improve air and water quality, reduce/eliminate pesticides, and use fewer energy inputs, reduce soil erosion, absorb and hold greater volumes of water that will be crucial during periods of present and coming drought, AND sequester carbon. It's a practice ready to go since there are years of data from programs and experiences in other States (and countries) to draw upon.

Cultivate Oregon can support, facilitate, and grow a community climate investment program.

- Our experienced staff are leaders in the fields of healthy soils production. We recently developed and held an international symposium on the topic of "Enabling Regenerative Agriculture: Getting Paid for Improving Soil Health" with 300 participants from various States, affiliations and from Australia. https://www.cultivateoregon.org/video_gallery

- Cultivate Oregon will make history next month when we hold an award/recognition ceremony with our coalition partner Friends of Family Farmers, to **recognize** and **award** Oregon farmers and ranches who are already active in producing healthy soil ecosystems for their communities; see this link https://www.cultivateoregon.org/press_release_living_soil_awards

- Cultivate Oregon has decades of agricultural technical experiences as university trained educators and scientists on topics of healthy soils production; we also have farmers on the Cultivate Oregon steering committee to work with and advise us on our efforts who already use healthy soil practices;
- We have professional experiences working, supporting, and collaborating with other nonprofits, networks, and community groups related to farming, food, and environmental justice in Oregon.

Cultivate Oregon has leadership capabilities and the desire to work with coalition partners to see that there is a state-wide unified coalition that is prepared to establish local projects in and around disproportionately impacted communities - should such a program ever become a reality in Oregon.

Cultivate Oregon is part of a coalition of like-minded non-profits located in different regions of Oregon that includes Our Family Farms, Friends of Family Farmers, Oregonians for Safe Farms and Families, Oregon Organic Coalition, Southern Oregon Climate Action Network, Beyond Toxics, Oregon Climate and Agriculture Network, and others. We are also a member of the Rogue Valley Food System Network and the Oregon Community Food Systems Network, a collaboration of 53 nonprofit organizations and allies dedicated to strengthening local and regional food systems to deliver better economic and social community environmental justice needs, as well as health and environmental outcomes in the food and seed systems across the state.

Cultivate Oregon and our coalition partners have deep and extensive roots in our communities across Oregon. We have the relationships, environmental attorneys support, decades of agricultural education experiences especially on the topics of healthy soils, and important connections with farmers and ranchers who are a part of the disproportionately impacted rural communities that would seek support if such a CCI program becomes a reality.

Cultivate Oregon would like to collaborate with the Department of Environmental Quality to bring Community Climate Investment programs to Oregon to incentizise and encourage the growth of health soils. Please See our website for more information https://www.cultivateoregon.org/

Sincerely,

Dr. Ray Seidler
Cultivate Oregon, Steering Committee

To: Colin McConnaha, Manager, Greenhouse Gas Program
Department of Environmental Quality

RE: Public Comment on Climate Protection Program RAC Meeting 3

Dear Mr. McConnaha,

The Douglas County Global Warming Coalition representing 450 residents of rural Douglas County offers the following comments regarding the RAC 3 meeting:

Regulation of Non-Gas Fuel Suppliers

A threshold of 300,000 metric tons is unacceptably high to ensure a comprehensive emissions reduction. This number allows 14% of emissions to escape regulation at a time when the best science tells us we must reach zero emissions by 2050. We urge DEQ to adopt a zero threshold approach. Since the reduction of emissions will take place over a thirty year period, there is ample time for polluting industries to adapt their business practices accordingly. A zero threshold also offers the advantage of addressing the vexing problem of variability since all entities would be covered. This removes the concern as to who would be covered and who would not. The program thus becomes easier to administer. While an initial benchmark needs to be set for each polluter, this would be true irrespective of where the threshold is set.

Community Climate Investment

While we fully support this concept, we wish to express our concern based on the presentation at the RAC 3 meeting. Specifically, there appears to be no correlation between the charge per metric ton to polluters and the cost of the projects designed to offset their emissions. Whether the price is set at $50, $100, or $200 per metric ton, if there is no way of determining in advance if it covers the cost of the project, it runs .the risk of not assuring a one-to-one equivalence in emission reduction offsets. Without that assurance, the reduction targets are severely compromised. Please clarify how DEU intends to address this concern.

We would like to suggest a different way of determining the cost of alternative compliance mechanisms. Rather than setting a price per ton in advance, Community Based Organizations would prepare projects in advance for submission with an accompanying price tag. . Emission reductions would be verified by a third party, or DEQ. Such a scenario for a ten ton offset might look like this:

Project A:	Ten Electric Charging Stations	$100,000
Project B:	Five Electric Vehicles	$150,000
Project C:	Twenty Electric Heat Pumps	$80,000

In this way, polluters would know precisely what they are paying for and what it would cost. There would be an assurance that the offset criteria of one-to-one is met and by having several bids, there is a built in cost containment mechanism. If there is a concern that this cost containment would provide too great an incentive for polluters to participate in the Climate. Community Investment Program rather than reduce their own emissions, the number of offsets allowed could be reduced.

We would reiterate the need to make sure any Community Climate Investment is measurable, verifiable, long term and, of course, offering· a one-to-one reduction in emissions.

Finally, this is not a case of having to choose between Community Climate Investments and full emission reduction. Two questions should always be asked when modeling this program:

Does it reduce emissions consistent with the established targets? Does it meet the standards of equity and climate justice? Both these questions must be answered in the affirmative.

Thank you for all your work on this program.

Sincerely,

Stuart Liebowitz on behalf of the Board of Douglas County Global Warming Coalition

143 Lane Avenue
Roseburg, OR 97470
Ph- 541-672-9819

From: Bob Yuhnke <Bob.Yuhnke@outlook.com>
Sent: Friday, March 19, 2021 12:23 AM
To: GHGCR2021 * DEQ
Cc: Zach Baker; Nora Apter; Meredith Connolly
Subject: Initial comments on Presentation at 3d RAC meeting (3/18/21)

DEQ Team, The modeling results presented today for scenario 1 show only a 33% reduction from the 2019 levels and 20% reduction from 1990 emissions, but it claims to reduce emissions by 80%. Scenario 3 shows only a 40% reduction from 2019 levels, and a 32% reduction from 1990, but claims to reduce emissions by 90%. The misleading nature of this presentation of the initial modeling results will seriously compromise the credibility of DEQ in this process if not clarified. The agency's credibility is important for all of us. Elders Climate Action is bringing this misleading information to your attention before filing more extensive comments so that you can ask ICF to clarify the presentation before it is distributed more widely. At this point the misleading information in today's presentation may be attributed to ICF. But if not corrected, it might appear as an effort by DEQ to mislead decision-makers, the media and the public.

The primary misrepresentation is that modeling scenarios 1 and 2 are presented as achieving 80% reductions, and scenario 3 as a 90% reduction. But the numbers presented do not demonstrate an 80% or 90% reduction from any baseline. To assert that the modeling demonstrates an 80% or 90% reduction is seriously misleading.

In the context of the Governor's EO directing DEQ to adopt a plan that reduces emissions by "at least 80%" from the 1990 baseline statewide GHG emission inventory, a casual observer would assume that emission reductions are referenced to that baseline. The Governor's EO builds on the statutory emission reduction targets enacted in HB 3543 (2007), which also establishes the 1990 emission baseline as the basis for calculating reductions. The six Global Warming Commission reports to the legislature measure all emission changes (increases and decreases) against the 1990 baseline. Your modeling does not report reductions against that baseline.

For those of us more involved in the Cap and Reduce process, the same assumption would apply based on DEQ's statement that "The Oregon Global Warming Commission utilizes the sector-based inventory to track progress toward Oregon's emission reduction goals." State of Oregon: AQ Programs - Oregon Greenhouse Gas Sector-Based Inventory Data. This statement implies that DEQ will also follow that method for reporting emissions changes. Nothing in the slides presented at the RAC today suggests that modeled emission reductions are not based on the amount of reductions the program will achieve compared to the 1990 baseline. But, in fact, the claimed emissions reduction reported for each regulatory scenario is not related to the 1990 baseline or any other baseline described in the presentation.

To avoid the misunderstanding that most observers would take from the presentation, the slides should clearly explain what baseline is used for calculating reductions, and at least one graphic should be shown for each scenario demonstrating the fraction of the 1990 baseline that would be reduced by that scenario, and the fraction that will not be reduced by regulatory actions, so that any observer can easily compare the asserted outcome of each scenario with the percent reduction targets from the 1990 baseline set by statute and Governor Brown's EO.

During her introduction of the presentation today, in response to a question asking why the initial program year shows only 33 mMT of CO_2e compared to the 66 mMT inventory for 2019, Lauren Slawsky explained that the % reductions are based on the baseline of emissions from regulated sources. But the 80% and 90% reductions claimed for these scenarios from the regulated sources baseline misrepresent the modeled results as well.

The emission bar for 2050 shows that Scenario 1 would presumably reduce regulated source emissions from 33 mMT CO_2e to about 11.6 mMT, but that is only a 65% reduction from the 2022 emission line, not 80%. When the unregulated emissions are added into the scenario, total emissions are reduced about 22 mMT to about 44 mMT which is only a 33% reduction from 66 MT in 2019 and a 20% reduction from 1990.

Scenario 3 would presumably reduce regulated source emissions to about 6.6 mMT, but that is only about an 83% reduction from the 2022 emission line, not 90%, a 40% reduction from 2019 levels, and a 32% reduction from 1990 .

None of the results reported for these scenarios achieve the asserted reductions of 80% or 90%. You need to get honest with the claims you make using these data.

In addition by not showing emissions from unregulated sources, it would appear that the presentation hides the effect that increased power generation to meet the added load from electrification of commercial and residential space heating, transportation and industrial process sources will have on emissions from electric power generators. ECA submitted comments after the first RAC meeting that included a link to a PGE planning document indicating that PGE expects demand in their service area will grow 75% to 90% between 2020 and 2050, partly as a result of the electrification of other sources. The report by Ms. Harris today identified electrification as one of the major reasons why emissions from transportation and buildings will decline by 2050, but she provided no information about the effect that increased electrification will have on emissions from EGUs. The climate program implications of your decision to exclude from regulation emissions from in-state EGUs is being covered up by not showing emissions from unregulated EGUs. The emission reductions shown in the slides may be a serious misrepresentation of net reductions if a significant share of those emissions are being shifted from tailpipes to power plant stacks.

The modeling results are misleading so long as they do not disclose the effect that electrification of petroleum and natgas-fueled sources will have on load. This is another reason why emissions from unregulated sources must be disclosed. In addition, the assumptions used to estimate the increase in load that will result from transitioning from petroleum fuels for vehicles, and from natgas for space heating to electric power must be explained so that the methodology used and results obtained can be compared with utility demand growth estimates.

For each scenario we would like to see the ICF estimates of the growth in the size of the OR vehicle fleet between 2020 and 2050, the fraction of the vehicle fleet assumed to be electrified by 2035 and 2050, total VMT within OR for each horizon year, and the conversion rate used to determine the increased power demand that will result from each ton of petroleum fuel not burned. We also request information from ICF about any comparisons they made between their electric power demand estimates and the load growth estimates developed by PGE and PacPower, how ICF estimates future demand, and what utility planning documents ICF referenced to obtain the utility load growth estimates used for comparison.

Please provide documentation for the assumptions used to develop ICF demand projections, and links to the utility planning documents consulted by ICF or DEQ in advance of the next RAC meeting.

ECA will submit more extensive comments addressing other issues raised today during the RAC presentation.

Bob Yuhnke
Elders Climate Action
303-499-0425

COMMENTS IN RESPONSE TO DEQ PRESENTATIONAT THIRD CAP and REDUCE ADVISORY COMMITTEE MEETING

Submitted by

Robert E. Yuhnke

On behalf of Elders Climate Action, Oregon Chapter

I. **Executive Summary.**

These comments focus on ECA's opposition to the regulation of fuel suppliers as the primary strategy for reducing CO2e emissions from on-road transportation sources.

ECA incorporates by reference its prior comments, including 1) comments highlighting the climate science demonstrating why anthropogenic emissions must be reduced to zero to stabilize the climate as reported by the Intergovernmental Panel on Climate Change (submitted Dec.9, 20202); and 2) comments summarizing the impending harm to numerous values important to Oregonians, including harm from expanding wildfire burn zones that damage forest and aquatic resources, property, community stability, public health, wildlife habitat and economic activity, that will continue to devastate Oregon as the climate continues to warm which emphasize the need to stabilize the climate by achieving zero emissions as soon as possible (submitted February 16, 2021).

ECA opposes this regulatory approach because it cannot achieve any of the three goals supported by ECA as the basis for the Cap and Reduce program: a) reductions in CO2e emissions sufficient to help protect Oregon from a continuously warming climate, b) equity for frontline communities adversely affected by emissions from transportation sources of GHGs, and c) minimize costs to Oregon's economy.

Regulating CO2e emissions through fuel suppliers will fail to meet these goals because--

- Regulation of the fossil C content of fuels to reduce CO2e emissions does not offer the possibility of achieving zero CO2e emissions from transportation sources because vehicles will continue to be powered by internal combustion engines (ICEs) that will remain dependent on the availability of petroleum-derived fuels.
- Zero CO2e emissions from transport vehicles can only be achieved by replacing ICE-powered vehicles with zero emission vehicle (ZEV) technologies.
- The Oregon Health Authority identified exposure to the myriad harmful pollutants emitted from ICE tailpipes as contributing to the greatest public health risk for low income and communities of color caused by air pollution. Oregon Climate and Health Report (OHA, 2020), pp. 40-41.
- Health risks are greatest for communities exposed to emissions from heavily trafficked highways where concentrations of the harmful co-pollutants emitted from tailpipes that cause or contribute to childhood asthma, increased mortality from cardiovascular disease, lung cancer, and obstructive pulmonary disease is greatest.

- Low income and BIPOC communities, including many elders and some residential facilities for elders requiring specialized care, are most likely to be located in close proximity to heavily trafficked highways.
- Greater exposure to highway pollution contributes to a nearly twofold greater incidence of childhood asthma compared to white children, and as much as a 30% greater incidence cardiovascular disease among adult men.
- The health risks to low income and BIPOC communities will not be significantly reduced by modifying liquid fuels to substitute bio-C for fossil-C because the co-pollutants emitted from ICEs will continue to be emitted regardless of the source of carbon in the fuels.
- Replacing ICE vehicles with ZEVs eliminates all tailpipe pollutants and protects residents near highways and students attending schools near highways from harmful exposure to incremental concentrations of tailpipe pollution, and will eliminate the largest source of emissions that cause metropolitan-wide exposure to urban smog.
- Programs to reduce CO2e emissions through modifying fuel sources or reducing fuel use are unfair and inequitable because they impose disproportionate and discriminatory costs on low income families and BIPOC communities.
- CO2e emissions reductions through the regulation of fuel suppliers are achieved by either reducing the carbon content of the fuel, or reducing the amount of fuel available. Either approach has the effect of increasing fuel cost to the end-user.
- Fuel and maintenance costs of compact and mid-sized ICE vehicles are equal or greater than the purchase cost over the 20 year life of the vehicle. For low income families, fuel and maintenance costs are the primary cost of transportation in the family budget since they rarely if ever pay the purchase cost of a new vehicle.
- Increased fuel costs have a much greater adverse economic impact on low income and BIPOC communities because transportation costs represent a much larger share of the family budget. In metropolitan areas with long commutes between neighborhoods with affordable housing and job locations, transportation can exceed 25% of low income family budgets.
- By driving up family transportation costs, without providing significant reductions in exposure to the co-pollutants emitted from ICE vehicles, residents in low income and BIPOC communities bear a disproportionate burden of the cost without experiencing any health benefit from reduced exposure to harmful pollutants.
- Where programs that drive up fuel costs have been implemented in Europe, Asia and Africa, public resistance has been organized and often violent. Public support for reducing climate emissions has been diminished, and programs defeated.
- The net economic and social cost of ZEVs is much more favorable. Used ZEVs are comparable in cost to used ICE vehicles, and the cost of fuel and maintenance is one-third or less than those costs for used ICE vehicles.
- Nationally, the estimated annual cost for electricity to drive the same distance (VMT) as currently driven by ICE vehicles is $125 – 150 billion annually compared to $330 billion paid at the pump by consumers for petroleum fuels.

- In Oregon, fuel cost savings would range between $2 to $3 billion annually. These savings will remain in the pockets of Oregon residents, be spent locally, and create thousands more jobs annually than if that revenue stream ended up in the Oil Patch.

ECA will submit more detailed comments at a later date to provide documentation supporting these conclusions.

ECA asks that DEQ develop a regulatory program designed to promote and require the replacement of ICE vehicles at the end of their useful lives with ZEVs.

Respectfully submitted,

Robert E. Yuhnke

Moore Noise, LLC

March 26, 2021

Oregon Department of Environmental Quality
Cap and Reduce Program
700 NE Multnomah Street, Suite 600
Portland, OR 97232-4100

Submitted via email to GHGCR2021@deq.state.or.us

Re: Rules Advisory Committee Meeting #3 – Comments

This comment letter is submitted on behalf of EVRAZ Portland. Thank you for the opportunity to participate in the Rules Advisory Committee (RAC) Workshop 3 to support development of the Oregon Climate Protection Program (CPP) regulations. Oregon Department of Environmental Quality (DEQ) staff requested input and discussion on Community Climate Investments and leakage in the fuels sector during Workshop 3.

RAC Process

We agreed to participate on the RAC with the full intention to bring our technical resources and understanding to the process and provide meaningful input, support for a greenhouse gas reduction program, and an openness to options and differing views. We are increasingly concerned that we have no reasonable ability to provide meaningful input, particularly on specific issues DEQ has stated are expected from the RAC. From the Advisory Committee Charter, the RAC is expected to consider:

- Whether the rules will have a fiscal impact, and if so, what the extent of that impact will be.
- Whether the rules will have a significant adverse impact on small businesses, and if so, how DEQ can reduce the rules' negative fiscal impact on small businesses.

In addition to the fiscal impacts, DEQ requests input on specific issues regarding program design elements at each meeting. As members of the RAC, we are asked to provide quality input to DEQ on program design issues in isolation from their interface with other program elements and supporting technical information regarding how they would function in the program. Increasingly, we are being asked to provide input on issues (specifically, leakage) for which DEQ has stated they do not intend to provide supporting technical analysis. We are becoming concerned that the technical analysis completed to support the assessment of program effects, particularly fiscal effects will be insufficient to support reasonable discussion, let alone conclusions. Given the scope of the CPP in the economy of the State of Oregon, this is very disturbing.

In leanings, DEQ appears to show an interest in having the minimal number of entities to regulate. Our current understanding is that this may result in all, or most, of the allowable emissions under the cap being allocated to 3 natural gas companies, and approximately 6 large liquid fuel companies. We would like to note that these companies appear to be publicly traded entities with a primary point of accountability to their shareholders. Although these companies may be good corporate citizens, by design, public benefit would not be a first goal of these companies. We are concerned that this arrangement may not provide the most cost-effective path to emissions reduction for the citizens of Oregon and will not support the innovation and infrastructure needed to successfully phase-out greenhouse gas emissions over the long period of the next 29 years. It may be difficult to change the basic structure of the regulations once they are in place.

Ordinarily, we would wait to see what the next RAC meetings bring prior to commenting on these broader issues. However, the CPP is on a tight timeline and we are halfway through the originally scheduled RAC meetings with the schedule to issue proposed regulations only 4 months away.

Community Climate Investments

In general, Community Climate Investments (CCI) appear to be a reasonable policy component to include in the overall category of Alternative Compliance Options (ACO) for the CPP, but not a full solution. We have the following comments on the potential use of CCIs:

- Noting that DEQ's initial policy assumption in the modeling scenarios was $200 per metric ton (2020 dollars) for CCI, this is not a realistic path to compliance for most entities and not reasonable for EITEs. Alternative paths of compliance would be needed.
- There is an inherent disconnect (and this was discussed in the breakout sessions) between the cost-effective need for emission reductions from regulated entities, and at least a portion of the needs of the Environmental Justice communities. EJ representatives expressed distress that CCI was only considered a monetized item by the regulated community. This is valid. EJ communities may need investments in entrepreneurship, training, or infrastructure that may not result in a ton of emissions reductions for the investment. On the other hand, regulated entities and the overall success of the program will be judged against firm emissions caps. Both investments in the need of the EJ communities, and the innovation needed to meet the long-term, more difficult emissions reductions are not served by the basic form of the Cap and Reduce (without a method to raise funding for investment) of the regulatory path versus the legislative path of Cap and Trade (or Cap and Invest).
- There must be a method to allow regulated entities to use a least cost path to compliance. This would not be possible in a system without cost competition. Compliance is likely to be difficult particularly in future years. Regulated entities will need broad flexibility to comply with the program. It might better serve the program to require a portion of ACO to go into a CCI at the same cost as other available ACOs.
- The use of Alternative Compliance Options should be broadly flexible to control costs. ACO from outside of Oregon, and broadly within Oregon should be allowed. Using a proportional contribution approach would allow funding of CCI and control costs. It could also allow decoupling of CCI from the metric of a one-to-one reduction of emissions.

Leakage

Leakage and the Tragedy of the Commons

Leakage is the tragedy of the commons, phase 2. In the classic tragedy of the commons story, farmers add more and more grazing animals to the common pasture until the grazing is not sustainable and the pasture becomes desert. In the analogy to greenhouse gases, the pasture is the atmosphere, the cows the emissions of greenhouse gases, and the farmers are the economic producers meeting consumer demand.

In phase 2 of the tragedy, some of the farmers decide to protect the land. They are unable to get broad cooperation from all the farmers so they divide up the land into individual ownership. Let us say there are 4 farmers. Farmer 1 wants to improve their land and reduces the number of animals grazing on their land. However, Farmer 1 does not want to reduce the amount of product they consume or sell, so they purchase products from Farmers 2, 3, and 4. The pastures of Farmers 2, 3, and 4 fall further into disrepair. Soon, Farmers 2, 3, and 4 are applying immense amounts of fertilizer and water to their land to increase production so they can continue selling to Farmer 1. The contaminated water seeps onto Farmer 1's land and the land is degraded anyway. In this analogy, Farmer 1 is Oregon imposing emissions caps, but not addressing leakage of emissions (the purchase of production from Farmers 2, 3, and 4). The impact changes location, but not intensity. In the analogy, because the atmosphere cannot be divided up, the concentration of greenhouse gases and their impacts continue, or even potentially increase.

The only realistic solution is for Farmer 1 (Oregon) to reduce their purchases and consumption, or to acknowledge there is a limit to the willingness, or ability to reduce actual consumption.

Leakage from the Oregon Fuels Sector

Leakage risks to outside of Oregon are substantial. Leakage has real costs associated with it. Modeling of program impacts should account for this issue. If this is not an issue to be explored in the initial sensitivity analyses, the models should at least be set up to account for it with reasonable accuracy in the program scenarios. Otherwise, the technical information needed to make appropriate decisions regarding how to control leakage and reduce emissions is not available.

General methods used to control leakage in Cap-and-Trade programs focus on cost controls. These methods may also be appropriate for use in Cap and Reduce (Oregon CPP).

Leakage in the Electric Sector

It is a concern that increases in the emissions from the electric sector are not being shown for evaluation of this program in DEQ presentations. It is an even greater concern that electric sector emissions are not being accurately accounted as a design of the modeling scenarios.

Recently published technical analyses of the Regional Greenhouse Gas Initiative (RGGI) and the California Cap and Trade electric sector emissions show likely substantive leakage from the electric sector under both programs (50% to 70%). The approach to accounting for electric system emissions DEQ is using is like the accounting under the California program. Oregon should appropriately account for electric emissions to show our reliance on the integrated system. Those coal plants in Montana are in fact contributing to reliability, cost control, and emissions on the system. We are benefitting from the emissions profile of our regional electric system. Making modeling assumptions that assume all the “bad” emissions stay in Montana, or Idaho is simply not real. This type of assumption is referred to as allowing “reshuffling contracts”.

Renewable Energy Portfolio standards have been, and will continue to be, an effective point of leverage to increase the overall renewable energy component of the regional electric system. But this should not be misinterpreted as changing the actual emissions contribution Oregon makes to the atmosphere through our electric use.

I have attached recently published articles on emissions leakage from the RGGI and California systems (Attachment 1). Note that the Oregon electric system is similar to California on its reliance on electric imports to meet electric needs, and DEQ’s currently proposed emissions accounting is similar to California’s in the potential use of reshuffling contracts (with unaccounted leakage) as the basis of emissions estimates.

Thank you for the opportunity to weigh in on these issues.

Sincerely,
Moore Noise, LLC

Martha Moore

Martha Moore, PE
Principal Engineer/Member

cc: Debbie Deetz Silva/EVRAZ

Attachment 1

Journal of Environmental Economics and Management 87 (2018) 1–23

Contents lists available at ScienceDirect

Journal of
Environmental Economics and Management

journal homepage: www.elsevier.com/locate/jeem

Leakage in regional environmental policy: The case of the regional greenhouse gas initiative ☆

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ARTICLE INFO

Article history:
Received 21 September 2016
Available online 9 November 2017

ABSTRACT

Subglobal and subnational greenhouse gas policies are often thought to be less effective than comprehensive policies as production and emissions of trade exposed industries may move from the regulated to the unregulated regions, a process referred to as "leakage". Leakage negates some emission reductions from the regulated regions. We use detailed electricity generation and transmission data to show that this is the case for the Regional Greenhouse Gas Initiative (RGGI), a CO_2 cap-and-trade program for the electricity sector in select Northeastern U.S. states. More specifically, our results indicate that RGGI induced a reduction in coal-fired generation in RGGI states and an increase in NGCC generation in RGGI-surrounding regions. This finding suggests that the pollution haven hypothesis holds for state-level variation in environmental policy, even when compliance costs are low.

Introduction

As a truly global climate policy appears unattainable, many nations have moved forward unilaterally or in coalition with other countries to establish their own emission reduction policies. This sub-global policy development is also now being mimicked at the national level as several sub-national regions are taking the initiative to develop climate policies despite the inability of their respective federal governments to take meaningful action to reduce greenhouse gas emissions.[1] These sub-global and sub-national policies raise concerns about policy-effectiveness. More specifically, the economics literature has well documented how regional policies may lead to emissions leakages, whereby emission reductions in regulated regions are at least partially offset by policy-induced emission increases in unregulated regions. While this leakage issue has garnered much attention, econometric studies on the topic are rare.

In this paper, we use the sub-national policy of the Regional Greenhouse Gas Initiative (RGGI), a regional cap-and-trade system for CO_2 emissions from electricity generation in the U.S. among select Northeastern states, to econometrically

☆ We thank ABB for providing access to their Velocity Suite database tool, as well as Brian Murray, Laura Grant, Ian Lange, Adrienne Ohler, Elizabeth Wilson, and participants at Colorado Energy Camp 2015, APPAM 2015, AERE 2015, and ASSA 2016 for their comments and suggestions. All remaining errors are, of course, our own.

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[1] Example of sub-national policies can be found in the U.S. where California and, separately, a collection of Northeastern states under the Regional Greenhouse Gas Initiative have forged their own carbon emissions trading programs. Likewise, in Canada, the provinces of British Columbia and Alberta have imposed a carbon tax and Quebec has a carbon trading program.

http://dx.doi.org/10.1016/j.jeem.2017.10.007
0095-0696/

investigate instances of leakage. This is a particularly interesting program to examine in light of the current movement towards local and state-based climate policies Worland, 2017. This push for state level climate programs has also manifested in the recent federal Clean Power Plan (CPP), a national plan which allows states substantial discretion in meeting emissions targets. Under the CPP, neighboring states could choose different compliance mechanisms while continuing to allow trade (see Bushnell et al. (2017) and Burtraw et al. (2015)).

As noted above, there is already an extensive economic literature on the issue of carbon leakage. This literature is largely focused on the impacts of sub-global policies and uses computable general equilibrium (CGE) modeling frameworks or other numerical simulation models. Carbone and Rivers (2014) provides a thorough review of these types of studies, as well as some basic meta analyses. Their review suggests that the leakage impact of climate policy in emission-intensive, trade-exposed industries is relatively small.[2] This result is not that surprising given imposed international trade frictions. Additionally, many of these studies compare various policies to combat leakage, such as border adjustment taxes or output based allocation schemes (see Fischer and Fox, 2012).

Several recent papers have also explored sub-national policies using simulation-based modeling. As it relates to carbon pricing policies, much of this literature has focused on two sub-national cap-and-trade systems in the U.S., RGGI and the California cap-and-trade program.[3] Fowlie (2009); Bushnell and Chen (2012); Bushnell et al. (2014), and Caron et al. (2015) explore leakage possibilities across states due to California's (CA's) recently enacted carbon cap-and-trade system. These papers find varying degrees of leakage in the electricity sector due to reshuffling, where states in the regions around CA reshuffle their power exports to CA such that they, at least on paper, export less emissions intensive power (e.g., natural gas-fired power) to CA and use more emissions intensive generation sources (e.g. coal-fired power) to satisfy their local demand resulting in increased emissions in the regions surrounding CA.

With respect to RGGI, Murray and Maniloff (2015) find a substantial reduction in emissions under the RGGI program, but do not examine the possibility of leakage. The simulation-based analyses of Wing and Kilodziej (2008) and Shawhan et al. (2014) predict considerable increases in power exports from states surrounding those covered by RGGI. There has also been several RGGI-based reports commissioned on behalf of RGGI Inc. and various states and carried out by consulting agencies and multi-state working groups (see RGGI (2007) and Hibbard and Tierney (2011)). These works also find a relatively wide range of leakage predictions. Below we more thoroughly discuss how our estimates compare to these and other ex-ante predictions and why our results may differ.[4]

Econometric estimates of leakage from imposed climate policies are far less common, though a few studies exist. For example, in Aichele and Felbermayr (2013) and Aichele and Felbermayr (2015), the authors conduct an econometric analysis and show that Kyoto Protocol signatories seem to have reduced emissions, but that countries with binding commitments under the Protocol have increased the embodied carbon of imports from non-committed countries by approximately 8 percent. From a domestic standpoint, and more closely related to this study, Kindle and Shawhan (2012) empirically estimate the relationship between daily Pennsylvania(PA)-New York(NY) transmission flows or daily PA CO_2 emissions and RGGI permit prices. Finding no statistically signficant impacts of RGGI permit prices on PA-NY transmission flows or PA CO_2 emissions, they conclude RGGI has had no significant effect on NY to PA leakage. However, their dataset only includes the early years of the program and given their linear specification and the relatively constant permit prices early in the sample it is not surprising that they fail to find a signficant impact of RGGI permit prices on their dependent variable. Also if the full effects of RGGI were delayed due to, for example, multi-year preexisting contracts for electricity procurement, then leakage could have occurred after their period of study. Additionally, if the effect of input fuel prices is kinked or nonparametric as in Cullen and Mansur (2017), a linear model could errantly find a null result, particularly with respect to Pennsylvania emissions. We are able to gain stronger statistical power in our analysis by using a panel data set with longer time coverage and nonparametric input-price controls.

Other related econometric literature can be found in those works exploring “pollution haven” effects and those looking at how regional energy prices affect trade flows and physical location of energy-intensive manufacturing facilities (e.g. Levinson and Taylor (2008); Kahn and Mansur (2013), and Aldy and Pizer (2015)). Similar to the idea of carbon leakage, these studies generally find that increases in a region's relative energy price or relative stringency of environmental regulation increase the emissions-intensity of imports into these regions and reduces the prevalance of energy-intense manufacturing. However, this work has primarily focused on trade between countries.

This study adds to the econometric investigations of pollution havens and environmental policy leakage from a sub-national policy by examining the RGGI program. As noted above, this application is particularly interesting for several reasons. First, as a sub-national policy aimed at the electricity industry, the leakage impacts of RGGI are likely quite different

[2] For instance, their meta analysis suggests that a policies aimed at reducing GHG emissions by 20 percent in developed countries results in a 5 percent output loss among energy-intensive, trade-exposed industries. They refer to “competitiveness” instead of leakage, but are describing a closely phenomenon in which industrial activity in a regulated region is displaced by activity in a non-regulated region.

[3] It should be noted there are several sub-national policy examinations that are not carbon-pricing related. For example, Carley (2011) models the impact of state energy policy portfolios, finding that leakage renders unilateral policies ineffective but that policies coordinated between states can result in substantial CO_2 reductions. Jacobsen et al. (2012) create a numeric simulation model to analyze the leakage affects brought about by some states' efforts to limit the GHG per mile of automobiles. They find that these state-level regulations are effective at reducing the emissions rates of new cars within the adopting states, but that there would also be significant leakages in non-adopting states in both used and new car markets.

[4] There are many other RGGI-based simulation studies, such as Hibbard and Tierney (2011); Matthias and Gabriel (2008), and Dallas and Palmer (2005), but the focus of these papers is largely on aspects other than leakage.

from those considered in the simulation-based or econometric models focused on leakage impacts in international trade contexts. More specifically, many of the trade frictions one may consider in an international trade context are much higher than those likely experienced in a domestic electricity trading scenario. Second, while some simulation-based studies of the potential impacts of RGGI exist, these electricity models often have some limiting assumptions made to allow for computationally tractable simulations or conversely are heavily parameterized to allow great technical detail. By econometrically estimating responses in a reduced form framework we can circumvent some of these assumptions.[5] Additionally, these simulation models were also ex-ante examinations of the program and thus conducted in a time before hydraulic fracturing greatly expanded the natural gas supply and lowered natural gas prices in the U.S. This turns out to be a key factor as it greatly changed the emission intensity of the unregulated areas surrounding the region regulated under RGGI and therefore affected the aggregate emissions impact of RGGI. Finally, this study differs significantly from other empirical investigations of RGGI-induced leakage, namely that of Kindle and Shawhan (2012), in that we use electricity generation data which allows us to estimate RGGI impacts on generation across technologies and regions.

In this analysis we conduct two distinct, but complementary analyses. The first uses detailed electricity generator-unit level data to estimate a difference-in-differences operational impacts associated with RGGI. For this analysis, we use operational data for coal-fired and natural gas combined cycle (NGCC) generators. We merge this with a rich set of controls including the plant's own fuel costs, prices for substitute fuels, regional demand, and controls for regulations a given plant faces. We use local load and NERC-region renewable generation covariates to control for demand for fossil generation.

Our results indicate that, after controlling for these factors, coal plant capacity factors (the ratio of actual generation to total generation capacity) have decreased substantially in the RGGI region when the policy was in place. Additionally and importantly, we also find that plants in Pennsylvania and Ohio, two states that are not part of RGGI but that have transmission capabilities that gives generators in these states access to RGGI regions, saw capacity factor increase by approximately 10 percentage points after controlling for input prices, demand, and other environmental rules. However, based on our preferred specification, this compensating Non-RGGI generation was not spread across all generating technologies, but rather the increase in generation from the RGGI-surrounding regions appears to come almost exclusively from natural gas combined cycle units. We also present evidence that this increase in gas-fired generation is independent of and in addition to the effects of the boom in gas production due to tracking. As a result of this generation substitution pattern we calculate RGGI-induced decrease in CO_2 emissions within RGGI at about 8.8 million tons annually and RGGI-induced increases in emissions in RGGI-surrounding areas of about 4.5 million tons annually.

In our second analysis, we examine changes in electricity transmission flows during RGGI. The dataset is monthly electricity transmission across electricity grid interfaces, where an interface represents the point at which two sub-units of the electricity grid connect. The primary interfaces to transmit electricity into the RGGI region are into New York from Pennsylvania and Ohio. Our analysis shows a statistically significant result that electricity imports to New York from outside the RGGI region increase substantially during RGGI. Thus it appears electricity transmission into the RGGI region increased during the RGGI period.

Taken together, these analyses provide evidence of generation leakage effect, whereby generation in RGGI regions decreased and was supplemented by increased generation from RGGI-surrounding regions. The leakage is not an accounting artifice but instead reflects real changes in fossil fuel generation activities.

The remainder of the paper is organized as follows. In section *Policy and industry background*, we give a brief description of the RGGI program and of the power system in the Northeast U.S. The estimation strategy is reviewed in *Empirical methodology*. *Data* describes the data used. Section *Results* discusses the results. Concluding remarks are made in *Conclusions*.

Policy and industry background

RGGI is a cap-and-trade system for CO_2 emissions from the electricity generation sector, currently covering generators in the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.[6] The program began in 2009, with permits being allocated through quarterly auctions. Permit prices from these auctions have been quite low, which is not surprising given that the program began during an economic downturn. However, the program does have a price floor in the auctions which has effectively maintained permit prices around two dollars per ton.[7].From the standpoint of leakage possibilities, another key aspect of the RGGI design is that power imported

[5] To be clear, conducting an econometric analysis also comes with multiple assumptions. Our point here is that many of the detailed simulation models tend to be either heavily parameterized to provide much technical detail about the electricity sector or more sectorally-aggregated to assess large economy-wide aspects. While the detail may lead to more specific predictions of generator behavior or overall economy behavior, the results rely on the underlying technical assumptions, such as cost or technology diffusion assumptions. Our reduced form econometric model does not make such underlying technical assumptions and generally finds relationships with relatively few assumptions. The downside of such reduced form is that we unable to provide the same level of detail about the mechanisms of RGGI-induced change that one may be able to ascertain from a highly parameterized engineering model or a more structural econometrics model.

[6] Generators in New Jersey were also covered under RGGI, but New Jersey opted out of the program in 2011. While the program targets greenhouse gases, reductions in greenhouse gas emissions have associated cobenefits from reducing other local air pollutants (Burtraw et al., 2014).

[7] More programmatic details on RGGI can be found on the RGGI Incorporated website: www.rggi.org

into RGGI-regulated regions is not subject to the emissions cap or any other border adjustment mechanism. Given this feature, it is obvious that the primary leakage mechanism possible is to reduce generation in RGGI-regulated regions and to cover the load in these regions by importing more power from generation sources outside the RGGI region. To more fully understand the particulars of this mechanism, some discussion of the U.S. power system in the Northeast U.S., and the U.S. more generally, is warranted.

Power generation and transmission in the U.S. is conducted through a somewhat unique mix of traditionally regulated integrated utilities, which own both the generation capacity and have a retail arm that sells power to end users, and competitive wholesale structures. The power sector in the Northeast U.S. falls largely in the competitive wholesale market structure. In these wholesale markets, generating units sell power on to a wholesale market and retail entities buy power on these markets to eventually sell to end-user consumers.[8] An Independent System Operator (ISO) organizes these wholesale markets such that power supplied and demanded across a particular region is constantly balanced. The RGGI states span three electricity grid management regions - New York ISO (NYISO), ISO New England (NEISO), and PJM RTO (formerly Pennsylvania-Jersey-Maryland). These regions can be seen in Fig. 1. As one can see, while NYISO and NEISO regions are made up entirely of RGGI-participating states, PJM covers states both in and out of RGGI. It is also worth noting that power within these regions can be transmitted relatively easily, though some intra-ISO capacity constraints exist. Transmission across adjacent ISO's is also possible through more limited “interconnection” points.

Given this set up, it seems likely that generation from RGGI would most likely be supplanted by generation from Ohio (OH) and other non-RGGI regions of PJM, in particular generation from Pennsylvania (PA).[9] We therefore identify our possible “leaker” states as OH and PA and use this designation in our analysis of generating units and transmission flows. That is, the entire states of PA and OH will be designated as “leaker” states.

Empirical methodology

The general goal of our empirical investigation is two-fold. First we test if RGGI had differential impact on generators' production decisions for those plants in RGGI and those in areas where RGGI-induced leakage is likely to occur relative to those plants not near the RGGI region and, thus, likely unaffected by the regulation. Second, we explore how RGGI has affected transmission flows out of the likely “leaker” region. Below we describe our strategy for both investigations.

At the outset, however, it should be noted that given the time frame of our analysis, combined with the relatively low permit prices during what may be considered an embryonic effort to price carbon emissions, we do not consider longer-run capital decisions (e.g. plant retirements and construction, widespread energy efficiency capital deployment, or deferred maintenance on fossil generators). While affecting the long-run investment behavior may be the ultimate goal of the regulator implementing a carbon pricing scheme, we do not have the data yet to explore these issues. This empirical estimation will thus only examine a subset of the total impacts of the RGGI program. This exercise will only consider short-term electricity generation decisions, conditional on demand and infrastructure. If the RGGI program's substantial investments in energy efficiency lead to reductions in total electricity consumption, or if the program changed other capital investment decisions, our estimates will not include these demand or capital effects and thus the total emissions effect of the RGGI program could be larger than our treatment effect estimates.[10]

Generator-level models

To determine if RGGI impacted the production of generators, we estimate a difference-in-differences (diff-in-diff) model using annual generator-level data. We estimate this diff-in-diff model separately for the two generating technologies most likely respond to the RGGI, coal-fired plants and natural gas combined cycle (NGCC) plants.[11] Our diff-in-diff set up is one in which we estimate two different treatment effects associated with RGGI, a treatment effect for those plants directly regulated by RGGI and a treatment effect for plants in the likely leaker regions, which we define to be all of PA and OH. For our core specifications, the control group consists of all generators within the given generation technology (i.e., coal-fired or NGCC) that are not either in a RGGI state or in a leaker state.[12] The dependent variable in this diff-in-diff are annual capacity factors, the ratio of annual generation to annual generation capacity. The more specific form of the estimation is given as:

[8] Beyond sales through the wholesale markets, bilateral trading between generating and retail units also exist in these markets.

[9] Leakage could also occur to eastern Canada, but the trade flows between NYISO and Canada have historically already been in the direction of Canada to NYISO, so there would seem less of a possibility of a RGGI-induced change on that front. To the extent RGGI did incentivize leakage from RGGI to Canada, that would largely be met with increased hydro production from Canada given its generation mix. Unfortunately we do not observe Canadian generation and thus restrict the scope of our study to intranational leakage.

[10] Annual electricity consumption in RGGI states from 2009-2012 was 6% below 2005 levels, while total US consumption increased by approximately 1% over the same period (EIA, 2014, 2017).

[11] Other lower cost technologies present in RGGI and surrounding regions, such as nuclear, hydro, and other renewables are non-emitting and generally inframarginal and are therefore likely unaffected by carbon pricing. Other higher-marginal cost fossil-fuel-fired plants, such as simple-cycle natural gas plants and diesel generators are generally called upon for production during high demand periods only. Given the relatively inelastic nature of electricity demand, it is also unlikely that carbon pricing will impact generation from these higher-cost technologies.

[12] We consider several other refinements of the set of control plants. These results are reviewed in more detail in our discussion of robustness checks.

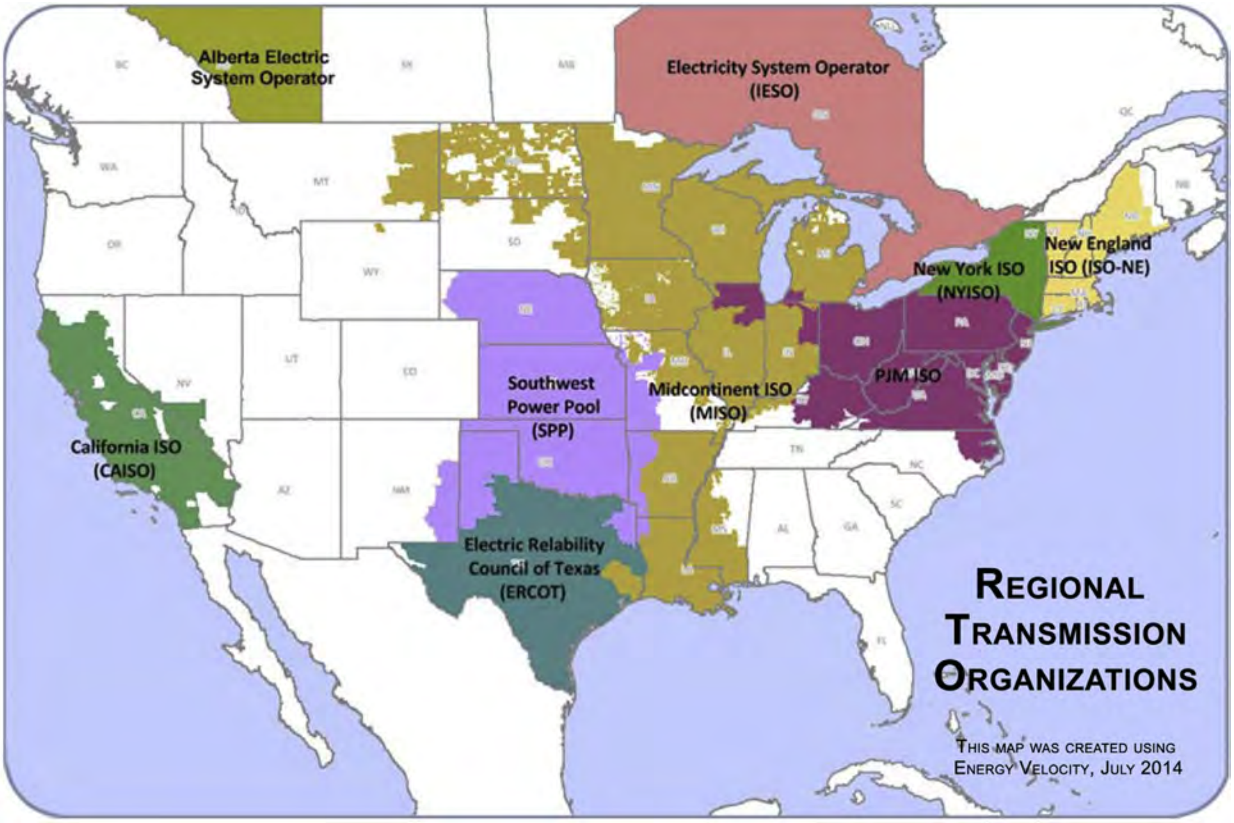

Fig. 1. Map of Independent System Operators and Regional Transmission Organizations.

$$CF_{it} = \sum_{j \in J} \alpha_j TREAT_{it}^{j} + \mathbf{X}'_{it}\beta + f(Z_{it}) + \gamma_t + \theta_i + \varepsilon_{it} \tag{1}$$

CF_{it} is generator i's capacity factor specifically defined as the net generation (MWhs) from plant-technology i in year t divided by nameplate capacity (MW) times the number of hours in t.[13] $\mathbf{X}_{it}$ is a set of controls such as regional demand for electricity and other relevant environmental policies affecting generator i in period t discussed in more detail below. Z_{it} is the ratio of plant-technology input fuel costs to regional fuel costs of competing generation technologies. The input price ratio enter (1) in the general functional form $f(Z_{it})$ because we consider specifications that allow input fuel prices to enter the model non-parametrically as well as polynomially.[14] Time and generator fixed effects are represented by γ_t and θ_i, respectively.

The variable $TREAT_{it}^{j}$ is the treatment dummy, with our base specification as $J = [RGGI, Leaker]$. The treatment dummies for the base specification are then defined as $TREAT_{it}^{RGGI} = 1$ if plant i is in a RGGI-participating state and $t \geq 2009$ (when RGGI is in effect)[15] and $TREAT_{it}^{Leaker} = 1$ if plant i is in OH or PA during the years t when RGGI is in effect.[16] Note also that the RGGI program effect is estimated as a discrete treatment effect instead of continuous treatment effect that would reasonably be determined by the carbon permit price. We model RGGI as a discrete treatment effect because over the time span we examine there was very little variation in the carbon price. Auction clearing prices before the compliance period started were slightly more than three dollars per ton of CO_2, and declined to the price floor of approximately two dollars in 2009.

[13] Note that several facilities are comprised of multiple generating "units", where each unit is of a specific generating technology. For plants with multiple generating units, we derive our CF_{it} variable for a given plant-technology i as the sum of the net generation from all units of the technology in question (coal or NGCC) within the given plant in year t divided by the sum of the capacities of those technology-specific units times the number of hours in t.

[14] Considering non-linear and non-constant responses to input prices in the electricity sector has been suggested by, among others, Cullen and Mansur (2017). In Cullen and Mansur (2017), they consider nonparametrically modeled coal-to-gas price ratios when estimating price impacts on regional emissions from the electricity sector and show there is a highly non-linear relationship between electricity-sector emissions and input price ratios.

[15] For New Jersey plants, $2009 \leq t \leq 2011$ because New Jersey left the program in 2011.

[16] We also considered specifications where only one treatment effect entered the model (i.e., the model would include *either* $TREAT_{it}^{RGGI}$ or $TREAT_{it}^{Leaker}$) and the control plants are the same as in our base specification. Treatment effect estimates from running the treatment effects separately are nearly identical to those presented below and were thus omitted from the text. In addition to this specification, we consider several other variations on our treatment and control specifications which we discuss in more detail below.

The carbon price was then approximately two dollars for the duration of our study period.[17]

Standard theory about regulation-induced leakage and emissions pricing in general help us frame expectations about the sign of the treatment effects (the α_j's) across the different treatment groups and generation technologies. First, in the absence of leakage, we might expect emissions pricing to lead within-RGGI fuel switching from higher emissions-intensive coal generation to relatively cleaner natural gas, suggesting a negative treatment effect for RGGI coal plants and a positive treatment effect for gas plants in RGGI. However, with trade exposure, one would also expect a leakage effect whereby generation in RGGI is decreased and generation in nearby unregulated regions increases. The leakage effect should therefore create negative treatment effects for RGGI plants and a positive treatment effect for plants in the leaker states. The overall policy effect will combine both the fuel switching effect and the leakage effect, implying that $\alpha_{RGGI} < 0$ for coal generators in RGGI and α_{RGGI} to be ambigously signed for RGGI-NGCC generators.

For the plants in the leaker region we would expect $\alpha_{Leaker} > 0$ given the leakage affect. However, whether or not both generation technologies examined, coal and NGCC, respond to this leakage affect in the leaker region will depend on their relative marginal costs (MCs) during the treatment period. For example, in the simple two-technology, two-region model we present above, the leaker-region coal did not respond to the policy as it remained inframarginal both pre- and post-implementation, but the leaker-region gas generator did increase its generation in response to the policy suggesting $\alpha_{Leaker} > 0$ for NGCC plants and $\alpha_{Leaker} = 0$ for coal plants. In reality, the MCs of the generator types over our time span and study areas is less obviously ordered. Typically, we expect coal generators to have a lower MC than NGCC generators, but near the time RGGI went into effect, natural gas prices dropped dramatically due to fracking. As such NGCC plants became more cost competitive with coal, so it is possible that the leakage effect in the leaker region could be even stronger for NGCC plants than coal plants.[18]

Proceeds from RGGI permit auctions also funds a variety of energy efficiency programs, renewable energy projects, and energy bill subsidies for low income households. To the extent that these policies alter energy demand and increase renewables, their impacts will be subsumed in our controls for load and renewable energy production, respectively. These additional impacts will thus not be picked up by our RGGI treatment dummies. Moreover, if the impact of energy efficiency programs compounds over time (due to the long lifespan of electricity-intensive consumer durables, for example), then *ceteris paribus* we would expect emissions demand to decline, causing a reduction in the emissions price and thus a reduction in leakage. However, energy efficiency investments are not happening in a vacuum. RGGI is also moving towards a tighter emissions cap (Vogel, 2017), which increase the emissions price and could lead to an increase in leakage. The future net effect is unclear.

Additionally, if the price of RGGI allowances is passed on to electricity consumers (as in Sijm et al., 2006), then consumers may demand less electricity. While this effect is likely modest due to the low allowance price and inelasticity of electricity demand (Ito, 2014), demand response would also act to reduce RGGI emissions beyond our point estimates.

Estimation of the generator model

There are two primary options for estimating a model with both fixed effects and a nonparametric term such as Eq. (1): either take first differences (as in Baltagi et al. (2002)) or make a parametric assumption about the nonparametric term and subtract the individual level average value of each variable.[19] Each method has tradeoffs for this application.

Working in first differences is a valid estimator in the limit, however our treatment effects each occur at the same time period. Thus in first differences, the *change in the treatment effect* has a zero value for all periods except the initial treatment period, when it is one. If firms do not respond fully in the initial period (for example, responses are lagged as firms learn about the new policy or undertake compliance activity), then this estimator may underestimate the true respose. This issue of requiring instaneous responses is particularly problematic for high frequency data, such as daily data, as it requires responses on day one of the policy. On the positive side, first differencing does allow us to estimate Eq. (1) with no assumptions about the functional form of $f(Z_{it})$. In order to ameliorate concerns about the immediate-adjustment assumption, we will aggregate to the calendar year level for this model.

Alternatively, we can also estimate Eq. (1) with a traditional within estimator. However, this manipulation requires an assumption about the functional form of $f(Z_{it})$. We approximate $f(Z_{it})$ with a high-order polynomial function. While we are forced to make somewhat more restrictive functional form assumptions, using the traditional within estimator is more appropriate for the higher frequency data as it does not require instaneous reponses in the treatment effect. Using higher frequency daily data is advantageous as it allows us to leverage intrayear variation in natural gas prices, more precisely identifying the effect of variation in input prices.

We thus have two different approaches to estimating Eq. (1): using low-frequency (annual) data that allows the price ratio to enter non-parametrically, and using higher frequency (daily) data but assuming a polynomial expression for price. For completeness, we will also present results from estimating the polynomial model with low-frequency data.

[17] Auction results available at https://www.rggi.org/market/co2_auctions/results

[18] One might also expect generators to respond to an emissions price by increasing their operational efficiency. We also examined this possibility by using heat rate (the amount of fossil fuel energy used to generate a unit of electricity) to efficiency and found no evidence of an effect on efficiency. These results are available on request. The econometrics follow our generation estimations below.

[19] Other options include assuming random effects (i.e. that the individual term is normally drawn and independent of other variables) or considering the individual effects as coefficients to be estimated. Neither is appropriate in this case.

Transmission model

We also estimate a diff-in-diff model of inter-region electricity transmission to find out whether there was a change in electricity exports from PJM to RGGI *relative to exports to other regions*. This is not a full model of electricity transmission which could support causal inferences as observations are not independent due to the process of balancing the electricity grid. Instead, any estimated effect should be considered to be merely correlative and supporting. If there were policy leakage from the RGGI region to the leaker region, we would expect an increase in generation from the leaker region to the RGGI region. However, due to the complexity of electrical transmission, we cannot give a causal interpretation to regression coefficients.

In our core specification, we use transmission between PJM and non-RGGI neighboring regions as a control for transmission from PJM to RGGI. If net exports from PJM increase uniformly, we expect to estimate a treatment effect of zero. However if net exports from PJM to RGGI increase relative to net exports to other regions, we will expect to find a positive treatment effect which would support the conclusion that an increase in generation in Pennsylvania and Ohio has indeed resulted in leakage into RGGI. The key identification assumption is that transmission in one region of an electricity grid (ISO or RTO) is a good control for transmission in another region. This is plausible because both non-policy determinants of generation and demand exhibit substantial spatial autocorrelation. If a weather system causes an increase in electricity demand, that happens at a regional scale. This increases transmission across the region.[20]

This logic motivates the empirical specification as:

$$y_{it} = \beta Treat_{it} + \gamma_t + \theta_i + \varepsilon_{it} \tag{2}$$

In (2), y_{it} is the net transmission across interface i in year t, where net transmission is defined as the sum of exports from PJM at interface i less the imports into PJM at that interface. $Treat_{it}$ in this specification is a treatment dummy equal to one if the interface i is one between PJM and a RGGI-regulated region for $t \geq 2009$ and zero otherwise. The parameters γ_t and θ_i pick up year and interface fixed effects, respectively, and ε_{it} is a mean-zero disturbance term.

The estimated coefficient β should be thought of as representing a conditional difference in means, but cannot be interpreted as a causal treatment effect.

It is important to note that the electricity grid boundaries do not neatly line up with political jurisdiction boundaries. Several states in RGGI are also part of PJM - Delaware, Maryland, and (until its departure from RGGI) New Jersey. Thus an increase of electricity imports into those states will not be counted in our analysis. If leakage also occurs inside PJM, then our estimates (with respect to transmission) will underestimate the full effect. Nevertheless, this analysis aides in reaffirming the estimation of RGGI-induced leakage.

Data

Our primary generation analysis uses generation unit-year level data. The data is provided by the data aggregation firm ABB and is based on largely on publicly available data sets, though some aggregation was conducted by ABB. Finally, as noted above, we present results only on coal and NGCC generators because they are the types most likely affected by the RGGI regulation.[21] As discussed in section *Estimation of the Generator Model*, there are tradeoffs to the estimation technique. Thus we also conduct analyses with daily generation unit data from the same sources. Using daily data also creates challenges. Primarily it is computationally infeasible to non-parametrically model the input price ratio using the daily data. Given the likelihood of a kink in generation responses to relative input prices, we consider the lower-frequency estimates to be our primary analysis because it allows for a more flexible functional form.[22]

We restrict our data to the period 2004-2012 because of subsequent changes in the electricity market in New England. Specifically, the only nuclear power plant in Vermont was closed in 2014, with the closure announced in 2013 (Wald, 2013). As operators could have responded in 2013, we truncate the study period to end in 2012. The period of study includes five years before and four years after the treatment date. While data is available for both before and after this time period, we are hesitant to extend our period of study because measuring the treatment effect over longer time horizons runs the risk of attributing other time-varying unobservables to the treatment effect estimate.

To form the dependent capacity factor variable for the generation analysis we get monthly generation (MWh's) and fuel

[20] Plug-in hybrids sales would constitute an unobserved demand shock that could be localized to particular parts of a transmission grid, i.e. high income areas. While they have increased in recent years, plug-in hybrid sales represented approximately one third of one percent of car sales in the final year of our study period and much smaller fractions in preceding years. Authors' calculation based on hybrid cars sales data from Inside EVs and light weight vehicles sales from the Bureau of Economic Analysis. Inside EVs: http://insideevs.com/monthly-plug-in-sales-scorecard/ BEA: https://research.stlouisfed.org/fred2/series/ALTSALES (both retrieved 01/20/2016).

[21] Results from single cycle gas-fired generators are provided in the appendix and, as expected, show effectively no RGGI impact on RGGI- and Leaker-region units.

[22] An additional benefit to using yearly time steps is that it smooths out maintenance outages. Plants undergoing periodic maintenance, both scheduled and unscheduled, appear in our data set to merely have abnormally low generation levels. Moreover, maintenance typically occurs during the shoulder season between summer and winter, but that is different months of the year in different climactic regions. By aggregating to the annual level, we effectively average out plant maintenance.

consumption (MMBtu's) data, based off of information provided in form EIA-923. To get capacity factors, we also collect generator-level nameplate capacity measures, based on EIA-860 data. With generation and capacity measures we form CF_{it} as described above. In addition, because some generation plants have multiple generators of the same technology (e.g. some plants have multiple NGCC generators or multiple coal steam generators) and because some of our data are at the plant-level only (e.g. fuel prices), we aggregate all generation, fuel consumption, and capacity measures for generators of the same technology within a plant. This aggregated data is then treated as a single generator in our analysis.[23]

Table 1 shows capacity factors for coal and gas plants before and during RGGI, along with their standard deviations. For this table, plants in Pennsylvania and Ohio are considered potential leakers, and all plants outside of RGGI, Pennsylvania, and Ohio are in the control group. Fig. 2 displays unconditional kernel density estimates which show this same information graphically. Note that coal use declined modestly in all regions during RGGI, and by a greater amount in RGGI states than in control states. Far more dramatically, note that while gas utilization increased modestly in control states and RGGI states, it increased by twenty-five percentage points in leaker states. This will form the core of our argument - natural gas generation in leaker states increased dramatically during RGGI, supplanting RGGI coal generation.

Controls for the generator-level analysis, X_{it}, include load and regulatory measures. Load is a measure of electricity demanded at a given time. As electricity is not storable and electricity generators are statutorily required to meet demand, load acts to shift the quantity supplied along the supply curve. Long-distance electricity transmission is costly and constrained by capacity, so we use the total load in the “transmission zone” for each plant.[24]

Electricity generators also face a variety of regulations unrelated to RGGI. Thus for coal plants we include indicator variables for SO_2 control equipment and NO_X phase as well as a NO_X budget plan indicator for gas plants. We additionally include the log of NERC-region renewable generation (including hydroelectricity) as a control variable. Including renewable generation is important because it may shift the relationship between load and fossil generation - as wind, solar, and hydroelectric generation are near zero marginal cost technologies, they are typically the first generation sources used when they are available.

The ratio of price of coal to the price of gas Z_{it} is based on plant-level fuel prices and local substitutes. The plant-level fuel prices are derived from monthly delivered fuel costs reported on EIA-923 forms.[25] For coal plants, the substitute fuel price is the natural gas price at the nearest natural gas price hub. For NGCC plants, the substitute price the generation-weighted mean cost of coal for coal plants in the NGCC plant's transmission zone. All prices are in cents per MMBtu, so the ratio of the coal to gas prices Z_{it} is ratio of the prices of equivalent amounts of energy from each fuel.[26]

Transmission data

Our transmission analysis uses interface-level data available from the PJM Regional Transmission Organization (RTO). PJM is one of a number of Independent System Operators (ISOs) and RTOs which manage the regional subgrids comprising the national electricity grid. PJM covers PA, OH, as all or parts of DE, IL, IN, KT, MD, MI, NJ, NC, TN, VA, WV, and DC. Fig. 1 illustrates the extent of ISOs and RTOs in the United States.

ISOs and RTOs in turn have sub-sub grids. Connections between these units are referred to as “interfaces”. We use monthly transmission across individual PJM interfaces.[27] Transmission can occur in either direction across an interface, and over the course of a month will typically occur in both directions. We collect the net transmission flow across an interface in each month. The data period is January 2004-Dec 2012, the same period of study as our generation analysis. For some specifications, we aggregate the net transmission across from PA to NY (across the NYISO, Linden, Neptune, and Hudson interfaces) into a single representative observation. Table 2 summarizes net transmission across control interfaces and New York interfaces before and during the RGGI period. Standard deviations are large because of substantial variation in both typical use of different interfaces and intra-interface variation. However, the key difference-in-differences result that transmission from PJM into New York increased relative to transmission across other interfaces is readily apparent.

[23] Beyond not having distinct fuel prices across same-technology generators within a given plant, this aggregation also makes sense within the fixed effects panel estimation undertaken here. More specifically, if the fixed effect picks up such generator-level heterogeneity as management quality, fuel terminal access, and/or transmission access these would be aspects shared by generators within the same plant.

[24] Transmission zones are defined by ABB. According to the ABB documentation, transmission zones “represent load pockets and these load pockets are derived through extensive analysis of FERC 714 data, ISO reports in ERCOT, WECC transmission cases and Multiregional Modeling Working Groups (MMWGs) in the Eastern interconnect.” Load for these areas is reported via data provided by the ISO's.

[25] The fuel cost data in the EIA-923 forms is reported for utilities in traditional cost of service regulated regions and other regulated power providers. Where the cost data is not available publicly, ABB assigns a fuel cost to the plant based on regional fuel prices and prices at similar plants.

[26] Coal is primarily transported by rail instead of by pipeline, so there is not a single public regional price.

[27] Available in Monitoring Analytics' annual “PJM State of the Market”, downloaded from http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml.

Table 1
Capacity factors before and during RGGI.

	Coal Pre Treatment	Coal Post Treatment	Gas Pre Treatment	Gas Post Treatment
Control	0.61	0.51	0.31	0.35
	(0.19)	(0.22)	(0.20)	(0.20)
RGGI	0.50	0.30	0.31	0.36
	(0.21)	(0.18)	(0.23)	(0.21)
Leaker	0.60	0.45	0.15	0.41
	(0.20)	(0.25)	(0.11)	(0.22)

Notes: Standard deviations listed below means. Gas is NGCC only.

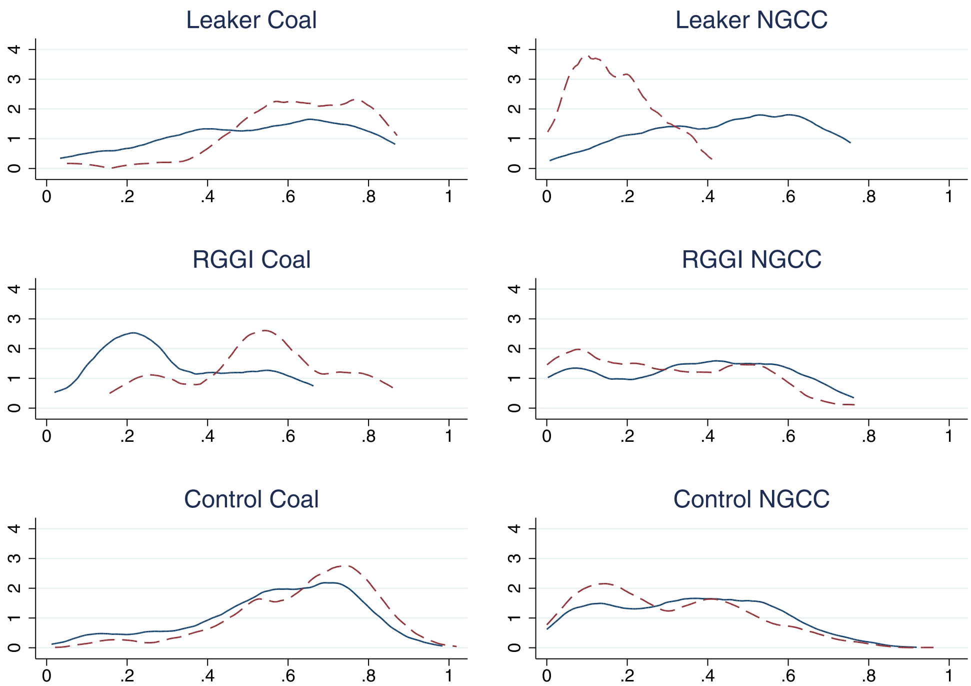

Fig. 2. Capacity factor kernel densities. *Dash line: Pre-treatment. Solid line: Post-treatment.*

Table 2
PJM transmission before and during RGGI.

	Before Treatment	After Treatment
Control	21.932	−13.452
	(314.809)	(339.903)
New York	488.557	756.505
	(351.886)	(740.943)

Notes: Standard deviations listed below means. Units are GwH.

Results

Generator-level results

We begin by presenting the estimation results from the analysis on capacity factors as given in equation (1). As noted above, this analysis was conducted for coal and NGCC plants separately. In specifications with annual data, the nonparametric term controlling for the coal-gas price ratio $f(Z_{it})$ is modeled with a rule-of-thumb bandwidth, while in specifications with daily data we use a high-order polynomial. We also consider two different specifications of the time trend, a cubic time trend and annual fixed effects. Generally, one would consider annual fixed effects to be a preferred specification in controlling for common time-varying unobservables. However, out of concern that annual fixed effects for annual data might

Table 3
Capacity factor - yearly.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
Leaker	0.119***	0.101***	−0.015	0.012
	(0.028)	(0.029)	(0.024)	(0.024)
RGGI	−0.019	−0.028	−0.103***	−0.073*
	(0.016)	(0.017)	(0.037)	(0.038)
Observations	1723	1723	2010	2010
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. "Time Trend" denotes the manner in which time effects are accounted for where "Cubic" means a cubic time trend was included and "FE's" mean the model includes year fixed effects.

Table 4
Capacity factor - daily.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
Leaker	0.157**	0.154**	0.0600***	0.0693***
	(0.0645)	(0.0651)	(0.0201)	(0.0209)
RGGI	−0.0167	−0.0183	−0.0952***	−0.0878***
	(0.0189)	(0.0195)	(0.0280)	(0.0281)
Observations	513191	513191	726688	726688
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. "Time Trend" denotes the manner in which time effects are accounted for where "Cubic" means a cubic time trend was included and "FE's" mean the model includes year and month-of-year fixed effects.

effectively soak up the variation in other control variables, and in particular in our flexible specification of the input price ratio, we additionally include specifications with a cubic time trend.

Tables 3 and 4 give the treatment effect parameter estimates for the specifications of (1). The first two columns give the results for the case where the sample is restricted to NGCC generators and across the two different time trend specifications and the final two columns are the results using only coal generators. The "RGGI" line gives the treatment effects estimate for α_{RGGI} and the "Leaker" line gives the parameter estimates for α_{Leaker}. Additional controls for this specification, beyond the nonparametric input price ratio, include the log of transmission area load and NERC region renewable generation, log of NERC region coal and NGCC capacity, NO_X phase, an indicator for the presence of SO_2 control equipment, time controls, and individual fixed effects. Parameter estimates associated with these controls are included in the appendix in Tables 11–13 .

For RGGI generators, we see that NGCC generators' capacity factors have a small and statistically insignificant response to RGGI, but RGGI coal generators did have a RGGI-induced reduction in capacity factors of about 9 to 10 percentage points. Conversely, in the leaker region, we estimate that RGGI led to 10 to 15 percentage point increase in capacity factors for NGCC generators, with mixed results for coal generators. In daily specifications we find that leaker coal capacity factors increased by approximately 6 percentage points, but we find a small and insignificant response from the annual, semiparametric model.[28] This discrepancy in leaker coal results could either be due to the higher frequency and stronger statistical power of daily analysis, or because the polynomial functional form for price ratio overstates the effect of fracking on coal plants. If this were the case, then the positive effect on coal would be spurious.

Together, these results suggests that there was no significant within-RGGI fuel switching from coal to NGCC plants, which is typically considered to be a low-cost option to reduce CO_2 emissions. Rather, it appears that a primary compliance mechanism was to turn down coal plants in RGGI. This, as the parameters describe, did lead to leakage whereby the reduced coal-fired generation in RGGI was compensated for by increased generation in the leaker regions of PA and OH.[29]

To further assess if the treatment effects imply a leakage effect we conduct a basic back-of-the-envelope calculation to

[28] These results are qualitatively robust to $f(Z_{it})$ being a lower order polynomial or a natural logarithm of Z_{it}. However, some fully parametric specifications yield substantially larger treatment effect estimates for Leaker NGCC plants. This result is consistent with Cullen and Mansur (2017)'s argument that a parametric price specification may not fully capture fuel switching behavior, and that instead there is a kink at the price ratio where NGCC generation becomes inframarginal to coal on the dispatch curve. If the parametric specification under-predicts fuel switching at high coal-gas price ratios (which would be consistent with Cullen and Mansur (2017)), then due to collinearity between Leaker treatment and low gas prices, the Leaker treatment effect would be overestimated. The semi parametric specification is therefore our preferred specification.

[29] For completeness sake, Table 5 presents treatment effects from estimating the fully parametric model with yearly data. We find substantially larger effects for Leaker NGCC plants, suggesting that the parametric price model may not precisely capture fuel switching. However, the results are broadly similar, with a significant increase in Leaker NGCC and a significant decrease in RGGI coal generation.

Table 5
Capacity factor - yearly parametric model.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
Leaker	0.210***	0.206***	−0.004	−0.002
	(0.028)	(0.029)	(0.019)	(0.020)
RGGI	−0.061**	−0.064**	−0.077**	−0.069**
	(0.026)	(0.028)	(0.031)	(0.031)
Observations	2,077	2,077	2,317	2,317
Controls	Y	Y	Y	Y
Fixed Effects	Y	Y	Y	Y
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. "Time Trend" denotes the manner in which time effects are accounted for where "Cubic" means a cubic time trend was included and "FE's" mean the model includes year fixed effects.

see if the reduction in RGGI-coal is roughly equal to the increase in Leaker-NGCC. To do this, we multiple our estimated treatment effects of an 11.9 percentage point increase in Leaker NGCC capacity factor and a 12.1 percentage point decrease in RGGI coal capacity factor (specifications 1 and 3 of Table 3, respectively) times the average annual generation capacities to find the estimated generation leakage. Per these estimates, we find that Leaker NGCC generation increased by approximately 11 million megawatt hours per year, whereas RGGI coal generation decreased by approximately 9.3 million megawatt hours per year. A t-test cannot reject the null that the RGGI-induced Leaker NGCC generation increase and RGGI coal generation decrease are equal (p-value = 0.67 for the test that their difference is different from zero). In terms of emissions, these generation changes imply that production leakage increased Leaker CO_2 emissions by 4.5 million tons per year and decreased RGGI CO_2 emissions by 8.8 million tons per year, for an aggregate decrease of 4.3 million tons per year.[30]

Our estimated RGGI-treatment effects imply a RGGI-induced leakage of approximately 50%.[31] This appears to be well within the range of ex-ante predictions of leakage from the simulation-based studies. For instance, on the lower end of the spectrum, RGGI (2007) found leakage rates of approximately 27%, whereas Shawhan et al. (2014) finds leakage short-run leakage rates over 100% and longer-run rates (20 years in) at around 70%.[32] Closer to our estimate, Wing and Kilodziej (2008) find an electricity-sector specific leakage of about 50%, but an overall leakage rate closer to 70%. While our econometrically estimated leakage rate falls within the range ex-ante predictions, the modeling assumptions and modeling structures are such that direct comparisons are difficult. For instance, RGGI (2007) and Shawhan et al. (2014) are examples of long-run models that include generation capital expansion and retirement. As a result, both papers get much of their leakage action through building of new gas-fired generators outside of RGGI rather than within RGGI (relative to a no-RGGI baseline). We have a relatively short window over which we are analyzing RGGI and therefore do not see much capital turnover, though affecting long-run capital decisions is clearly a goal of carbon pricing policies. On the other hand, Wing and Kilodziej (2008) is a static CGE model that models several sectors of the economy. While this model is useful in showing the potential emission impacts of RGGI on industries outside the electricity sector, it aggregates in a manner that does not allow one to see the inter-fuel substitutions we find in our results.

The reader may be skeptical that the modest carbon prices under RGGI were enough to affect the price difference between Leaker region NGCC plants and RGGI region coal plants. We calculate a back-of-the envelope calculation to compare the effect of the carbon price to other operating price differences between generators. Table 6 shows several percentiles of calculated variable costs for RGGI coal plants, RGGI coal plants including the RGGI carbon price, and Leaker NGCC plants under several gas price scenarios. Column (1) describes the 25th, 50th, and 75th percentiles of RGGI coal generators' fuel cost per kilowatt hour. In Column (2), we add the cost of emissions per kilowatt hour for RGGI coal plants facing a $2 carbon price. Columns (3)–(5) list the same percentiles of fuel cost per kilowatt hour for Leaker NGCC plants under low, medium, and high gas price scenarios.

The median fuel cost for RGGI coal plants increases from 1.9 cents per kwh to 2.1 cents per kwh with a $2 carbon price. If gas prices are low, as they often have been during RGGI, the median RGGI coal plant facing a $2 carbon price has a fuel and emissions cost per kwh that is comparable to the fuel cost per kwh of the median Leaker NGCC plant (column (3)). In a medium gas price scenario, Leaker NGCC plants generally have higher per kwh fuel costs than the RGGI coal plants' fuel and emissions cost, but the gap between relatively expensive RGGI coal plants at the 75th percentile (2.5 cents per kwh) and relatively cheap Leaker NGCC plants at the 25th cost percentile (2.8 cents per kwh) is substantially reduced (column (4)). If

[30] Based on an average RGGI coal heat rate of 11,184 BTU/KwH and coal CO_2 content of 205 lbs/mmbtu and average Leaker NGCC heat rate of 6722 BTU/KwH and gas CO_2 content of 117 lbs/mmbtu.

[31] Note that the implied emissions changes from the RGGI-treatment effects are not the same as the total emission changes during the periods RGGI is in effect. Other changes, including changes to load, input fuel prices, renewable energy, and unobservable factors picked up by our time trends or time fixed effects, will also drive generation and emission changes over our sample. However, these changes are not specifically attributable to RGGI, whereas our RGGI treatment effects are.

[32] Leakage rates for Shawhan et al. (2014) are based on their 5k bus model results presented in Table 4 of their text.

Table 6
Calculated fuel costs in cents per kwh.

Percentile	RGGI Coal		Leaker Gas		
	(1)	(2) $2/ton	(3) Low Gas	(4) Medium Gas	(5) High Gas
25th	1.7	1.9	2.1	2.8	3.5
50th	1.9	2.1	2.1	2.9	3.6
75th	2.3	2.5	2.3	3.1	3.9

Calculations based on generation units reported fuel consumption and generation. Calculations used a carbon price of $2/ton, coal price of $44/ton, and gas prices of $3, $4, and $5 per mcf across scenarios. Calculations used emissions rates of 0.05 tons/mcf of gas and 9.37 x 10-4 tons/pound of coal from https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

gas prices are relatively high, even relatively efficient NGCC plants at the 25th percentile of cost remain a cent per kilowatthour more expensive than RGGI coal plants facing a carbon price (column (5)). These calculations are only illustrative - in particular, are based on average rather than marginal fuel costs. However, they do suggest that the modest RGGI carbon price would have substantially reduced the cost gap between gas and NGCC, particularly during times of low gas prices.

An examination of identification assumptions

The identification of the treatment effect in this diff-in-diff setting hinge on several key assumptions. First, we must assume the treatment is exogenous. Given that the formation was a largely political process among geographically close states it seems reasonable to assume that the decision to start RGGI was largely exogenous to generator behavior. The decision of a state to join RGGI may however have been a function of the state's generation profile which may prompt concerns of selection bias, but even if this was true it seems unlikely that the participation decision was driven by the operations (capacity factors and heat rates) of the given plants. Second, we must also assume that RGGI does not affect generators beyond the RGGI region and adjacent leaker region. This too seems plausible as states farther away than the leaker region have less direct access to RGGI and are therefore not likely places for leakage and given the relatively small geographic region of RGGI it is unlikely its passage had noticeable impacts on input prices or other important electricity supply determinants. If RGGI does cause leakage to states beyond Pennsylvania and Ohio (such as Virginia), that would bias our estimation towards zero.

We also need to assess whether or not our control generators have similar pre-treatment trends as the treatment regions. To explore this more thoroughly we estimate the following equation:

$$CF_{it} = \sum_{j \in J} \alpha_{jt} D_t TREAT_i^j + \mathbf{X}'_{it}\beta + f(Z_{it}) + \gamma_t + \theta_i + \varepsilon_{it} \tag{3}$$

where D_t is a year dummy with $D_t = 1$ in year t and 0 otherwise, $TREAT_i^j = 1$ if generator i is *ever* in treatment j, and, thus, α_{jt} are estimated parameters that pick up a treatment group specific time trend. We do this for both polynomial and non-parametric specifications of $f(Z_t)$. A plot of the α_{jt} terms, along with 95% confidence bands, are given in Figs. 3–6. These plots show that for both the RGGI and Leaker treatments the pre-treatment period time fixed effects are not statistically different from zero, indicating they have similar pre-treatment trends as the control group.

The treatment period coefficients are substantially larger for than the semiparametric difference-in-difference estimates. There are two distinct reasons. First, the semiparametric panel estimator is a first differences estimator, so its estimated treatment effect describes the change from 2008–2009. Second, the scale of fracking operations trended upwards over our

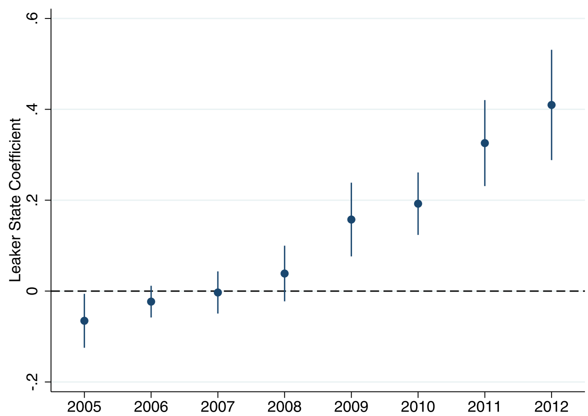

Fig. 3. Semiparametric NGCc treatment effects, leaker states. Vertical lines represent 95 percent confidence intervals.

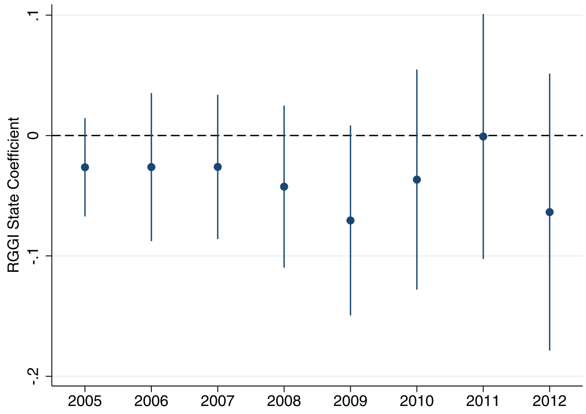

Fig. 4. Semiparametric NGCC treatment effects, RGGI states. Vertical lines represent 95 percent confidence intervals.

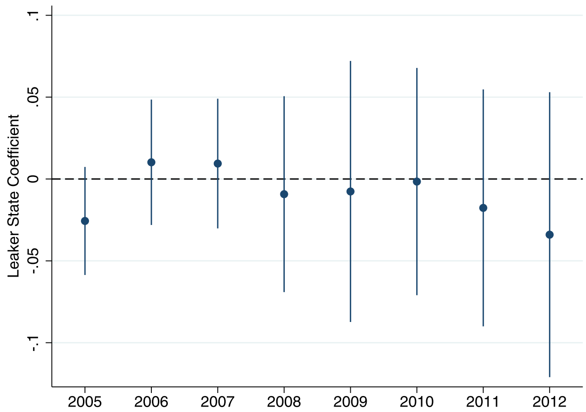

Fig. 5. Semiparametric coal treatment effects, leaker states. Vertical lines represent 95 percent confidence intervals.

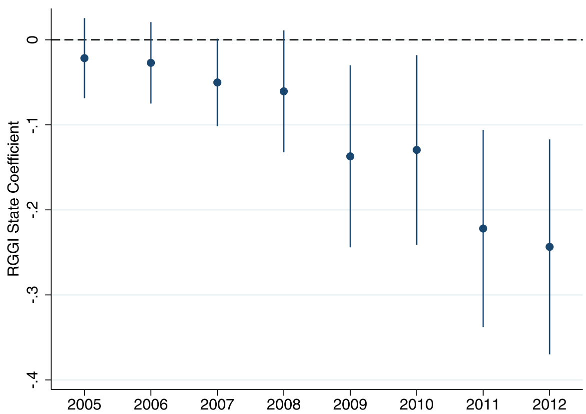

Fig. 6. Semiparametric coal treatment effects, RGGI states. Vertical lines represent 95 percent confidence intervals.

treatment period. If there were to be collinearity between treatment and Z_{it}, perhaps due to the increasing scope of fracking activity, then allowing the treatment effect to vary by year could exacerbate the collinearity.

There may also be concern that the fracking boom which occurred in Pennsylvania during our treatment period exposed Pennsylvania NGCC plants to uniquely low gas prices. If so, the Leaker NGCC treatment effect could merely reflect low gas prices. However, gas is transported via pipeline on a regional basis, so we would expect prices to have declined across leaker, RGGI, and control states. We see this in Fig. 9. We see that both coal and gas plants faced higher coal-gas price ratios (cheaper gas) during the RGGI period than before. However, there was a common support of prices - leaker plants did not

Table 7
Sensitivity analyses for yearly regressions.

VARIABLES	(1) NGCC	(2) Coal	(3) NGCC	(4) Coal
Leaker	0.124***	−0.038	0.111***	−0.018
	(0.029)	(0.025)	(0.028)	(0.024)
RGGI	−0.013	−0.126***	−0.012	−0.104***
	(0.017)	(0.038)	(0.016)	(0.037)
Observations	680	745	1168	1641
Control Group	Deregulated	Deregulated	Eastern	Eastern

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications account for time effects with a cubic time trend and for price effects non parametrically. “Control Group” describes whether the control group is non-treatment deregulated states (“Dereg”) or non-treatment plants in the Eastern Interconnection (“Eastern”).

have higher price ratios than control plants. Instead, even for values near one (reflecting very cheap gas), we see that the control state plants faced a similar distribution of prices as leaker plants, and that control plants covered the full range of prices faced by leaker plants.

Robustness checks

We perform a variety of robustness checks to further assess the sensitivity of the estimated treatment effects. To begin, because the control group includes plants from all the contiguous U.S., we estimate Eq. (1) with two different sets of control generators. First, because RGGI and the leaker regions are in states that have deregulated their electricity markets, we limit the control group to generators also in states that have also deregulated. Results from this specification have the control group designated as “Deregulated States”.[33] Second, because plants in the western United States may be poor controls for unobserved common time effects in the northeastern U.S., we limit the control group to plants on the Eastern Interconnection.[34]

Tables 7 and 8 present the treatment effect estimates under various control group specifications for the model using annual data with nonparametrically modelled input-price ratios and the model using daily data with parametrically modelled input-price ratios, respectively. The first two columns of these tables show the treatment effects for NGCC and Coal generators using the “Deregulated States” control group and the last two columns report results using the “Eastern” control generators. Results are numerically similar across both control group specifications and are similar to our base results that use a broader control group.

We also assess the sensitivity of the treatment effects to changes in the merit order. More specifically, when natural gas prices are high, the carbon price introduced by RGGI should have little impact on the merit order and less impact on leakage. To examine this we use the daily data to form two indicator dummies, one that equals one for a day that has a daily gas price in the top 10 percent of our sample (a “High Gas” dummy) and the other that equals one for days where the daily gas price falls in the bottom 10 percent of observed prices (a “Low Gas” dummy). We then estimate models, using the daily data, that include “Leaker” and “RGGI” treatment dummies and these treatment dummies interacted with the “High Gas” and “Low Gas” dummies. Results for these specifications are given in Table 9. As expected, when gas prices are high, there is no statistically significant, RGGI-induced leakage (i.e. the sum of the parameters on “RGGI” and “RGGI * High Gas” and the sum of the “Leaker” and “Leaker * High Gas” parameters are both not statistically different from zero for both columns of Table 9). On the other hand, when gas prices are low, the carbon price can more dramatically change the merit order, and leakage increases somewhat. This is consistent with Cullen and Mansur (2017)'s finding that carbon prices cause a smaller reduction in electricity-sector emissions when gas prices are high because the carbon price is not enough to switch the merit order. High gas prices mean that the dispatch curve (essentially a supply curve for electricity from different plants) is steeper, and that coal plants are inframarginal.

In a similar vein, we also use hourly generation data (also accessed from ABB) to explore treatment effect heterogeneity across peak and off-peak periods. To do this we aggregate generation across the 12-h peak period of 8 a.m. to 8 p.m. to form a daily “peak” capacity factor and aggregate over the remaining hours to form a daily “off-peak” capacity factor. We then use these daily capacity factors to estimate the treatment effects. Results from the “peak” and “off-peak” regressions are given in Table 14 of the appendix. Here we find no statistically significant difference between peak and off-peak treatment effect estimates. While one might expect the treatment effect to be smaller in peak periods because generation from more units is required, leaving less room for leakage, ramping constraints may limit the difference across the time blocks. That is, given that most leakage appears to come from turning down RGGI-coal and coal-fired plants cannot quickly ramp up generation, the peak/off-peak differences may be limited.

[33] The control group for the “Deregulated States” includes generators in the following state: IL, MI, OR, and TX. This group of states was based on EIA (2010) PA and OH are omitted from the control group.
[34] The control group for the “Eastern” states includes plants in the FRCC, MRO, NPCC, RFC, SERC, and SPP NERC regions.

Table 8
Sensitivity analyses for daily regressions.

VARIABLES	(1) NGCC	(2) Coal	(3) NGCC	(4) Coal
Leaker	0.145**	0.0420**	0.133**	0.0641***
	(0.0659)	(0.0205)	(0.0648)	(0.0216)
RGGI	−0.0199	−0.109***	−0.0367*	−0.0951***
	(0.0209)	(0.0257)	(0.0192)	(0.0285)
Observations	263206	283628	273495	434913
Control Group	Deregulated	Deregulated	Eastern	Eastern

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications account for time effects with a cubic time trend and for price effects non parametrically. “Control Group” describes whether the control group is non-treatment deregulated states (“Dereg”), non-treatment plants in the Eastern Interconnection (“Eastern”), or all plants in the country (“All”).

Table 9
Capacity factor treatment under high and low gas prices.

	(1) Gas	(2) Coal
Leaker	0.141**	0.0579***
	(0.0600)	(0.0188)
Leaker * High Gas	−0.0939***	−0.0613*
	(0.0338)	(0.0353)
Leaker * Low Gas	0.0915*	0.0444**
	(0.0521)	(0.0212)
RGGI	−0.0169	−0.0972***
	(0.0193)	(0.0292)
RGGI * High Gas	0.0130	0.120***
	(0.0206)	(0.0243)
RGGI * Low Gas	−0.0350	−0.0298
	(0.0233)	(0.0379)
Observations	513,191	726,688

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications include a cubic time trend. High and Low Gas are indicator variables for the highest and lowest 10% of gas prices, respectively.

We also conduct cross-sectional and temporal placebo tests. First, we randomly assign individual generation units to placebo RGGI and Leaker groups, which are treated (i.e., placebo treatment value $==1$) from 2009 onwards. We then reestimate our daily model with these cross-sectional placebos. Then, we conduct a temporal placebo by using the period 2004–2008, and assign RGGI and Leaker state plants placebo treatments for 2007–2008. Estimation results are in the table below. Estimation results are in Table 16 of the appendix. Across specifications, the coefficients are small and generally statistically insignificant. This suggests that our primary results are not spurious.

Finally, given that near the time RGGI was introduced, natural gas prices dropped dramatically due to fracking-induced supply expansions, some discussion of the coal-to-gas price ratio impacts is warranted. We display the marginal effect of the

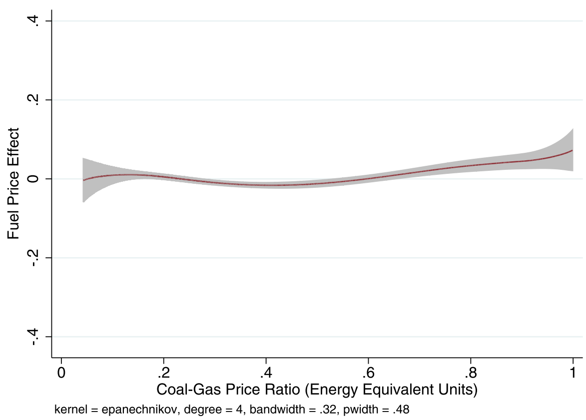

Fig. 7. $f(Z_{it})$ for NGCC plants with 95 percent confidence interval.

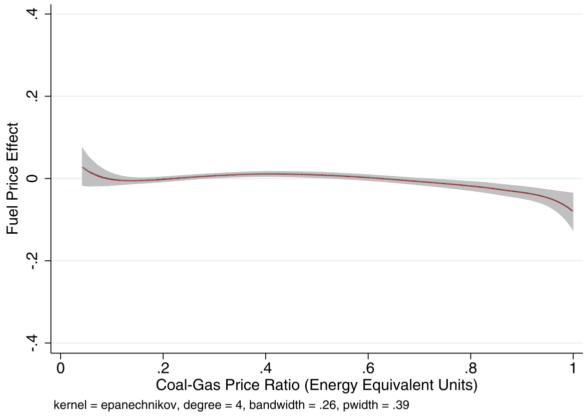

Fig. 8. $f(Z_{it})$ for coal plants with 95 percent confidence interval.

coal-to-gas price ratio from our generator-level analysis on NGCC capacity factors over a range of price ratios and using the nonparametric price ratio specification. The plot of the effects of the price ratio Z_{it} is given in Fig. 7.[35] As shown in Fig. 9, the coal-to-gas price ratio is well below one for the majority of the sample, but during periods of very low gas prices the fuels were price equivalent, and occasionally coal was more expensive than gas on a per MMBtu basis .

To consider the relative magnitudes of the effect of leakage versus the effect of cheap gas prices, first we note that Table 1 shows that Leaker NGCC capacity factors increased by approximately 25 percentage points during our treatment period while Control NGCC capacity factors increase by approximately 4 percentage points. Fig. 7 shows that an increase in the coal-gas price ratio from 0.4 to 1 would increase NGCC capacity factors by approximately 7 percentage points while a smaller price ratio increase (gas price decrease) would cause a smaller increase in capacity factor. Thus, a large decrease in gas prices can account for the entire increase in Control NGCC capacity factors, while accounting for less than a third (7/25) of the increase in Leaker NGCC capacity factors .

Transmission results

Our transmission results in Tables 10 show an economically substantial and statistically significant increase in electricity transmission from PJM into New York during the RGGI program. Table 10 shows the increase in net exports from PJM to New York during RGGI, relative to other interfaces. Columns 1 and 3 estimate the RGGI-effect of transmission across all interfaces to New York. That is, parameter estimates for columns 1 and 3 give average RGGI-induced transmission response for a given PJM-NY interface. On the other hand, columns 2 and 4 replace the individual interfaces in the model with a single representative observation whose value is the sum of all gross exports to New York. Parameter estimates from columns 2 and 4 thus give the aggregate RGGI treatment effect on net generation flow from PJM to NY. We see that net electricity exports from PJM to New York increased by 1498 gigawatt-hours per month during RGGI (Column 2).

To compare these results to the generation results, we note that 1498 gigawatt-hours per month is approximately 18 million megawatt-hours per year. In section *Generator-level results*, we found that Leaker NGCC generation increased by approximately 11 million megawatt hours per year under the Leaker treatment. While the estimated increase in transmission is not precisely equal to the increase in generation, they are of generally similar magnitudes.

This analysis should not be taken as a causal model of electricity flows. Instead, it should be taken as supporting our primary generation analysis. If there was indeed generation leakage from RGGI to Pennsylvania, we would expect to see an increase in electricity transmission from Pennsylania to RGGI. Conversely, if transmission from Pennsylvania to RGGI did not change, that would cast doubt on the leakage hypothesis. The econometric evidence suggests that electricity transmission into RGGI did increase, which bolsters the results of section with the results of section *Generator-level results*.

Conclusions

Sub-global and sub-national climate policies have been, and continue to be, the primary mechanisms of regulating GHG's. Unfortunately, as has been well documented, these regional programs can often lead to emission leakage whereby regulated regions' abatement is partially offset by increase in emissions in unregulated cases. In the worst case scenario,

[35] Fig. 8 shows f(Z) for coal plants. We see that coal generation is less sensitive to prices than NGCC generation, consistent with Linn et al. (2014)'s finding that coal generation is much less responsive to gas prices than gas generation. Both Figs. 7 and 8 have wide confidence intervals for very high and very low coal-gas price ratios. This is because there are few observations with very high or low price ratios, as can be seen in Fig. 9. Estimating regions with few observations nonparametrically yields wide confidence intervals.

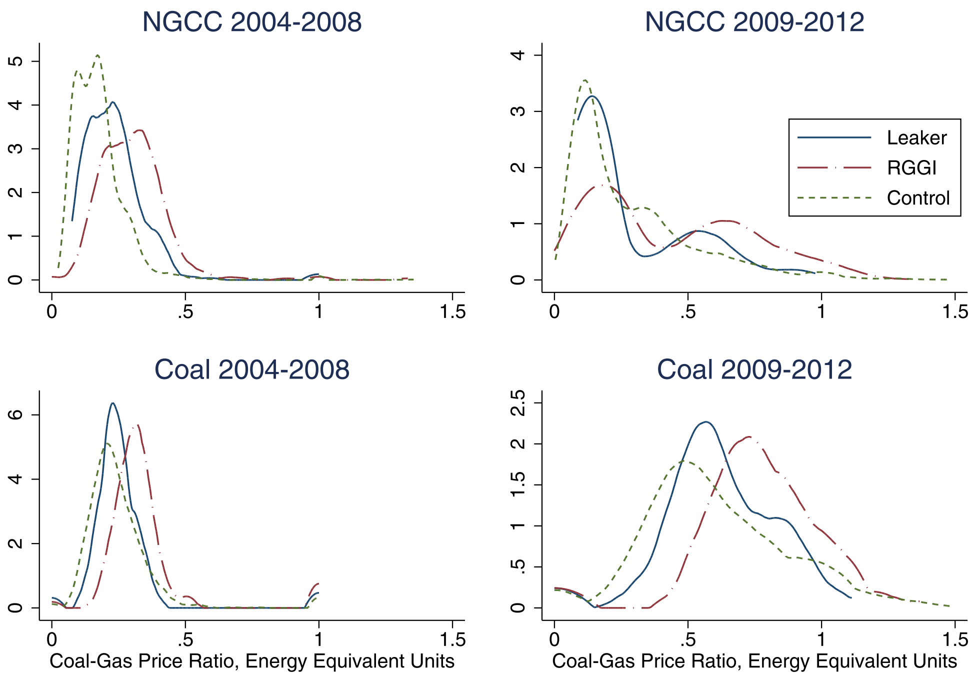

Fig. 9. Kernel densities of the coal-gas price ratio. Density functions of the coal-gas price ratio. Leaker plants in solid line. RGGI plants in long dash - dot line. Control plants in short dash line.

Table 10
PJM net exports to NY relative to net exports to other regions.

	(1)	(2)	(3)	(4)
RGGI	133***	1,498***	326***	1,707***
	(35.1)	(46.9)	(45.8)	(68.8)
Observations	2416	2256	748	588
NY Interfaces	Distinct	Aggregated	Distinct	Aggregated
Control	All	All	External	External

Notes: *** represents 1 percent confidence level. Units are gigawatt-hours per month. All specifications include interface and monthly fixed effects. “NY Interfaces” refers to whether interfaces between PJM and New York are included individually (“Distinct”) or are aggregated into a single measure of transmission between PJM and New York (“Aggregated”). “Control” refers to whether the control group is all PJM interfaces (“All”) or only interfaces with other ISOs/RTOs (“External”).

aggregate emissions may even increase if regional regulations induce production to move to more emissions intensive areas.

While the possibility and severity of leakage has been explored thoroughly in theory and simulation modeling, few econometric estimates of leakage exist in the literature. We provide econometric evidence of leakage. More specifically, we use electricity generator-level data to estimate how the RGGI policy affected those plants directly regulated by the program and those geographically near the regulation region relative to plants further away and therefore less affected by the policy. We also use generation transmission flow data to identify how the policy has affected electricity trade around the region most likely impacted by the regulation.

Our generator-level analysis implies that RGGI induced coal plants in the RGGI region to reduce their capacity utilization by approximately 10 percentage points. This reduced generation in the RGGI region was not compensated for by increase in gas-fired generation in the area, but rather RGGI led to an increase in generation from the areas surrounding RGGI, the deemed leaker region. However, the RGGI-induced increase in generation from the leaker region came from relatively cleaner NGCC generators. Thus, RGGI did induce leakage (emissions in the unregulated regions were higher than they otherwise would have been), but the policy motivated a reduction of emissions-intensive generation in the regulated region and an expansion of relatively cleaner generation in the unregulated region leading to an aggregate reduction of emissions across the regulated and neighboring unregulated regions. The electricity transmission further supports this generation substitution pattern.

This type of leakage pattern, where the policy forces a reduction of production from emissions-intensive sources in the regulated regions and moves production to a region with relatively cleaner production, is not often discussed, but appears possible in other settings. In particular, we might see this type of leakage in regulation-induced movement of production from capital- and emissions-intensive, generation in developed countries to production in more labor-intensive production in developing regions. Overall, further empirical analyses are necessary to evaluate possible severity of regional-policy-related leakage.

Appendix A. Additional controls

Tables 11–13 present the parameters associated with the other control variables included in the estimation of Eq. (1), using the annual data (Table 11) and daily data (Tables 12 and 13). Controls include the logs of load (lnload), renewable

Table 11
Control variables - capacity factor - yearly.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
lnload	−0.002	0.015	0.517***	0.230***
	(0.069)	(0.073)	(0.068)	(0.071)
lnrenewable	−0.057***	−0.039**	−0.041***	−0.025*
	(0.017)	(0.017)	(0.015)	(0.014)
lncoalcap	−0.154*	−0.118	0.321***	0.138
	(0.079)	(0.081)	(0.088)	(0.100)
lngascap	0.023	0.000	−0.028	0.015
	(0.051)	(0.052)	(0.036)	(0.036)
noxphase1			0.001	0.004
			(0.020)	(0.019)
noxphase2			0.022	0.026*
			(0.016)	(0.015)
noxphase3			−0.001	0.005
			(0.017)	(0.017)
noxphase4			0.167***	0.182***
			(0.042)	(0.042)
noxphase5			0.011	0.015
			(0.017)	(0.017)
so2controlequip			0.009	0.003
			(0.010)	(0.011)
2005		0.032***		0.006
		(0.009)		(0.007)
2006		0.035***		−0.014
		(0.012)		(0.008)
2007		0.063***		−0.007
		(0.015)		(0.011)
2008		0.057***		−0.016
		(0.017)		(0.012)
2009		0.086***		−0.081***
		(0.022)		(0.016)
2010		0.109***		−0.077***
		(0.024)		(0.017)
2011		0.114***		−0.106***
		(0.027)		(0.018)
2012		0.184***		−0.166***
		(0.028)		(0.022)
trend	0.144***		−0.023	
	(0.033)		(0.028)	
trend2	−0.019***		0.004	
	(0.004)		(0.004)	
trend3	0.001***		−0.000*	
	(0.000)		(0.000)	
Observations	1,723	1,723	2,010	2,010
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. “Time Trend” denotes the manner in which time effects are accounted for where “Cubic” means a cubic time trend was included and “FE's” mean the model includes year fixed effects.

Table 12
Control variables - capacity factor - daily.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
colgas	5.542	1.323	−330.3***	−319.9***
	(14.19)	(14.10)	(56.19)	(54.35)
colgas2	17.67	587.1	33260.6***	32131.9***
	(1708.9)	(1678.0)	(6576.2)	(6364.0)
colgas3	12497.0	−6868.5	−1073791.1***	−1036381.8***
	(63724.5)	(62109.2)	(231826.5)	(224467.9)
colgas4	−294730.4	−30231.1	14419309.0***	13911671.8***
	(918189.7)	(892597.8)	(3226471.5)	(3124513.1)
colgas5	2463445.7	734465.9	−93467254.6***	−90159395.3***
	(6186624.5)	(6007508.8)	(21243040.9)	(20571954.6)
colgas6	−8929592.9	−3497628.6	292169342.8***	281797504.8***
	(19800717.6)	(19217109.3)	(66855296.5)	(64740326.0)
colgas7	11947615.5	5339198.8	-354291965.9***	-341689484.4***
	(24385503.6)	(23660320.5)	(81270835.3)	(78694095.0)
lnload	0.443***	0.446***	0.240***	0.235***
	(0.0240)	(0.0241)	(0.0515)	(0.0507)
RPS	−0.528**	−0.565**	0.132	0.0677
	(0.232)	(0.235)	(0.220)	(0.226)
lngascap	−0.139***	−0.144***	−0.000889	0.00177
	(0.0389)	(0.0403)	(0.0195)	(0.0192)
lncoalcap	−0.564***	−0.552***	0.0785	0.0659
	(0.0858)	(0.0900)	(0.0626)	(0.0617)
trend	0.0366***		−0.00106	
	(0.0105)		(0.00736)	
trend2	−0.00590**		−0.000861	
	(0.00291)		(0.00196)	
trend3	0.000646***		−0.000186	
	(0.000221)		(0.000152)	
noxphase1			0.00238	0.00260
			(0.00735)	(0.00738)
noxphase2			0.00357	0.00450
			(0.0105)	(0.0104)
noxphase3			−0.0111	−0.0103
			(0.0117)	(0.0117)
noxphase4			−0.0272	−0.0176
			(0.0505)	(0.0526)
noxphase5			0.00909	0.00878
			(0.00803)	(0.00777)
so2controlequip			−0.00918	−0.00925
			(0.00713)	(0.00711)
o._Iyear_2004				0
				(.)
_cons	2.288**	2.214*	-2.868***	-2.700***
	(1.081)	(1.126)	(0.934)	(0.927)
Observations	513191	513191	726688	726688
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. “Time Trend” denotes the manner in which time effects are accounted for where “Cubic” means a cubic time trend was included and “FE's” mean the model includes year and month-of-year fixed effects.

power generation (lnrenewable), regional coal-generation capacity (lncoalcap), and regional gas-generation capacity (lngascap). For coal generators, we also include dummies if they were included in the various phases of the NOx regulations (noxphase1 - noxphase5) and if they have SO_2 emissions control equipment (so2controlequip).

Table 13
Control variables - capacity factor - daily continued.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
2004		−0.0361***		
		(0.0120)		
2005		0		0.00554
		(.)		(0.00710)
2006		0.00852		−0.0131
		(0.00892)		(0.00923)
2007		0.0420***		−0.00560
		(0.0111)		(0.0109)
2008		0.0492***		−0.0178
		(0.0121)		(0.0115)
2009		0.0912***		−0.0693***
		(0.0171)		(0.0139)
2010		0.124***		−0.0719***
		(0.0195)		(0.0146)
2011		0.129***		−0.103***
		(0.0228)		(0.0159)
2012		0.219***		−0.161***
		(0.0250)		(0.0186)
February	0.0161***	0.0163***	−0.0152***	−0.0153***
	(0.00371)	(0.00373)	(0.00407)	(0.00407)
March	0.0252***	0.0258***	−0.0576***	−0.0583***
	(0.00610)	(0.00611)	(0.00906)	(0.00900)
April	0.0332***	0.0339***	−0.0855***	−0.0864***
	(0.00807)	(0.00810)	(0.0111)	(0.0110)
May	0.0201**	0.0204**	−0.0713***	−0.0719***
	(0.00931)	(0.00933)	(0.00954)	(0.00947)
June	0.0221**	0.0220*	−0.0289***	−0.0286***
	(0.0112)	(0.0112)	(0.00585)	(0.00584)
July	0.0674***	0.0670***	−0.0000377	0.000923
	(0.00924)	(0.00923)	(0.00656)	(0.00650)
August	0.0879***	0.0876***	−0.00165	−0.000827
	(0.00995)	(0.00994)	(0.00609)	(0.00605)
September	0.0685***	0.0687***	−0.0379***	−0.0380***
	(0.00929)	(0.00932)	(0.00633)	(0.00629)
October	0.0556***	0.0561***	−0.0660***	−0.0665***
	(0.00846)	(0.00851)	(0.00953)	(0.00943)
November	0.0293***	0.0298***	−0.0441***	−0.0444***
	(0.00657)	(0.00662)	(0.00769)	(0.00760)
December	0.0213***	0.0216***	−0.0256***	−0.0252***
	(0.00458)	(0.00461)	(0.00424)	(0.00422)
Time	Cubic Trend	FE's	Cubic Trend	FE's

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. “Time Trend” denotes the manner in which time effects are accounted for where “Cubic” means a cubic time trend was included and “FE's” mean the model includes year fixed effects.

Appendix B. Supplemental analyses

This section describes a series of robustness checks and supplemental analyses. The first sections analyse varying treatment effects for subgroups. The third section discusses intra-RGGI region gas price variation. And the final section describes several placebo tests.

B.1. Treatment effects for peak and offpeak hours

In the first, we reestimate our core model of Eq. (1), but break the sample into peak and offpeak periods. Here we define peak to be 8:00 A.M.–8:00 P.M., and offpeak to be 12:00 AM–8:00 AM and 8:00 PM–12:00 AM. We use hourly generation data based on EPA CEMS. Load is calculated for peak and offpeak hours based on hourly data. All other controls are the same as in the daily analyses of section *Generator-level results*.

Table 14 presents estimation results for peak and offpeak hours. We see that the results are very similar to the core estimates of Table 4. This may be due to the long ramping periods for coal plants.

Table 14
Capacity factor - peak vs offpeak hours.

VARIABLES	(1) Gas Offpeak	(2) Gas Peak	(3) Coal Offpeak	(4) Coal Peak
Leaker	0.160***	0.157**	0.0741***	0.0733***
	(0.0612)	(0.0684)	(0.0228)	(0.0203)
RGGI	−0.00282	−0.000975	−0.104***	−0.0944**
	(0.0241)	(0.0245)	(0.0396)	(0.0415)
Observations	509466	509466	720263	720263

Notes: *, **, *** denote statistical significance at at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications include a cubic time trend. Due to difficulty matching CEMS and EIA 923 data, the top 1% of observations by capacity factor were dropped. This corresponded to capacity factors above 1.14 for NGCC and 1.99 for coal.

Table 15
Capacity factor – natural gas simple cycle.

	(1)	(2)	(3)	(4)
Leaker	−0.00310	−0.00282	−0.00311	−0.00414
	(0.00504)	(0.00538)	(0.00512)	(0.00501)
RGGI	−0.00771**	−0.00149	0.00499	0.000251
	(0.00329)	(0.00368)	(0.00601)	(0.00581)
Observations	4374	4374	5772	5772
Time	Cubic	FE's	Cubic	FE's
Price	Nonpar	Nonpar	Parametric	Parametric

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. “Time” denotes the manner in which time effects are accounted for where “Cubic” means a cubic time trend was included and “FE's” mean the model includes year fixed effects. “Price” describes whether the coal-gas price ratio was controlled for parametrically or nonparametrically.

Table 16
Capacity factor – placebo tests.

	Cross-sectional Placebo		Time Placebo	
	Gas (1)	Coal (2)	Gas (3)	Coal (4)
RGGI	0.00270*	−0.00202*	−0.0208	0.00942
	(0.00147)	(0.00107)	(0.0202)	(0.0147)
Leaker	0.00463	−0.00161	0.0357	0.0256
	(0.00298)	(0.00269)	(0.0327)	(0.0182)
Observations	513191	726688	230869	308588

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates.

B.2. Natural gas single cycle generators

In this section, we repeat our analysis of natural gas plants, but focus on single cycle plants (NGSC) instead of combined cycle plants. NGSC plants are generally less efficient and more expensive to operate than NGCC plants, and thus are used as peaker plants. That is, they are used only during very high load periods. We would thus expect minimal effects of RGGI on either RGGI or Leaker region plants. We would not expect RGGI region plants to respond, because NGSC plants are unlikely to become inframarginal from a modest carbon price. And we would not expect Leaker NGSC plants to respond, for much the same reason.

Table 15 shows regression results. All specifications use plant-year data. Columns 1 and 2 use a nonparametric function of the price ratio as in Table 3, while Columns 3 and 4 use a polynomial of the price ratio as in Table 5. We see that all estimated coefficents are small, and only one is significant at the 5% level. This suggests that NGSC plants did not substantially respond to the RGGI program.

Table 17
The effect of spare NGCC capacity.

VARIABLES	(1) NGCC	(2) NGCC	(3) Coal	(4) Coal
Leaker	0.141**	0.142**	0.0638***	0.0639***
	(0.0616)	(0.0617)	(0.0201)	(0.0201)
RGGI	−0.00826	−0.00973	−0.0992***	−0.0999***
	(0.0187)	(0.0189)	(0.0281)	(0.0281)
Observations	477803	477803	681677	681677
Slack NGCC Capacity		Y		Y

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications include cubic time trends. Sample is from 2005-2012.

Table 18
Plant age.

	(1) Coal	(2) Gas
Leaker	0.157**	0.0604***
	(0.0645)	(0.0202)
RGGI	−0.0167	−0.0953***
	(0.0189)	(0.0280)
Observations	513191	726688

Notes: *, **, *** denote statistical significance at least the 10%, 5%, and 1% levels, respectively. Robust standard errors, clustered at the plant level, are given in parentheses below the parameter estimates. All specifications include cubic time trends.

B.3. Placebo tests

We have added two different sets of falsification tests with our generation data. First, we randomly create two different treatment groups in the same proportion as the RGGI and Leaker treatment groups, and assign members of these groups to a placebo treatment starting in 2009. Second, we use the period 2004–2008, and assign RGGI and Leaker state plants placebo treatments for 2007–2008. This provides us with a cross-sectional placebo and a time placebo. Estimation results are in the table below Table 16.

Across specifications, the coefficients are small and generally statistically insignificant. Two point estimates are significant at the 10% level. These have very small magnitudes. This suggests that our primary results are identifying real effects and not spurious.

B.4. Testing for the role of spare NGCC capacity

The Pennsylvania area had substantial spare NGCC capacity at the start of the treatment period. If fracking-induced low gas prices lead to a disproportionate increase in NGCC utilization in this area (due solely to the low initial utilization), then our leakage result could be spurious. In this section, we test for the role of initial NGCC utilization and find results similar to our core analyses.

We will reestimate our core model, interacting the coal-gas price ratio with a measure of spare NGCC capacity. We first calculate the ratio of spare NGCC capacity to total NGCC and coal capacity in 2004 (the first year of our sample) in each transmission zone:

$$r_a = \frac{\sum_j (CAP_j^{NGCC} - GEN_j^{NGCC})}{\sum_j (CAP_j^{NGCC} + CAP_j^{COAL})}$$

where r_a indexes transmission zones, j indexes generation units in each transmission zone, *CAP* measures annual generation capacity and *GEN* measures annual generation. If r_a is large, then there is a large spare NGCC capacity relative to the total coal and NGCC capacity and thus substantial potential for an increase in NGCC generation.

We reestimate Eq. (1), adding r_a and r_a interacted with the coal-gas price ratio. Results are presented in Table 17. Columns (1) and (3) replicate columns (1) and (3) from Table 4, but are estimated on observations from 2005 onwards. We see that results are very much like those in Table 4, suggesting that dropping 2004 from the estimation sample does not substantially change our results. Columns (2) and (4) include r_a and $r_a{*}Z_{it}$ as controls (where $*Z_{it}$ is the coal-gas price ratio as in section *Generator-level models*).

After controlling for spare NGCC capacity, we still see about a 14 percentage point increase in Leaker NGCC, a 6 percentage point increase in Leaker coal, and a 10 percentage point decrease in RGGI coal capacity factors. These are quite similar to the estimates in Table 4, suggesting that spare NGCC capacity was likely not responsible for our primary results.

B.5. The effect of plant age

In this section, we allow the effect of fuel prices to vary with plant age as measured in years. If the Leaker region had newer plants which were more responsive to changes in fuel prices, then the increase in NGCC generation could be due to plant age instead of treatment. We calculate plant age as the time (in years) since the first generation at the plant, and include both age and age interacted with the coal-gas price ratio. Results are in Table 18. Results are very similar to those of Table 4, suggesting that age heterogeneity is not responsible for our results.

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California's cap-and-trade program and emission leakage in the electricity sector: an empirical analysis

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January 3, 2019

Abstract

We conduct the first econometric analysis of leakage in the electricity sector from California's cap-and-trade program. The paper presents three sets of empirical results that support the hypothesis of leakage. First, we measure the policy impact on baseload power plant operations in the Western Interconnection applying a differences-in-differences estimator to a novel dataset at the monthly level from 2009 to 2016. Second, we preprocess the data to improve balance between treated and control plants by matching on hour-of-day specific variables, and explore treatment effect heterogeneity across daytime and nighttime hours using daily measures of plant utilization. Third, we test for leakage from the cap-and-trade program by examining the relationship between emission allowance prices and scheduled power imports into California. Results suggest a policy-induced reduction in natural gas combined cycle generation in California and an increase in coal-fired generation in the Western U.S., corresponding to a leakage rate of about 70%.

1 Introduction

California has been at the forefront of U.S. environmental policies for years. The Global Warming Solutions Act of 2006 (also known as Assembly Bill 32 or AB 32) set the state's target to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020 [1]. In September 2016, California passed Senate Bill 32 (SB 32), which limited emissions to 40% below 1990 levels by 2030 [2]. Further, Executive Order S-3-05 set a GHG emission reduction target of 80% below 1990 levels by 2050 [3]. In order to achieve these ambitious goals, the

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state relies on a suite of complementary policies, including a multi-sector cap-and-trade program that covers about 80% of the state's emissions from the electricity sector, large industrial facilities, and fuel distribution sector, and is expected to drive roughly 22% of emission reductions by 2020 [4].

A central issue in the implementation of cap-and-trade programs is represented by the choice of the point of regulation. For example, the Regional Greenhouse Gas Initiative (RGGI), an emission trading system for CO_2 emissions from electricity generation in U.S. Northeastern and mid-Atlantic states, adopted a production-based (or source-based) approach where the point of regulation is at the generator level. In contrast, given its reliance on imports to satisfy electricity consumption,[1] California opted for a first deliverer approach, whereby entities that own electricity at the first point of delivery in the state represent the point of regulation: in-state generators must monitor and report their emissions following a source-based paradigm, while electricity importers are responsible for emissions associated with in-state sales.

The introduction of a border adjustment mechanism for the electricity sector was intended to mitigate concerns of leakage, defined as the shift in production and associated emissions from the region where climate regulations apply to surrounding unregulated jurisdictions [6, 7, 8]. However, energy modeling studies have concluded that the possibility of reshuffling contracts may enable substantial leakage under the AB 32 cap-and-trade system [6, 7, 9, 10, 11]. Under resource shuffling, electricity contracts are rearranged so that production from low emission sources serving out-of-state load is directed to California, while production from higher emission sources is assigned to serve out-of-state load [12]. This would result in apparent emission reductions due to changes in the composition of imports to California, although emissions in exporting regions are unchanged or even increase. It is worth noting that, in recent years, the decrease in GHG emissions from the electric power sector in California has been attributed primarily to measured reductions in emissions from imports [13]. This underscores the importance of assessing whether leakage has occurred in practice and considering potential policy modifications to mitigate its impacts.

We contribute to the literature by conducting the first econometric analysis of leakage in the electricity sector from California's cap-and-trade program. While earlier studies were prospective (*ex ante*) and employed numerical models, our study is retrospective (*ex post*) and employs statistical analysis of historical data. The paper presents three sets of empirical results. First, we measure the impact of California's carbon policy on baseload power plant operations in the Western Interconnection applying a differences-in-differences estimator to a novel dataset at the monthly level from 2009 to 2016. After controlling for key determinants of plant capacity factors like fuel costs, electric demand, nuclear and renewable generation, temperature and

[1]California imports about a third of its total electricity consumption from out of state [5].

precipitation levels, the estimated average treatment effects suggest a policy-induced reduction in NGCC generation by 14% in California and increase in coal-fired generation by about 4% in the Western U.S., corresponding to a leakage rate of about 70%. Results are robust to the choice of leaker and control groups, clustering methods and sample definition. In our second set of empirical results, we preprocess the data to improve balance between treated and control groups by matching plants on coarsened hour-of-day variables, and carry out parametric inferences using daily measures of plant utilization. This approach changes the estimand to a local average treatment effect for the plants that were matched, and allows us to explore heterogeneity across daytime and nighttime periods. Results from the matched sub-samples are broadly consistent with those from the full sample, and robust to the inclusion of matching variables and choice of cut points. In our final set of analyses, we test for leakage from the policy by examining the relationship between the AB 32 allowance price and scheduled power imports into the California Independent System Operator (CAISO), which centrally dispatches generation and coordinates the movement of wholesale electricity in much of California and part of Nevada. Specifically, we estimate a model of daily scheduled power flows into CAISO, and test for leakage based on the statistical significance of the AB 32 allowance price as one of the explanatory variables. The analysis of daily scheduled flows across major CAISO interfaces further supports the hypothesis of leakage.

The remainder of the paper is organized as follows. Section 2 reviews the literature on emission leakage and Section 3 provides background on California's cap-and-trade program. Section 4 describes the data, while Section 5 outlines the research design and econometric approach. Section 6 presents the empirical results, and Section 7 offers concluding remarks.

2 Literature review

The potential for emission leakage in the electricity sector under regional climate policies has been analyzed using numerical models. A first strand of the literature employs simulation-based models of the electricity sector. [7, 9, 14, 10] explore leakage in the context of California's *proposed* cap-and-trade program for GHG emissions (i.e., before regulations were finalized). [7] uses partial equilibrium analysis to determine the extent of leakage potential under incomplete, market-based regulation of CO_2 emissions in California's electricity sector. Results indicate that emission leakage is greater when emission rates per unit of production are high, demand is more elastic, and the industry is more competitive. The theoretical framework is used to investigate related welfare effects in the electricity sector under a range of assumptions regarding market competitiveness. [9] formulate a market equilibrium model to compare source-based, load-based and first deliverer approaches for cap-and-trade regulation in California, and examine related economic and emission implications on the electricity market. They find that leakage is substantial (85%)[2] and largely due to reshuffling: emission reductions due to changes in the composition of electricity imports to California are illusory, because emissions in the rest of the Western Interconnection increase under regulation. [14] and [10] examine the impacts of alternate cap-and-trade designs applying to Western U.S. states and California, respectively, and conclude that a first deliverer approach in California is vulnerable to leakage due to laundering and reshuffling of import resources. In contrast to the studies cited above, [11] consider California's *actual* cap-and-trade program. The authors simulate distributions of emission allowance prices assuming that price containment mechanisms may be binding or market participants engage in withholding strategies. With respect to RGGI, [15] develop a model of the Eastern U.S. and Canada to analyze the effects of a CO_2 price in RGGI on emissions, electricity prices, and generator entry and exit decisions, finding that leakage represents a likely market outcome.

Computable general equilibrium (CGE) models have also been used to examine the impacts of regional climate policies [16]. CGE models can account for several potential leakage channels, but are sensitive to assumptions about the parameters. One such study is [17], that develops a multi-state CGE model of the U.S. economy. In the context of RGGI, the authors estimate that, if the program's cap was fully binding, power imports to New York (a RGGI state) from Pennsylvania (a non-RGGI state) could result in emission leakage rates of more than 50%. [18] develop a modified version of the GTAP-E model to assess the economic and carbon emission effects of alternative trade policy measures aimed at reducing carbon leakage. [19] conduct a general equilibrium assessment of leakage from sub-national climate policies, using California's cap-and-trade program as an example. When imported electricity is included in the cap and provisions to prevent reshuffling are enforced, the estimated leakage rate is only 9%.

Empirical analyses of leakage are less common in the literature. [20], [21] and [22] examine leakage in the context of the Kyoto Protocol. In particular, [22] develop a gravity model to calculate the carbon content of bilateral trade flows for forty countries between 1995 and 2007, and find that binding commitments under the Kyoto Protocol led to emission leakage to noncommitted countries. With respect to RGGI, [23] analyze the relation between CO_2 permit prices and transmission power flows on seven high-voltage interties between New York and Pennsylvania between 2008 and 2010. Higher net flows from Pennsylvania to New

[2]This percentage (also referred to as "leakage rate") is given by one minus the ratio of aggregate emission decrease in the regulated and unregulated regions, relative to a baseline in which no emission cap applies, over emission decrease in the regulated region, relative to the no cap scenario and including emissions associated with electricity imports.

York associated with a higher RGGI allowance price would indicate leakage. The authors do not find a significant impact of RGGI permit prices on PA-NY transmission flows, but prices may have been too low in the early years of the program to affect leakage. [24] conduct two complementary analyses of RGGI-induced leakage. First, they use plant-level data to assess operational impacts of the carbon policy. They estimate that RGGI induced a reduction in coal-fired generation in the regulated region and an increase in cleaner NGCC generation in the unregulated region, leading to an aggregate emission reduction across regions. Their second analysis examines changes in electricity transmission flows, finding that power imports to New York from outside the RGGI region increased substantially since the policy was implemented: this supports the generation substitution pattern identified previously.

Finally, a growing body of research in economics assesses the potential for leakage risk across sectors (e.g., [25]), and explores how environmental regulation affects trade flows and the location choice of firms in the long run ("pollution haven" effect) [26, 27, 28, 29, 30, 31].

3 Policy background

California's cap-and-trade program regulates GHG emissions from large industrial facilities, electricity generators and importers, and transportation fuel suppliers. Covered entities emit at least 25,000 metric tons of CO_2e per year and are responsible for about 80% of the state's GHG emissions [32]. The first phase of compliance for the program began on January 1, 2013. The 2013 emission cap was set at approximately 98% of forecast 2012 emissions, with an annual decline of 2% in 2014 and 3% from 2015 through 2020. In July 2017, the scheme was extended through 2030 with bipartisan support: emission reductions in the carbon market are expected to deliver about 40% of the state's total mitigation efforts [32].

The California Air Resources Board (CARB) is responsible for implementing AB 32 and designed the cap-and-trade system. CARB issues annual emission allowances equal to the cap, and each allowance represents a permit to emit one ton of carbon dioxide equivalent. Entities must monitor and annually report their emissions, and return an amount of allowances equivalent to their GHG emissions each year. Capped sources that keep emissions below the allowance amount can sell excess permits on the market, while sources that cannot cover total emissions may take measures to reduce pollution and/or buy allowances on the market.[3] Emission allowances are distributed through a mix of free allocation and quarterly auctions, transitioning over time to greater auctioning of allowances: in 2016, 46% of allowances were auctioned and 50% were

[3] Covered entities may also use carbon offsets (e.g., GHG emission reduction projects undertaken by entities not subject to the carbon policy) to cover up to 8% of their emissions.

given away for free [33].[4] CARB allows banking and borrowing of allowances, and the risk of unexpected price changes and excess volatility is mitigated through the use of a price collar; secondary market allowance prices have generally hovered at or near the auction price floor from market launch to 2016 [34].

Two provisions in the current design of AB 32 cap-and-trade system are intended to mitigate concerns about leakage. First, free emission allowances are allocated to energy-intensive, trade-exposed industries as an incentive to keep production in California. Electric distribution utilities are granted free allowances to ensure that their ratepayers do not experience sudden increases in electricity prices as a result of emission costs, although the share of free permits declines over time [35]. In particular, investor-owned utilities (IOUs) are required to auction their allowances and credit the resulting revenues to their electricity customers [33]. Further, electricity generators operating under long-term contracts are eligible to apply for free allowances for emissions related to contracted power [36].

Second, the cap-and-trade program features a first deliverer approach, whereby both in-state electricity generators and electric utilities that import power from out-of-state are subject to the carbon policy. In-state generators must monitor and report their emissions following a source-based paradigm, while electricity importers must acquire emission allowances (and possibly offsets) equal to measured or estimated emissions of generation resources supplying their power imports. Since energy entering the grid flows over the path of least resistance (rather than directly from an injection point to a withdrawal point), the CO_2 intensity of electricity imported in California from the rest of the Western Interconnection cannot be determined unambiguously.[5] To address the issue, CARB classifies imports as specified or unspecified source power.

Specified sources include generation resources owned by or under long-term contract to California's load serving entities, as well as generation resources owned by non-California entities that are approved and registered by CARB [37]. First deliverers may claim facility-specific emission factors for power imports from out-of-state generation resources that are owned or under long-term contract. Further, CARB has developed the designation of Asset-Controlling Suppliers for out-of-state electric power entities that operate interconnected generating facilities. Once approved and registered by CARB, Asset-Controlling Suppliers are assigned a system emission factor for wholesale electricity procured from their systems and imported into California. For example, specified source power from Bonneville Power Administration (BPA) and Powerex (a subsidiary of BC Hydro) must be reported using CARB-approved emission factors reflecting the hydro-

[4]The remaining 4% were made available at predetermined prices to reduce price volatility.

[5]California is part of the Western Interconnection, a synchronous electric grid that encompasses all or parts of 14 Western states in the U.S., the Canadian provinces of Alberta and British Columbia, and Northern Baja California in Mexico. Since reliability within the area is overseen by the Western Electric Coordinating Council, this synchronous grid is commonly referred to as WECC. Figure 1 presents the U.S. portion of WECC.

dominant resource portfolio of these systems [38]. Specified sources mainly consist of coal, natural gas and nuclear power from the Pacific Southwest, and of hydro and wind power from the Pacific Northwest [5].[6]

In contrast, unspecified source power (representing about 40% of total imports, as of 2016) corresponds to wholesale market purchases from power plants that do not have a contract with a California utility and have not gone through the CARB process to become specified. Since in this case the generation source is unknown, unspecified sources are assigned a default emission factor of 0.428 metric ton CO_2/MWh, which was set by CARB based on the generation technology expected to be at the margin in WECC (i.e., a fairly clean natural gas plant) [10]. According to the California Energy Commission, much of the Pacific Northwest spot market purchases are served by surplus hydro and gas-fired plants, while Southwest spot market purchases generally come from coal and natural gas combined cycles [5]. The presence of a default emission factor creates an incentive for electricity importers to not report the emission content of out-of-state higher-emitting generation resources, in order to attain the lower default emission factor ("laundering"). This has been identified as one of the primary types of resource shuffling [39], defined by CARB as "any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation" (Cal. Code Regs., Title 17, Article 5, § 95802(a) [40]). As discussed in Section 1, contract shuffling would lead to apparent emission reductions due to changes in the composition of imports to California, although emissions in the exporting regions are unchanged or even increase. As a result, contract shuffling creates potentially severe leakage risks for the electricity sector in California. In response to these concerns, CARB released a guidance document listing a number of "safe harbor" exceptions to the regulatory ban on resource shuffling (i.e., transactions deemed not to be resource shuffling) (Cal. Code Regs., Title 17, Article 5, § 95852(b)(2) [40]). This approach has been controversial because it is difficult to identify all potential violations *ex ante* [10]. Further, allowance prices hovering near the auction floor have been interpreted as evidence that contract shuffling is taking place, enabling regulated entities to avoid a significant part of their carbon liability and reducing demand for allowances [11, 34].

4 Data

We use a novel panel dataset built from publicly available sources including the U.S. Department of Energy's Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), the Federal

[6] According to the California Energy Commission, the Pacific Northwest includes Alberta, British Columbia, Idaho, Montana, Oregon, South Dakota, Washington and Wyoming. The Pacific Southwest includes Arizona, Baja California, Colorado, Mexico, Nevada, New Mexico, Texas and Utah [5].

Energy Regulatory Commission (FERC) and the California Independent System Operator. The period of our study spans January 2009 through December 2016, including four years before and four years after the treatment date (January 2013, when compliance obligations began).

4.1 EIA data

U.S. electric generating facilities with more than one MW of capacity are required to complete an annual survey to report plant characteristics. Form EIA-860 collects information on the status of existing plants in the U.S., while EIA-923 gathers information on plant operations. Relying on these surveys, we assemble a dataset for power plants within the U.S. portion of four NERC regions (WECC, MRO, SPP, TRE) from 2009 to 2016 (Figure 1). A plant consists of at least one, but typically several, generating units, which may be added to or retired from service over its lifetime. Although energy output, operating capacity and fuel input are available at the unit level, we aggregate this information for units of the same technology within a plant because our analysis relies on capacity factors and heat rates. For natural gas combined cycle plants, in particular, energy output is reported separately for the steam and combustion parts of the plants, but both are needed to calculate capacity factors and heat rates accurately. The advantage of EIA data is that its coverage is comprehensive, including not only large thermal plants, but also nuclear, hydro and renewable facilities. Plant-level characteristics reported at the annual level include primary fuel type, operating capacity, month and year when each unit was in service, type and number of emission abatement controls, EIA regulatory status,[7] NERC region and subregion, balancing authority and planning area.[8] In addition, the EIA provides monthly plant operating statistics like energy output (measured by megawatt-hours or MWh of net electricity generation),[9] consumption and heat content by fuel type, and cost of fuel delivered to the plant. We rely on EIA Form 860 for primary fuel type and operating capacity [42], and EIA Form 923 for other plant characteristics [43]. Plants with operating capacity below 25 MW are excluded for

[7]For the purpose of EIA's data collection efforts, regulated entities include investor-owned electric utilities that are subject to rate regulation, municipal utilities, federal and state power authorities, and rural electric cooperatives. Facilities that qualify as cogenerators, small power producers under the Public Utility Regulatory Power Act (PURPA) and other nonutility generators (including independent power producers) are non-regulated plants.

[8]Each power plant falls under the operational control of a balancing authority, which is responsible for dispatching generation units and maintaining consumption-interchange-generation balance within a region of the electric grid [41]. Balancing authority areas and electric utilities with a planning area annual peak demand greater than 200 MW must file FERC Form 714. Electric utilities charged with carrying out resource planning and demand forecasts for a planning area ("planning authorities") are required to report actual hourly demand in their planning area in Part 3 of FERC Form 714. The definition of balancing authority and planning authority is similar, and the footprint of most planning authorities in WECC coincides with that of balancing authorities. WECC balancing authorities in the U.S. are presented in Figure 2. Summary statistics by balancing authority and fuel type are provided in Tables A1 and A2 in the Appendix.

[9]Net generation excludes power consumption for plant operations.

consistency with CEMS data (Section 4.2).[10]

Plant fuel costs are not publicly available for non-regulated plants and plants with nameplate capacity below 50 MW. In these instances, we use state average costs of fossil fuels for electricity generation provided by the EIA [45]. If state average coal costs are also not available, we impute these costs assuming the same growth rate of Rocky Mountain Colorado Rail prices (Section 4.4). Fuel costs are used to construct monthly ratios for assessing power plant competitiveness. For coal plants, the coal-to-gas cost ratio divides plant-specific variable cost of generation by state average variable cost of natural gas for power generation. Similarly, for natural gas plants the gas-to-coal ratio divides plant-specific variable cost of generation by state average variable cost of coal for power generation. After January 2013, variable costs for California include emission allowance prices (Section 4.4).

4.2 CEMS data

To complement monthly data from the EIA, we assemble a database of hourly gross electricity generation, heat input and CO_2 emissions for NGCC and coal-fired plants from the EPA's Continuous Emissions Monitoring System (CEMS) [44]. CEMS represents the only publicly available information on high frequency operating data for thermal power plants in the U.S., and has been widely used in empirical studies [46, 47, 48, 49, 50, 51, 52]. We match units in CEMS to EIA generators using a 2015 crosswalk provided by the EPA (personal communication), and aggregate unit level information from CEMS at the plant level by EIA site code and technology type. This step allows us to assign operating capacity to each power plant for which EPA data is available. Following [52], we apply a 5% reduction to gross generation from CEMS to obtain an implied measure of net generation that can be compared to net generation from the EIA. Finally, as noted above only thermal plants with capacity above 25 MW are required to report to CEMS; cogeneration, industrial and commercial facilities are also generally not in CEMS. These exceptions do not result in a substantial loss of coverage for our analysis: net generation of NGCC (coal-fired) plants from CEMS represents about 84% (79%) of EIA generation in WECC over the period of our study.

4.3 CAISO data

We collect hourly data on available transmission capacity and scheduled net power flows on twelve major transmission interfaces connecting the California ISO to the rest of WECC from the ISO's Open Access

[10] 25 MW corresponds to the minimum size of generators subject to requirements for monitoring and reporting emissions under EPA's Continuous Emissions Monitoring System [44]. Plants with capacity below 25 MW generally use renewable energy sources and represent less than 5% of generating capacity in our sample.

Same-time Information System (OASIS) [53]. Grid interfaces are identified based on [54] and the analysis of CAISO annual reports detailing the frequency of import congestion on each intertie [55]. We also obtain hourly aggregate generation by technology, including wind and solar production, from CAISO [56]. It should be noted that transmission capacity and scheduled net energy from imports/exports are only available from April 2009 to October 2015, while hourly aggregate generation by technology is only available from April 2010.

4.4 FERC, NOAA and price data

We complement detailed information on the operations and status of electric power plants with data from other sources. Electricity consumption (or load) comes from the Federal Energy Regulatory Commission (FERC). FERC Form 714 provides hourly load information by planning area [57]. We aggregate load to the monthly and daily level, and assign it to power plants based on their planning area. Monthly population-weighted heating and cooling degree days, as well as measures of water scarcity (like the Standardized Precipitation Index or SPI [58]) by state climate division are from the National Oceanic and Atmospheric Administration's (NOAA) National Centers for Environmental Information [59]. Finally, we obtain daily natural gas prices at four locations in WECC (Sumas, PG&E Citygate, SoCal Border and El Paso San Juan [60]) and weekly Rocky Mountain Colorado Rail coal prices (with a heat rate of 11,700 Btu/lb and a sulfur content of 0.8 lb/MMBtu) from SNL Energy,[11] and daily carbon futures prices for year vintage allowances expiring in December of the same year, in $/ton, from California Carbon Dashboard [61].

5 Research Design

5.1 Empirical Framework

Based on the potential outcome framework that is commonly used in the treatment evaluation literature [62], each observation has two potential outcomes $Y_{it}(d_i)$ depending on treatment status. Let $d_i = 1$ if observation i is treated, and $d_i = 0$ if i is not treated. Potential outcomes for observation i at time t are denoted by $Y_{it}(1)$ and $Y_{it}(0)$ for treatment and non treatment status, respectively. We are interested in estimating the average treatment effect on the treated (ATT), defined as the average difference between treated and untreated (or

[11] There exists no public regional price for coal. S&P Global Market Intelligence's physical market survey details spot prices for coal traded for physical delivery in forward quarters. Weekly prices are "assessments" based on direct supplier-consumer transaction data collected from utility buyers and sellers through a weekly survey.

control) outcome, conditional on treatment:

$$\alpha = E[Y_{it'}(1) - Y_{it'}(0)|d_i = 1] \tag{1}$$

where α measures the average treatment effect, E is the expectation operator, and t' represents any period after treatment. Outcomes after treatment can be used to identify $E[Y_{it'}(1)|d_i = 1]$. In contrast, $[Y_{it'}(0)|d_i = 1]$ represent counterfactual outcomes to be estimated based on the outcomes for control observations.

The objective of our study is to investigate the leakage effects of the AB 32 cap-and-trade program in the electricity sector. The primary leakage mechanism consists in supplanting power generation in the regulated region (California) by increased generation in the unregulated regions ("leakers"). Thus, α_C is the treatment effect in California and α_L is the treatment effect in potential leaker region L outside California. The choice of potential leakers and controls is a key point of our empirical framework. In principle, all plants in the Western Interconnection may be leakers because contract shuffling could create knock-on effects. In practice, however, some balancing authorities in WECC have transmission capabilities allowing plants in their footprint direct access to California load. These plants are more likely to adjust their generation in response to policy changes in California. Therefore, in the baseline specification we identify potential leakers based on the CARB's Greenhouse Gas Emission Inventory, which reports annual estimated CO_2 emissions from power plants supplying specified source power to California [63]. Specifically, we designate as leakers WECC balancing authorities in the U.S. that dispatch power plants supplying specified source power to California. We emphasize two points here. First, we do not intend to suggest that our approach identifies the only leakers unequivocally. Rather, the approach identifies generation resources outside California that are deemed likely to provide exports to California. Other methods for identifying potential leakers in the Western Interconnection are possible and worth exploring for further empirical analyses; we consider alternate leakers in one of the robustness checks, and return to this point in Section 7. Second, Western Canada and the northern portion of Baja California in Mexico may also be leakers because they are part of WECC. In particular, British Columbia is a net exporter of power to the Western U.S., and a large share of its power export sales are directed to California [64]. However, since we do not observe Canadian and Mexican monthly generation, we restrict the scope of our study to intranational leakage.

After identifying potential leakers, we group balancing authorities into regions of contiguous connected electrical components, following the classification in [65]. As discussed in Section 5.1.1, we focus on two baseload technology types (natural gas combined cycle and coal-fired plants) that are most likely affected by the carbon policy. Region definition differs slightly by technology, depending on the location of plants supplying specified source power. For NGCC plants, the Northwest region includes plants in BPAT, PACE and PACW, and the Southwest region includes plants within the CAISO footprint but located in Arizona and Nevada, as well as plants in AZPS, HGMA, NEVP, SRP and WALC (Figure 3). For coal-fired plants, the Northwest region includes plants in BPAT, LDWP in Utah, NWMT, PACE and PGE; the Eastern region includes plants in PSCO and WACM; the Southwest region includes plants in AZPS, NEVP, PNM, SRP, TEPC and WALC (Figure 4). In our baseline specification, the set of treated plants consists of plants of a given technology type that are either in California or one of the leaker regions. For NGCC plants, the set of controls consists of WECC plants that are not in California or one of the leaker regions; for coal-fired plants, the number of controls in WECC outside of the leaker regions is limited, and thus we extend the set of controls to include plants in MRO, SPP and TRE. Alternate definitions of the set of treated and control groups are considered in the robustness checks.

5.1.1 Differences-in-differences regressions

Our first set of empirical results obtains estimates of the treatment effects of interest with the following differences-in-differences (DID) model specification:

$$Y_{it} = \alpha_C TREAT_{it}^{C} + \sum_{L} \alpha_L TREAT_{it}^{L} + \mathbf{X}_{it}^{'}\underline{\beta} + \gamma_i + \gamma_y + \gamma_{sm} + \epsilon_{it} \tag{2}$$

where i indexes a plant-technology, t indicates month, L denotes a leaker region, and s, y, m stand for state, year, and month-of-year respectively. Our dependent variable Y_{it} is the capacity factor of plant-technology i in month t, defined as the ratio of net generation over operating capacity multiplied by total number of hours. We focus on two baseload technology types that are most likely affected by the carbon policy (natural gas combined cycle (NGCC) plants and coal-fired plants), and run separate regressions by technology type.[12] $TREAT_{it}^{C}$ is a dummy equal to 1 if plant i is in California and t is January 2013 or later; $TREAT_{it}^{L}$ is similarly defined for plants in leaker region L. Assuming treated and control facilities would have followed parallel trajectories in the absence of the carbon policy (as discussed in Section 5.2), the treatment effects of interest, α_C and α_L, measure the average effect of the cap-and-trade program on capacity factors of power plants in California and each leaker region, respectively, conditional on observable covariates. It is worth

[12]Natural gas steam turbines represent a small fraction of generating capacity in the WECC region (Figure A1 in the Appendix). Other technology types like natural gas combustion turbines and oil turbines that are used as peaker plants during high load periods are unlikely to have responded to California's carbon policy, given the modest level of permit prices in our sample period.

noting that California has limited coal generation capacity. Hence, leakage would result in lower natural gas generation in state and higher coal and/or natural gas generation out of state. In terms of the model in (2), in the presence of leakage we would expect negative and statistically significant treatment effects for California plants, and positive and statistically significant treatment effects for plants in the leaker regions.

$\mathbf{X}'_{it}$ represents a broad set of determinants of capacity factors. First, in the baseline specification we include the natural log of electricity consumption in the plant's planning area, and the log of nuclear and renewable generation (including hydro) in the plant's state. This functional form implies low responsiveness of capacity factors when demand or non-thermal power generation is high, in line with [51, 6, 24]; however, estimation results do not critically hinge on this assumption, and are robust to a linear specification. Second, we include variables that may affect plant productivity, like temperature (measured by heating and cooling degree days in the plant's climate division) and precipitation (measured by the Standardized Precipitation Index in the plant's climate division). Third, we consider a measure of plant competitiveness, the fuel cost ratio described in Section 4.1, including both linear and quadratic terms to account for potential nonlinear responses to input prices [50]. It is worth noting that, besides the cap-and-trade program, AB 32 relies on a suite of complementary policies to achieve emission reductions, such as renewable electricity policies and energy efficiency standards; similar programs are also implemented in other WECC states. These policies clearly affect capacity factors of baseload generation technologies (e.g., through the merit order effect of renewables dispatched before thermal units). However, their impacts are accounted for through some of our covariates (load and nonhydro renewable energy production), while the estimated treatment effects measure changes that are specifically induced by California's cap-and-trade program. Finally, we include individual and time fixed effects in the regressions. Plant specific effects, γ_i, may be associated with time invariant differences in plant characteristics, like ownership (private utilities or political subdivision) and vintage. Year fixed effects, γ_y, capture differential changes in average utilization that are common to all plants in a given year, while state by month-of-year fixed effects γ_{sm} allow us to account for seasonality within the vast WECC footprint and control for differential changes that are common to all plants within a state in a given month. The error term ϵ_{it} is assumed independent of the covariates and treatment indicators.

5.1.2 Matching and differences-in-differences

The regression approach described above has some potential drawbacks [66]. First, temporal aggregation at the monthly level may bias results [67]; thus, using higher frequency measures of generation would be advantageous. Another concern is that plants with similar monthly average capacity factors may be operated very differently. As a result, counterfactual outcomes may be estimated incorrectly. To illustrate, consider two periods; a plant with zero net generation in period 1 and operated at 80% capacity factor in period 2 would have the same average capacity factor of a plant operated at 40% capacity factors in both periods. Yet, the two plants would hold different positions in the dispatch order of their respective balancing authority, and thus not represent a suitable pair of treated-control observations. More accurate estimates of the counterfactual outcomes may be constructed based on control plants that had similar utilization and efficiency levels to the treated units before policy implementation. The treatment effect of interest could then be obtained estimating a DID model in which the impact of other policies potentially affecting capacity factors (e.g., renewable electricity policies) are subsumed in the covariates. In order to mitigate potential bias, we take two steps. First, we use hourly generation data to construct daily measures of plant utilization. Increased generation from renewable energy sources affects the operations of fossil fuel units during the day. Thus, we explore treatment effect heterogeneity across daytime and nighttime. We average capacity factors across a twelve hour period (7am to 7pm) to form a daily "daytime" capacity factor for plants reporting to the EPA's Continuous Emissions Monitoring System, and average over the remaining hours to obtain a daily "nighttime" capacity factor. Second, we preprocess the data to improve balance between treated and control groups by matching on high frequency pre treatment variables. The basic idea of matching is to find untreated units that are similar to the treated ones in terms of variables that influence the outcome of interest (i.e., so called "matching variables"), except for treatment status. Counterfactual outcomes for treated plant i are then inferred using a weighted average of the outcomes of units that are comparable to i, but receive a different treatment. Control units whose observable characteristics are closer to those of plant i are weighed more heavily in the construction of the counterfactual estimate. While earlier empirical work in energy and environmental economics employed parametric and semi-parametric matching methods,[13] we explore the use of coarsened exact matching (CEM) to improve balance between treated and control observations [70, 71, 72]. CEM is a nonparametric method that bounds the maximum imbalance between treated and control groups with respect to the full joint distribution of the covariates *ex ante*. Unlike model dependent methods, CEM does not extrapolate counterfactual outcomes when there is limited overlap in the distributions of covariates across treatment and control groups, because matched data are restricted to areas of common empirical support. Recent applications of this matching method are presented in [73, 74, 75].

[13] In the context of Southern California's RECLAIM program, [66] employ a semi-parametric DID matching estimator of the ATT that compares differences between post and pre treatment NO_x emissions across treated and control plants, and use a regression-based adjustment to mitigate bias introduced by poor match quality [68, 69]. As a robustness check, the authors implement a propensity score matching estimator, which relies on a parametric regression model to estimate the propensity score. One disadvantage of this approach is that a misspecified matching model may produce greater imbalance in variables that are omitted from the matching procedure.

The objective of our matching procedure is to achieve statistically indistinguishable distributions between treated and control plants across a set of exogenous covariates that are highly correlated with the outcomes of interest (i.e., daily daytime and nighttime capacity factors). Hour-of-day specific capacity factors are clearly correlated with time-of-day capacity factors; further, more efficient plants tend to be used more heavily [76]. Therefore, we choose 2009 and 2010 as pre treatment period,[14] and use hour-of-day specific capacity factors and heat rates (averaged over this two-year period) as matching variables. Next, we coarsen the average hourly variables into discrete bins that identify strata corresponding to different levels of plant utilization and efficiency.[15] The following step is to perform exact matching on these discrete bins and discard observations from bins that do not contain both treated and control observations. It should be noted that the matched control sample varies by treated region and time of day, and CEM produces weights for each matched unit in each stratum [71].[16] Finally, we measure the impact of the cap-and-trade policy on plant operations by estimating the following differences-in-differences models with weighted least squares:

$$Y_{it} = \alpha_C TREAT^C_{it} + \mathbf{X}'_{it}\underline{\beta} + \gamma_i + \gamma_y + \gamma_{sm} + \epsilon_{it} \tag{3}$$

$$Y_{it} = \alpha_L TREAT^L_{it} + \mathbf{X}'_{it}\underline{\beta} + \gamma_i + \gamma_y + \gamma_{sm} + \epsilon_{it} \tag{4}$$

where t indicates daytime or nighttime, and Y_{it} is the capacity factor of plant-technology i reporting to CEMS in period t. Daily electric load by planning area is obtained from FERC Form 714; other covariates in $\mathbf{X}'_{it}$ are invariant at the monthly level (as in Section 5.1.1), since we do not observe higher frequency data for the entire WECC region.

5.1.3 Scheduled power flow regressions

In our final set of empirical results, we switch from analyzing plant operations to examining the relationship between the AB 32 allowance price and scheduled power imports into CAISO. Building on [23], we estimate a model of daily scheduled power flows into CAISO, and test for leakage based on the statistical significance of the AB 32 allowance price as one of the explanatory variables. As detailed in Section 4, we identify the major

[14] We exclude 2011, a wet hydrological year in which NGCC plants ran at much lower capacity factors than usual [77], and 2012, the year before compliance obligations began. We also remove from the matching dataset outliers (i.e., plants for which generation from CEMS is greater than generating capacity from EIA) and plants that were not operating over the entire period of our study.

[15] A detailed discussion of matching hour sets and binning strategies is presented in Section 6.2.

[16] Matched units receive a weight of 1 if they belong to the treatment group, and $\frac{m_C}{m_T}\frac{m^s_T}{m^s_C}$ if they belong to the control group, where m_C is the total number of control units, m_T is the total number of treated units, and m^s_C and m^s_T are their counterparts in stratum s. Weights normalize the variance in distribution of attribute bins across treatment and control observations. Unmatched units receive a weight of 0.

electricity grid interfaces into CAISO based on [54] and the analysis of annual CAISO reports detailing the frequency of import congestion on each intertie [55]. Scheduled flows on major interties are aggregated into two regions: the Northwest region including lines from the BPAT, PACE and PACW balancing authorities, and the Southwest region with interties from the AZPS, SRP, TEPC and WALC balancing authorities.[17] To account for the highly interconnected nature of power flows in WECC and mitigate potential endogeneity bias in our estimates, we model net scheduled energy flows from the Northwest and Southwest regions as a system of equations, and estimate it using maximum likelihood:

$$
\begin{aligned}
Z_{NW_t} &= \mathbf{X}_t^{'}\underline{\beta} + \delta_{NW}\mathrm{CO}_{2_t} + \gamma_d + \gamma_q + \epsilon_t \\
Z_{SW_t} &= \mathbf{X}_t^{'}\underline{\theta} + \delta_{SW}\mathrm{CO}_{2_t} + \eta_d + \eta_q + \zeta_t
\end{aligned}
\tag{5}
$$

where t indicates day, d denotes day-of-week, q indexes a quarter, Z_{NW_t} refers to scheduled flows from the Northwest region, and Z_{SW_t} refers to scheduled flows from the Southwest region.

A key determinant of net scheduled flows is given by the electric demand in CAISO and exporting balancing authorities. Higher load in CAISO increases net imports, while higher load in Northwest or Southwest balancing authorities is expected to reduce export availability from each region to California. Further, net scheduled flows in each export region may be reduced by scheduled flows into CAISO from the other region; as a result, we include net flows from the competing export region as a covariate in each equation. We also control for daily nuclear, wind and solar generation in CAISO. These technology types are unlikely to have responded to the carbon policy because they operate at near maximum capacity most of the time (nuclear), or their output depends on resource availability (wind and solar). Higher renewable and nuclear output in CAISO would reduce the need for imports. On the other hand, higher production from hydro and renewable energy sources in the Northwest and Southwest regions is expected to increase electricity imported from outside of California, displacing in-state natural gas-fired generation. Since daily aggregate production by technology is not publicly available for WECC balancing authorities other than CAISO, we include monthly generation from EIA-923; further, we only consider the most significant non-fossil energy source for each region, i.e., hydro in the Northwest and solar in the Southwest. Fuel prices in California and other WECC regions are also likely to affect electricity imports into CAISO. Since fuel prices at the plant level are only available from EIA-923 at the monthly level, we use wholesale natural gas prices at four locations in WECC (Sumas, PG&E Citygate, SoCal Border and El Paso San Juan) [60] to control for daily price dynamics in

[17] Northwest interties include Cascade, Pacific AC Intertie, Nevada-Oregon Border, COTPISO, Summit, IPP DC Adlanto, Mona IPP DC, Mead, and El Dorado; Southwest interties include Palo Verde and IID-SCE [54].

the Northwest, CAISO and Southwest regions. Higher PG&E Citygate prices in Northern California and SoCal Border prices in Southern California are likely to make power imports more economically viable. In contrast, higher natural gas prices at Sumas in the Northwest and El Paso San Juan in the Southwest are expected to favor in-state electricity generation relative to power imports.[18] As an alternate measure of fuel prices, we use ratios of PG&E Citygate/Sumas prices and SoCal Border/El Paso San Juan, expecting that higher fuel price ratios increase imports in CAISO. To account for seasonal effects, we include day-of-week and quarter dummies in each regression.

Finally, the daily price of AB 32 CO_2 allowances is equal to zero until the beginning of compliance obligations on January 1, 2013. A positive and statistically significant coefficient associated with the CO_2 price in the Northwest equation, δ_{NW}, would suggest empirical evidence of emission leakage from the Northwest region of WECC. Similarly, a positive and statistically significant δ_{SW} would support the hypothesis of leakage from the Southwest region.

5.2 Identifying Assumptions

Our estimation strategy relies on several identifying assumptions. First, treatment is exogenous: participation in the cap-and-trade program does not depend on the outcomes (i.e., plant capacity factors). Second, in order to interpret α_C and α_L as estimates of the effect of California's cap-and-trade program on plant-level capacity factors, an important identifying assumption is that treated and control plants would have followed parallel trajectories, absent the AB 32 cap-and-trade program [78]. We assess the parallel trends assumption by testing the equivalence of time trends between treatment and control groups before program implementation [79].[19] Specifically, we test the significance of the interaction term between the time trend and the treatment group: estimated parameters associated with group specific time trends that are not statistically different from zero indicate that pre treatment trends are similar for treated and control groups, and are consistent with a causal interpretation of the results in (2). We estimate the following equation:

$$Y_{it} = \alpha_{Ct} D_t TREAT_i^C + \sum_L \alpha_{Lt} D_t TREAT_i^L + \mathbf{X}'_{it}\underline{\beta} + \gamma_i + \gamma_y + \gamma_{sm} + \epsilon_{it} \tag{6}$$

[18]We only observe weekly Rocky Mountain Colorado Rail coal prices for the Western Interconnection (Section 4.4). Absent regional variation, we do not control for coal prices in the scheduled power flow regressions.

[19]In [79], court decisions altering common law occur at different times providing multiple experiments (i.e., multiple treatment periods); in our setting, the treatment period is instead unique and corresponds to January 1, 2013, when the California cap-and-trade program began its compliance obligation.

where D_t is a quarterly dummy equal to 1 after January 2013 and 0 otherwise, $TREAT_i^C = 1$ if plant i is in California, $TREAT_i^L = 1$ if plant i is in one of the leaker regions, and α_{Ct} and α_{Lt} are the estimated coefficients associated with group specific time trends. Other variables are defined as above. If the parallel trends assumption is satisfied, α_{Ct} and α_{Lt} are not statistically different from zero before the implementation of the cap-and-trade program. Not all the α_{Ct} can be identified as the $TREAT_i^C$ dummies are perfectly collinear in the presence of state effects. Hence, similarly to [24] we omit the first year for all groups in our tests.

Matching relies on selection on observables (ignorability assumption) and common support (overlap assumption). Based on the ignorability assumption, once we control for matching variables, treatment is randomly assigned, experimental conditions are re-established, and biases in the DID estimator are removed because capacity factors at treated and control plants would have followed parallel paths over the study period. We run balancing tests to compare matching variable means in the treated and control groups before and after matching. Finally, the overlap assumption requires that the support of the distribution of covariates in the treated group overlaps the support of the distribution of these covariates in the control group. Coarsened exact matching automatically restricts the matched data to areas of common support, as discussed in Section 5.1.2: this helps avoid making inferences based on extrapolation, which are known to be highly model dependent.

6 Results

6.1 Differences-in-differences regressions

Tables 1 and 2 present our differences-in-differences regression results from the analysis of capacity factors. We run the baseline specification with monthly data in equation (2) for NGCC and coal plants separately, and present estimation results in Column (1) of the two tables. Our dependent variable is the capacity factor of plant-technology i in month t. The unit of observation in the analysis is a plant-month, and standard errors are clustered at the plant level. As noted in Section 5.1, leaker regions and the set of controls differ by technology type. For NGCC plants, treatment effects are estimated for California and two leaker regions (Northwest and Southwest) including plants that supply specified source power to California. In Table 1, the "California" line presents the treatment effect estimate for α_C, while the "Northwest" and "Southwest" lines present the estimated effects for α_L in equation (2). The set of controls consists of all NGCC power plants in WECC, but outside of California or any of the leaker regions. Treated and control regions are presented in Figure 3, and summary statistics by region are given in Table A3 in the Appendix. Figure 5(a) reports the results of the parallel trend tests. Specifically, we plot the estimated α_{Ct} and α_{Lt} from equation (6) with 95% confidence intervals: with one exception, pre treatment period coefficients are not statistically different from zero for California and the leaker regions, indicating that treated and control regions have similar pre treatment trends.

For coal-fired plants, we do not include a treatment effect for California. Generating capacity from coal is limited, and capacity factors have declined steadily in the three quarters before the introduction of the cap-and-trade system, resulting in a rejection of the parallel path assumption before treatment. However, coal plants supplying specified source power to California are located throughout WECC. After grouping them into three regions (Northwest, Southwest and Eastern) according to [65], the number of control plants in WECC is limited (Table A4). As a result, in our baseline coal specification we extend the set of controls to include coal plants in the MRO, SPP and TRE regions besides WECC facilities that are outside California or any of the leaker regions. Treated and control regions are presented in Figure 4, and summary statistics by region are given in Table A4. Figure 5(b) reports the results of the parallel trend tests, indicating that treated and control regions exhibit similar pre treatment trends.

Estimated treatment effects in the baseline specification suggest that NGCC generators in California had a statistically significant policy-induced reduction in capacity factors of about 14%. In contrast, California's cap-and-trade led to a 4% increase in coal capacity factors in the Northwest and Eastern leaker regions (statistically significant at the 5% and 10% significance level, respectively). We find a small and insignificant response for NGCC plants in the Northwest and Southwest regions, and coal plants in the Southwest regions. Overall, this result suggests empirical evidence of leakage: the policy induced a reduction in NGCC generation in California and an increase in coal-fired generation in WECC balancing authorities that dispatch plants supplying specified source power to California.

We conduct a back of the envelope calculation to examine whether our estimated coefficients result in realistic magnitudes of leakage. First, we find the estimated generation leakage by multiplying the treatment effect (when statistically significant) by the average annual generation capacity in each region and number of hours in a month. That is, we multiply the estimated treatment effect of 14.1% by the average NGCC generation capacity in California between 2009 and 2016 (19,369 MW), and the estimated treatment effects of 4.25% and 3.93% by the average coal generation capacity in the Northwest and Eastern leaker regions (13,259 MW and 5,723 MW, respectively). Due to the cap-and-trade policy, NGCC generation in California decreased by approximately 2 million MWh per month, while coal generation in the leaker regions increased by about 0.6 million MWh per month.[20] In turn, this implies that emissions increased by about 8.5 million tons per year in the Northwest and Eastern regions of WECC, and decreased by about 12 million tons per year in California, corresponding to an aggregate decrease of about 3.6 million tons per year and an estimated policy-induced leakage of about 70%.[21] This estimate is within the range of predictions obtained from simulation-based studies considering California's cap-and-trade program, although direct comparisons between *ex ante* and *ex post* analyses are difficult [24]. On the lower end of the spectrum, [19] find leakage of 9% when provisions to prevent resource shuffling are enforced. [10] simulate the effects of a first deliverer approach with default emission factor of 0.428 tons CO_2/MWh applied to imports, assuming a 15% and a 25% reduction in California utility power sector emissions from 2007 levels. Compliance with the lower cap yields no change in emissions, relative to the no cap scenario. Assuming a 25% reduction, the first deliverer approach would lead instead to an emission decrease of 4.5 million tons in California and an increase of 1.6 million tons in the rest of WECC relative to a no cap scenario, i.e. an implied leakage of about 35%. Closer to our estimate, under a first-deliverer approach [9] predict a leakage rate of about 85% (corresponding to an emission decrease of 0.7 million tons in California and 0.1 million tons in the Western U.S.), while [14] find that carbon regulation in California would result in leakage of about 89% (corresponding to an emission decrease of 5.5 million tons in California and 0.6 million tons in the Western U.S.). Finally, a recent econometric study of leakage in the context of the Regional Greenhouse Gas Initiative [24] estimates a leakage rate of approximately 50% for the policy (corresponding to an emission decrease of 8.8 million tons per year in RGGI and an aggregate decrease of 4.3 million tons per year).

Robustness checks. We conduct several robustness checks to assess the sensitivity of our estimates. First, results are robust to alternate clustering (e.g., at the balancing authority or state level, to account for the likely dependence in capacity factor innovations across plants in the same power control area/state, and arbitrary time series correlation within the same power control area/state), and the inclusion of different fixed effects (plant, year, and month-of-year; and plant, state-by-year, and month-of-year).

Second, we adjust standard errors to allow for correlation along two dimensions (plant and time). Standard errors clustered at the plant level assume that correlation of the residuals within the cluster may be nonzero, but residuals across clusters are uncorrelated. This may lead to incorrect standard errors and t statistics, if residual correlation exists both within a plant across time and across plants at a moment in time

[20] Between 2009-2012 and 2013-2016, monthly power generation from solar and wind in California increased, on average, by about 1 million MWh and 0.6 million MWh per month, respectively.

[21] Our calculations are based on an average heat rate of 12,046 Btu/kWh and CO_2 emission rate of 207.87 lb/MMBtu for coal plants in the Northwest region, heat rate of 12,163 Btu/kWh and CO_2 emission rate of 207.82 lb/MMBtu for coal plants in the Eastern region, and heat rate of 8,645 Btu/kWh and CO_2 emission rate of 118.88 lb/MMBtu for NGCC plants in California. Average heat rates and CO_2 emission rates over the period of our study (2009-2016) are from Tables A3 and A4.

[80, 81]. In Column (2) of Tables 1 and 2, we allow for arbitrary correlation of the error terms at the plant and month level, and find that estimation results are robust to double clustering.[22]

In Column (3) of Tables 1 and 2, we restrict our sample to facilities that were operating over the entire period of our study to account for entry and attrition at the plant level.[23] For NGCC plants, 10 facilities out of 121 operating in WECC in 2009 were no longer in service in 2016 (about 2% of 2009 operating capacity), and 14 plants out of 125 operating in 2016 were not active in 2009 (about 10% of 2016 operating capacity). For coal-fired plants, 15 plants out of 55 operating in WECC in 2009 were no longer in service in 2016 (about 6% of 2009 operating capacity), and 3 plants out of 43 operating in 2016 were not active in 2009 (about 2% of 2016 operating capacity). Estimated treatment effects are in line with those from the full sample, and suggest that capacity factors of NGCC generators in California decreased by about 13%, while capacity factors of coal generators in the Northwest and Eastern leaker regions increased by about 6% and 5%, respectively. The estimated coal treatment effect in the Northwest region is statistically significant at the 1% level (rather than 5%, as in the baseline regressions).

In Column (4) of Table 1, we estimate equation (2) for NGCC plants with a broader set of controls including plants in SPP and TRE, in addition to the rest of WECC.[24] Figure A2 in the Appendix shows that the parallel trend assumption holds for treated and control groups before the introduction of the cap-and-trade program. Estimated treatment effects confirm a statistically significant reduction in capacity factors for NGCC plants in California, but indicate a smaller effect (about 11%) than in the baseline specification.

We also test the sensitivity of our estimates to alternate definitions of the leaker regions. Concerns have been raised about resource shuffling in the context of the California ISO's Energy Imbalance Market (EIM), a real-time power market to meet short-term supply imbalances in the Western United States [83, 13], and CAISO has been experimenting with approaches to mitigate leakage [84, 85]. We designate as leakers WECC balancing authorities in the U.S. that are active or pending (as of 2018) participants of the Western EIM. These entities include AZPS, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP, and are divided into two leaker regions, as shown in Figure A3 in the Appendix. We control for the same variables of the baseline specification, and cluster standard errors at the plant level. Results for the parallel trend tests are given in Figure A4. Estimated treatment effects in column (5) of Table 1 and column (4) of Table 2 confirm a policy-induced reduction of about 12% in capacity factors for NGCC power plants in California. The estimated increase in coal capacity factors for Northwest plants is lower than in the baseline regressions

[22] Two-way clustering relies on asymptotics in the smaller number of clusters (i.e., the dimension with fewer clusters), and is thus likely to produce unbiased estimates when each dimension has many clusters [82].

[23] Entry and attrition at the unit level are limited, as plant capacity did not vary significantly over the period of our study.

[24] We exclude MRO from the set of controls because capacity factors are much lower than in the rest of WECC.

(about 3%), and statistically significant at the 10% level.

6.2 Matching and differences-in-differences

Our second set of empirical results explores the use of coarsened exact matching methods to prune observations that have no close matches on pre treatment variables in both treated and control groups. We then run a differences-in-differences model on matched plants only to measure policy impact using high frequency measures of generation and load for a subset of power plants reporting to the EPA's Continuous Emissions Monitoring System.

Our baseline specification matches treated and control plants based on four pre treatment, hour-of-day specific capacity factors in each period. We consider three sets of matching hours: in hour set 1, matching is based on hours 7,10,13,16 (Daytime) and 19,22,1,4 (Nighttime); in hour set 2, matching is based on hours 8,11,14,17 (Daytime) and 20,23,2,5 (Nighttime); in hour set 3, matching is based on hours 9,12,15,18 (Daytime) and 21,0,3,6 (Nighttime). We coarsen each matching variable according to manually defined cut points that identify strata corresponding to different levels of plant utilization. In general, fewer strata yield more matches, but result in more diverse observations within the same stratum. To balance this trade-off, we define cut points based on the empirical distribution of capacity factors by technology type (0.3, 0.5, and 0.7 for NGCC plants, 0.6 and 0.8 for coal-fired plants).[25] Balancing tests confirm that matching achieves statistically indistinguishable distributions between treated and control plants. Tables 3 and 4 present the t statistics of tests of identical means in the treated and control groups for hour set 2. Before matching, there exist significant differences between the covariates, particularly in California and the Northwest and Eastern regions in WECC; after matching, the null of identical means in both group is no longer rejected for all variables.[26] Further, it is worth noting that in each period matching helps to reduce bias not only for specific hours used as matching variables, but across all hours, bringing us closer to a quasi-experimental dataset.[27]

Tables 5 and 6 present the treatment effects from the differences-in-differences regressions estimated using weighted least squares.[28] Results from the matched sub-samples are broadly consistent with the ones

[25]Coal-fired plants (particularly in the Southwest region of WECC) tend to be more heavily utilized than NGCC plants, motivating our choice of higher capacity factors as cut points.

[26]In the Southwest region, raw data does not show statistical difference across treated and controls, thus matching does not yield substantial benefits.

[27]To illustrate, consider Table 3. Columns 2 to 7 present t statistics of a balancing test of identical means when matching is based on hours 8,11,14,17, while columns 8 to 13 present balancing tests when matching is done on hours 20,23,2,5. In Columns 2-7, balance improves not only for matching covariates (i.e., hours 8,11,14,17), but for all hours, including those omitted from the matching procedure.

[28]Estimated coefficients for other covariates in the DID regressions have the expected sign and statistical significance, and areavailable from the authors upon request. Further, in Table 5 the presence of one additional outlier for hour set 1 leads to

from the full sample. For California, the effect is smaller (in absolute value) compared to the OLS result, suggesting a policy-induced reduction of NGCC capacity factors in California by about 7% only during daytime hours. Leakage from coal plants in the U.S. Northwest region of WECC is confirmed across all periods, while nighttime leakage for the Eastern and Southwest regions are more sensitive to the choice of matching hours and statistically significant at the 10% level. A decrease in NGCC generation in California during daytime hours and an increase in coal generation in the leaker regions over the entire day may be due to heavy utilization of Western U.S. coal plants, which tend to ramp more slowly than NGCC plants [86]. It should be noted that our matching procedure is based on quite small subsamples of plants reporting to CEMS, which represent 81% of NGCC generation in California and 96%, 100%, and 62% of coal-fired generation in the Northwest, Eastern and Southwest regions, respectively.[29] Further, the estimated treatment effects are only averaged over the subset of treated units for which good matches exist among available controls (i.e., constitute local ATTs [71]), and do not account for correlation across daytime/nighttime hours or treated groups. Thus, we believe that the causal effects defined on the full sample are better suited for obtaining an estimate of policy-induced leakage.

Robustness checks. Empirical findings are robust to the inclusion of matching variables and choice of cut points. We present results for hour set 2. In our first robustness check (Table A5 in the Appendix), we include hourly heat rates as matching variables and set cut points at the percentiles of the distribution of matching variables. For NGCC, we use the 40th, 60th and 80th percentiles, while for coal we use the 20th, 40th, 60th and 80th percentiles. These cut points define four strata for NGCC capacity factors and heat rates, and five strata for coal matching variables, respectively. We choose a different number of strata for each technology type to balance the trade-off of matching described above, since five strata for NGCC yield few matches. In our second robustness check (Table A6 in the Appendix), we match based on hour-of-day specific capacity factors in each period, as in the baseline specification, but coarsen the matching variables using the statistical-based binning algorithm that returns the lowest value for the L_1 statistic, a measure of imbalance with respect to the full joint distribution [72].[30] Results are in line with those from the baseline specification, but do not suggest leakage from the Southwest region in WECC.

fewer control plants (72), relative to hour sets 2 and 3 (73).

[29] These percentages represent region-specific average shares of CEMS generation over EIA generation in 2009-2016.

[30] The Scott and Freedman-Diaconis automatic binning algorithms perform well in our sample [87, 88] and result in more strata, relative to coarsening by fixed cut points or percentiles. Note that there exists a trade-off between bin width and value of the L_1 statistic. Coarsening by user choice results in values of L_1 close to zero and more overlap between the distribution of covariates in the treated and control groups; automated coarsening yields narrower bin width that better approximates each distribution, but results in higher values of L_1 and less overlap between the two distrbutions.

6.3 Scheduled power flow regressions

Our last set of empirical results examines changes in daily net power flows across major CAISO interfaces after the introduction of California's cap-and-trade program [23]. We estimate a model of scheduled power flows into CAISO, including the AB 32 emission allowance price as one of the explanatory variables. As discussed in Section 5.1.3, the main drivers of scheduled flows are electric demand in CAISO and exporting balancing authorities, hydroelectric, nuclear and renewable generation in CAISO, fuel prices in California and exporting regions, and electricity imports from the competing region. After controlling for these variables, a positive and statistically significant coefficient associated with the allowance price (δ_{NW} or δ_{SW}) would support empirical evidence of leakage from the Northwest or Southwest region of WECC into CAISO.

Model (1) in Table 7 represents the system of equations with fuel prices as covariates, while model (2) includes fuel price ratios. All covariates have the expected sign. Further, in both models the CO_2 allowance price is highly significant as an explanatory variable for Northwest flows, but does not have a statistically significant effect on power flows from the Southwest. Therefore, results suggest that net scheduled flows into California increased from the Northwest region of WECC in response to the carbon policy, further supporting the hypothesis of leakage.

7 Discussion and conclusions

California has pledged to reduce its greenhouse gas emissions to 1990 levels by 2020, 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050. These ambitious goals are being accomplished through a suite of complementary policies, including a multi-sector cap-and-trade program that covers about 80% of the state's emissions and applies to in-state electricity generation and imports. To mitigate leakage in the electricity sector, California opted for a source-based regulation applied to in-state sources, with first deliverer measures for imports into California. However, the possibility of reshuffling contracts may enable substantial leakage under the AB 32 cap-and-trade system. Under resource shuffling, electricity contracts are rearranged so that production from low emission sources serving out-of-state load is directed to California, while production from higher emission sources is assigned to serve out-of-state load. This would result in apparent emission reductions due to changes in the composition of imports to California, although emissions in exporting regions are unchanged or even increase.

Simulation-based studies have concluded that resource shuffling represents a significant potential conduit for emission leakage in the electricity sector under California's cap-and-trade program [9, 14, 10, 11]. Our paper brings empirical evidence to bear on this issue, using a novel dataset from 2009 to 2016. We present three sets of results that support the hypothesis of leakage. First, we analyze monthly operations of baseload power plants in WECC applying a differences-in-differences estimator. Regression results point to a policy-induced reduction in NGCC generation by about 14% in California and an increase in coal-fired generation by about 4% in regions of the Western Interconnection that supply specified source power to California. In turn, these estimated treatment effects imply a policy-reduced leakage of about 70%, which is within the range of *ex ante* predictions and in line with recent econometric estimates for the Regional Greenhouse Gas Initiative. Results are robust to the choice of leaker and control groups, clustering methods and sample definition. In particular, direction and magnitude of the estimated treatment effects is confirmed when we designate as leakers WECC balancing authorities in the U.S. that are active or pending participants of the California ISO's Energy Imbalance Market, a real-time power market in the Western U.S. Our second set of empirical estimates combines differences-in-differences with matching methods to ensure common support in the covariates across treated and control groups. We preprocess the data by matching units on coarsened hourly variables and carry out parametric inferences using daily measures of plant utilization. This approach changes the estimand to a local average treatment effect for the plants that were matched. Importantly, results from the matched sub-samples are broadly consistent with those from the full sample, and robust to the inclusion of matching variables and choice of cut points. In our final set of analyses, we test for leakage from the policy by examining the relationship between the AB 32 allowance price and scheduled power imports into CAISO. Specifically, we estimate a model of daily scheduled power flows into CAISO, and test for leakage based on the statistical significance of the AB 32 allowance price as one of the explanatory variables. The CO_2 allowance price is highly significant as an explanatory variable for Northwest flows, but does not have a statistically significant effect on power flows from the Southwest. This suggests that net scheduled flows from the Northwest region of the Western Interconnection into California have increased in response to the carbon policy, in line with the analysis of power plant operations with differences-in-differences and matching methods.

While the consistency of results across statistical approaches supports the hypothesis of leakage, our study is subject to limitations. For example, one caveat is that we do not observe power contracts between California utilities and out-of-state power plants. Absent this information, we are unable to control, for example, for the divestiture from long-term contracts with coal facilities [89]. Yet, if coal-fired production was redirected to out-of-state electricity consumers, resource shuffling (and leakage) would have happened. Another caveat relates to our approach for identifying potential leakers. Due to the specific features of electric power systems, identifying out-of-state generation resources that are deemed to provide exports to California represents a challenge. For example, until recently the California ISO was testing a "two-pass solution" of the Energy Imbalance Market algorithm to identify out-of-state resources dispatched to California in response to the carbon price [12]. This two-stage solution has been subject to criticism because it introduces discriminatory constraints applying in the second stage economic dispatch, and may lead market participants to distort their offers relative to the true generation costs [84]. As noted in Section 5.1, alternate approaches for identifying leakers in the Western Interconnection are possible and worth exploring for further empirical analyses. Ongoing work considers this important issue.

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Figures and Tables

Figure 1: NERC regions in the United States

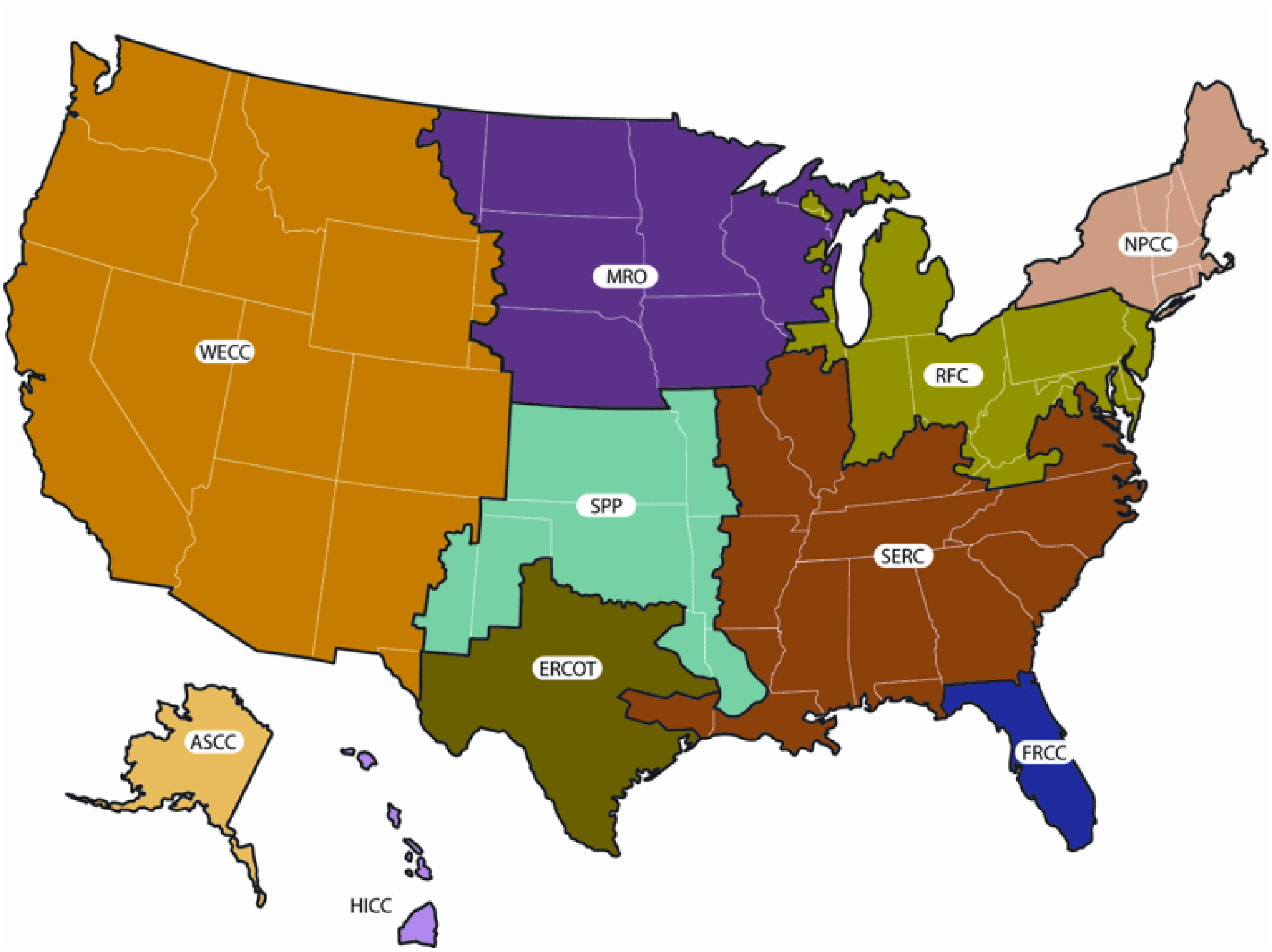
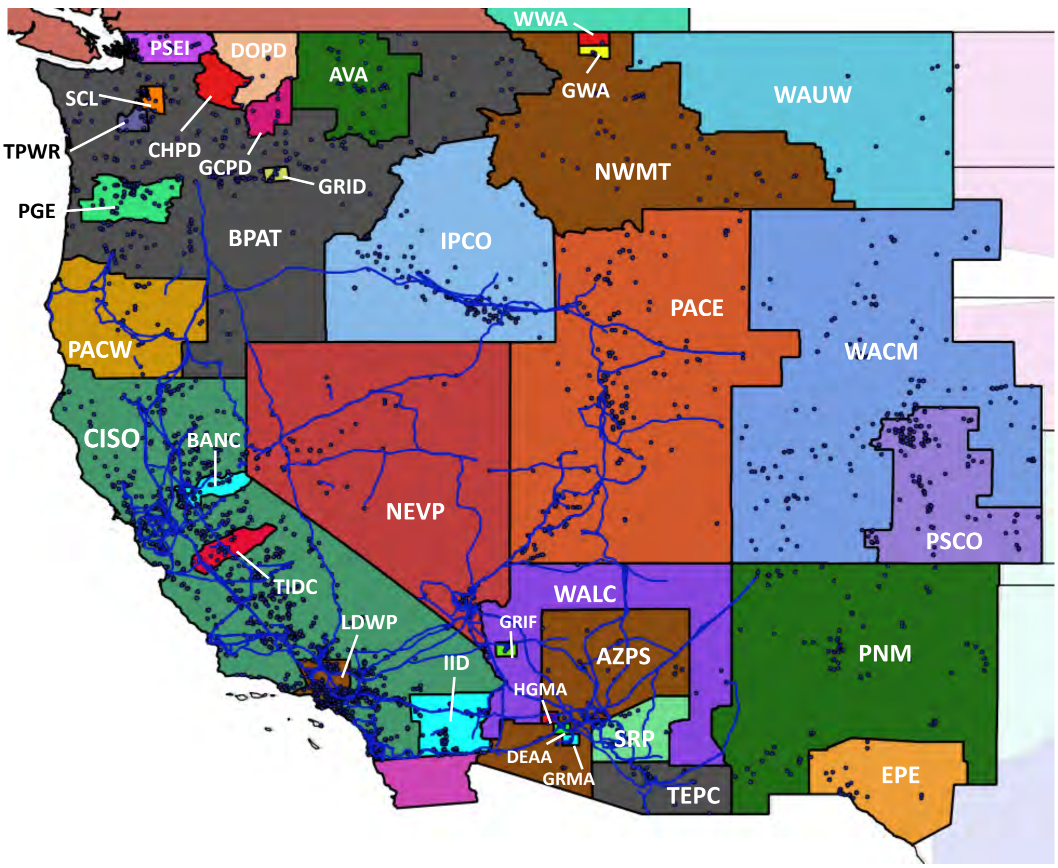
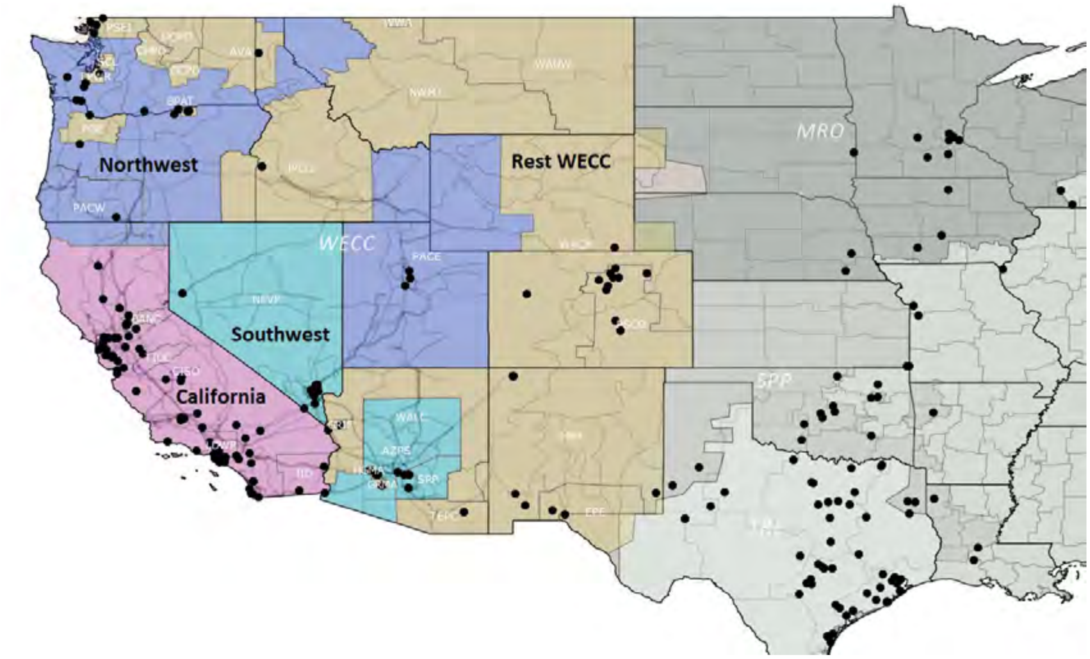


Figure 2: WECC balancing authorities in the United States, 2016



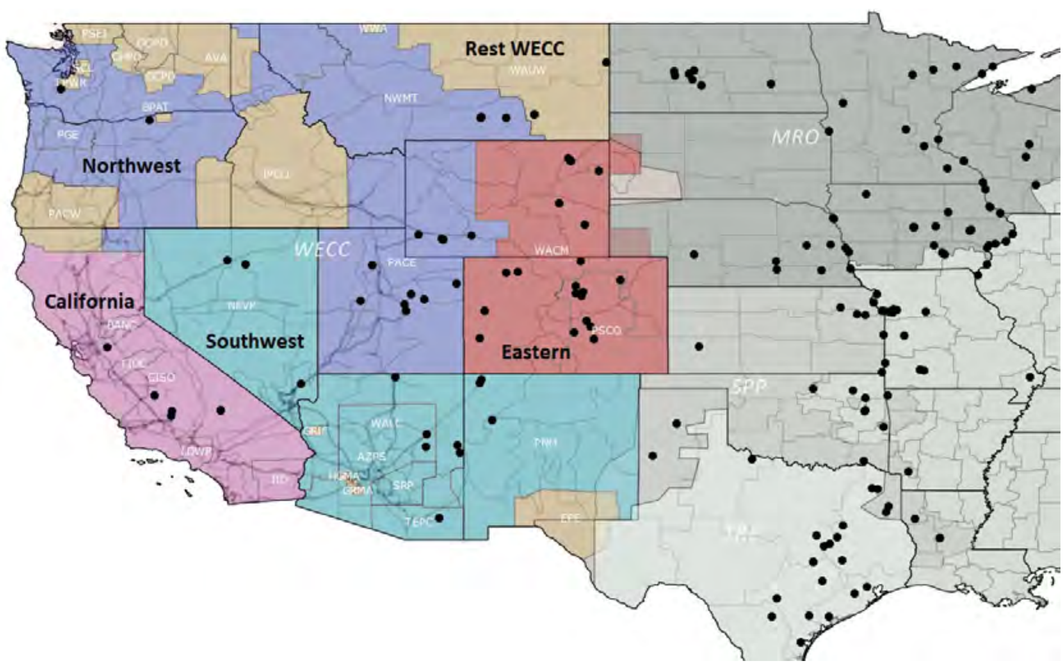
Notes: black dots represent NGCC and coal-fired power plants, blue lines indicate transmission lines.

Figure 3: Treated and control regions in WECC, NGCC plants



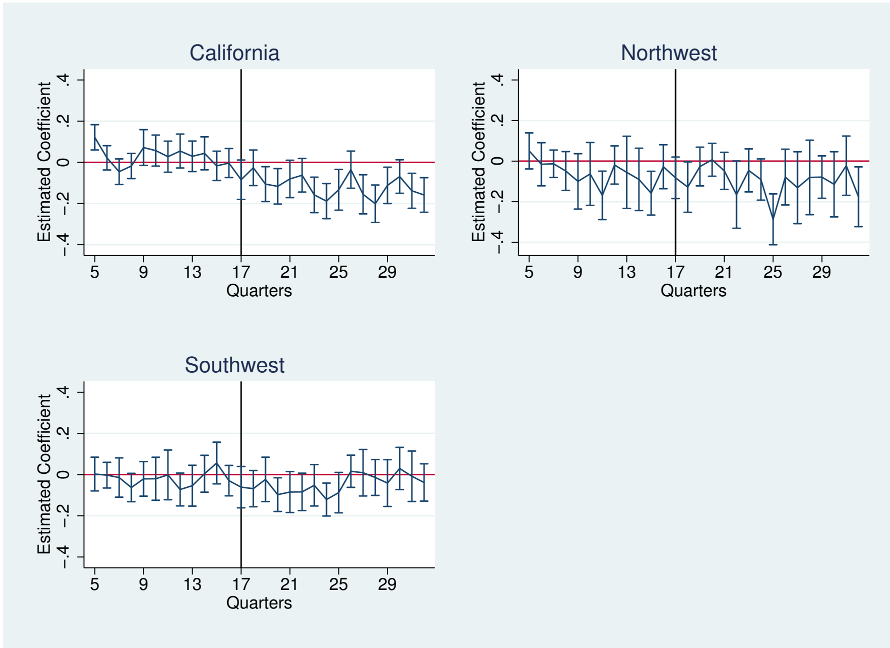
Note: black dots represent power plants.

Figure 4: Treated and control regions in WECC, coal-fired plants

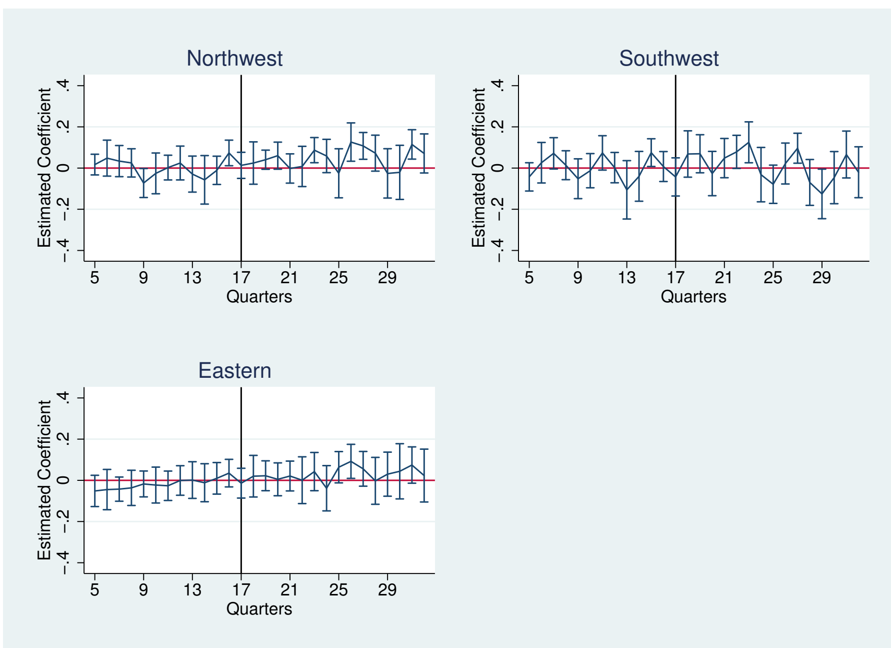


Note: black dots represent power plants.

Figure 5: Estimated quarterly treatment effects - baseline



(a) NGCC plants



(b) Coal-fired plants

Notes: vertical lines represent 95% confidence intervals. Controls include NGCC plants in the rest of WECC, and coal-fired plants in the rest of WECC, MRO, SPP and TRE.

Table 1: Differences-in-differences: Estimated effects of California's cap-and-trade program on NGCC plant capacity factors in WECC

	(1)	(2)	(3)	(4)	(5)
California	−0.1414***	−0.1414***	−0.1338***	−0.1036***	−0.1222***
Northwest	−0.0483	−0.0483	−0.0432	−0.0266	−0.0315
Southwest	−0.0321	−0.0321	−0.0280	−0.0138	0.0111
Electric Demand	0.0757	0.0757	0.0815	0.1170***	0.0605
Nuclear and Renewable Generation	−0.2202***	−0.2202***	−0.2209***	−0.1656***	−0.2225***
CDDs	0.0002***	0.0002***	0.0002***	0.0003***	0.0003***
HDDs	0.0001*	0.0001	0.0001*	0.00001	0.0001*
SPI	−0.0074***	−0.0074**	−0.0073***	−0.0043***	−0.0077***
NG-to-Coal	−0.0602***	−0.0602***	−0.0586***	−0.0660***	−0.0605***
NG-to-Coal^2	0.0022***	0.0022***	0.0021***	0.0026***	0.0022***
Intercept	1.4686***	1.4686***	1.4280***	0.3470	1.5938***
Plant FE	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes
State x Month-of-Year FE	Yes	Yes	Yes	Yes	Yes
N	11,938	11,938	10,858	19,368	11,938
R^2	0.6705	0.6705	0.6683	0.6636	0.6703
Controls	Rest of WECC	Rest of WECC	Rest of WECC	Rest of WECC, SPP, TRE	Rest of WECC
S.E. Clustering	Plant	Plant & Month	Plant	Plant	Plant

Notes: In specifications (1)-(4), we designate as leakers WECC balancing authorities in the U.S. that dispatch power plants supplying specified source power to California, and divide them into two regions, based on [65]. Northwest includes plants in BPAT, PACE and PACW, and Southwest includes non-California plants in AZPS, AZ CAISO, NV CAISO, HGMA, NEVP, SRP and WALC. In specification (5), we designate as leakers WECC balancing authorities that are active or pending participants of the California ISO's Energy Imbalance Market: these include AZPS, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP. LDWP and BANC are also pending participants of the Western EIM, but are not considered leakers as their footprint is entirely within California. *, **, and *** indicate statistical significance at 10%, 5% and 1% level, respectively. The unit of observation for these regressions is plant-month.

Table 2: Differences-in-differences: Estimated effects of California's cap-and-trade program on coal-fired plant capacity factors in WECC

	(1)	(2)	(3)	(4)
Northwest	0.0425**	0.0425**	0.0559***	0.0276*
Eastern	0.0393*	0.0393*	0.0478*	-
Southwest	0.0088	0.0088	0.0160	−0.0298
Electric Demand	0.0318	0.0318	0.0285	0.0367
Nuclear and Renewable Generation	−0.0315**	−0.0315**	−0.0316**	−0.0299**
CDDs	0.0002***	0.0002***	0.0002***	0.0002***
HDDs	0.0001***	0.0001***	0.0001***	0.0001***
SPI	−0.0066***	−0.0066***	−0.0073***	−0.0064***
Coal-to-NG	−0.2843***	−0.2843***	−0.2808***	−0.2847***
Coal-to-NG^2	0.0878***	0.0878***	0.0889***	0.0896***
Intercept	0.8888***	0.8888***	0.8773***	0.8752***
Plant FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
State x Month-of-Year FE	Yes	Yes	Yes	Yes
N	14,298	14,298	12,615	14,298
R^2	0.6029	0.6029	0.5769	0.6022
Controls	Rest of WECC, MRO, SPP, TRE	Rest of WECC, MRO, SPP, TRE	Rest of WECC, MRO, SPP, TRE	Rest of WECC, MRO, SPP, TRE
S.E. Clustering	Plant	Plant & Month	Plant	Plant

Notes: In specifications (1)-(3), we designate as leakers WECC balancing authorities in the U.S. that dispatch power plants supplying specified source power to California, and divide them into three regions, based on [65]. Northwest includes plants in BPAT, UT LDWP, NWMT, PACE and PGE. Eastern includes plants in PSCO and WACM. Southwest includes plants in AZPS, NEVP, PNM, SRP, TEPC, and WALC. In specification (4), we designate as leakers WECC balancing authorities that are active or pending participants of the California ISO's Energy Imbalance Market: these include AZPS, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP. LDWP and BANC are also pending participants of the Western EIM, but are not considered leakers as their footprint is entirely within California. *, **, and *** indicate statistical significance at 10%, 5% and 1% level, respectively. The unit of observation for these regressions is plant-month.

Table 3: Balancing tests, NGCC plants

	Daytime						Nighttime					
	California		Northwest		Southwest		California		Northwest		Southwest	
	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching
Hour 0	2.753***	−0.473	2.088**	−0.736	0.788	1.724	2.753***	0.077	2.088**	−0.154	0.788	0.195
Hour 1	2.691***	−0.571	2.240**	−0.634	0.710	1.682	2.691***	0.168	2.240**	−0.034	0.710	0.194
Hour 2	2.644***	−0.628	2.293**	−0.605	0.629	1.613	2.644***	0.189	2.293**	−0.001	0.629	0.111
Hour 3	2.643***	−0.627	2.299**	−0.604	0.536	1.520	2.643***	0.164	2.299**	−0.009	0.536	−0.011
Hour 4	2.752***	−0.543	2.216**	−0.690	0.351	1.340	2.752***	0.126	2.216**	−0.155	0.351	−0.289
Hour 5	2.580**	−0.711	2.134**	−0.858	0.059	1.054	2.580**	−0.077	2.134**	−0.436	0.059	−0.550
Hour 6	2.486**	−0.727	2.213**	−0.889	−0.055	0.770	2.486**	−0.146	2.213**	−0.609	−0.055	−0.831
Hour 7	2.575**	−0.560	2.543**	−0.644	−0.134	0.524	2.575**	−0.062	2.543**	−0.365	−0.134	−0.971
Hour 8	2.489**	−0.545	2.682***	−0.522	−0.278	0.351	2.489**	−0.107	2.682***	−0.165	−0.278	−1.209
Hour 9	2.249**	−0.599	2.562**	−0.539	−0.406	0.208	2.249**	−0.282	2.562**	−0.185	−0.406	−1.439
Hour 10	2.044**	−0.666	2.417**	−0.593	−0.401	0.177	2.044**	−0.418	2.417**	−0.267	−0.401	−1.470
Hour 11	1.884*	−0.767	2.333**	−0.644	−0.319	0.152	1.884*	−0.548	2.333**	−0.332	−0.319	−1.377
Hour 12	1.799*	−0.820	2.256**	−0.692	−0.247	0.144	1.799*	−0.615	2.256**	−0.389	−0.247	−1.294
Hour 13	1.786*	−0.821	2.241**	−0.694	−0.171	0.166	1.786*	−0.606	2.241**	−0.409	−0.171	−1.195
Hour 14	1.764*	−0.833	2.266**	−0.670	−0.089	0.252	1.764*	−0.620	2.266**	−0.395	−0.089	−1.107
Hour 15	1.742*	−0.850	2.289**	−0.649	−0.040	0.308	1.742*	−0.637	2.289**	−0.373	−0.040	−1.053
Hour 16	1.666*	−0.920	2.268**	−0.666	−0.015	0.342	1.666*	−0.722	2.268**	−0.378	−0.015	−1.008
Hour 17	1.687*	−0.899	2.232**	−0.691	0.034	0.398	1.687*	−0.717	2.232**	−0.396	0.034	−0.936
Hour 18	1.726*	−0.856	2.169**	−0.728	0.082	0.441	1.726*	−0.761	2.169**	−0.483	0.082	−0.936
Hour 19	1.837*	−0.770	2.131**	−0.764	0.164	0.501	1.837*	−0.669	2.131**	−0.530	0.164	−0.865
Hour 20	1.943*	−0.735	2.205**	−0.727	0.292	0.591	1.943*	−0.735	2.205**	−0.727	0.292	0.591
Hour 21	2.289**	−0.515	2.271**	−0.702	0.619	0.962	2.289**	−0.332	2.271**	−0.336	0.619	−0.335
Hour 22	2.739***	−0.231	2.303**	−0.663	0.842	1.430	2.739***	−0.097	2.303**	−0.115	0.842	0.041
Hour 23	2.929***	−0.219	2.040**	−0.805	0.897	1.724	2.929***	0.071	2.040**	−0.221	0.897	0.234

Notes: the table provides t statistics of a two-sided t test of mean comparisons between treated and control groups. *, **, and *** indicate statistical significance at 10%, 5% and 1% level, respectively.

Table 4: Balancing tests, Coal-fired plants

	Daytime						Nighttime					
	Northwest		Eastern		Southwest		Northwest		Eastern		Southwest	
	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching	Before matching	After matching
Hour 0	3.801***	2.260**	2.702***	1.364	1.277	1.141	3.801***	0.788	2.702***	0.530	1.277	0.170
Hour 1	3.942***	2.406**	2.906***	1.585	1.368	1.263	3.942***	1.037	2.906***	0.654	1.368	0.261
Hour 2	4.002***	2.471**	2.962***	1.653	1.368	1.264	4.002***	1.165	2.962***	0.683	1.368	0.249
Hour 3	3.933***	2.388**	2.953***	1.651	1.309	1.195	3.933***	1.031	2.953***	0.668	1.309	0.177
Hour 4	3.617***	2.022**	2.787***	1.506	1.197	1.067	3.617***	0.545	2.787***	0.565	1.197	0.062
Hour 5	3.215***	1.561	2.464**	1.210	1.028	0.853	3.215***	0.089	2.464**	0.414	1.028	−0.081
Hour 6	2.716***	0.871	2.006**	0.772	0.658	0.296	2.716***	−0.390	2.006**	0.221	0.658	−0.544
Hour 7	2.445**	0.463	1.763*	0.553	0.566	0.134	2.445**	−0.544	1.763*	0.158	0.566	−0.671
Hour 8	2.289**	0.229	1.600	0.397	0.601	0.162	2.289**	−0.635	1.600	0.091	0.601	−0.625
Hour 9	2.188**	0.093	1.499	0.306	0.670	0.257	2.188**	−0.683	1.499	0.054	0.670	−0.523
Hour 10	2.154**	0.046	1.442	0.251	0.779	0.445	2.154**	−0.685	1.442	0.025	0.779	−0.334
Hour 11	2.138**	0.018	1.401	0.200	0.849	0.565	2.138**	−0.722	1.401	−0.014	0.849	−0.230
Hour 12	2.119**	−0.023	1.384	0.166	0.873	0.601	2.119**	−0.779	1.384	−0.028	0.873	−0.197
Hour 13	2.142**	0.017	1.404	0.186	0.937	0.713	2.142**	−0.777	1.404	−0.022	0.937	−0.090
Hour 14	2.206**	0.131	1.449	0.234	1.006	0.836	2.206**	−0.716	1.449	−0.005	1.006	0.015
Hour 15	2.270**	0.236	1.495	0.282	1.049	0.906	2.270**	−0.643	1.495	0.011	1.049	0.078
Hour 16	2.276**	0.245	1.520	0.309	1.099	0.992	2.276**	−0.634	1.520	0.023	1.099	0.164
Hour 17	2.211**	0.145	1.491	0.293	1.091	0.989	2.211**	−0.660	1.491	0.019	1.091	0.168
Hour 18	2.144**	0.049	1.423	0.229	1.064	0.951	2.144**	−0.721	1.423	−0.020	1.064	0.126
Hour 19	2.141**	0.042	1.440	0.248	1.024	0.871	2.141**	−0.735	1.440	0.004	1.024	0.049
Hour 20	2.332**	0.360	1.583	0.385	1.093	0.983	2.332**	−0.544	1.583	0.074	1.093	0.142
Hour 21	2.674**	0.913	1.803	0.569	1.077	0.920	2.674**	−0.257	1.803	0.132	1.077	0.025
Hour 22	3.121***	1.496	2.123**	0.820	1.164	1.021	3.121***	0.131	2.123**	0.244	1.164	0.086
Hour 23	3.526***	1.963	2.395**	1.037	1.210	1.053	3.526***	0.519	2.395**	0.351	1.210	0.103

Notes: the table provides t statistics of a two-sided t test of mean comparisons between treated and control groups. *, **, and *** indicate statistical significance at 10%, 5% and 1% level, respectively.

Table 5: Matching and Differences-in-differences: Estimated effects of California's cap-and-trade program on NGCC plant capacity factors in WECC

	Daytime			Nighttime		
	California	Northwest	Southwest	California	Northwest	Southwest
Hour set 1						
Before matching						
Control plants	72	72	72	72	72	72
Treated plants	37	11	19	37	11	19
After matching						
Control plants	68	57	69	58	51	67
Treated plants	31	9	18	29	9	17
Estimated treatment effect after matching						
	-0.0627^{**}	-0.0265	-0.0786	-0.0135	-0.0161	0.0218
N	190,632	129,214	168,884	166,544	117,164	162,938
R^2	0.4278	0.3565	0.4276	0.4669	0.3952	0.3993
Hour set 2						
Before matching						
Control plants	73	73	73	73	73	73
Treated plants	37	11	19	37	11	19
After matching						
Control plants	65	59	70	66	57	60
Treated plants	37	11	18	28	9	16
Estimated treatment effect after matching						
	-0.0791^{***}	-0.042	-0.0747	-0.0006	0.0215	0.0301
N	196,491	136,428	170,752	180,466	128,451	146,810
R^2	0.5454	0.5585	0.4246	0.4384	0.5635	0.3579
Hour set 3						
Before matching						
Control plants	73	73	73	73	73	73
Treated plants	37	11	19	37	11	19
After matching						
Control plants	62	62	69	70	57	65
Treated plants	36	11	17	30	9	17
Estimated treatment effect after matching						
	-0.0776^{**}	-0.0387	-0.0403	-0.0247	-0.0236	-0.0003
N	188,554	142,455	166,740	192,562	128,917	158,757
R^2	0.5505	0.5664	0.4465	0.5395	0.5542	0.4640

Notes: matching is on hourly capacity factors. Hour set 1 matches on hours 7,10,13,16 (Day) and 19,22,1,4 (Night). Hour set 2 matches on hours 8,11,14,17 (Day) and 20,23,2,5 (Night). Hour set 3 matches on hours 9,12,15,18 (Day) and 21,0,3,6 (Night). We coarsen each matching variable according to cutpoints 0.3, 0.5 and 0.7, which identify four strata corresponding to different levels of plant utilization. DID regressions include plant FE, year FE and state by month-year FE. Standard errors are clustered at the plant level.

Table 6: Matching and Differences-in-differences: Estimated effects of California's cap-and-trade program on coal-fired plant capacity factors in WECC

	Daytime			Nighttime		
	Northwest	Eastern	Southwest	Northwest	Eastern	Southwest
Hour set 1						
Before matching						
Control plants	88	88	88	88	88	88
Treated plants	13	14	9	13	14	9
After matching						
Control plants	63	76	65	35	62	55
Treated plants	13	12	9	12	13	9
Estimated treatment effect after matching						
	0.0383**	0.0281	0.0256	0.0611*	0.0498*	0.0494*
N	141,225	157,597	137,699	85,500	133,511	117,618
R^2	0.2919	0.3011	0.2682	0.3569	0.4226	0.3275
Hour set 2						
Before matching						
Control plants	88	88	88	88	88	88
Treated plants	13	14	9	13	14	9
After matching						
Control plants	66	82	68	42	69	48
Treated plants	13	13	9	12	14	9
Estimated treatment effect after matching						
	0.0376*	0.0312	0.0259	0.0814***	0.0489*	0.0493*
N	146,874	171,179	143,348	99,869	148,961	104,014
R^2	0.2913	0.3088	0.2731	0.3611	0.4105	0.3368
Hour set 3						
Before matching						
Control plants	88	88	88	88	88	88
Treated plants	13	14	9	13	14	9
After matching						
Control plants	68	83	68	43	79	72
Treated plants	12	13	8	13	14	9
Estimated treatment effect after matching						
	0.0415**	0.0221	0.038	0.0719***	0.0335	0.0446
N	149,289	173,447	141,980	103,544	167,337	143,309
R^2	0.2916	0.3078	0.2611	0.3495	0.4066	0.3503

Notes: matching is on hourly plant capacity factors. Hour set 1 matches on hours 7,10,13,16 (Day) and 19,22,1,4 (Night). Hour set 2 matches on hours 8,11,14,17 (Day) and 20,23,2,5 (Night). Hour set 3 matches on hours 9,12,15,18 (Day) and 21,0,3,6 (Night). We coarsen matching variables according to cutpoints 0.6 and 0.8, which identify three strata corresponding to different levels of plant utilization. DID regressions include plant FE, year FE and state by month-year FE. Standard errors are clustered at the plant level.

Table 7: Scheduled power flow regressions

	(1)		(2)	
	Northwest Flows	Southwest Flows	Northwest Flows	Southwest Flows
Electric Demand CAISO	0.1114***	0.0619***	0.1122***	0.0644***
Electric Demand Northwest	−0.3048***		−0.3357***	
Electric Demand Southwest		−0.0303***		−0.0286**
Northwest Flows		−0.1738***		−0.1932***
Southwest Flows	−0.1987		−0.1522	
Nuclear Generation CAISO	−0.0479	−0.0474*	−0.0392	−0.0461*
Wind Generation CAISO	−0.0754***	−0.0861***	−0.0687***	−0.0884***
Solar Generation CAISO	−0.0022	0.0435	0.0028	0.0287
Hydro Generation Northwest	0.0071***		0.0073***	
Solar Generation Southwest		0.1978***		0.2052***
CO_2 Price	3.3390***	−0.3633	3.4188***	−0.3122
PG&E Citygate NG Price	2.4457			
Sumas NG Price	−4.6487***			
SoCal Border NG Price		11.8540***		
El Paso San Juan NG Price		−10.1424***		
NG-to-NG North			0.6332	
NG-to-NG South				14.0579
Intercept	91.1052***	44.8026***	85.1667***	39.0537***
Day-of-week dummy	Yes	No	Yes	No
Quarter dummy	Yes	Yes	Yes	Yes
N	2,017		2,017	
R^2	0.8570		0.8521	
Log-likelihood	-82,522.57		-77,238.14	
AIC	165,195.1		154,622.3	
BIC	165,615.8		155,031.8	

Appendix

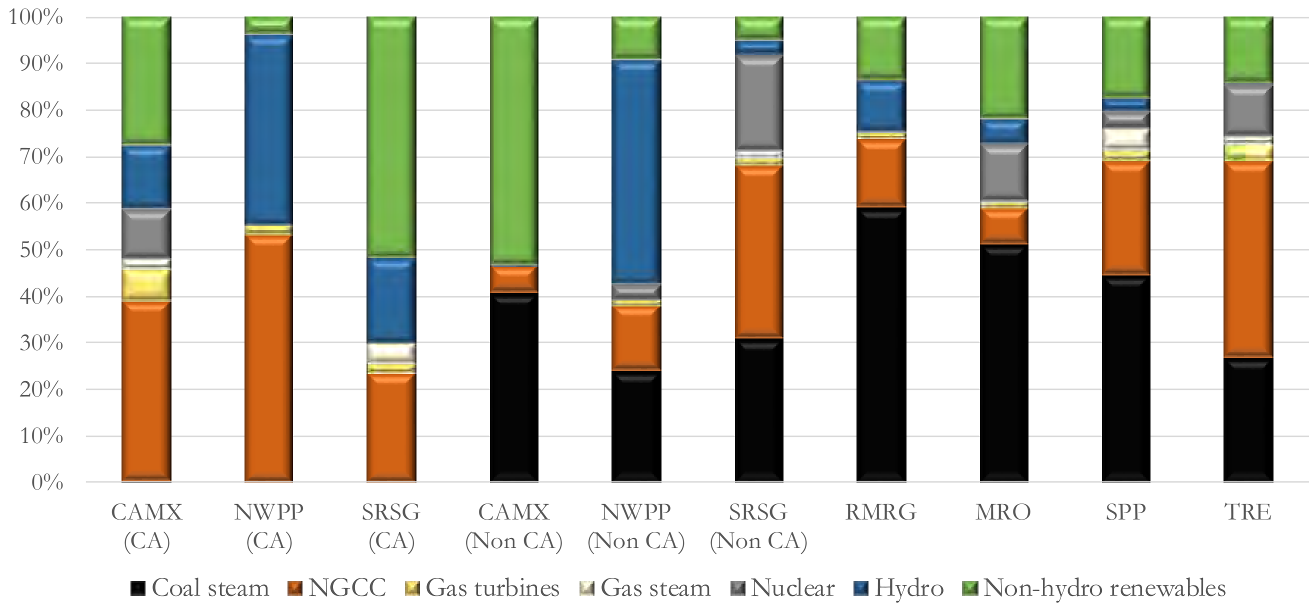
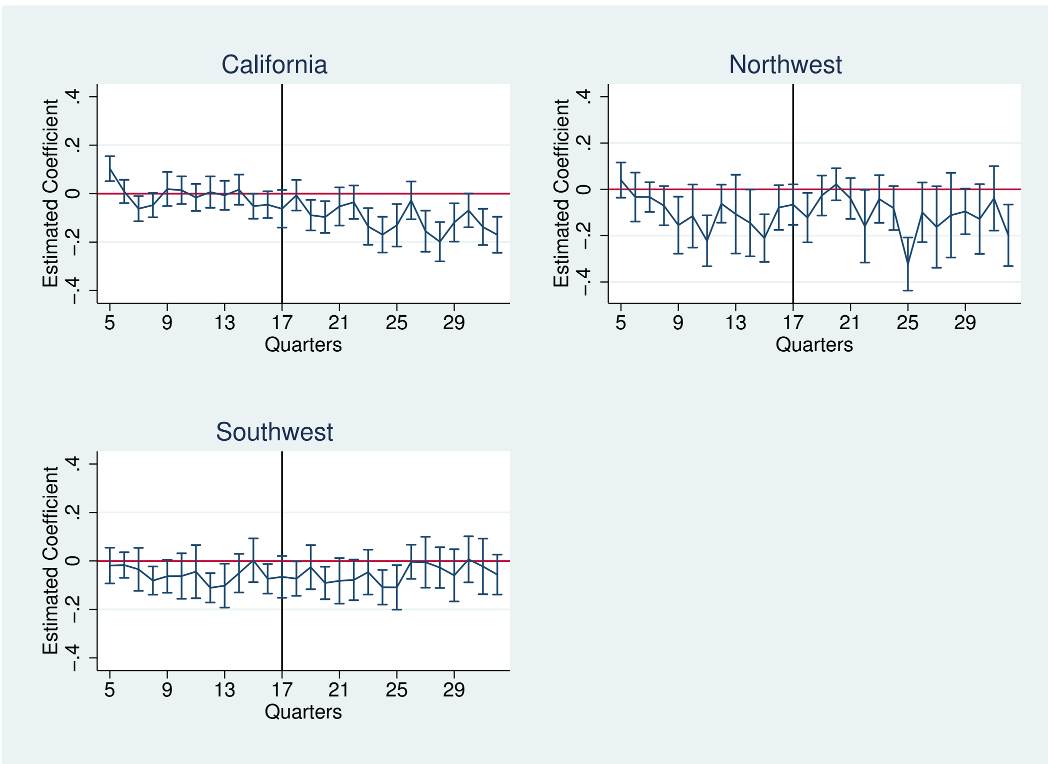
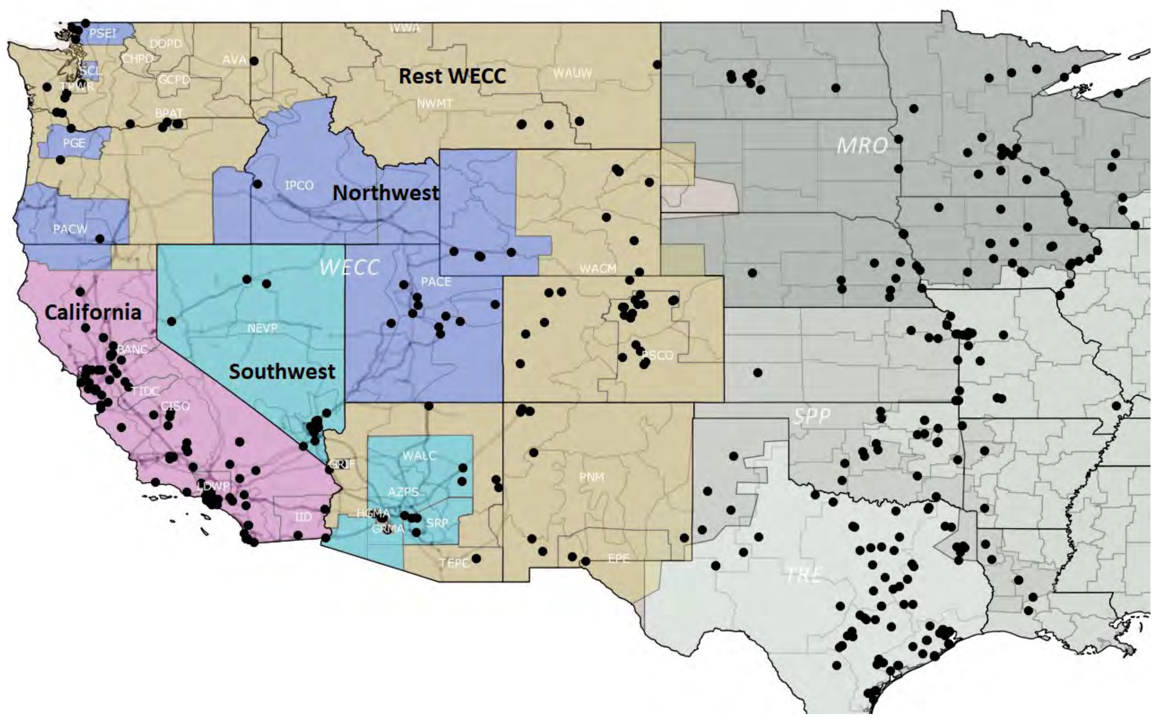

100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
CAMX (CA)
NWPP (CA)
SRSG (CA)
CAMX (Non CA)
NWPP (Non CA)
SRSG (Non CA)
RMRG
MRO
SPP
TRE
Coal steam
NGCC
Gas turbines
Gas steam
Nuclear
Hydro
Non-hydro renewables

Figure A2: Estimated quarterly NGCC treatment effects - broader control group



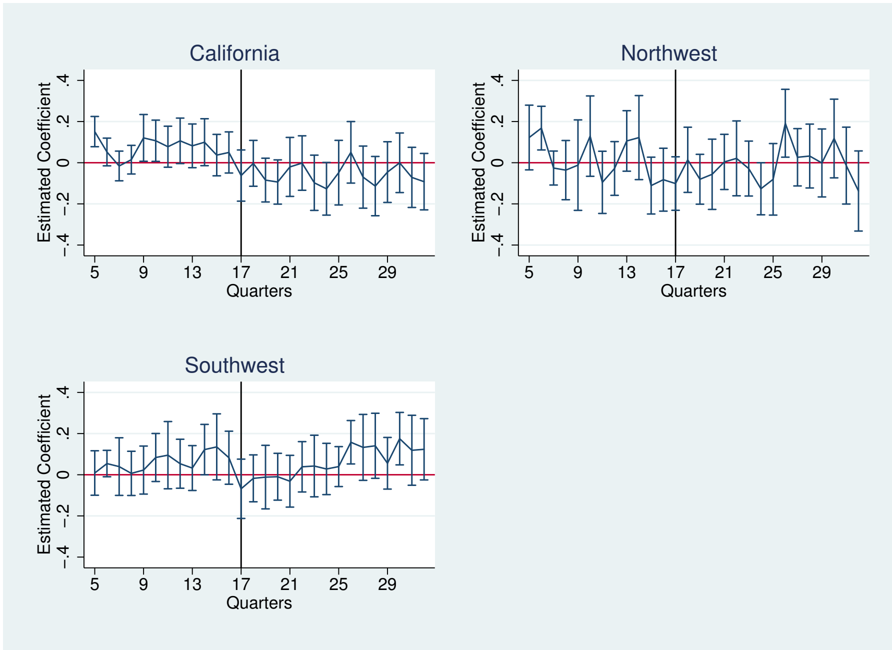
Notes: vertical lines represent 95% CIs. Controls include plants in the rest of WECC, SPP and TRE.

Figure A3: Treated and control regions in WECC, NGCC and coal-fired plants - EIM leakers

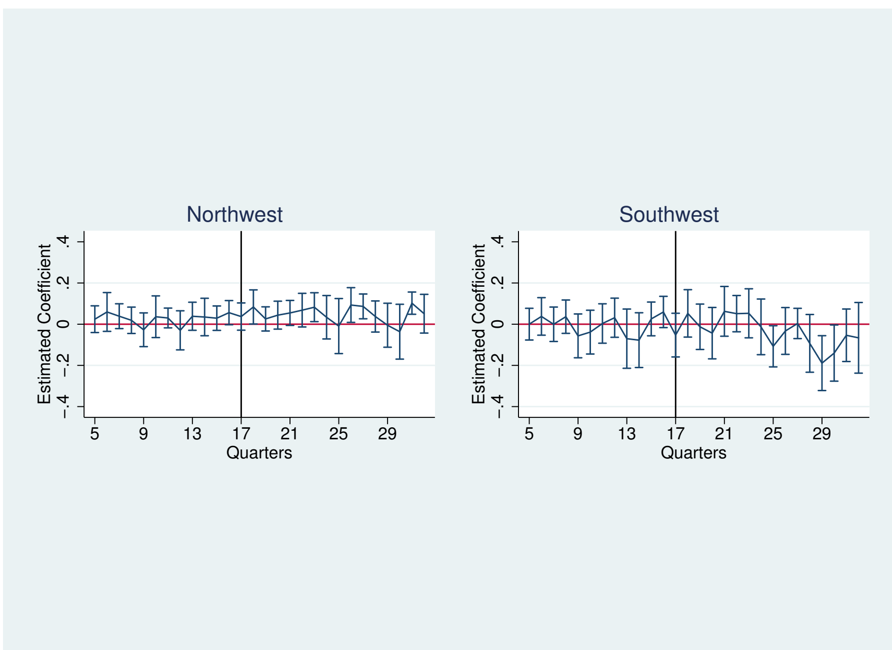


Note: black dots represent power plants.

Figure A4: Estimated quarterly treatment effects - EIM leakers



(a) NGCC plants



(b) Coal-fired plants

Notes: vertical lines represent 95% confidence intervals. Controls include NGCC plants in the rest of WECC, and coal steam plants in the rest of WECC, SPP and TRE.

Table A1: Summary statistics by major WECC balancing authority (BA), NGCC plants

BA	Pre ETS					Post ETS				
	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)
BANC	7	171	0.44	8,124	120.13	7	178	0.55	7,747	118.61
CISO	56	288	0.58	9,009	118.85	57	316	0.49	8,625	118.79
IID	1	154	0.38	7,203	118.90	1	259	0.43	8,112	118.86
LDWP	5	353	0.32	7,497	118.86	6	356	0.31	8,210	117.64
TIDC	1	269	0.60	7,881	118.86	1	269	0.60	7,829	118.86
AVA	2	290	0.49	7,264	118.85	2	294	0.61	6,908	118.86
BPAT	8	441	0.38	6,315	118.86	7	457	0.49	6,737	118.84
IPCO	1	331	0.25	6,713	118.86	1	312	0.57	6,973	118.86
PACE	3	421	0.44	7,660	118.86	3	581	0.42	7,671	118.86
PACW	2	414	0.66	8,816	118.86	1	486	0.54	7,743	118.86
PGE	3	370	0.46	9,292	118.83	4	386	0.46	8,106	118.86
PSEI	5	207	0.37	8,537	118.91	5	215	0.40	9,092	118.99
PSCO	9	280	0.23	8,692	118.86	10	302	0.25	7,704	118.87
WACM	1	497	0.35	8,041	118.86	2	341	0.34	7,779	118.86
AZPS	5	1,074	0.27	7,602	118.77	5	1,074	0.33	7,736	118.79
EPE	1	445	0.36	10,003	118.85	1	522	0.38	9,319	118.85
HGMA	1	1,128	0.17	5,503	118.86	1	1,106	0.20	5,701	118.86
NEVP	12	474	0.52	8,047	118.88	12	484	0.56	7,823	118.89
PNM	3	306	0.18	9,528	118.86	3	307	0.23	8,415	118.86
SRP	3	966	0.41	7,787	118.86	3	964	0.37	7,686	118.87
WALC	4	218	0.49	9,043	118.80	4	240	0.42	7,029	118.89

Notes: pre ETS refers to January 2009-December 2012, post ETS to January 2013-December 2016. Emission rates are only available for a subset of plants from CEMS.

Table A2: Summary statistics by major WECC balancing authority (BA), Coal-fired plants

BA	Pre ETS					Post ETS				
	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)
CISO	6	52	0.78	17,598	-	4	57	0.48	19,133	-
LDWP	1	1,800	0.78	9,728	205.20	1	1,800	0.70	9,497	205.20
BPAT	1	1,358	0.52	8,666	205.62	1	1,340	0.50	9,218	209.76
NWMT	5	493	0.74	12,483	208.75	5	525	0.71	12,776	208.58
PACE	12	630	0.81	11,997	207.73	12	621	0.78	13,343	207.93
PGE	1	585	0.65	8,763	209.57	1	585	0.55	8,259	209.11
PSCO	10	382	0.66	13,825	206.52	8	502	0.70	12,081	206.59
WACM	9	273	0.81	11,679	208.61	8	279	0.76	11,011	208.97
AZPS	3	1,083	0.67	14,573	205.21	2	1,321	0.63	10,315	205.20
NEVP	3	439	0.54	11,165	209.30	3	389	0.48	11,390	209.49
PNM	2	950	0.74	10,687	209.74	2	966	0.66	10,919	209.69
SRP	2	1,510	0.84	10,327	209.76	2	1,506	0.77	10,471	209.76
TEPC	1	1,609	0.73	10,325	209.66	1	1,621	0.72	10,304	209.56
WALC	1	350	0.65	10,944	196.55	1	350	0.72	10,890	203.62

Notes: pre ETS refers to January 2009-December 2012, post ETS to January 2013-December 2016. Emission rates are only available for a subset of plants from CEMS.

Table A3: Summary statistics by region, NGCC plants

Sub-region	Pre ETS Number of plants	Pre ETS Operating capacity (MW)	Pre ETS Capacity factor (%)	Pre ETS Heat rate (Btu/kWh)	Pre ETS CO_2 emission rate (lb/MMBtu)	Post ETS Number of plants	Post ETS Operating capacity (MW)	Post ETS Capacity factor (%)	Post ETS Heat rate (Btu/kWh)	Post ETS CO_2 emission rate (lb/MMBtu)
California	68	278	0.54	8,779	119.09	70	304	0.49	8,511	118.66
		(293)	(0.31)	(2,819)	(1.96)		(290)	(0.32)	(3,115)	(1.45)
Northwest	13	433	0.43	6,922	118.86	11	494	0.48	7,084	118.85
		(178)	(0.31)	(3,320)	(0.05)		(258)	(0.28)	(2,078)	(0.07)
Southwest	27	625	0.44	7,959	118.83	27	633	0.44	7,600	118.85
		(501)	(0.30)	(2,814)	(0.73)		(496)	(0.30)	(2,429)	(1.18)
Rest of WECC	25	296	0.31	8,731	118.86	28	307	0.36	8,077	118.88
		(190)	(0.29)	(4,809)	(0.85)		(186)	(0.29)	(4,001)	(1.59)
MRO, SPP, TRE	98	555	0.38	8,555	117.73	100	559	0.39	8,575	117.69
		(350)	(0.26)	(3,334)	(11.75)		(367)	(0.26)	(3,286)	(11.45)

Notes: standard deviations listed below means. Pre ETS refers to January 2009-December 2012, and post ETS to January 2013-December 2016. Leaker regions are defined as in Section 4. Emission rates are only available for a subset of plants from CEMS.

Table A4: Summary statistics by region, Coal-fired plants

Sub-region	Pre ETS					Post ETS				
	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)	Number of plants	Operating capacity (MW)	Capacity factor (%)	Heat rate (Btu/kWh)	CO_2 emission rate (lb/MMBtu)
California	6	52	0.78	17,598	-	4	56	0.48	19,133	206.44
		(26)	(0.26)	(11,998)	(-)		(25)	(0.31)	(18,623)	(11.76)
Northwest	20	691	0.76	11,638	207.74	20	695	0.73	12,454	208.00
		(695)	(0.23)	(5,090)	(4.54)		(700)	(0.24)	(7,517)	(5.68)
Eastern	19	332	0.73	12,830	207.70	16	379	0.73	11,495	207.93
		(389)	(0.20)	(5,591)	(6.88)		(418)	(0.22)	(4,259)	(6.70)
Southwest	12	957	0.68	11,700	207.55	11	992	0.64	10,780	208.35
		(732)	(0.20)	(3,743)	(8.09)		(689)	(0.21)	(1,484)	(3.44)
Rest of WECC	2	1,414	0.81	10,287	209.76	2	1,057	0.79	10,362	209.76
		(550)	(0.14)	(255)	(0.05)		(656)	(0.17)	(317)	(0.06)
MRO, SPP, TRE	119	591	0.60	12,447	209.76	115	638	0.56	12,367	207.23
		(578)	(0.26)	(5,332)	(12.93)		(583)	(0.26)	(5,725)	(25.19)

Notes: standard deviations listed below means. Pre ETS refers to January 2009-December 2012, and post ETS to January 2013-December 2016. Leaker regions are defined as in Section 4. Emission rates are only available for a subset of plants from CEMS.

Table A5: Matching and Differences-in-differences: Estimated effects with percentile binning

	Daytime			Nighttime		
NGCC						
	California	Northwest	Southwest	California	Northwest	Southwest
Before matching						
Control plants	73	73	73	73	73	73
Treated plants	37	11	19	37	11	19
After matching						
Control plants	66	49	58	57	27	51
Treated plants	32	7	15	27	7	18
Estimated treatment effect after matching						
	-0.0727^{**}	-0.0154	-0.0276	-0.0107	-0.0054	0.0011
N	188,737	108,498	140,886	160,699	66,415	132,658
R^2	0.4779	0.4669	0.4983	0.5585	0.4529	0.5247
Coal steam						
	Northwest	Eastern	Southwest	Northwest	Eastern	Southwest
Before matching						
Control plants	88	88	88	88	88	88
Treated plants	13	14	9	13	14	9
After matching						
Control plants	44	48	32	13	16	21
Treated plants	10	12	6	6	9	8
Estimated treatment effect after matching						
	0.0456^{**}	0.0209	-0.0386	0.0851^{**}	0.1055^{***}	-0.0005
N	95,396	107,151	68,265	33,932	44,955	51,610
R^2	0.3684	0.3262	0.3001	0.3434	0.4022	0.3875

Notes: matching is on hourly plant capacity factors and heat rates for hours 8,11,14,17 (Day) and 20,23,2,5 (Night). We coarsen matching variables according to cutpoints defined by the 40th, 60th and 80th percentiles for NGCC, and 20th, 40th, 60th and 80th percentiles for coal steam. DiD regressions include plant FE, year FE and state by month-year FE. Standard errors are clustered at the plant level.

Table A6: Matching and Differences-in-differences: Estimated effects with algorithm binning

	Daytime			Nighttime		
NGCC	California	Northwest	Southwest	California	Northwest	Southwest
Before matching						
Control plants	73	73	73	73	73	73
Treated plants	37	11	19	37	11	19
L1	0.43	0.52	0.47	0.52	0.75	0.40
After matching						
Control plants	57	39	52	46	18	46
Treated plants	28	8	15	27	8	17
L1	0.10	0.03	0.31	0.17	0.27	0.25
Algorithm	Scott	Scott	Scott	Scott	Scott	Scott
Estimated treatment effect after matching						
	-0.0754^{*}	-0.0533	-0.0042	0.0013	-0.0122	0.0189
N	163,513	93,656	128,978	139,130	51,803	120,913
R^2	0.4350	0.3721	0.4458	0.4779	0.3935	0.4648
Coal steam	Northwest	Eastern	Southwest	Northwest	Eastern	Southwest
Before matching						
Control plants	88	88	88	88	88	88
Treated plants	13	14	9	13	14	9
L1	0.50	0.59	0.70	0.72	0.74	0.77
After matching						
Control plants	52	44	26	25	23	20
Treated plants	12	13	7	13	12	8
L1	0.35	0.04	0.03	0.40	0.08	0.23
Algorithm	FD	FD	FD	Scott	FD	FD
Estimated treatment effect after matching						
	0.0379^{*}	0.0229	0.0362	0.0633^{**}	0.0508^{*}	0.0502
N	119,770	106,751	57,783	71,559	68,202	49,466
R^2	0.3226	0.3025	0.2772	0.3539	0.3413	0.3641

Notes: matching is on hourly plant capacity factors for hours 8,11,14,17 (Day) and 20,23,2,5 (Night). We coarsen matching variables according to cutpoints defined by the Scott rule and Freedman-Diaconis (FD) rule. DiD regressions include plant FE, year FE and state by month-year FE. Standard errors are clustered at the plant level.

March 29, 2021

Via Email: GHGCR2021@deq.state.or.us

Colin McConnaha
Manager, Office of Greenhouse Gas Program
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

RE: Cap & Reduce Rule Advisory Committee Meeting, March 18, 2021

Dear Mr. McConnaha,

Food Northwest appreciates the opportunity to provide the following comments on the materials and discussion at the March 18 meeting of the RAC.

Maximize Program Compliance Flexibility

Food Northwest urges DEQ to maximize compliance flexibility by including all of the mechanisms in the program: broad banking flexibility, broad trading flexibility, alternative compliance instruments, and distribution of compliance instruments based on a technology standard.

Given the fact that the Climate Protection Program (CPP) will have no periodic sale of allowances, alternative compliance instruments will of necessity play a greater role in compliance than those experienced in cap and trade programs. We urge DEQ to take this into account when setting the allowable use of alternative compliance instruments. In addition, carbon sequestration should be included as offset projects.

Address EITEs: Design the Program to Contain Costs and Avoid Leakage

Cost containment and the potential for leakage must be addressed for Energy Intense and Trade Exposed (EITE) companies. The cost impacts and leakage potential of the policy scenarios on regulated sectors need to be provided by the modeling analysis so that the CPP can address cost containment and prevent leakage. Energy costs are certain to increase under the CPP and energy is a significant input in production and transportation of products. Energy cost increases and the costs of CPP compliance will directly affect the competitiveness of EITEs.

Include cost containment elements

Cost containment mechanisms such as compliance instrument reserves, price ceilings for compliance instruments, and off-ramps should be included. Additionally, measures should be included to provide rate relief for residential, commercial and industrial customers of natural gas utilities. Industrial customers will be particularly impacted by natural gas price increases due to natural gas utility CPP compliance. Rate caps, rebates or grants for emissions reduction projects could be provided to EITEs as a means to contain costs and prevent leakage. Affordable natural gas and transportation fuel prices are critical for food processors and other EITEs to remain competitive in national and global markets. Without protective mechanisms, energy cost increases could drive production, jobs, and emissions to other jurisdictions.

Food Northwest appreciates the opportunity to provide comments on RAC Meeting #3. We look forward to continuing to work with DEQ and the RAC to shape a CPP that meets the three goals and is good for Oregon's economy, environment and its citizens. Please contact me if you have any questions.

Sincerely,

Pamela T. Barrow

Pamela Barrow
Vice President

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March 31, 2021

Colin McConnaha
Manager, Office of Greenhouse Gas Programs
Oregon Department of Environmental Quality
Via email to CapandReduce@deq.state.or.us

Re: Comments on Climate Protection Program Rulemaking Advisory Committee Meeting No. 3 on Community Climate Investments

Dear Mr. McConnaha:

The Green Energy Institute at Lewis & Clark Law School is a nonprofit energy and climate law and policy institute within Lewis & Clark's top-ranked environmental, natural resources, and energy law program. We greatly appreciate the opportunity to participate in the Rulemaking Advisory Committee (RAC) for the Department of Environmental Quality's (DEQ) Climate Protection Program, and respectfully submit these comments on issues relating to the proposed Community Climate Investment program.

Our comments aim to respond to the following discussion questions presented by DEQ during the March 18, 2021 RAC meeting:

1. *What are your thoughts about integrating potential community climate investments in the CPP? Should there be a limit on how much regulated entities are allowed to use community climate investments?*
2. *What types of projects should be funded by community climate investments? How could DEQ ensure and prioritize investments in environmental justice and other impacted communities?*
3. *How could DEQ incorporate community input throughout this process?*

1. Introduction: DEQ Should Incorporate Community Climate Investments into the Climate Protection Program

In several previous comments submitted throughout this rulemaking process, we urged DEQ to incorporate flexibility mechanisms into the Climate Protection Program that would enable regulated entities to meet a portion of their compliance obligations through investments in GHG-reduction projects that benefit Oregon's impacted communities.[1] We are very encouraged by

[1] *See* GEI Comments on Cap and Reduce Technical Workshop 3: Alternative Compliance Options (Sept. 10, 2020); GEI Comments on Cap and Reduce Technical Workshop 5: Cost Containment (Oct. 2, 2020); GEI Comments on Cap and Reduce Illustrative Scenarios (Dec. 9, 2020); GEI Comments on the Climate Protection Program RAC Meeting 2: Flexibility Mechanisms (March 1, 2021).

DEQ's proposed Community Climate Investment (CCI) mechanism, which has the potential to further the program's environmental and equity objectives by incentivizing investments in technologies and infrastructure that benefit impacted communities.

Oregon's impacted communities, including environmental justice, BIPOC, low-income, and other frontline communities, face disproportionate risks from the impacts of climate change, yet are also at risk of being left behind or burdened by the transition to a low-carbon economy. The proposed CCI mechanism would fill an important gap in the Climate Protection Program by incentivizing Oregon's largest sources of greenhouse gas (GHG) emissions to invest in projects and programs that provide just and equitable benefits to communities and the climate.

To design an effective CCI program for Oregon that supports the state's climate and equity goals, we encourage DEQ to consider incorporating design elements from similar programs that have been successfully implemented by other jurisdictions. For example, the California Climate Investment program has comprehensive criteria and guidelines to ensure that funded projects achieve strict equity and climate objectives. Section 2 of these comments provides a brief overview of the California program. Section 3 urges DEQ to incorporate similar guidelines and criteria into a CCI program to drive investment in a wide range of projects that reduce GHG emissions in Oregon while also providing meaningful benefits and co-benefits to impacted communities across the state. Section 4 describes some strategies for identifying communities and populations that have the greatest needs for CCI projects, and section 5 encourages DEQ to develop community engagement guidelines that give residents the opportunity to influence investment decisions in their communities. Sections 6 and 7 describe some important considerations relating to the use and procurement of CCI credits. We conclude our comments by encouraging DEQ to incorporate the proposed CCI mechanism into the Climate Protection Program.

2. The California Model

Oregon's Community Climate Investments program should be tailored to meet Oregon-specific needs and objectives, DEQ should consider incorporating components from other successful climate investment programs into the CCI. The California Climate Investments program presents a particularly useful model for DEQ to draw from due to its robust community-centered, benefits-oriented processes. This section briefly summarizes the key elements of the California program.

California Climate Investments funds nearly 40 programs administered by 19 state agencies.[2] The initiative is funded by auction revenues collected under the state's cap and trade program. California law requires that at least 35% of investments benefit disadvantaged and low-income communities, but the program has dramatically exceeded this threshold—as of 2019, 57% of the program's investments were projected to benefit those priority populations.[3]

[2] Cap-and-Trade Auction Proceeds Third Investment Plan: Fiscal Years 2019–20 through 2021–22 at 11 (2019), https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auctionproceeds/2019_thirdinvestmentplan_final_021519.pdf?_ga=2.182242151.198233417.1616712492-218237969.1610481227.

[3] Cal. Air Resoures Bd., *California Climate Investments Provided More than $1 Billion for Underserved Communities in 2019* (April 22, 2020), https://ww2.arb.ca.gov/news/california-climate-investments-provided-more-1-billion-underserved-communities-2019.

Under the California Climate Investments program, administering agencies design and implement targeted funding programs in accordance with state criteria and funding guidelines. The agencies first consult with the California Air Resources Board (CARB) to develop project evaluation methodologies and community benefit criteria, then develop project evaluation criteria to determine whether eligible projects will provide direct, meaningful, and assured benefits to priority populations. Each agency designates a community liaison to engage with priority communities and identify community needs.[4]

To determine which projects will provide "direct, meaningful, and assured benefits" and qualify for California Climate Investments funding, administering agencies (1) identify a priority population or populations, (2) engage with members of the population to identify an important community or household need that can be meaningfully addressed through climate investments, and (3) apply evaluation criteria to identify at least one benefit from the project that will directly address an identified need.[5]

Through this process, California Climate Investments fund a broad variety of projects ranging from grants and rebates for equipment upgrades, to large capital projects, such as transit and intercity rail projects.[6] Consumers, small businesses, non-profit organizations, local governments, and state agencies are all eligible to receive funding under the program, though specific eligibility requirements vary between investment subprograms.[7]

California and Oregon are two very different states with unique economic and social dynamics, and regulatory mechanisms that work well in one state may be suboptimal for the other. We therefore do not mean to imply that an Oregon Community Climate Investments program should mirror the California Climate Investments program. However, certain mechanisms from California's program are designed to achieve similar objectives to those identified by DEQ for the Climate Protection Program, and we encourage DEQ to consider incorporating similar mechanisms into a CCI program. The following sections provide some additional examples of relevant substantive and procedural mechanisms from California's program.

3. Eligible Projects

Rather than create a prescriptive list of projects eligible for Community Climate Investment funding, we encourage DEQ to establish general project eligibility criteria and guiding principles that ensure investments support the program's goals while giving communities an opportunity to

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[4] CAL. AIR RESOURCES BD., FUNDING GUIDELINES FOR AGENCIES THAT ADMINISTER CALIFORNIA CLIMATE INVESTMENTS 7 (2018), https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auctionproceeds/2018-funding-guidelines.pdf?_ga=2.259552259.809046808.1617037184-218237969.1610481227 [hereinafter CARB 2018 FUNDING GUIDELINES].
[5] CAL. AIR RESOURCES BD., CALIFORNIA CLIMATE INVESTMENTS EVALUATION CRITERIA FOR PROVIDING BENEFITS TO PRIORITY POPULATIONS: SUSTAINABLE TRANSPORTATION 1 (2019), https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auctionproceeds/criteria-table-sustainabletransportation.pdf?_ga=2.224537049.258146968.1615833213-1802687480.1513294504.
[6] *See* Cal. Air Resources Bd, *CCI Quantification, Benefits, and Reporting Materials,* https://ww2.arb.ca.gov/resources/documents/cci-quantification-benefits-and-reporting-materials.
[7] CARB 2018 FUNDING GUIDELINES, *supra* note 4, at 8.

influence investment decisions. Under this model, CCI funds would be available for projects that meet general eligibility criteria and are selected through robust public engagement processes that ensure investments meet community needs and provide the greatest benefits to impacted communities.

To ensure that CCIs support the Climate Protection Program's goals and objectives, DEQ should establish ***general eligibility criteria*** that direct CCI funds to projects that: (1) are located in Oregon; (2) achieve real, measurable, additional, verifiable, and permanent reductions in anthropogenic greenhouse gas emissions from fossil fuel combustion; (3) provide direct and meaningful benefits to priority communities in the state; and (4) to the maximum extent feasible, provide measurable economic, environmental, or public health co-benefits, such as reductions of local co-pollutant emissions and improved air quality, equitable job and/or training opportunities, and/or equitable access to clean and affordable transportation.[8]

In addition to the general eligibility criteria, DEQ should develop ***guiding principles*** that direct CCI administrators to engage with priority communities to determine community needs and identify eligible projects that would maximize community benefits and co-benefits and avoid substantially burdening impacted communities. For example, the California Climate Investment program's guiding principles "provide direction to help administering agencies target investments to benefit priority populations, with a focus on maximizing disadvantaged community benefits; maximize economic, environmental, and public health 'co-benefits'; and provide fiscal and program transparency and accountability."[9]

The general eligibility criteria and guiding principles described in this section will help ensure that the CCI program funds projects that reduce anthropogenic GHG emissions while meaningfully benefitting communities impacted by the program and by climate change in general. But to ensure that CCI-funded projects provide meaningful benefits in the communities that need them the most, DEQ must first identify the communities across the state that should be prioritized in investment decisions.

4. Prioritizing Investments in Impacted Communities

To prioritize Community Climate Investments in environmental justice and other impacted communities, DEQ first must identify the communities and populations across the state that have the greatest needs for eligible projects and will experience the greatest benefits from CCI funding. Priority communities should include communities of color and low-income communities that have been historically disadvantaged, are disproportionately burdened by pollution or other environmental impacts, and/or are disproportionately vulnerable to cost increases resulting from the program, the energy transition, or climate change.

There are several available models and data sets that DEQ could draw from to help the agency identify (or develop processes for identifying) historically disadvantaged and/or at-risk populations across the state. The following models and mapping tools may provide useful data

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[8] For example, the California Climate Investment program's general criteria ensures that funded projects contribute to the state's climate goals and provide direct and meaningful benefits to priority populations. *Id.* at 2.
[9] *Id.* at 9.

sets for identifying priority CCI communities in Oregon, or serve as models for state-specific tools that may be developed in the future:

- ***EPA EJScreen:*** EPA's environmental justice screening and mapping tool allows users to map and identify environmental justice communities based on demographic indicators (including race, linguistic isolation, income, education, and age), environmental indicators (such as proximity to traffic, hazardous waste, or wastewater discharges) and public health risks (such as cancer risk, respiratory hazards, and exposure to dangerous air pollution).[10]
- ***CalEnviroScreen:*** The California Climate Investments program uses the California Communities Environmental Health Screening Tool (CalEnviroScreen) to identify priority communities based on demographics and pollution burdens.[11] While CalEnviroScreen only maps communities located in California, it could serve as a model or template for a similar Oregon-specific screening tool.
- ***Regional Equity Atlas:*** The Regional Equity Atlas for the Portland Metro region provides a series of maps and an interactive mapping tool to identify communities based on demographic profiles, access to health care and exposure to public health risks, and access to opportunity as determined by a variety of factors, such as access to public transit, education, housing affordability, proximity to food stores, and environmental health.[12]
- ***PBOT Equity Matrix:*** The Portland Bureau of Transportation's Equity Matrix and demographic indicator maps apply census tract data on race, income, and English language proficiency to identify equity communities in Portland.[13]

After DEQ identifies communities and populations that have the greatest needs for CCI projects, DEQ should develop community engagement guidelines to ensure that members of those communities have ample and meaningful opportunities to provide input and help identify priority CCI projects for their communities.

5. Incorporating Community Input

Community climate investments will provide the greatest public benefits when members of impacted communities have ample opportunities to engage in the program's development, participate in deliberative processes, and influence investment decisions. To achieve these objectives, the Climate Protection Program needs functional mechanisms to promote robust community engagement in communities that may often lack the resources or capacity to participate in public processes.

Community outreach and engagement are critical elements of the California Climate Investments program, and we encourage DEQ to consider incorporating elements from California's program

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[10] U.S. Envtl. Protection Agency, *EPA EJScreen,* https://ejscreen.epa.gov/mapper/.
[11] Cal. Office of Envtl. Health hazard Assess., *CalEnviroScreen 3.0,* https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.
[12] *Regional Equity Atlas,* http://www.equityatlas.org.
[13] Portland Bureau of Transport., *PBOT Equity Matrix and Demographic Indicator Maps,* https://pdx.maps.arcgis.com/apps/MapSeries/index.html?appid=2e2252af23ed4be3a666f780cbaddfc5&utm_medium=email&utm_source=govdelivery.

into the Climate Protection Program. As we noted in section 2, when selecting projects for California Climate Investments funding, administering agencies must (1) identify a priority population, (2) identify an important need within that population that a climate investment project can help meet, and (3) identify a direct, meaningful, and assured benefit that the project will provide to the priority population.[14] To ensure that these criteria are met, each agency administering California Climate Investment funds must designate a community liaison to engage with communities and conduct outreach efforts to identify community needs. These liaisons also provide technical support to help priority populations access funding opportunities, navigate application processes, and leverage additional funding from other sources.[15]

To promote engagement by a broad variety of community members, the California program directs administering agencies to conduct a variety of outreach efforts, such as hosting regular workgroups with community organizations, as well as public workshops and community meetings that are widely publicized at local schools, libraries, community centers, medical clinics, bus stops and grocery stores.[16] Agencies must also provide regular updates via list serves, phone calls, videos, social media, radio, television and newspapers, and maintain connections with leaders in the community outside of formal processes.[17] In addition, every administering agency must maintain a website that provides information on funding opportunities, public outreach events, all submitted applications, final project selections, points of contact and resources for information and technical assistance, project outcomes, and opportunities for continued public engagement.[18] To make information accessible to a wide public audience, agencies are encouraged to coordinate with community groups to convey information at existing community meetings, host events at public locations such as schools and community centers that are accessible by public transportation, host meetings during convenient times, such as evenings and weekends, and invite diverse groups of stakeholders to participate in public events.

In addition to engaging directly in public outreach, administering agencies are directed to encourage funding applicants and recipients to engage with the community as much as feasible. Depending on the nature of the projects and funding opportunities, applicants may be encouraged to convene public steering committees to help oversee the design and development of a funded project, or partner with community-based organizations to solicit input on a project's design or selection.[19]

DEQ has put a commendable amount of effort into designing processes and creating opportunities for public engagement through the Climate Protection Program rulemaking, and the agency should certainly apply the lessons it has learned throughout this process into the draft rules. Oregon's impacted communities each have unique needs, objectives, and capacities to participate in public processes, so DEQ should avoid creating a rigid "one-size-fits-all" approach

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[14] CAL. AIR RESOURCES BD., CALIFORNIA CLIMATE INVESTMENTS EVALUATION CRITERIA FOR PROVIDING BENEFITS TO PRIORITY POPULATIONS: SUSTAINABLE TRANSPORTATION 1 (2019), https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auctionproceeds/criteria-table-sustainabletransportation.pdf?_ga=2.224537049.258146968.1615833213-1802687480.1513294504.

[15] CARB 2018 FUNDING GUIDELINES, *supra* note 4, at 7.

[16] *Id.* at 26–27.

[17] *Id.*

[18] *Id.* at 23–25.

[19] *Id.* at 27.

to community engagement. Instead, a CCI program should have adaptive, responsive community engagement guidelines that can be easily tailored to fit the needs and resources of the communities the program aims to serve.

6. Limiting the Use of Community Climate Investment Credits

Several factors relating to the program's design and available sector-based compliance pathways will influence the utility and risk of Community Climate Investment credits, and DEQ should account for those variables when setting limits for the use of CCI credits. For example, CCI credits could undermine the integrity of the cap if they are additional to compliance instrument allocations that represent the entire quantity of GHG emissions permitted under the cap. CCI credits could also deter some sectors from directly reducing emissions, which could potentially deter or delay compliance activities that would otherwise improve air quality in local communities.

As an overarching principle, DEQ should limit the use of Community Climate Investment credits if the availability and use of CCI credits could undermine the integrity of the Climate Protection Program's emissions caps. This outcome could occur if the compliance instruments allocated by DEQ equal the total quantity of allowable emissions under the program cap, and regulated entities are permitted to use CCI credits in addition to their allocated compliance instruments. Under this scenario, total GHG emissions would exceed the cap during a given compliance period, which would undermine the integrity of the program.

However, if the program includes mechanisms to protect the integrity of the cap, limiting the use of CCI credits may not be necessary for some sectors or regulated industries. For example, DEQ could limit the number of compliance instruments it allocates to regulated entities, and then allow entities to use up to an equal number of CCI credits as those withheld by the agency. If DEQ withholds compliance instruments in direct proportion to the amount of CCI credits that may be created under the program, it would ensure that CCIs never undermine the integrity of the cap. Under this model, CCI credits would simply represent GHG emissions reductions that provide additional benefits to Oregon communities.

DEQ should also limit the use of CCI credits by certain sources and sectors if the use of such credits would deter or delay emissions reductions that would otherwise benefit local communities. For example, industrial sources that are subject to regulation due to their process-based GHG emissions should be restricted from using CCI credits if doing so would result in co-pollutant emissions that degrade air quality in vulnerable communities. Similarly, because transportation fuels represent the largest source of GHG emissions in Oregon and a primary source of air pollution in environmental justice communities, transportation fuel suppliers should be required to invest in projects that directly reduce transportation emissions in Oregon.

7. Procuring Credits

Rather than establish a specific dollar amount that regulated entities would be required to pay to receive a CCI credit, we encourage DEQ to authorize a designated third party administrator to set CCI credit rates based on market costs that exist at the time of issuance. The costs to implement emissions reduction projects will vary over the course of the program, and rates established by regulation may not reflect the actual cost of reducing one ton of carbon. This dynamic has played out in other regulatory offset programs. For example, through 2019, the average cost spent by the Climate Trust to offset one ton of carbon dioxide (CO_2) emissions was more than double the CO_2 monetary offset rate established by the Oregon Energy Facility Siting Council.[20] To prevent this outcome, the program should allow CCI rates to fluctuate in response to real-world conditions.

If a CCI credit represents a one-ton reduction in GHG emissions, the entity administering CCI funds must have the flexibility to set CCI fees that reflect real-world project costs. This does not mean that CCI fees must necessarily reflect the *entire* cost of reducing one ton of carbon; a CCI-administering organization should be encouraged to seek additional funding from outside sources to maximize investments in eligible projects. But the program should not establish set CCI rates that could prevent fund administrators from investing in projects that achieve the level of emissions reductions reflected in CCI credits.

8. Conclusion

We strongly encourage DEQ to establish a Community Climate Investment program in Oregon's Climate Protection Program, and to incorporate some of the mechanisms we have described in these comments into the program to encourage investments in projects that further the state's climate goals while providing direct and meaningful benefits to impacted communities across Oregon.

We appreciate your consideration of our comments.

Sincerely,

Amelia Schlusser
Staff Attorney
The Green Energy Institute at Lewis & Clark Law School

Carra Sahler
Staff Attorney
The Green Energy Institute at Lewis & Clark Law School

[20] Prior to 2020, EFSC's monetary offset rate was \$1.90 per ton CO_2. In June 2020, EFSC increased the monetary offset rate to \$2.85 per ton. Or. Admin. R. § 345-024-0580. Offset fees collected by EFSC are allocated to the Climate Trust, an independent nonprofit organization qualified by EFSC to administer the state's offset funds. As of December 31, 2019, the Climate Trust had invested a total of \$50,279,293 in offset projects that were estimated to offset 12,590,656 tons of CO_2. THE CLIMATE TRUST, 2019 ANNUAL REPORT 5 (2020), https://climatetrust.app.box.com/s/b23ica2rohs6fno8pqg5f3tkmd2uyid1; *see also* OR. ENERGY FACILITY SITING COUNCIL, OREGON EFSC'S CARBON DIOXIDE EMISSIONS STANDARDS (2018), https://www.oregon.gov/energy/Get-Involved/rulemakingdocs/2018-03-21-CO2-RAC-Background.pdf.

Oregon Department of Environmental Quality
March 26, 2021
capandreduce@deq.state.or.us
RE: DEQ climate protection program rulemaking
GHGCR2021@deq.state.or.us

DEQ Staff for the Climate Protection Program,

I write this letter in order to discuss the 2 ways to include equity in a climate program or policy.

First, equity is typically conceived of as an additional or supplemental project that is added to a climate program or policy like the investments in impacted and environmental justice communities from alternative compliance instruments in the climate protection program. This is not an ideal way to include equity into a program. When equity is viewed as supplemental, it is often minimized over time as a program goes through revisions. Additionally, when part of the program is viewed as the "equity component" then equity may not be seriously considered in other parts of the program. I have noticed that when asked "where is the equity [in the climate protection program]?" DEQ staff tends to say "in the alternative compliance instrument investments," now called community climate investments. The DEQ needs a broader view of equity.

Second, equity can be integrated into and centered by a climate program. This would include:
1) Embracing science - Meeting scientific goals for reducing greenhouse gas emissions. This is an issue of climate justice according to international advocates. Because people of color are harmed first and worst, it is a justice issue to quickly reduce emissions and meet goals in 2035 and 2050. Excluding the 2035 interim goal from some modeling and exempting major polluters not only goes against environmental interests but also contradicts the equity frame of the program.

2) Reducing harms based on need - Address acute harms that have already occurred from climate change and programs to address it. A new program should reduce those harms or at least spread them out so they are not concentrated in low-income, impacted communities. Hopefully, identifying where harms have occurred, to whom, and the outcomes will be part of the equity mapping in meeting #4 of the RAC. Program design should state how exactly it will reduce these specific, acute harms to highly impacted communities and not just avoid making them worse. The DEQ should also avoid assuming that reducing greenhouse gas emissions in general will address these emissions in particular or that outcomes will be comparable in white and POC communities.

Thus far DEQ has not indicated that the program will take this targeted approach.
Any focus on the distribution of benefits assumes that harms are already addressed.

3) Distributing benefits by need & sharing decision making – The DEQ has several good ideas on distributing benefits in terms of identifying high-need, impacted communities and asking communities what they need. I want to highlight the difference between inviting someone to the

table and including them in decision making. The DEQ should work with and compensate community partners to create a process for outreach and community input on how community climate investments should be spent. For example, Recordings of PowerPoint/voice presentations explaining the program should be available online in Spanish and English. If there is an advising committee, academic studies show that a minimum of 35% of the people on a committee need to be people of color in order for their voices not to be drowned out. Also, clarify the decision-making power that representatives will have (a vote, majority rules, advisory only and no decision-making power?). In order to serve that committee, DEQ needs to define and track measures for equity outcomes. If something is not measured it is usually ignored in follow-up work.

Please take these comments into consideration for the next DEQ RAC meeting on the climate protection program.

Sincerely,

Prof. Janet Lorenzen
Willamette University
Department of Sociology, WGS, AES
900 State Street
Salem, OR 97301
jlorenze@willamette.edu

From: KathyMoyd-gmail <kmoyd11@gmail.com>
Sent: Friday, March 26, 2021 3:38 PM
To: GHGCR2021 * DEQ
Subject: Climate Protection Program RAC 3

These are my personal comments for the Climate Protection Program RAC 3 meeting and are not on behalf of any organization.

I have been following the Climate Protection/Cap and Reduce Program starting with the Workshops last summer. My working career consisted of 36 years at the NASA/Jet Propulsion Laboratory doing computer programming, system engineering, and spacecraft operations. I have a bachelors degree in physics and masters degrees in astronomy and computer science.

I appreciate your having posted the material on the Community Climate Investments and Non-Natural Gas Fuel Suppliers in advance of the meeting, and I spent considerable time reviewing them. It was therefore frustrating to find that there was no way for me to provide comments to the RAC members before their discussions of those topics. I suggest that like the EQC you provide written comments received before the meeting to the members. This will also provide an opportunity for comments from different view points and lived experiences to affect the discussions.

The presentation on the modeling was very disappointing, both because of its late availability and the lack of detail regarding the various flexibility options for different sectors. Based on my experience, I have reservations about the reliability of any models trying to predict what is happening in thirty years, especially one with so many different aspects and do not think so much of the valuable meeting time should be devoted to it.

I appreciate the effort DEQ is making in incorporating equity into the program, especially since it was not provided any funds for that purpose. The Community Climate Investments are a promising mechanism. I particularly like the restriction to emission reduction in Oregon, so it shows up when evaluating whether the goals in the Executive Order are being met. I was surprised to see an apparent equivalence of using a 1 MTCO2e Compliance Instrument to buy 1 MTCO2e of reduction. It is not clear to me that very many projects can be found to decrease emissions that much for a price like $200.

I was disappointed by the lack of specific information about the threshold for non-natural gas fuels, with only two values given; 300,000 and 5,000. DEQ has a lot of detailed information and it would be helpful to the public and the members to provide links. The brief seems to be leaning toward a threshold of 300,000 because of both in state and out of state leakage. I'm not sure out-of-state leakage will be that great a problem, especially with the likelihood of federal and other state action. I used your data to determine that there would be over 3 million unregulated MTCO2e/year between thresholds of 25,000 and 300,000. To avoid significant in-state leakage, the threshold could be set even lower than 25,000.

I realize that having significant flexibility, including the CCIs, is desirable as the program is getting started. However, the main goal should be to have the regulated entities decrease there emissions. Therefore, I suggest phasing out the flexibility options with time. In addition, some of the regulated entities, particularly the large stationary sources, have toxic co-pollutants. They should not be allowed to use flexibility options to avoid making early reductions. I also suggest that regulation of fuels, including natural gas, be be done at large stationary sources for which they are above the threshold, in order too decrease co-pollutants. Thank you for considering my comments.

Kathy Moyd

From:	Kristin Edmark <kristinedmark@hotmail.com>
Sent:	Friday, March 19, 2021 1:47 PM
To:	GHGCR2021 * DEQ
Subject:	Greenhouse Gas Emissions Program 2021 Rule Making

Dear Department of Environmental Quality:
All fossil fuel facilities must be included in the Greenhouse Gas Emissions Rule in or der to transition to clean energy and to meet Oregon's climate goals.

it is especially necessary that utilities be included. Electricity is only clean if generated without fossil fuels. Fossil fuel generators last decades; we do not have decades. Crude methane (aka LNG or "natural" gas) is often obtained through fracking which is well documented to leak large amounts of climate destroying methane, to contaminate water supplies, increase miscarriages and birth defects near fracking sites, use large amounts of water, leave behind contaminated water holding ponds, etc. Fracking should not be encouraged.

We do not need crude methane (aka LNG or"natural gas"). Clean fuels are less expensive, produce more jobs and keep money in Oregon. We are on the brink of a huge clean fuel expansion. Tesla already has energy walls for storage and solar roof tiles being installed in California, Off shore wind turbines are expanding off Europe. Until now the powerful fossil fuel sector has prevented significant investment or incentives in clean energy but that is changing. Fossil fuel bail outs, grants, subsidies and investment tax advantages are going away. All industries need to held to the same standard for transition to happen in time.

Making exceptions for large polluters would be a mistake. Please include all fossil fuel based facilities in the Greenhouse Gas Emissions Rule.

Respectfully submitted,

Kristin Edmark
(510) 825-1899,
kristinedmark@hotmail.com

March 25, 21

TO: DEQ Office of Greenhouse Gas Programs Staff
RE: March 18th, 2021 Rulemaking Advisory Committee Meeting

Thank you for the opportunity to comment on materials presented at the March 18th, 2021 Rulemaking Advisory Committee (RAC) meeting. Below you will find comments that draw on the expertise of Multnomah County staff and consultation with community partners.

Community Climate Investments
We are cautiously supportive of community climate investments (CCIs) as a compliance flexibility mechanism. Suggestions for equitable and effective design of CCIs are below.

All CCIs (100%) should benefit environmental justice communities, tribal communities, and impacted communities that have been historically burdened by fossil fuel combustion and infrastructure. Relief from the burdens of disease and premature death that result from fossil fuel combustion should be the first priority of CCIs. We assume that environmental justice communities exist throughout the state, but we reiterate our previous call for a descriptive analysis of existing conditions with regard to demographics and exposure to greenhouse gas co-pollutants. In addition, environmental justice principles demand that those communities most burdened by fossil fuel combustion and infrastructure have a clear and primary role in the design and implementation of CCIs.

All CCIs (100%) should eliminate human exposure to products of fossil fuel combustion. We are concerned that investments in more efficient fossil-fuel burning equipment, rather than combustion-free equipment, would perpetuate unnecessary exposure to pollution by locking in the use of equipment with a long lifespan.

CCIs can maximize health benefits by including active transportation investments, including travel demand management programs, e-bikes, transit service, and biking/walking infrastructure investments. Active transportation investments provide three types of immediate health benefits: increased physical activity, decreased air pollution, and reduced risk of crash injuries. Of these, physical activity delivers the largest health benefit. Such investments would achieve immediate health benefits than electrification investments because single passenger electric vehicles, unlike active transportation, produce significant particulate pollution from brake wear, tire wear, and resuspension. Analysis of Metro's Climate Smart Strategy demonstrates the health benefits of active transportation investments and can inform the design of CCIs.

We look forward to further discussion of the design of CCIs that addresses the questions of how permanent, verifiable emission reductions can be achieved, as well as the process to include impacted communities in the design and implementation of eligible projects.

Non-gas fuel suppliers

We are sympathetic to the concerns about the complexity of regulatory compliance for smaller non-gas fuel suppliers. The Climate Protection Program must be efficient and implementable. However, it must also achieve, at a minimum, the emissions reductions directed under the Governor's Executive Order 20-04. Exempting a large number of non-gas suppliers by selecting a high threshold will allow for continued, significant unregulated greenhouse gas emissions and associated co-pollutants in the state, and may encourage "leakage" from suppliers regulated in the program to those who are not. We are interested in seeing from DEQ additional regulatory options that could apply to smaller suppliers, ensuring that a consistent price on carbon is set for all non-gas fuels in the state, but that allow for the different business circumstances facing smaller suppliers. We would prefer to fully understand the regulatory options for smaller suppliers before providing feedback on the specific emissions threshold.

Modelling results and scenarios

We are closely attuned to the results of the model that reflect changes in the "other fuels" category, as this includes the largest sources of exposure to harmful pollutants for most people (e.g. transportation fuels). A full explanation of the influences on this category during upcoming RAC meetings would be welcome.

Regards,
Andrea Hamberg
Interim Environmental Health Services Director
Multnomah County Health Department

Brendon Haggerty
Healthy Homes and Communities Supervisor (Interim)
Multnomah County Health Department

Tim Lynch
Senior Sustainability Analyst
Multnomah County Office of Sustainability

The Nature Conservancy
Protecting nature. Preserving life.™

The Nature Conservancy in Oregon
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nature.org/oregon

March 25, 2021

Comments on DEQ Climate Protection Program Rulemaking

Submitted by: Amelia Porterfield, Senior Policy Advisor

To the Department of Environmental Quality and Members of the Climate Protection Program RAC:

Thank you for the opportunity to provide comments as the Climate Protection Program Rulemaking Advisory Committee works to develop a program to cap and reduce greenhouse gas (GHG) emissions to meet the goals identified in Governor Brown's Executive Order 20-04.

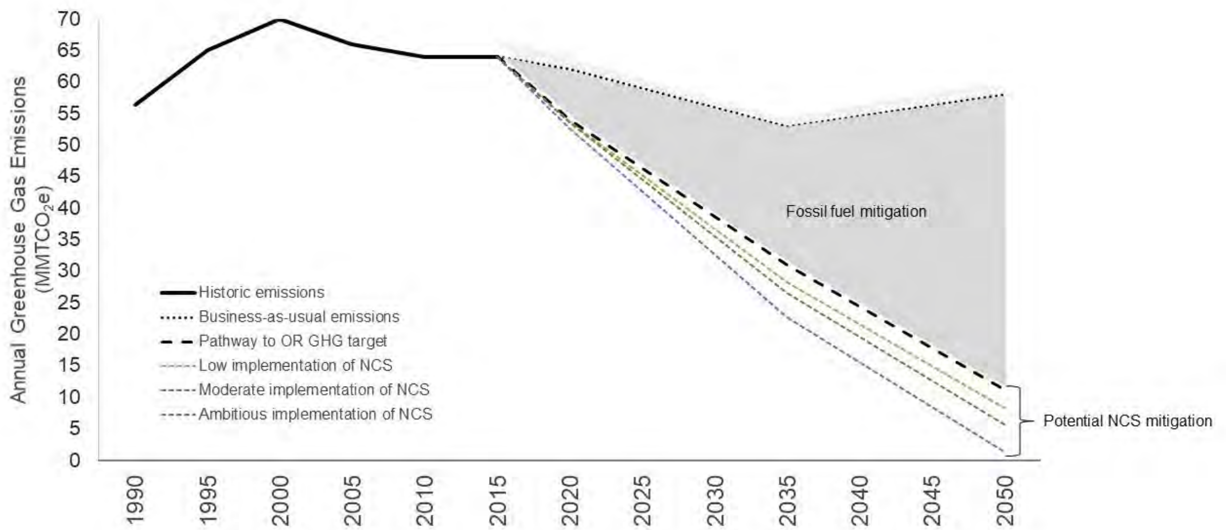
The Nature Conservancy in Oregon is a non-partisan, science-based organization that works in communities across the state, manages lands and waters in varied ecosystems, and partners with ranchers, farmers, fishers, timber and environmental interests on some of the most challenging conservation issues facing people and nature. Addressing climate change by reducing emissions, increasing carbon sequestration and improving ecosystem and community resilience are top priorities for our organization in Oregon and around the world. We strongly believe that Oregonians have a responsibility to enact policies to address our contributions and enable the necessary responses to climate change. The extreme weather events of the past year served as a sobering reminder that the climate crisis is already here, and we must act swiftly.

The Climate Protection Program offers a path for climate action in Oregon. We appreciate the agency and the Committee for wrestling with some important questions as you develop this program, and would like to share the following comments at this stage of the process:

1) **Oregon Deserves a Rigorous Program:** TNC supports a strong and rigorous Climate Protection Program to cap and reduce (GHG) emissions that includes comprehensive measurement and reporting, and at least meets the 2035 and 2050 reductions targets in Governor Brown's Executive Order 20-04. We are concerned that the program, as currently discussed by DEQ, would be weakened by the potential for exemptions (including electricity generation and non-natural gas fuel suppliers below a set threshold), effectively omitting some of the largest sources of GHG emissions from the program and undermining Oregon's ability to meet its emissions cap. DEQ has articulated policy reasons for not regulating these sectors under the program, but a better course of action would include regulatory solutions that keep everyone accountable to our climate goals.

2) **Natural and Working Lands:** The management of natural and working lands is a critical component of our overall response to climate mitigation and adaptation. Investments in our natural environment can help mitigate climate impacts while supporting community health and prosperity. Our research shows that the restoration and protection of our natural and working lands—forests, rivers, estuaries, grasslands, and farmland—have tremendous potential to reduce GHG emissions when combined with a transition to clean, renewable energy. Natural climate solutions should be considered *in addition* to and beyond the fossil emission reductions

necessary to meet the Governor's Executive Order 20-04 targets. They are not a substitute for other necessary actions. Natural climate solutions should be incentivized and promoted via programs that are complimentary to fossil fuel emissions reductions.



Adapted from Graves et al. 2020[1], demonstrating the potential of natural climate solutions to provide <u>additional</u> GHG emissions reductions benefits compared to business-as- usual management of natural and working lands.

3) **Community Climate Investments:** TNC strongly supports Community Climate Investments (CCIs) in frontline communities. Low-income Oregonians, communities of color, and rural communities will be disproportionately impacted by climate change. The primary focus for CCI's should be to support just transitions for these frontline communities. At the same time, CCIs play an important though modest role in helping Oregon meet a rigorous GHG emissions cap. During prior debate on Cap and Invest legislation, TNC supported offsets as 8 percent of a statewide GHG emissions cap. While CCI's are not the same as offsets, we believe this offers a solid precedent, and that 8 percent of capped emissions is a reasonable starting point for CCI's. The primary focus for CCI's should be to support just transitions for frontline communities. We recognize that in promoting just transition for rural communities, there are opportunities for sequestration and natural climate solutions. As such, CCI's that promote both climate mitigation and community resilience (e.g., floodplain and riparian area reforestation). should be allowed as CCI's in the Climate Protection Program.

DEQ's rulemaking for the Climate Protection Program is a bellwether for Oregon's climate progress and needs to be grounded in fact and accountable to the public and the state's climate goals. Oregon must take strong action now to address GHG emissions and invest in a just transition.

Again, thank you for the opportunity to provide comments. We look forward to continuing discussions with the Committee as you refine this important work to develop a strong, comprehensive Climate Protection Program.

[1] Graves, R. A., R. D. Haugo, A. Holz, M. Nielsen-Pincus, A. Jones, B. Kellogg, C. Macdonald, K. Popper, and M. Schindel. 2020. Potential greenhouse gas reductions from Natural Climate Solutions in Oregon, USA. Plos One **15**:e0230424.

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March 29, 2021

VIA ELECTRONIC MAIL

Department of Environmental Quality
Office of Greenhouse Gas Programs
700 NE Multnomah Street, Suite 600
Portland, Oregon 97232

RE: NW Natural Comments- DEQ Climate Protection Program Rulemaking Session #3

NW Natural ("NW Natural" or "we") appreciated the opportunity to provide comments on the discussions from the Department of Environmental Quality (DEQ) staff during the March 18th, 2021 Rules Advisory Committee (RAC) meeting to implement Governor Brown's Executive Order 20-04. As mentioned in our comments from previous RAC meetings, NW Natural continues to strongly support the development of effective programs to address the existential crisis of climate change. This guided our support of proposed Cap and Invest legislation, HB 2020 and SB 1530. We are working vigorously to decarbonize our pipeline by 2050. It is critical that DEQ design a Climate Protection Program in a way that complements and accelerates the work already underway. We also agree that it is critical that impacted communities are meaningfully engaged in program design and commend DEQ for designing an inclusive, transparent process.

That being said, we continue to have significant concerns around the scenarios, compliance instrument design, and transparency of the modeling process. Our comments on the content discussed in the 3rd RAC meeting can be found below by topic area:

Potential Utility Rate Impacts

Under the currently proposed program scenarios, the expected costs of the Climate Protection Program for all gas utility customers is predicted to be severe. The current conversation in the RAC meeting lacks the clear connection between the cost to regulated parties and the resulting impact on all energy customers.

Absent cost control mechanisms or cost off-ramps, the impact of this program will increase the cost of not only building and industrial operations, but also the competitiveness of goods and services in our region that was already experiencing significant income inequities before the compounding effects of the global pandemic. The discussion of and assumptions about the Community Climate Investments or CCIs (previously characterized as Alternative Compliance Instruments) has increased our concern about the cost impacts to all customers of this program's execution.

We urge DEQ to do additional work around equity and cost containment. Preliminary modeling of compliance projects has shown that residential rates are likely to at least double in order to comply with the Cap and Reduce Climate Protection Program. To date, there has been very little conversation about these rate impacts on low income and near-low income customers. Nearly one third of NW Natural's customers are either low income or near-low income. Such a dramatic rate increase will be extremely difficult for customers living on the economic edge. NW Natural recommends carving their emissions out of the program, and holding them harmless from any other costs associated with complying with the Cap and Reduce program.

Alternative Compliance Instrument/ Community Climate Investment Design

The inclusion of a market-based compliance option in the program has potential to provide meaningful opportunities for equitable investment in emission reductions, as well as a means of cost controls for our customers and the economy at large. However, following the discussion on Community Compliance Instruments in RAC meetings #2 and #3, we are concerned that this program element has significant design challenges, and as is currently being considered would likely be a design element that increases the cost of the program to Oregonians rather than act as a cost containment mechanism and might not deliver substantial emissions reductions. Per DEQ's June report on the program, "if properly designed, alternative compliance instruments…. could mitigate the costs of compliance, while simultaneously producing greater overall emissions reduction." NW Natural is concerned that the current program design criteria, which would price CCIs at $200/ton, a price that is more expensive than most other options available to reduce emissions, does not meet this threshold of proper design. The program should also consider ACIs in addition to the CCIs discussed during the meeting, with the stated purpose of providing the opportunity for reducing compliance costs.

Also, as a utility regulated by the Oregon Public Utility Commission (OPUC), the concept of CCIs at a price of $200/ton raises important questions about what the OPUC would have the authority to allow utilities covered under the program to purchase CCIs if they do not meet the Commission's standards for cost-effectiveness. If it is possible for a utility to achieve all of the emissions reductions for compliance at less than $200/ton, would the utility even be allowed to pay $200/ton for CCIs from a regulatory standpoint? As part of this conversation it is also important to put the $200 price in context. The EPA's estimate of the Social Cost of Carbon is currently in the range of $75/ton and the price of allowance trading in the Western Climate Initiative market that includes California is currently less than $20/ton.

Additionally, NW Natural remains concerned by the way DEQ has framed the CCI discussion. DEQ staff has made it clear that they are applying three lenses to the Cap and Reduce program - equity, cost containment and GHG reduction. NW Natural supports all three, and believes they are all incredibly important. However, in presenting the notion of a CCI during the RAC meeting, staff made no mention, asked no questions, nor guided any discussion on cost containment, thus setting up the false binary choice that the program can either address: 1) equity, or 2) GHG reduction and cost containment. We flatly reject that choice. Instead, we believe all three are simultaneously achievable. To that end, NW Natural urges DEQ staff to bring the CCI conversation to the RAC and lead a discussion on how CCIs can achieve GHG reduction and cost containment, while doing so in a way that does not harm equity work.

Electrification Bias

In meeting materials and, again, expressed in Director Whitman's opening remarks the emphasis on the conversion of home heating from gas to electric indicates a strong focus on electrification that is not reflective of the state's current electricity supply mix.

This departure from a focus on decarbonization to a preference for particular technology solutions could result in reduced emissions reductions under the program at a greater cost. Natural gas customers are already going to pay for a large share of compliance. These costs should be in support of emission savings benefitting these customers. Electrification/fuel switching would yield additional burden to these same customers.

NW Natural also questions whether DEQ has the statutory authority to pivot from designing a carbon reduction program to a program pushing electrification. NW Natural asks that DEQ provide the RAC with clarification of their authority for this approach.

Precedent, Examples and Best Practices

NW Natural urges DEQ to survey GHG reduction programs across the world for best practices, particularly evolving approaches relative to building electrification in Europe.
As an example, Denmark initially pursued an energy policy that eliminated the use of natural gas and natural gas structure. However, they quickly realized that there was not enough available resource capacity, nor electric grid capacity to accept the additional load growth. Instead, they decided to decarbonize and expand their gas system with renewable resources while doing the same to the electric sector. Denmark is currently using 25% RNG and is expanding their pipeline network as their RNG supply increases.

Rather than designing a system from scratch to decarbonize the energy system that has never been tested, DEQ should look to those progressive governments that are half a decade or more ahead of both Oregon and the United States, and apply the best practices to the design of Cap and Reduce. A mistake or flaw in the design could cost the Oregon economy billions of dollars, while doing very little to actually reduce GHG emissions.

Presentation of Modeling Scenarios
For a program with three central goals—equity, emissions, and costs—the presentation of only the emissions modeling results during RAC meeting #3 provided a limited and potentially misleading view of the possible success of each program scenario. NW Natural understands that the modeling results for equity and economic modelling will be presented at RAC meeting #4, but we question whether reviewing these models separately, a month apart, provides for a thorough understanding of the implications of each program parameter and observe this approach did not allow for a robust discussion of the program. The choices made in the development of each scenario have implications for each of the program goals. These implications should be reviewed together to understand the tradeoffs of each program design. Discussing emissions assuming a $200/ton CCI cost, but not discussing the impact that has on all energy customers' rates does not allow for meaningful feedback from the committee.

It is imperative that stakeholders be allowed to review the analysis underlying the CPP's rulemaking process, including detailed modeling inputs and results, rather than cursory summaries and visuals. It appears likely that without thorough review, the conclusions of this analysis may be unacceptably flawed, misleading to those tasked with designing the program in Oregon's best interests, and unnecessarily costly to the state's households and businesses.

For one apparent example, refer to Slide 33 of the presentation from March 18th, which represents the consultants' reference case forecast for emissions in the state (which we understand is what would be expected to happen in the state under current policy and in absence of the Climate Protection Program).

It suggests[1] that electric sector emissions in Oregon declined from ~17 MMT in 2018 to about 11 MMT in 2019. This clearly contradicts DEQ's own greenhouse gas inventory (GHG inventory) which shows that emissions in the electric sector in 2018 were 16.7 MMT (roughly what is shown on slide 33)and they *increased* to 18.8 MMT tons in 2019, an emissions increase of more than 2 MMT. The graph on Slide 33 conflicts with this data and shows a decline of ~6 MMT between 2018 and 2019. This means that the reference case in this modeling effort shows electric sector emissions being about 40% lower in 2019 than they actually were. To put this in perspective, this 40% underestimation of emissions in the electric sector for 2019 is approximately 8 MMT tons, a discrepancy which is *larger than the entire current contribution of the direct use natural gas sector to Oregon's GHG emissions*.

Furthermore, slide 33 shows electric sector emissions continued to decline until the current year (2021), to a level that is less than half of what the DEQ's own GHG inventory shows for emissions in the sector in 2019. This result defies logic, analytical rigor, and is also at odds with the publicly available forecasts from the state's major electric utilities. To further put the magnitude of the drastically overstated reduction in the electric sector being shown as part of the reference case in perspective, this modeled reduction from 2018 to 2021 is equivalent of having added 4 GW of new renewable resources while also closing 3 and a half Boardman-sized coal plants exclusively serving load in Oregon since 2018. 4 GW of new renewable resources is roughly equivalent to either the entirety of currently installed wind and solar resources in Oregon, 9 new wind farms as large as Portland General's largest wind resource (Biglow Canyon) or what is expected to be added in the *entire Northwest region* between 2020 and 2027.[2] This has not happened, and a forecast of the electric sector that is this disjointed from reality is a serious issue with major implications for the results of the scenarios that need to be reviewed and discussed as part of a public process.

We presume that the last year of actual data being shown is 2018 (as it aligns with DEQ's own GHG inventory), and 2019 is the start of the consultants' forecast, but because so little has been shared in terms of data, assumptions, and modeling methodologies. Even something as trivial as when the forecast begins is not currently transparent. There are numerous reasons for why the emissions forecast for the electric sector could be drastically out of line with official forecasts for the state (e.g. regional data averages are being applied to Oregon), but unless this work (being completed with public funds) is made available to the RAC and other members of the public, it cannot be known whether the problem is one of data and/or assumptions and/or modeling methodology. Furthermore, if the work continues to be a black box with minimal public input, an assessment about whether these problems extend to sectors other than the electricity sector cannot be made.

An important implication of this underestimation of electricity sector emissions in the reference case is that it ignores much of the expensive work from the electric sector that still needs to take place to reach those reduced emission rates and incorrectly accounts for them as *free* to Oregonians. This is likely leading to a drastic overstatement of both the emissions reductions associated with building electrification of direct use natural gas loads, and consequently greatly underestimating the cost of emissions reduction from building electrification.

[1] NW Natural is estimating numbers from looking at the graph, given that actual data from this analysis has not been made available to the RAC or the public and it has not been put together or reviewed as part of public stakeholder process.

[2] See *Northwest Regional Forecast of Power Loads and Resources: 2020 Through 2030.* Pacific Northwest Utilities Conference Committee, 2020. https://www.pnucc.org/wp-content/uploads/2020-PNUCC-NRF_0.pdf

Furthermore, neither DEQ or its consultant, ICF, has provided the actual data and assumptions being used for the cost of different types of emissions reduction opportunities for the program evaluation scenarios. NW Natural is concerned that the estimates for building electrification grossly understate the cost to Oregon's ratepayers to fully electrify their homes and businesses given that the high-level list of sources (see Slide 37, though one can only guess what data is being pulled from which sources unless DEQ and ICF make the data available as was discussed during the first RAC meeting) cites NREL's "Electrification Futures Study," which uses a simplified model that underestimates the electric sector capacity needs – and therefore the costs – of building electrification. We are disappointed that one or both of ICFs own work on the cost of building electrification[3] (a topic in which the consultancy has marketed as a strength), or Oregon-specific work on the cost of building electrification completed by E3[4] are not cited as sources, as these studies are much more detailed in their treatment of electric system needs under building electrification in our climate.

The combination of the unrealistic electric sector emissions forecast and the presumed source chosen for the cost of building electrification creates a modeling effort that is biased against emissions reduction from the direct use natural gas sector and towards building electrification. This bias could unnecessarily cost Oregonians hundreds of millions of dollars in utility bills if the CPP is implemented based upon these results. While the issues are surely unintentional, they underscore the criticality of thorough stakeholder review of the work being performed on the state's behalf. Further, this review needs to occur in a timely fashion in order to be consequential. The current process of sharing high-level summaries of results after modeling runs have been designed, completed, and passed to decisionmakers virtually eliminates the possibility of a meaningfully public review and feedback process- an issue that NW Natural and others have consistently raised during RAC meetings and in comments over the last several months. While DEQ has seemed amenable to having meetings that will allow review of the modeling work, and seemed to commit to this during the first RAC meeting, the level of transparency and public process has fallen far short for this work.

Point of Regulation

NW Natural continues to question the effectiveness and efficacy of using natural gas utilities as the point of regulation for this program and disagrees with DEQ's theory that utilities are the "generative stimulus, force, or cause" of their customers' direct emissions. Natural gas utilities do not "force" or "cause" a customer to purchase gas from the utility. The customer is in control of the amount of gas consumed. In addition, transport customers do not purchase their gas from the utility by choice. The utility provides a delivery service for the gas through the pipeline infrastructure, but the natural gas utility is not the fuel supplier for transport customers. Regulating this program at the end user provides a direct relationship between the emissions generated and the limits presented by the program.

Conclusion

Thank you for the opportunity to provide these comments. We are open to further discussion and providing any data that will help DEQ and ICF International analyze the impacts of different Climate Protection Program designs on the majority of Oregonians who are natural gas utility customers. We

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[3] See *Implications of Policy-Driven Residential Electrification*, Prepared by ICF for the American Gas Association, , 2018. https://www.aga.org/globalassets/research--insights/reports/AGA_Study_On_Residential_Electrification

[4] See *Pacific Pathways to 2050: Achieving an 80% economy-wide reduction in Greenhouse gases by 2050,* E3, 2018. https://www.ethree.com/wp-content/uploads/2018/11/E3_Pacific_Northwest_Pathways_to_2050.pdf

look forward to producing additional input as DEQ provides more information about the continued modeling results and program element design and as DEQ proceeds through this rulemaking process.

Sincerely,

/s/ Nels Johnson

Nels Johnson

Enclosures

cc: Colin McConnaha, DEQ
Nicole Singh, DEQ
Kristen Sheeran, Office of Governor Kate Brown

Northwest Pulp & Paper
ASSOCIATION

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Submitted to: GHGCR2021@deq.state.or.us

March 26, 2021

TO: Oregon Department of Environmental Quality

FROM: Northwest Pulp & Paper Association

RE: Rulemaking Advisory Committee Meeting 3, Oregon Climate Protection Program

Thank you for the opportunity for the Northwest Pulp & Paper Association (NWPPA) to provide comment on Oregon Department of Environmental Quality's (DEQ) Oregon Climate Protection Program Rulemaking Advisory Committee (RAC) Meeting 3, held March 18, 2021. As a member of the RAC, Kathryn VanNatta Director of Regulatory Affairs for NWPPA, submits the following written comments.

Background

NWPPA is a 65-year-old regional trade association representing 10-member companies and 14 pulp and paper mills and various forest product manufacturing facilities in Oregon, Washington and Idaho. Our members hold various permits issued by DEQ including permits for Title V Air Operating Program and the Air Contaminant Discharge Program, and also report Greenhouse Gas (GHG) emissions under DEQ's GHG Reporting and Third Party Verification Program.

NWPPA members are at the forefront of Oregon air quality improvement efforts. Our members have embraced technically advanced and scientifically sound controls on air emissions over the past 20 plus years. We are proud of our dedication to efficient and environmentally sound processes and reduction of GHG emissions over time. We are committed to the hard work, expense and discipline it takes to be contribute to our communities.

NWPPA staff are long-standing-stakeholder participants in numerous DEQ advisory committees including groups on: establishing regulatory programs, administrative rules (RACs), agency program improvement efforts and agency fee increases.

Overarching comments

Oregon's pulp and paper sector has been recognized as an essential business by state and federal governments. Without fail, our Oregon mills' essential workers have been making vital paper products we all use every day to help fight against COVID-19. Our essential paper products are used by Oregon consumers as well as being distributed within the Western US and abroad.

NWPPA's comments on the March RAC meeting held should be construed as preliminary in nature, given the enormous complexity of the proposal the many assumptions with very limited details, and the short comment turn-around time. NWPPA will provide additional comments on this rulemaking as we continue our analysis over the coming months.

While many details are unclear, pulp and paper manufacturing could face increased costs from Scope 1 (on-site combustion and process emissions), Scope 2 (cost of energy) and Scope 3 (transportation fuels required to get our vital products to consumers). We ask the Department to keep this triple-threat cost profile in mind as you design Oregon's program.

Shared goals

NWPPA member mills have been longtime leaders in minimizing GHG emissions by maximizing the use of carbon-neutral biomass as the sector's primary (57%) fuel source and the use of highly efficient combined heat and power (CHP) systems for onsite energy generation of steam and electricity. Since 2010 Oregon pulp and paper sector has reduced emissions from anthropogenic sources by 62,000 mt CO_2e. That's the same as removing over 13,400 passenger vehicles from the road for one year.

Oregon's pulp and paper mills make their products with predominantly zero-carbon emitting hydropower and other renewables for purchased electricity, carbon neutral biomass, and natural gas—resulting in one of the most environmentally responsible manufacturing methods in the world. As a result, in 2019 Oregon's pulp and paper sector emitted only about 1% of the state's anthropogenic GHG emissions.

Biogenic recognition and incentives

NWPPA appreciates the fact that emissions from the combustion of biomass and process by-products are not proposed for regulation. Biogenic emissions clearly should not be included. NWPPA believes that the pulp and paper sector should be recognized for our leadership in reducing anthropogenic fuel use in manufacturing by using residual materials generated in our manufacturing processes for energy production and for our manufacture of recycled paper products.

Well-designed and operated CHP systems have been shown to be more energy efficient than the separate generation of heat and power. The most common fuels used within forest product CHP systems are pulping liquors, a by-product of the chemical pulp manufacturing process, and wood waste, though some fossil fuels are used as well. Abundant research has made it clear that the types of biomass being used in CHP systems in the forest products industry, i.e., black liquor, bark, and other woody residues from manufacturing, are characterized by very low or even negative net emissions of biogenic GHGs.

The operation of biomass-based CHP systems results in significant CO_2 emission reductions due to the greater energy efficiency of CHP systems and the wide-spread utilization of low GHG emission biomass fuels. Other benefits of CHP systems include resiliency benefits to the electricity grid, and the avoidance of transmission and distribution losses by consuming power at the point of generation. The pulp and paper industry generates steam and electricity via predominantly low GHG and energy efficient CHP systems that are part of the kraft recovery system. The functions of the kraft recovery system that utilize black liquor, a by-product of the kraft pulping process, not only generate energy but recover pulping chemicals and manage black liquor solids.

With Oregon's abundant forest resources and our Oregon forest products supply chain from timber harvest-to-papermaking-to-consumers, Oregon's pulp and paper sector should be incentivized for the use of biomass, CHP and recycled materials. Incentives could assist in our use of biomass for onsite CHP, as CHP allows us to efficiently self-generate much of our steam and energy needs onsite and also incentives to continue and increase our use of recycled materials.

Pulp and paper sector is energy intensive and trade exposed (EITE)

Pulp and paper manufacturing is one of the most energy intensive and trade exposed sectors in the country. The Governor's 2018 study, titled *Oregon Sectoral Competitiveness under Carbon Pricing, Final Report December 2018*, prepared for the Oregon Carbon Policy Office study by Vivid Economics,[1] categorizes Oregon's pulp and paper sector as an EITE sector. Therefore, a primary DEQ consideration for elements of the future program must be the fact that Oregon's pulp and paper sector is vulnerable to regulatory programs that increase production costs relative to producers in other jurisdictions because these costs typically cannot be passed on to consumers. Carbon regulation increases the cost of energy (a major cost component of pulp and paper production) and therefore has the potential to cause production to "leak" to other jurisdictions. As discussed in more detail below, such leakage to locations that likely have higher GHG emissions intensities would in fact increase the greenhouse gas emissions for an equivalent amount of pulp and paper or wood products

[1] https://www.vivideconomics.com/wp-content/uploads/2019/08/Oregon-Industrial-Sector-Competitiveness-Under-Carbon-Pricing-1.pdf (downloaded March 25, 2021).

produced, which works against the clear intent of Executive Order 20-04 to reduce carbon emissions.

Leakage

DEQ's Greenhouse Gas Emissions Program 2021 Rulemaking: Background Brief [2] states there could also be costs for consumers and businesses. We believe there will be significant cost increases for consumers and businesses and that the program should be designed to ensure Oregon business may thrive. Regarding leakage, the Brief also states at page 4,

> DEQ also seeks to minimize leakage, which is the shifting of greenhouse gas emissions outside of Oregon or outside the scope of the program's regulation. This may result in emissions in areas or sectors where there are no emissions regulations or there are less strict emissions regulations.

Leakage of a small percentage of Oregon's pulp and paper sector's production related emissions to nearly any other part of the world has the potential to increase the GHG emissions, both in areas with and without GHG emission regulations. Another key factor to consider is that Oregon has one of the lowest state-based GHG emission factors associated with purchased electricity of any major pulp and paper producing state in the US. Production shifts outside of the state would increase purchased electricity GHG emissions as well as increase transportation related GHG emissions by shifting production from local mills to facilities outside of the state or country. Production shifts outside Oregon would also bring the devastating effects of the loss of family-wage essential worker jobs in rural areas within the state.

The pulp and paper industry is an energy intense industry and is sensitive to carbon policy programs that increase the cost of energy which can cause production to shift to other jurisdictions without the added carbon costs. Due to the sector's extensive utilization of biomass for energy needs (the industry derives approximately two-thirds of its fenceline energy needs from biomass), the pulp and paper industry has a larger energy intensive footprint than GHG intensive footprint. As when federal cap and trade was being considered in the American Clean Energy and Security Act of 2009 (Waxman-Markey cap and trade legislation), it is important that EITE eligibility criteria be defined on a basis of energy intensity or GHG intensity.

[2] Climate Protection Program, Greenhouse Gas Emissions Program 2021 Rulemaking: Background Brief, dated Dec. 18, 2020.

Necessity of Alternative Compliance Mechanisms

NWPPA believes that mitigating the risk of leakage for Oregon's EITE pulp and paper sector should be a major program design consideration. NWPPA's preferred way to protect our essential paper manufacturing base and our highly-trained essential workers is to exclude Oregon mills and our energy supply from the program. However, if the rule moves forward including the pulp and paper mills and our forest products supply chain in the program, there must be multiple compliance pathways *thoughtfully and carefully built into the core of the program*.

In general, NWPPA believes all alternative compliance mechanisms being discussed in DEQ's RAC briefs, Role of Compliance Flexibility Mechanisms[3] and Community Climate Investments[4] are viable and necessary mechanisms for EITE sectors such as pulp and paper and should be fully utilized.

Thank you for the opportunity to provide written comment on DEQ's Oregon Climate Protection Program Rulemaking Advisory Committee (RAC) Meeting 3, held March 18, 2021.

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[3] Climate Protection Program, Role of Compliance Flexibility Mechanisms, dated February 10, 2021
[4] Climate Protection Program, Community Climate investments, dated March 12, 2021

March 25, 2021

Colin McConnaha
Manager, Office of GHG Programs
Oregon Department of Environmental Quality
GHGCR2021@deq.state.or.us

Comments on Oregon Climate Protection Program: Rulemaking Advisory Committee Meeting 3

Dear Colin,

Thanks to you and your colleagues for another well-organized RAC meeting on this important program. The OLCV Metro Climate Action Team (MCAT) is a community of experienced volunteers working to steward significant greenhouse gas reduction legislation into law in Oregon, and several of our members attended the meeting. As a member of our Steering Committee with professional experience in energy system modelling and policy analysis, I have prepared the following comments on behalf of the full committee regarding the three topics below a discussed at the meeting.

Community Climate Investments

Community Climate Investments are a potentially powerful tool through which DEQ can incentivize investments into impacted communities. Because the program's goal is emission reductions within the covered sectors, community climate investment projects should be focused on helping impacted communities to contribute to the decarbonization goals. Specifically, there should be no restrictions on projects involving conversion from fuels to electricity. Example projects include:

- Construction of EV Charging infrastructure
- EV purchases for school buses or other fleets
- Funding Building energy efficiency upgrades (both Residential and Commercial)
- Funding programs to incentivize heat pumps for space heating

There must be a limit on how many CCI offsets a company can use in a given period, and because the CCI offsets are activities within the covered sectors, they MUST be deducted from the CAP. So that in the initial allocation of allowance DEQ must hold back the amount allowed for CCI offsets.

To incorporate community input throughout this process, DEQ should assure it's open to all impacted communities, urban and rural. Community based organizations should be allowed to submit their proposals for projects that reduce GHGs and provide community benefits into a process where they can qualify for funding if they meet specific criteria, and covered entities should then be allowed to buy into the qualified projects to gain credits.

To ensure and prioritize investments in environmental justice communities, as opposed to other impacted communities, DEQ could set a basic exchange rate (X$=1 credit) for qualified project credits and apply bonus credit (e.g. X$ = 1.5 credits) for projects benefiting minority and low-income communities. The federal social cost of carbon (interim value at $51/ton) could be adopted as a starting basis for the cost of one CCI credit.

Considerations for Non-Natural Gas Fuel Suppliers

We urge DEQ to include ALL non-natural gas fuel suppliers under the program, with NO threshold. Analysis of non-natural gas fuel supplier data does not show any clear breakpoint for a threshold that would minimize variability, except for 300,000 ton per year. Unfortunately, this threshold is too high. Not only does this threshold leave 14% of all emissions unregulated, but the top five supplies could easily shed market share to a dozen or more suppliers that would remain unregulated.

If DEQ decides to have a threshold, a level of 25,000 metric tons with 38 entities to track seems quite reasonable administratively, and provides 99%.emissions coverage, but will not avoid variability risks, which can adversely impact allowance allocation.

In either event, all fuel suppliers should be required to report their annual sales by fuel type. These values should be readily available and can be quickly converted into emission levels. The annual sales reports from all suppliers will also allow DEQ to identify new covered entities whose sales are now above the threshold. It will also allow DEQ to monitor market shifts for collusion to promote leakage.

The Baseline emission level for each regulated entity could be calculated for a historical period of 3 to 5 years, to determine the entity's first year allowance allocation. But this is problematic without an auction to provide the flexibility needed by covered entities to factor in anticipated changes in market conditions.

We recommend that DEQ consider developing an allowance allocation methodology based on proposals by each regulated entity that would request a specific allocation of permits based on their historical data and near-term projected need. These requests should justify why the requested allocation is reasonable, based on their current emissions relative to benchmarks for their industry sector, recent and planned near-term actions to reduce emissions, and activities to relieve co-pollutant impacts to local communities or provide benefit qualified communities. The total requests for permits are likely to exceed the amount of permits available under the cap, and after consideration of reserve accounts, DEQ will need to adjust every request, based on criteria like those described above, such that the distributed compliance permits do not exceed the amount available under the cap.

Modeling

As a modeling expert, I was confused at many points in the modeling presentations because several important details were either glossed over or skipped entirely. For example, the Reference case results (slide 33) shows emissions from all sectors, while slide 34 states that "one cap was applied across all sectors…and therefore scopes of regulated emissions vary by sector. This statement was never clarified, and implies that the cap was applied across just the regulated, not all regulated and non-regulated sectors. This only becomes clear on slide 39, where we first see the term "Reference Case for Regulated Sectors," which is clearly not the Reference case shown on Slide 33. The presentation failed to place the Reference Case for Regulated Sectors in the proper context. Furthermore, it did not explain how non-regulated sectors contribute to meeting the overall cap and what happens in the non-regulated sectors under the different policy scenarios.

This missing information is critical to a having a complete understanding of what is happening in the covered sectors, and led to serious misunderstanding at the RAC meeting, where the levels of reductions from the covered sectors were shown to be much less than the target reductions in EO 20-04.

If DEQ see this Climate Protection Program (CPP) as only one components of the plan to reach the targets in the Governor's Executive Order, then DEQ should show how the CPP complements the other elements of the plan. The Baseline scenario assumptions regarding the transportation sector are clear, but DEQ is completely silent regarding, for example, assumptions for the electricity supply sector. However, to run the electric sector of their IPM model, ICF must be making specific assumptions; such as PGE meets its 2040 net zero corporate commitment. DEQ should provide the key Reference and Policy scenario assumptions for all the non-regulated sectors, but especially the electricity supply sector.

Furthermore, it was clear from some comments made by ICF at the meeting that the electricity supply was modeling, and that some changes in that sector were noted between the different policy scenarios, but these impacts were not clarified.

Another example of missing information is that the Reference Case for Regulated Sectors is different for Scenario 3 than for Scenario 1, which is understandable for future years, but not for 2022, which is the start of the program. This implies that the model is allowing actions in either the regulated or non-regulated sectors prior to 2022 to reduce the starting emission level in this scenario. It's not clear that the starting points for these scenarios should be different.

The next bit of serious confusion starts on slide 40, which states, "The cap is met in all years." While that is true, it hides the fact that in the early years of all scenarios the actual emissions are well below the cap! This is an unusual modeling result, as most models would show net emissions following the cap. In addition, there appears to be an unusual amount of both banking of unused allowances, particularly in the early years, along with very significant purchases of CCI credits that are also banked until they are most needed near the end of the model horizon.

The biggest difference between Scenarios 1 and 2, besides the interim GHG target in Scenario 2, is the limit of 5% CCI credits available. However, based on the Net emissions line in the results diagrams, it appears that this limit applies only to the use of CCI credits to meet compliance obligations. There appears to be no limit on the purchasing of CCI credits to save for later use. Indeed, the number of CCI credits purchased in Scenario 1 appears to greatly exceed the number of CCI credits needed to meet the cap starting in 2045. Scenario 2 shows similar large purchases of CCI credits up until 2034, but here the 5% limit prevents all the credits from being used to meet the cap, resulting in the two periods where the cap is not met. Clarification is needed as to whether this interpretation of the results is correct, and what is driving the apparent large purchases of CCI credits – especially given the cost range ($50, $100 and $200 per ton).

The fact should be emphasized that the CCI prices are incremental costs (only the difference between free allowances and actual emissions) and should not be compared to typical offset costs, which are a full emission price, tied to allowance auction costs. As noted earlier, the federal social cost of carbon (interim value at $51/ton) could be adopted as a starting basis for the cost of one CCI credit.

As ICF develops the preliminary policy scenario results, it's most critical that DEQ release the high level sectoral results from all regulated and non-regulated sectors so that we can see the program's relative impact and what is required from other programs to meet the targets in EO 20-04 under the different policy constraints. Furthermore, in the presentation of the policy scenario results, it will be important to see more granular modeling results, including sub-sector results and marginal costs for various energy efficiency, renewable energy and other emission reduction activities.

Rather than designing a 4th Policy scenario, I believe DEQ should focus on improving their description of the current modeling approach, presenting results from all sectors (regulated and non-regulated) and presenting detailed results on technology changes, changes in systems costs (investments, operating costs and fuel expenditures) over time for each policy scenario compared to the Reference.

Sincerely,

Dr. Pat DeLaquil, DecisionWare Group LLC, www.decisionwaregroup.com
on behalf of the OLCV MCAT Steering Committee:
Brett Baylor, Rick Brown, Dan Frye, Debbie Garman, Mark McLeod, KB Mercer, Michael Mitton, Rich Peppers, Rand Schenck, and Jane Stackhouse

Oregon Association of Conservation Districts

February 24, 2021

Colin McConnaha, Manager
Greenhouse Gas Program
Department of Environmental Quality
700 N.E. Multnomah St., Suite 600
Portland, Oregon 97232

Submitted to: GHGCR2021@deq.state.or.us

RE: Climate Protection Program
Comments Following March 18th Meeting

Mr. McConnaha and staff:

Thank you for the opportunity to comment on topics from the third meeting of the rules advisory committee (RAC) for the Climate Protection Program. The Oregon Association of Conservation Districts (OACD) is a non-profit association that represents the 45 Soil and Water Conservation Districts (SWCDs), local governments organized primarily at the county level. The mission of SWCDs is to support conservation of natural resources through a variety of efforts ranging from education to implementing on-the ground projects, and providing technical services and support funding to landowners, both urban and rural.

We appreciate that much of the meeting was devoted to the very important topic of Community Climate Investments (CCIs), formerly referred to as Alternative Compliance Instruments or offsets. Despite the concerns that have been expressed about CCIs, we applaud the staff at DEQ for continuing to see their importance in an overall climate program. We are also pleased that there are many members of the RAC who hold similar beliefs. Following are our specific comments.

The Climate Protection Program must include CCIs. Recognizing that purpose of the program is to reduce greenhouse gasses in the atmosphere, we need to proceed with all the good tools. Reducing emissions is one critical tool and taking carbon out of the atmosphere through CCIs is another. The first results of the modeling presented at the March 18 meeting make it clear that CCIs are critical to getting the best results in the long run.

CCIs must include carbon sequestration opportunities. The CCI program as currently described is focused on projects that reduce emissions outside of the regulatory framework. DEQ staff needs to start presenting this program in a way that makes it abundantly clear that CCIs also include projects that take carbon out of the atmosphere, i.e., sequestration.

Sequestration on natural and working lands has much potential. We believe that natural and working lands can provide significant and important reductions to greenhouse gas emissions through the implementation of good management practices in wetlands, forests, and agricultural systems that provide for voluntary sequestration of carbon. Much is known about carbon sequestration in natural and working lands, but the state of the science will continue to make significant strides forward in the future to provide more precision on quantifying the benefits of individual management practices.

The Oregon Watershed Enhancement Board is addressing climate mitigation projects in their grant programs funded by lottery dollars. The Oregon Global Warming Commission is also addressing potential strategies in their natural and working lands study to address greenhouse gas reductions. We need to provide the opportunity and vehicles for these programs to come to fruition.

CCIs must have real greenhouse gas benefits. One of the primary concerns expressed about CCIs is that they may not be as effective as intended. This is an important concern and CCIs must be designed to achieve benefits that are real, measurable, and long lived. We believe that this can be achieved and that it will be important to have oversight mechanisms to verify the efficacy of projects. Oregon has at least 4 sequestration projects underway, using verification software.

CCIs will take time to develop. It is unrealistic to think that we can have a full suite of CCI projects ready to go on day one when the rules for the Climate Protection Program are adopted. Some will be able to be developed and put into use quickly, while other will take years to decades to fully mature. To enable the development of the best possible CCIs there should be flexibility in developing CCI projects. Don't draw the lines so tightly that projects with new technology and other benefits are precluded in the future. Make adjustments to the CCI program on some regular basis to review what works and what doesn't and then make changes. As science and technologies increase and change in future years, we must take advantage of those opportunities.

Reconsider the structure of caps for CCIs. The current discussion in the RAC describes caps on CCIs in terms of a percent of allowed emissions. Under the belief that a ton of GHG that is introduced or removed from the atmosphere has the same benefit in terms of climate change, we do not favor placing caps on the CCI program. The highest cap currently in discussion is 25%. In no cases should we consider going lower.

It is important to recognize that a cap that is based on percent of allowed emissions will lead to less and less opportunity for CCIs as time goes forward. Twenty five percent of a number that gets small means that the CCI program will get smaller over time.

If it is necessary to have a cap, we urge that the cap not decrease over time. We need the CCI program to grow over time as the need increases and the tools and projects become better over time. Perhaps the cap could be a fixed number of tons that stays constant from year to year with regulatory flexibility for that number to be adjusted based on proven success of the CCI program.

Rural communities associated with natural and working lands are often low income and disadvantaged. Much of the discussion on disadvantaged communities appears to be focused on the urban sector. It is important to recognized that the rural sector has important needs as well. Accordingly, we need to make sure that CCIs are developed throughout the State to bring benefits to both urban and rural sectors.

Non-GHG environmental benefits are important too. It is clear that the Climate Protection Program is focused on making sure to address environmental justice needs. This is an important part of the program. However, we are concerned that the program is not paying enough attention to environmental needs beyond greenhouse gases. This program can have significant influence on the quality of our soils, land, water, plants and wildlife. All of these need to be considered too.

Value added benefits of CCIs in natural and working lands are substantial. CCIs on natural and working lands offer a wider range of value-added benefits as follows:

- CCIs on natural and working lands enhance the overall environment.
- They provide value added benefits to agriculture and forestry. For example, carbon sequestration is clearly encouraged as the health of soils is improved. Healthy soils result in better growth of plants with fewer synthetic inputs in the form of fertilizers and pesticides and result in more resilient natural systems.
- They can be a source of new technological innovation and additional jobs while promoting management and conservation techniques.
- They can benefit impacted and rural communities.

We appreciate the opportunity to participate in the RAC and look forward to a final set of rules that will lay the foundation for an equitable and effective Climate Protection Program.

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OREGON FARM BUREAU

Locally Grown and GROWING STRONG

March 29, 2021

Richard Whitman
Director, Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Re: Oregon Climate Protection Program

Director Whitman,

Thank you for the opportunity to respond to the slide deck presented by the Oregon Department of Environmental Quality ("DEQ") at the third RAC meeting of the Oregon Climate Protection Program ("CPP"). As a reference, the Oregon Farm Bureau Federation ("OFB") is the state's largest general agriculture association representing nearly 7,000 families engaged in production agriculture.

OFB observed the last three rules advisory committee ("RAC") meetings in order to provide the agency with timely feedback about the impact of the proposed CPP to farm and ranch families. We are not a member of the RAC, which has hampered our ability to effectively engage. When paired with the challenges of a rulemaking of this magnitude being undertaken in the midst of a very challenging virtual session, it has made meaningful engagement in this process exceedingly difficult.

While we agreed with the agency's early leanings concerning broad compliance flexibility, trading, and banking as methods to control costs, we don't see those leanings reflected in the agency's March 18th presentation to RAC members. In fact, DEQ appears to have taken a contradictory approach, proposing very costly and inflexible community climate investments ("CCI") as the sole mechanism for alternative compliance with the CPP. As currently envisioned, CCIs will not contain costs for everyday users and consumers, and are likely to instead drive up the cost of compliance with this program.

The agency's March 18th presentation to the RAC represented a significant shift in approach from previous RAC meetings. It is clear on slide 18 that DEQ intends to raise revenue from the sale of alternative compliance mechanisms in order to bankroll projects that reduce co-pollutants in Oregon communities, as opposed reducing greenhouse gas emissions. This is a significant departure from the agency's stated intent, and OFB strongly disagrees with this approach. It is inappropriate to craft the CPP in such a way so as to generate revenue for pet projects related to air quality, as opposed to greenhouse gas reductions generally. Additionally, the list of potential CCIs is very short-sighted, and DEQ ignores the potential for sequestration across Oregon's working farm, ranch and forest lands. Nowhere in the slide presentation does DEQ contemplate the sequestration potential of our working landscapes, nor the opportunity for farmers, ranchers, or small woodland owners to participate in an alternative compliance program. As currently crafted, the CPP is a lose-lose program for our farmers and ranchers.

The proposal for $50 or $200 CCI's will also result in significant increases in the cost of fuel, propane and natural gas, three critical inputs for farmers and ranchers, and products for which there are not credible alternatives on the market today for agricultural equipment or machinery. As an example, a $50 CCI price will double the price of natural gas for consumers. A $200 CCI price equates to a price increase over four times today's price of $2.50 to $2.75 per MMBtu for natural gas customers. These arbitrary prices, as established by DEQ, will reduce the competitiveness of homegrown businesses so substantially that leakage is sure to be the result, particularly since the agency has presented no affordable pathway to compliance. The agency's proposal for CCIs is neither workable nor accessible to farm and ranch families, and the resulting cost of compliance will be so significant that many businesses will be unable to continue to afford to operate within the State of Oregon. ORB urges the agency to work to avoid this outcome.

OFB respectfully urges the agency to reconsider its approach related to alternative compliance mechanisms, as DEQ's proposed CCIs will harm local farm and ranch families and rural communities.

Sincerely,

Jenny Dresler
Lobbyist
Oregon Farm Bureau

March 22, 2021

Colin McConnaha
Nicole Singh
Office of Greenhouse Gas Programs
Oregon Department of Environmental Quality
Sent Via Email: GHGCR2021@deq.state.or.us; Colin.McConnaha@state.or.us; Nicole.Singh@state.or.us

RE: Oregon Fuels Association March 18th RAC Comment Letter

Dear Colin and Nicole:

Thank you for an opportunity to provide comment following the Cap-and-Reduce / Climate Protection Program rules advisory committee meeting.

The Oregon Fuels Association (OFA) is the voice of Oregon's locally-owned fuel stations, fuel distributors and heating oil providers. OFA members are at the forefront of environmental stewardship within the industry and continue to make investments toward a cleaner, greener economy. In fact, Oregon's locally owned fuel providers are leaders in the use of fuel blending and promoting the use of low carbon fuels and biofuels. We are dedicated to helping Oregon reduce emissions from fuels by at least 10 percent by 2025. These investments by our members have helped eliminate millions of tons of greenhouse gas emissions since the Clean Fuels Program (CFP) was implemented in 2015.

As a reminder, OFA members are small, family and locally owned Oregon businesses. They are not large national or international energy companies. Nevertheless, they have been a big part of Oregon's growing regulatory structure designed to reduce greenhouse gas emissions (GHG) in the transportation sector. In fact, OFA has leaned into the CFP and as DEQ is well aware, OFA has publicly supported the CFP because they believe this is the best approach for reducing greenhouse gas emissions in the transportation sector. More than just supporting the program, OFA members have also made significant investments in infrastructure to enable fuel blending that lowers the carbon intensity of fuels, thereby lowering the state's GHG emissions. The same CFP that regulatory targets are expected to more than double pursuant to the Governor's EO 20-04.

In addition to the sizeable CFP infrastructure investments, the CFP and greenhouse gas emissions reporting programs have created significant burdens on these small businesses. We believe it is important to consider the regulatory costs of existing GHG programs when evaluating whether small businesses should succumb to new regulatory burdens and costs.

OFA recognizes the goal of the program is to do a number of things, including reduce emissions. But not at any cost. Specifically, EO 20-04 provides that agencies must "[p]rioritize actions that reduce GHG emissions in a cost-effective manner." With that in mind, OFA believes DEQ can create a program that focuses on reducing emissions, but in a fair, responsible, and ***cost-effective manner*** that recognizes the needs of small business. Consistent with that approach, OFA strongly supports a 300,000 MtCO2e threshold for the following reasons:

- First, nearly 100% of transportation fuels is already regulated by the CFP and this will help the state meet its GHG reduction goals.
- Second, potential compliance costs for these new regulations will have a disproportionate impact on OFA's small businesses that have already struggled to meet existing regulatory burdens.
- Third, a lower threshold will be a significant burden on DEQ potentially adding 4-6 times the number of regulated entities.
- Fourth, OFA members' GHG emissions fluctuate dramatically. Examples over the last five years show GHG emissions fluctuating between 50% to 200%. It is unclear how the state will allocate permits or allowances since they will not be auctioned. With fluctuations of this magnitude, it is hard to understand how the agency would allocate limited compliance instruments / allowances under a declining cap. It will get very complicated for the agency and small businesses.
- And fifth, lowering the threshold will have little to no climate impact and will not meaningfully reduce emissions. Meaning, the burdens of regulating these small businesses would far outweigh the benefits. Again, nearly 100% of transportation fuels are regulated by the Clean Fuels Program and a 300,000 MtCO2e is a reasonable threshold and will reduce the impacts on small, locally owned businesses.

Thank you for considering our comments.

Sincerely,

Mike Freese
Oregon Fuels Association

MEMORANDUM

To: Richard Whitman, Director, Oregon Department of Environmental Quality
Sent via email: GHGCR2021@deq.state.or.us

From: Oregon Manufacturers and Commerce
Shaun Jillions, sjillions@oregonmanufacturers.org

Date: March 26, 2021

Re: Feedback on Oregon Climate Protection Program: Rulemaking Advisory Committee Meeting 3

Thank you for the opportunity to provide feedback on the topics presented by the Oregon Department of Environmental Quality ("DEQ") at the third meeting of the Oregon Climate Protection Program: Rulemaking Advisory Committee ("RAC"). As a reference, Oregon Manufacturers and Commerce ("OMC") is an association dedicated to promoting, protecting, and advancing Oregon manufacturers and their allied partners.

OMC is concerned with the direction of the DEQ's policy proposals regarding alternative compliance instruments. We were alarmed to see DEQ move away from the concept of a cap and reduce program with flexible compliance pathways, and instead craft a program that generates revenue to fund projects in Oregon with the stated goal of reducing co-pollutants. This proposal is the highest cost pathway to compliance and will result in leakage. Energy Intensive, Trade Exposed ("EITE") entities must be provided with affordable compliance pathways under the proposed Climate Protection Program ("CPP"). We expand on our concerns below.

(1) *What are your thoughts about integrating potential community climate investments in the CPP?*
OMC does not support the agency's proposal of community climate investments ("CCI") as the sole pathway for alternative compliance with the proposed CPP. It is clear the agency intends to raise revenue from regulated entities through the sale of CCIs and subsequently direct those funds to projects intended to reduce co-pollutants in Oregon communities, as opposed to reductions in greenhouse gas emissions generally. As noted in comments submitted by OMC on February 26, 2021, greenhouse gases are global pollutants and are not local. Any reduction in greenhouse gases benefits Oregon communities, regardless of where that reduction occurs. As such, we disagree with DEQ's proposal of CCIs as the sole mechanism

for alternative compliance. DEQ's should focus policy proposals on greenhouse gas reductions, not revenue generation or the reduction of other air pollutants.

Limiting alternative compliance options to those generated Oregon will limit the effectiveness of this tool as there likely are not sufficient opportunities for in-state projects, nor are they likely to be cost effective. As long as the compliance instrument results in a greenhouse gas reduction, there is no difference from a global emissions or greenhouse gas accounting standpoint. Any limit on alternative compliance instruments to meet an entity's compliance obligation would be arbitrary. Before advancing the concept of CCIs, DEQ must study the availability of qualified in-state projects to ensure that there are adequate options available to control costs throughout the life of the program. OMC urges DEQ to revisit the proposed CCI model and to provide an affordable and flexible compliance pathway for regulated entities in order to avoid the very real threat of leakage.

Further, DEQ proposes a CCI price of $200/ metric ton of carbon for the purposes of modeling the three policy scenarios, although the agency has offered no justifiable reason for limiting the market for compliance instruments to those that cost $200 (or even $50)/ metric ton of carbon. Certifiable offsets and allowances are available in the U.S. and around the world that correlate to an actual reduction in greenhouse gas emissions. These programs range in price from $15 to $20/ metric ton of carbon,[1] not $200 as the agency proposes on slide 37. DEQ's proposed CCI price will subject regulated entities to compliance costs that are 10 times the price of those currently available for the same carbon reduction in the global marketplace. DEQ's proposal of $200 CCIs provides no feasible alternative for EITE businesses to comply with the proposed regulatory program. By setting its own CCI price far above that of the global offset and allowance market, this policy proposal will ultimately result in the leakage of emissions to jurisdictions with a less favorable electricity profile than Oregon's relatively clean electric grid.

(2) *Should there be a limit on how much regulated entities are allowed to use community climate investments?*
As shared in previous comments, OMC does not support limiting the use of alternative compliance options to a percentage of regulated entities' compliance obligation. For some regulated entities, these tools may provide the only cost-effective means to achieve compliance with a cap and reduce program. Alternative compliance options provide a verified reduction in global greenhouse gases. As that is the stated goal of the CPP, DEQ should not limit the use of alternative compliance mechanisms, as currently proposed in the agency's modeling scenarios.

Regarding the regulation of non-natural gas fuels, OMC is concerned about the indirect costs associated with transportation fuels and the potential for dual regulation under the

[1] California Carbon.info. 2030 WCI Emissions and Price Forecast
file:///C:/Users/JDresler/Downloads/2030%20Emissions%20and%20Price%20Forecast%20Excerpt.pdf

CPP. DEQ cannot view sectors independently from one another when analyzing impacts or the feasibility of the CCP. Local manufacturers, for example, will be impacted through the direct regulation of facilities, but could also realize significant indirect cost impacts related to transportation or the upstream regulation of natural gas.

Thank you for the opportunity to provide the agency with feedback during the public comment period. OMC looks forward to future engagement with the DEQ.

PPGA
PACIFIC PROPANE GAS ASSOCIATION

March 26, 2021

Nicole Singh, Senior Climate Policy Advisor
Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

RE: PPGA Comments - Cap and Reduce Rule Advisory Committee Meeting, March 18, 2021

Dear Ms. Singh:

Thank you for the opportunity to provide feedback on the Oregon Department of Environmental Quality's (DEQ) second Rules Advisory Committee (RAC) meeting of March 18, 2021.

The Pacific Propane Gas Association (PPGA) is the state trade association representing Oregon's propane industry. Our membership includes small multi-generational family businesses and large corporations engaged in the retail marketing of propane gas to Oregonians. PPGA members provide propane to the residential, commercial, agricultural, transportation and industrial markets throughout Oregon. Currently, users of propane have found value in propane's environmental benefits, versatility, and affordability. This is demonstrated in the growth of propane demand across all sectors of the energy market. Our members play a uniquely critical role in rural Oregon where often natural gas is unavailable and electric load is unable to meet all energy needs of farms, homes, and businesses. Propane is extremely efficient because it is employed directly at the point of use and does not require the initial infrastructure investment or maintenance costs of other energy sources.

PPGA offers the follow comments regarding key topics discussed at the third RAC meeting.

Community Climate Investments

The PPGA is concerned the conversations from DEQ are beginning to focus on electrification and not greenhouse gas emission reductions. This was of particular concern when at the outset of a seven-hour RAC meeting, Director Whitman commented on the importance of switching natural gas utility customers to electricity. As DEQ has acknowledged the electricity sector is a major emitter of greenhouse gas emissions and those emissions will be unregulated under the program. While Oregon's electrical grid is one of the cleanest in the country, emissions remain and getting to net zero in the electricity market is not currently feasible.

Renewable propane has an extremely low carbon intensity score, often lower than electricity depending on the electricity's generation source. Additionally, new technologies such as blending renewable dimethyl ether (DME) and propane can reach cardon intensity scores near zero. Already, nearly all propane used as transportation fuel in Oregon is renewable propane.

We are concerned there is a significant benefit of the doubt given to the electricity sector being able to meet significant decarbonization targets while the propane industry receives none.

The PPGA strongly encourages the Community Climate Investments to focus on projects that will return the best "bang for the buck" in terms of GHG emissions. Replacing a 95% AFUE propane furnace with an electric heat pump that may need additional electric heat strips or even gas backup will not achieve substantial GHG reductions. Neither would focusing on electrifying school transportation. Propane school buses reduce NOx emissions by 96% when compared to a diesel bus. An electric school bus costs approximately three times as much as a propane school bus and site preparation and infrastructure requirements for electric busines costs considerably more.

INFRASTRUCTURE COMPARISON	PROPANE AUTOGAS	ELECTRIC*
Buses Serviced	10	10
Site Prep + Infrastructure Maximum Total	$45,000 - $60,000	$80,000 - $480,000
Installation	$18,000 - $24,000*	$30,000 - $280,000**
Site Prep + Equipment	$27,000 - $36,000*	$50,000 - $200,000***
Station Setup	One 1,000 - 2,000 gallon tank	Five level 3 fast EV chargers
Additional Costs	No	Most Likely — Electric sub-panels, added amperage to power multiple stations, upgrading and replacing incoming power line
Scalable to Growing Fleet	Yes	No

*Argonne National Laboratory, Center for Transportation Research, AFLEET Tool 2017.
**U.S. Dept. of Energy, Vehicle Technologies Office, Nov. 2015.
***Rocky Mountain Institute, April 2014.

Oregon has the largest percentage of school buses running on propane out of any state in the country and is only behind California, Texas, and Pennsylvania in total buses.

The PPGA strongly believes in a flexible approach to projects that will receive funds by the Community Climate Investment program, but we also believe that these projects need to achieve significant GHG reductions and DEQ should not simply choose one source of energy over the other. We believe energy efficiency programs a much fairer and more meaningful way to reduce GHG emissions, which is why our industry provides a robust, industry funded, appliance rebate program for our customers.

Point of Regulation

The PPGA is generally supportive of the point of regulator being at the fuel supplier level. PPGA members are small businesses often with 5-10 employees. Having a complex regulatory reporting scheme would be a major challenge to many of our small business members. Additionally, we see some challenges in our industry for reporting the emission source level—such as propane grill cylinders and temporary heat at places like construction sites or outdoor dining. Having regulation at the fuel supplier level combined with a 300,000 $MtCO_2e$ threshold would capture an overwhelming majority of emissions while limiting the regulatory burden of the program. Should the DEQ recommend a lower threshold we would request they give strong consideration how to limit the regulatory burden on small family-owned businesses.

Thank you for allowing us to share our feedback. We look forward to continuing to work on this important rule making process.

Sincerely,

Matthew Solak
Executive Director
Pacific Propane Gas Association
matt@kdafirm.com
Office: (844) 585-4940
Cell: (269) 470-8729

To: ODEQ GHG reduction taskforce

From: Ralph M Cohen, PE

Subject: Rulemaking Session #3 (03/18/21) comments

Date: 03/21/21

Thank you for the opportunity to participate in the Cap and Reduce program. I am submitting these comments or concerns to the material reviewed at the meeting.

I am currently an independent engineering consultant/concerned citizen with many years of experience across a wide range of industries in mechanical and facility design, energy conservation, and pollution control. As a board member of Professional Engineers of Oregon (PEO), I am keeping them apprised of the workshop proceedings, but views and comments I provide are strictly my own and have not been reviewed in advance or endorsed by PEO.

Comments concerning CCI (Community Climate Investment):

My public testimony comment during the meeting was premature; after reflection I would like to clarify:

An example of an industrial project I analyzed and that was implemented had a capital cost of $5M with an expected $1M per year electrical power cost. Based on the Oregon electric power source mix, it would reduce CO_2 by 4100 MT/year (0.5 lb. CO_2/kWh saved). That works out to $1220 per MT/year ($5M divided 4100 MT) invested and a 5 year simple payback.

In the meeting, I incorrectly stated that the above example would equate to a CCI cost of $1220 per MT – significantly greater than $200 per MT used in the ICF model. However, I failed to consider that the initial investment in the example, above, continues to save 4100 MT every year for the life of the investment - 10 years or more. For a 10 year life, without considering the time value of money, depreciation, etc. the capital cost would be $122 per MT. Would that value then be a CCI = $122 per MT? It is certainly closer to the ICF value used in the modeling example.

I believe a distinction needs to be made when discussing the CCI concept between the amount that must be invested in a project that reduces GHG emission and the annual cost per MT of reduction. Exactly which value is the CCI value?

Additional points

1. **Community Climate Investment (CCI)**. I believe the CCI concept has great merit if projects can be identified for investment by regulated entities needing alternative compliance instruments. The cost, economic benefit, and annual GHG reduction quantity for these projects would need to be determined in advance and presented as such. Those projects yielding the most reduction at the lowest capital cost would most likely be adopted first with less beneficial projects remaining for future implementation as the caps continue to be more restrictive. Paramount would be administration of the program by qualified, regional entities as was suggested during the presentation. More difficult than identifying projects would be implementation – who will provide the design and construction/contracting required for these projects? And who certifies the project after installation? The Energy Trust of Oregon model might be a starting point, but falls short because this program depends on applicants/end users to implement their projects.

2. Severely limiting the amount of CCI may not be good overall policy, especially if the only internal projects that regulated entities have available are very costly relative to the GHG reduction. EJ and impacted communities would benefit from the demand for implementation ready, cost effective, GHG reducing projects to be financed by regulated entities.

3. **Regulating fuel suppliers** (slides 23 – 27). The level at which fuel suppliers are regulated is more a regulatory challenge than a technical problem. My concern is that irrespective of the threshold level, how will those regulated suppliers exert influence on their customers once existing fuel blending and RNG replacement technologies have been fully applied and likely at less than an 80% GHG reduction? Regulating fuel suppliers rather than consumers seems to assume that, somehow, suppliers will be able to get customers to change behaviors and find ways to reduce consumption. The main tools would be price increase to reduce demand, coerce transition to, hopefully, available clean electricity, or encouraging customers to utilize existing programs (e.g. Energy Trust) or creating new and more generous programs. Failing to effect reduction, fuel suppliers will become large users of alternative compliance instruments or CCI's – not totally bad, but not completely desirable. ODEQ avoiding providing a "leaning towards" point of regulation continues to raise questions on how reductions will be accomplished.

   Reviewing RAC 2 public testimony, BP (p. 26), Cascade Natural Gas and Avista (p. 32), and NW Natural Gas (p. 100) favor regulation at the point of combustion. Contrary views were provided by Evraz (p. 52) and at least one other non-supplier organization.

4. **Modeling** (slide 41-42). Although the graph shows the expected reduction and the prior slide explains, generally, how the reduction is achieved, it does not yet inspire confidence that the target can actually be achieved and at what investment cost. For example, the results rely on movement from natural gas to electricity – what if the electricity isn't sufficiently "green"? What program inspires or incentivizes all/most home owners and fossil fuel powered vehicle owners to migrate to low GHG emitting technologies? It would be helpful to see all the technical assumptions in greater detail stated so that participating engineers and scientists can test those assumptions.

[END of COMMENTS]

March 26, 2021

Oregon Department of Environmental Quality
Office of Greenhouse Gas Programs
700 NE Multnomah St., Suite 600
Portland, OR 97232

Sent Via Email To:
GHGCR2021@deq.state.or.us

RE: Climate Protection Program 2021 – RAC Meeting #3

Dear members of the Environmental Quality Commission, Director Whitman, DEQ staff and members of the Rulemaking Advisory Committee,

We remain concerned about the direction the Climate Protection Program is headed. As you know, Governor Brown has mandated DEQ to devise a program to cap and reduce greenhouse gas emissions from large stationary sources, transportation fuels, and all other liquid and gaseous fuels as part of a larger goal to reduce all of Oregon's GHG emissions by 80% from 1990 levels by 2050. *See* Exec. Order 20-04. Based on the information DEQ has shared, we are highly skeptical that any of the three modeled policy scenario options outlined by DEQ is the right tool to fulfill the Governor's mandates.

We are disappointed that every policy scenario DEQ modeled exempts Oregon's most significant greenhouse gas emitters: fracked gas power plants. DEQ seems to have made this decision without studying the impact of this policy choice on the overall carbon reductions that the CPP can deliver or the Program's equity or environmental justice impact.

We appreciate that, in contrast, DEQ did analyze the impact of exempting some non-natural gas fuel suppliers from the Climate Protection Program, but we are disappointed that the analysis did not analyze environmental justice impacts. We encourage DEQ to complete its analysis by analyzing the equity and environmental justice impacts of each option. We also urge DEQ to include all non-natural gas fuel suppliers in the Climate Protection Program, rather than exempting some and depriving neighboring communities of the co-benefits of GHG reductions.

In addition, we are concerned about the lack of information DEQ has shared about the assumptions underlying its proposed policy scenarios and, in particular, the Community Climate Investment program. It is unclear to us whether CCI is intended to function as an offset program (it appears to have been modeled as such) or a community investment program that is not intended to achieve any particular greenhouse gas emissions reductions. DEQ should clarify its assumptions and apply its resources to actually study different forms that the CCI program could take.

I) **DEQ should model a policy scenario that does not exempt Oregon's fracked gas power plants from the Climate Protection Program.**

We are disappointed that DEQ appears not to have modeled any policy scenario that would involve applying the Climate Protection Program to the full spectrum of polluters over which DEQ has jurisdiction, which includes the Oregon's fracked gas power plant facilities. As you know, these plants are Oregon's top six greenhouse gas polluters (even excluding their upstream fugitive GHG emissions which are not included in DEQ's GHG reporting data), which account for more than half of all of Oregon's GHG emissions from regulated facilities.[1]

To date, DEQ has failed to offer any clear legal reason why these plants must be exempted from the Climate Protection Program. The most thorough explanation of the sources and limits of DEQ's regulatory authority for the Climate Protection Program that DEQ has offered appears to be DEQ's June 2020 Final Report on Program Options to Cap and Reduce Greenhouse Gas Emissions. But nothing in that report suggests a reason to believe that DEQ lacks the authority to include these plants in the Program; they are located in Oregon, and emit greenhouse gases as a result of processes that occur entirely in Oregon.

DEQ has also failed to explain how the Climate Protection Program will advance the state's goal of reducing emissions to 80% below 1990 levels by 2050 despite the exclusion of Oregon's largest climate polluters. DEQ must explain why it believes that this rule is rational. It cannot do so without addressing whether a regulatory scheme that exempts most of Oregon's emissions from regulated facilities can achieve reductions consistent with Oregon's overall climate goals.

We urge DEQ to use its resources to at least study a version of the Climate Protection Program that would employ DEQ's full regulatory reach, rather than treating it as a foregone conclusion that these major producers of GHG emissions should be exempted from the Program without ever analyzing the climate or equity impacts of that policy decision. As we pointed out in our prior letter, exempting the electric sector has obvious negative impacts on environmental

[1] *See* Oregon DEQ, Greenhouse Gas Emissions from Facilities Holding Air Quality Permits (2019), https://www.oregon.gov/deq/aq/programs/Pages/GHG-Emissions.aspx.

justice, depriving communities in Morrow and Umatilla counties that are already overburdened by air pollution of the co-benefits of GHG reductions.

We ask DEQ to share details of its analysis of this decision with the RAC.

II) **DEQ should analyze the equity implications of excluding non-natural gas fuel suppliers and set the threshold for inclusion in the CPP at zero.**

With respect to the narrow question DEQ posed to the RAC regarding an appropriate threshold for regulating non-natural gas fuel suppliers, our view is that DEQ should set the threshold at zero.

We would first note that, while DEQ has shared information about how exempting some of these suppliers would affect GHG reductions through 2050 and would affect the regulated entities, it has not offered any analysis of the equity or environmental justice impacts of this choice. DEQ should analyze which communities will bear the benefits and costs of each of DEQ's proposed options for including some or all of this sector. We have no doubt that the most equitable policy option will be to include them all rather than denying some of the communities surrounding these facilities of the co-benefits of greenhouse gas reductions.

Including all of the non-natural gas fuel suppliers in the Climate Protection Program will increase the odds that Oregon can achieve the Governor's mandate. And achieving all emissions reductions possible within DEQ's jurisdiction is even more important in light of DEQ's apparent insistence on exempting the electric sector, Oregon's largest greenhouse gas emitters, from the Program.

III) **DEQ should clarify the goals of the Community Climate Investments program, specify what assumptions about the program DEQ relied on in modeling its proposed policy scenarios, and use its resources to analyze the benefits that could be achieved by different versions of the program.**

Although the Community Climate Investment (CCI) program was a major focus of the agenda for Meeting #3, DEQ's materials about the CCI program raise more questions than they answer. The program appears startlingly underdeveloped; it is not clear to us whether DEQ invested any resources into modeling the potential benefits and costs of different versions of the program.

DEQ's policy scenario modeling appears to treat the CCI program as an offset program in which regulated entities that are unable to cost-effectively reduce emissions below the Climate Protection Program cap can instead buy credit for emissions reductions by paying into a CCI fund $200 for each 1 MT CO2e of excess emissions. Indeed, DEQ has indicated that these CCI offsets are necessary to meet the caps under all three of its modeled scenarios.

However, it also appears to be up for debate whether CCI investments would actually be required to produce *any* reduction in GHG emissions—let alone whether they would be required to cost-effectively deliver a reduction of 1 MT CO2e at the given CCI price. DEQ's slides suggested only that DEQ "could" require all CCI investments to reduce GHG emissions, and asked RAC members to discuss "what types of projects should be funded by community climate investments."

If the CCI program is not an offset program that must reduce GHG emissions somewhere by an amount equivalent to the credit being awarded for the CCI price, then it shouldn't be treated as such in DEQ's modeling. DEQ should clarify and share detailed information about the assumptions about the CCI program that it incorporated into the policy scenario modeling.

We have previously explained the environmental justice concerns inherent in offset programs. Our last letter voiced our concern that DEQ's Climate Protection Program appeared overly focused on delivering cost savings to industry and appeared on course to allow major polluters to forgo any reductions in greenhouse gases when it benefits their investors to do so, depriving surrounding communities of the co-benefits of decarbonization like reductions in co-pollutants. We pointed to evidence out of California that, when regulated facilities were allowed to purchase credits to offset GHG emissions, GHG emissions and co-pollution actually *increased* in low-income communities and communities of color.

These problems are greatly exacerbated if the CCI program fails to even deliver equivalent reductions in a cost-effective way. If regulated entities can buy credit for greenhouse gas reductions by paying into a CCI fund that does not efficiently reduce GHG emissions somewhere else by an equivalent amount, then the CCI price is, in effect, simply a monetary penalty for the regulated entities' failure to adequately reduce GHG emissions. There is no guarantee that the emissions reductions resulting from the CCI program will benefit the communities most likely to be harmed by climate change or the communities being deprived of the co-benefits of GHG emissions reductions. In fact, it appears that which communities will receive the benefits of CCI investments, and whether or not the investments will even be required to be made in Oregon, is still up for debate.

In order to ensure that any CCI program actually achieves greenhouse gas reductions equivalent to the credit being given for them, DEQ should working in partnership with environmental justice communities to develop a list of potential offset projects, measuring the anticipated impact of each project in terms of reductions in greenhouse gas emissions and co-pollutants, and assessing a CCI price for each project that actually corresponds to the anticipated project outcomes. It should go without saying that the priority sites for these projects should be environmental justice communities in Oregon that have disproportionately borne the burden of pollution for years and that are disproportionately likely to suffer the climate impacts of fossil fuel pollution. DEQ should also require polluters to reduce GHG emissions first before they are eligible to use CCI credits.

Finally, we implore DEQ to use its resources to study and model different possible versions of the CCI program and analyze the costs and benefits of each. DEQ is charged with developing and analyzing regulatory proposals. This is a resource-intensive process, as the agency is well-aware. For the CCI program, however, DEQ appears to be asking community groups to take on this significant task in the first instance. DEQ has not offered to provide community groups with the resources to develop and analyze specific policy options. There is a difference between asking for input and asking communities to do the agency's work for it. Here, DEQ's failure to present any significant proposals and analysis of the CCI program fall into the latter category. DEQ must devote the time and resources to develop and analyze a detailed and credible range of options for the CCI program, rather than asking representatives of overburdened communities to do that work for DEQ.

IV) **DEQ should share more detailed information about the greenhouse gas emissions reductions it expects the Climate Protection Project to produce under the modeled policy scenarios.**

DEQ shared only a high-level (and largely graphical) overview of its three modeled policy scenarios. In order for RAC members to meaningfully evaluate DEQ's proposed program, DEQ must share more granular information about the baselines, assumptions, and anticipated outcomes of each of its policy proposals.

Significantly, it remains unclear what level of GHG emissions reductions DEQ actually expects its Climate Protection Program to produce. Although DEQ's slide deck states that each of its modeled policy scenarios will put Oregon on track to achieve "80% reduction by 2050," it is not clear what baseline DEQ is using or what data that conclusion is based on. DEQ should clarify whether the baseline for that 80% reduction is the 1990 emissions levels of the regulated sectors or the modeled 2050 "reference case," which we understand to refer to anticipated GHG emissions in 2050 absent a Climate Protection Program.

V) **DEQ should devote more resources to analyzing the equity impacts of its proposed policy scenarios.**

DEQ has plainly poured time and energy into studying the impact of its proposed policy scenarios on the regulated (and exempted) businesses, but we have yet to see an equivalent study of the impact of DEQ's proposed policy scenarios on frontline communities. It remains unclear how DEQ intends to fulfill its goal of "prioritiz[ing] equity" in its development of the Climate Protection Program, as DEQ has thus far not shared any concrete analysis of the equity implications of its proposed program or even offered a framework for analyzing equity.

We previously raised concerns about DEQ's failure to incorporate community-level data into its modeling. It is difficult to imagine how DEQ can analyze the equity impacts of its proposed Program without examining which communities will enjoy the co-benefits of actual greenhouse gas emissions reductions and which will not when neighboring polluters trade or bank allowances or pay into a CCI fund instead of reducing emissions.

We understand that RAC Meeting #4 will focus on equity. We hope and expect that before the next meeting, DEQ will use its resources to analyze the environmental justice impacts of each of DEQ's proposed policy options. We expect that the analysis will include an identification of which Oregon communities will likely enjoy the co-benefits of GHG emissions reductions and which will likely be sacrificed under each policy option and an examination of those communities' demographics and cumulative exposures to environmental hazards.

VI) **Conclusion**

In conclusion, we remain concerned with the direction and tenor of DEQ's rulemaking. In order to fulfill DEQ's goal of prioritizing equity and allow community partners to offer meaningful input on the Climate Protection Program, DEQ should conduct additional equity-focused analyses and share with the RAC detailed information clarifying key assumptions and anticipated outcomes of DEQ's proposed policy scenarios. In sum, we ask DEQ to:

- Analyze the climate and environmental justice impacts of excluding fracked gas power plants from the Climate Protection Program
- Analyze the environmental justice impacts of excluding some non-natural gas fuel suppliers from the Climate Protection Program
- Proceed with a policy option that includes all non-natural gas fuel suppliers in the Climate Protection Program
- Clarify the whether the Community Climate Investments program is intended to offset greenhouse gas emissions and clarify the assumptions about the CCI program underlying DEQ's policy scenario modeling
- Study different possible versions of the CCI program and analyze the climate and environmental justice impacts of each policy option
- Clarify what level of GHG emissions DEQ anticipates the CPP will produce and what baseline the 80% reduction by 2050 is measured against

- Analyze the environmental justice impacts of each modeled policy scenario, identifying the specific communities likely to enjoy or be deprived of the benefits of each option, examining each community's demographics and cumulative exposures to environmental hazards
- In general, share much more detailed and specific information and analysis about the underlying data sets, assumptions, and anticipated outcomes of each policy option that DEQ has considered, rather than offering only high-level summaries.

Thank you for your time and consideration of our requests. We remain committed to working with DEQ to fulfill its mandates for the Climate Protection Program.

Sincerely,

Allie Rosenbluth, Campaigns Director, Rogue Climate, RAC member

Erin Saylor, Conservation Director, Columbia Riverkeeper, a member of the Power Past Fracked Gas Coalition

Molly Tack-Hooper and Amanda Goodin, Staff Attorneys, Earthjustice

LMI Environmental, LLC

March 26, 2021

VIA EMAIL

Colin McConnaha
Manager, Office of Greenhouse Gas Programs
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Re: Comments on DEQ's Cap and Reduce Rule Advisory Committee March 18, 2021 Meeting

Dear Mr. McConnaha,

Thank you for the opportunity to comment on DEQ's materials presented at the March 18, 2021 Cap and Reduce Rule Advisory Committee (RAC) meeting. On behalf of Roseburg Forest Products and other affected manufacturing companies, we offer the following comments:

1. Community Climate Investments:

   We applaud DEQ's creative thinking regarding the Community Climate Investments (CCI). We agree that incorporating a concept such as CCI into a larger compliance option framework could result in benefits for all involved. However, as presented at the RAC meeting, there remains several critical details and questions that must be addressed in order to minimize the potential unintended, negative consequences. To that end, we request that DEQ consider incorporating the following into their thought process:

   a. CCIs should be one of several alternative compliance option (ACO) tools. There are numerous reasons why the facilities subject to this rule should have options as to the ACOs they ultimately select achieve compliance. Some reasons might include specific company goals, offset preference, cost, and marketing considerations, just to name a few. Limiting facilities' use of ACOs to CCIs, creates too narrow a path for compliance and results in facilities being given no discretion as to the projects their compliance dollars will fund.
   b. In addition to the reasons noted above, limiting facilities' ACOs to CCIs will likely be problematic for cost containment which may ultimately result in failure of the program. If only CCIs are allowed, there will be no mechanism to keep prices affordable as free market forces will not be a limiting factor on cost. It will be imperative to the viability of the regulated community to not only have options as to the ACOs they fund, but to also keep

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costs within reach.

c. DEQ explained during the RAC meeting that no effort has yet been made to quantify potential eligible projects for use as CCIs. This effort will be critical if CCIs are to be included as an option for ACO use. Facilities will need to be assured there are adequate CCIs available if their continued operation will be dependent on their availability. Due to the current lack of information regarding the potential availability of CCIs, we reiterate the comment above that CCIs must be only one of several ACO options available for facilities to use to achieve compliance with the rule.
d. During the RAC, we heard some members advocate that 100% of CCIs be earmarked for underserved or Environmental Justice communities. Again, imposing that limitation will result in too narrow a path toward achieving true carbon reduction as well as options for facilities to achieve compliance. In addition to broadening CCI availability to areas beyond underserved or Environmental Justice communities, DEQ should include rural communities and those who are likely to see the greatest impact from climate change.

2. Although the CCI concept is intriguing and if well thought out, may create benefits for all, we have only had high-level discussions about this approach and the details will be critical. Specifically:
   a. As presented, CCIs may be significantly more expensive than offsets that are available to facilities in other jurisdictions (by an order of magnitude). If CCIs are either an option or a mandated sole option, their use will likely result in high costs. Accordingly, it is imperative that DEQ provide adequate free compliance allowances to allow facilities to achieve compliance without creating a substantial, disproportionate economic burden. In addition, DEQ should take a disciplined approach at setting the pace at which those free allowances will begin to be withheld.
   b. Regarding the previous comment, DEQ should provide EITE facilities with additional consideration. EITEs will be particularly susceptible to the likely financial burden that will result from the use of CCIs, and it is important to plan for that reality during this rulemaking.

3. If the concept of creating and utilizing CCIs is ultimately adopted, there are other considerations to include:
   a. Establishing the certification process and other management guidelines for third party entities charged with identifying and overseeing the CCI process. Specifically, what would be some of the basic requirements or standard to which these entities will be held? Will their past experiences be allowed to show particular bias? Will all interested parties including the regulated sector have the ability to weigh in on this process? How will DEQ ensure they will not operate in a manner that funds particular pet projects that may not ultimately hold up to a federal carbon reduction standard? If the price of one CCI is worth one metric tonne of carbon reduction, how will third party entities be compensated?
   b. Determining whether CCI projects will be available inside and outside of Oregon. We believe that more meaningful carbon reduction is maximized when he regulated sector is provided with a broad range of ACO options. For this, and other reasons mentioned

   above, ACOs as well as CCIs should not be narrowed to only projects within Oregon.
   c. Additional thought and discussion needs to be given as how to identify potential CCI projects. Again, a broader scope results in more meaningful carbon reduction opportunities. However, additional thought should also be given as to how these potential projects might fit within a broader federal program. Otherwise, Oregon's manufacturing base could very likely be penalized for early action that is deemed to be inadequate for that potential federal use. The regulated community is an indispensable party for that discussion.
4. Non-natural gas fuels. We respectfully provide no comment on this issue at this time as we believe the fuel suppliers are better informed to make meaningful comment on the concepts presented.
5. Results from modeling scenarios. We find the results of the modeling scenarios interesting, but expect there will be additional refinement for upcoming presentations. We were surprised and concerned, however, to hear that the modeled CCI price was set at such a high dollar amount. Neither rates at $200/MT nor $50/MT reflect anything close to current market pricing for offsets which are commonly $15-20/MT. As mentioned above, we should work to identify ACOs that will result in true carbon reduction while keeping Oregon's manufacturing base viable. Expensive micro projects will likely not achieve that result.
6. Lastly, we feel it is worth mentioning our disappointment with the process when all interest groups except the Environmental Justice representatives were asked not to speak. We understand that theirs is an important voice in this process, but other voices are important as well. We understand that DEQ wanted to allow them to speak for the CCI concept as their communities of interest will be direct beneficiaries of the result. However, DEQ should also recognize that the regulated community is expected to fund that benefit and should not be silenced in the process.

Again, thank you for the opportunity to provide these comments. We look forward to continuing working with you.

Sincerely,

Ellen Porter

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Southern Oregon Climate Action Now
SOCAN
Confronting Climate Change
https://socan.eco

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March 24th 2021

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SOCAN Comments on DEQ RAC 3

First, I would like to compliment DEQ staff again on the transparency of the process and their willingness to accept public comment on the developing Climate Protection Plan.

Second, I would like to express appreciation for the thoughtful creativity that led to the development of a Community Climate Investment program as a way of thinking about and addressing the issue of Alternative Compliance Options (offsets).

My comments will largely follow the sequence in which issues were originally raised during the RAC 3 meeting.

A Goal of Electrification?

Early in the March 18th meeting, a question was posed by a proponent of Renewable Natural Gas (RNG) about whether the goal of DEQs Climate Protection Plan was to promote electrification across the economy. In response, Manager of the DEQ Office of Greenhouse Gas Programs Colin McConaha indicated that he supported RNG while DEQ Director Whitman indicated he also supported RNG and added Hydrogen.

Electrification is reasonably argued as a positive step in efforts to reduce greenhouse gas emissions from the transportation sector because electric motors are vastly more efficient than the Internal Combustion Engine (ICE), so electric vehicles are preferred even if the electricity is generated from a fossil-fuel-powered facility. Meanwhile, in general domestic, commercial, and industrial settings, electricity is a preferred energy source especially if it is generated from genuine renewable energy largely in the expectation the electricity generation will turn away from fossil fuels. One concern with promoting electrification, however, is that, if successful, this will likely increase the demand and thus the generation need. If electricity generation is from natural gas plants, and these remain unregulated, enhanced electrification of our economy could increase the greenhouse gas emissions resulting from natural gas usage (see

Fossil Gas Myth below). However, we must anticipate that electricity generation will soon become localized and based on renewable sources.

Community Climate Investments.

As indicated above, I found this concept encouraging. However, I remain confused as to the extent that these investments must involve projects that result in greenhouse gas emissions reductions or removals. As the discussion proceeded it seemed that at times this was the expectation, but at other times it was not. While I can see great merit - in a general sense - in promoting investments in social justice projects that benefit low income or disadvantaged communities generally, since the authority for the Climate Protection Plan stems from the Governor's Executive Order targeting greenhouse gas emissions through an equity lens, it seems reasonable that either GHG emissions reductions or removals should be required of any project earning investments from this program.

In terms of the principles that should be required in establishing these investments, I offer the following:

1) Any emissions reductions or removals should be credited on a 1 for 1 basis, so each ton of GHG reductions or removals counts for one ton of compliance.
2) In order to facilitate projects that meet equity goals as well as GHG reduction/removal goals, projects that do both should be favored.
3) It is not clear to me from where the values of $50, $100 or $200 per ton as C charges came or how these were justified.
4) While it is inevitable that any projects receiving investments would have to be third-party certified as actually leading to reductions or removals, it is not clear to me why a third-party agency is necessary to serve as an intermediary between the investor and the project manager in terms of the funding stream. Why is it not possible to allow the investor to invest directly with the project manager in approved projects? The certifying agency could then provide the investor with certificates of GHG reduction or removal achievement once this has been verified.
5) Whether investment projects should be restricted to Oregon is problematic. On one hand, this would certainly make any potential projects easier to certify and would better assure they serve Oregonians. However, on the other hand, since Oregon has a wealth of potential sequestration opportunities, we might find restricting these to Oregon has unforeseen negative consequences. One of these could be that other jurisdictions developing climate action plans might respond to our restriction by precluding their potential investors from investing in Oregon projects. Maybe investment projects could be restricted to jurisdictions that have a climate action plan exhibiting at least equivalent rigor to that in effect in Oregon.
6) It is critical that any projects that are the subject of this program not be double-counted in the overall Oregon Climate Action Program.

7) In order to protect Climate Protection Plan legitimacy and credibility, certain restrictions should be applied on participation eligibility for potential investors:
    a. Before eligibility to invest is awarded, potential investors should demonstrate either they have installed best available emissions reduction technology or have concrete (contracted?) plans to do so within (say) two years.
    b. Investors should be precluded from investing to offset GHG emissions from facilities that emit co-pollutants that compromise the air quality of neighboring communities.
    c. Since the purpose of the Climate Protection Plan is to reduce or remove emissions, it is unreasonable to allow emitters a substantial investment option because that would allow them to evade the purpose of the program. We know that negative emissions (i.e., sequestration from the atmosphere) is necessary if we are to limit global warming to the target of 1.5°C (2.7°F) above pre-industrial conditions, so encouraging investment in sequestration projects represents a valuable contribution to the effort. However, allowing these investments to count a substantial amount towards an emitters compliance obligation simply undermines the effectiveness of the entire program. Based on nothing more than subjective judgment, 5% seems rather small and potentially fails to allow facilities having difficulty achieving reductions a reasonable alternative, while 25% seems excessive and potentially allows emitters far too great an opportunity to evade their responsibility to reduce emissions.
    d. As the cap and reduce program of compliance instrument allocations proceeds, future calculations should be based on current allocations. Compliance achieved by investments rather than reductions should not be discounted in future reduced allocations.
    e. Projects receiving investment that either result in emissions reductions or removals should be monitored for leakage and any leakage detected should be accounted in the assessment of certification totals. For example, if a forest sequestration project in location A, results in increased timber harvest in location B, the increased emissions in location B should be deducted from the sequestration recorded in location A.
8) For emissions reductions or removals to be certified, they must be:
    a. Real
    b. Measurable
    c. Additional
    d. Long-lived replacing the requirement of Permanent because carbon in biological systems is dynamic and exhibits constant flux. We do not expect any single carbon atom to be sequestered in vegetation or soil permanently, but for an extended period so the amount stored increases over time.
    e. Monitored
    f. Verifiable

The Fossil Gas Myth

In considering how to reduce greenhouse gas emissions, it is important to appreciate that all fossil fuels result in greenhouse gas emissions. While the majority of these emissions occur when the fuel is combusted, emissions also occur throughout the lifecycle of those fossil fuels: during extraction, processing, and transmission/transport. When the life cycle emissions are gases that are more potent as warming agents than carbon dioxide, it is important to assess these emissions. In the case of natural gas, the prime gas emitted throughout the lifecycle prior to combustion is methane. This is because natural gas is some 90% methane, this gas leaks (called fugitive emissions), and methane is some 86 times more powerful than carbon dioxide as a global warming agent on a 20-year basis and some 34 times worse on a 100-year basis. Assuredly, natural gas companies would prefer that leakage does not happen, but they have seemed been unable to stop the phenomenon. While the claim that fossil gas is 'the clean fossil fuel' may have persuaded many folks that this gas is clean, it most profoundly is not (https://socan.eco/fossil-gas/)! While new extraction facilities and new pipelines may well result in fewer leaks than aging structures, the reality is that every new structure ages. With an expected life span of up to 50 years ((e.g. WILLIAMS TRANSCO CENTRAL PENN LINE SOUTH: A CITIZEN'S GUIDE), it is inevitable that pipelines will age and leakage will increase. Regrettably, the fugitive emissions of methane over the fossil gas lifecycle negate combustion benefits of this fuel compared to coal and oil. A study of emissions from natural gas versus electricity in California revealed: "The largest driver of greenhouse gas emissions savings in all-electric buildings comes from eliminating carbon dioxide emissions from natural gas combustion." (Mahone et al. 2019).

Even if we forget the lifecycle emissions that result from natural gas extraction, processing and transmission, and focus only on the emissions of greenhouse gases during the end use and in the generation of electricity (https://en.wikipedia.org/wiki/List_of_power_stations_in_Oregon#Natural_gas), we find that these emissions resulted in 10.8 MMT of greenhouse gas emissions in 2019 in Oregon (https://www.oregon.gov/deq/aq/programs/Pages/GHG-Emissions.aspx). This represents over 50% of the emissions from permitted facilities in 2019 and over 20% of total regulated In-Boundary emissions for 2019. There can be little doubt that natural gas is not a solution. The solution offered by the Gas industries is to convert to so-called Renewable Natural Gas. The problems with this are discussed immediately below.

Renewable Natural Gas

Essentially two methods are available for producing the methane that comprises so-called Renewable Natural Gas (RNG): one process realizes a ***synthetic RNG*** product that results from splitting water (H_2O) molecules into hydrogen and oxygen and then inserting the hydrogen into carbon dioxide (CO_2) to produce methane (CH_4) with oxygen as a by-product. The process is energy intensive so this process can only result in a renewable product if the energy source is itself renewable and not a fossil fuel. Note, this is also the mechanism for producing Hydrogen.

The second process involves capturing the methane that results from decomposition of biomass under oxygen free (anaerobic) conditions. The ***biogas*** results from decomposition in an anaerobic digester where bacteria break down the organic matter and release methane. This is what happens in landfills that are covered and sealed. One problem with this is that to produce substantial methane requires a vast amount of decomposing organic matter. However, one advantage of this process over the fracked natural gas alternative is that it requires a sealed environment thus eliminating the leakage that occurs in fracking. However, leakage that occurs during transmission under pressure through pipelines remains, so methane leakage as pipelines age remains a problem. A relatively plentiful source of biogas is the decomposition of manure in Confined Animal Feedlot Operations (CAFOs) so we must beware that reliance on RNG does not become a justification for expanding the development of this unfortunate industry.

The main environmental concerns regarding RNG are availability, cost, carbon intensity, and industry obfuscation as discussed briefly here: The Four Fatal Flaws of Renewable Natural Gas. Meanwhile, a recent 2020 report revealed: "RNG is not inherently climate friendly. Based on consideration of both the source of methane used to produce RNG and the likely alternative fate of that methane, and using reasonable assumptions about likely system methane leakage, it is unlikely that an RNG system could deliver GHG negative, or even zero GHG, energy at scale."

The bottom line with RNG is that it should not be considered a renewable solution unless its production and transmission result in net zero emissions, it is sufficiently available to replace natural gas, and that it is cost effective compared to genuine renewable energy sources. However, Mahone et al (2018) report that, for California: "RNG faces large technical obstacles. Biomethane supplies within California are limited, and on their own fall short of meeting the long-term demand for low-carbon gaseous fuel in the state's buildings and industries, without electrification." If RNG is insufficient for replacing natural gas in California, is there any reason to think Oregon is different?

Threshold for Fuel Suppliers

In discussing the threshold for inclusion of fuel suppliers in the program, DEQ offered 300,000 MT accounting for 86% of emissions, 25,000 MT accounting for 99% of emissions and 5,000 MT accounting for 99.8% of emissions as potential values. Unfortunately, 300,000 should simply not even be considered (see below) since it would blow the EO 2050 target.

Given the comments by a fossil fuel apologist about the likelihood of fuel suppliers simply gaming the system to keep their emissions below whatever threshold is applied, I have come around to the position that the threshold should be as close to zero as possible to allow an exemption for *de minimus* emitters.

What the calculation presented below reveal is that the Climate Protection Plan simply cannot allow any further exemptions of any meaningful capacity if the Governor's Executive Order 2050 goal is to be within range

The DEQ 'leaning' regarding electrical utilities.

As we know, the Department of Environmental Quality is developing a Climate Protection Plan designed to address the Executive Order 20-04 signed by Governor Brown in March. 2020.

This order charges state agencies with reducing greenhouse gas emissions in Oregon at least 45% below 1990 levels by 2035, and at least 80% below by 2050. It is inevitable that, in order to achieve the interim target and final goal, the agencies will be obliged to achieve reduction of emissions within their purview a commensurate amount.

When the agencies began their discussions last year of how to develop a response to the charge in the EO, I was very impressed, excited and enthusiastic about how DEQ initiated the process. This was generated by the open and transparent nature of the process and the willingness of staff to listen to suggestions. However, as the months have passed, my enthusiasm has waned as the developing program has seemed not only to ignore submitted comments, but also to ignore the interim target and goal stated in the E.O.

Most recently, DEQ has identified as a strong 'leaning' in its proposed Climate Protection Plan exempting the electricity sector. This means that electricity generation facilities fueled by fossil (natural) gas will be exempt from the program. This creates a serious flaw in the program because:

(a) natural gas extraction, processing and transmission result in substantial emissions of the potent greenhouse gas methane thus causing phenomenal leakage of emissions out-of-state (see Fossil Gas Myth above), and

(b) because these facilities themselves (see adjacent table) emit huge amounts of greenhouse gases as CO_2e.

Oregon Natural Gas Electricity Generation		
PGE	Boardman	2543943
Hermiston Power LLC		1700894
PGE	Coyote Springs	1364781
Klamath Cogeneration		1350083
Hermiston Generating CO		1154924
PGE	Carty	1152211
PGE	Port Westward I	1027716
PGE	Beaver	274905
PGE	Port Westward II	186666
Klamath Energy LLC		49,735
TOTAL		10805858

Oregon's estimated total greenhouse gas emissions for 2019 stands at 65 Million metric tons. Of this, as can be seen in the adjacent table from DEQ facility data for 2019, the total emissions from Oregon's natural gas-powered generation facilities are 10,805,858 MT of carbon dioxide equivalent greenhouse gases. This amounts to 51% of source emissions for which DEQ issues permits and nearly 17% of the state's total emissions. This, alone, should indicate we cannot afford **not** to cap and reduce these emissions.

Notably, total GHG emission for 1990 are listed by DEQ at 58 MMT. If the state is to achieve emissions 80% below the 1990 level, that target is 11.6 MMT. If the 2050 goal is to be taken seriously, clearly the electricity sector exemption suggested by DEQ means there is almost no opportunity to exempt any other emitters beyond that sector.

Unfortunately, in considering the threshold for inclusion in the fuel supplier emissions, DEQ offered as an option the following cut-offs: 300,000 MT which would address 86% of emissions; 25,000 MT which would address 99% of emissions; and 5,000 MT addressing 99.8% of emissions. Given that the total for 2019 emissions from fuel suppliers is listed at 24.1 MMT, this means these cut-offs would respectively add to annual emissions 3.74 MMT, 0.241 MMT, and 0.0482 MMT.

Mathematically, the 300,000 MT cut-off is simply not an option since that, added to the natural gas facility emissions exemption of 10.81 MMT, would result in some 14.12 MMT of emissions and blow through the 2050 goal by over 2.5 MMT. This would render the EO goal completely unachievable regardless of what any other agency achieves.

Furthermore, this calculation does not even account for the fact that the drive to electrification, which is most valuable if that electricity is generated from renewable energy sources, will cause an increase in demand that, absent DEQ regulation, will likely be met by the utilities increasing their fossil gas usage rather than turning to renewable energy sources.

I have been engaged in advocacy for climate action for some three decades. I was alerted to the threat posed by global warming projections when teaching ecology at Southeast Missouri State University. While teaching a segment on community ecology - i.e., the factors of temperature and precipitation that determine the distribution of natural ecosystems (forests, woodlands, grassland, deserts, wetlands, tundra) across the globe, I realized that the projections at the time would devastate these ecosystems and the biodiversity of flora and fauna they comprise. We have since seen a massive increase in extinctions, confirming that fear. Incidentally, our agriculture, forestry, and fisheries are dependent on the same factors. If we do not collectively reduce our greenhouse gas emissions and remove a substantial percentage of those already released, we will confront an existential crisis. This is urgent. Anyone who is not alarmed, is simply not paying attention. We owe it to our children and grandchildren - if we care about them - to take this seriously. Oregon should do its part to reduce and remove greenhouse gases.

We urge the state DEQ to take seriously the interim target and goal identified in the Governor's EO. This would at least mean eliminating from consideration the 300,000 MT threshold for fuel suppliers. However, more importantly, it should mean rejecting the DEQ 'leaning' towards exempting the electricity sector. Thus, natural gas-powered electricity generation facilities would be included in the program and be required to reduce emissions.

Sincerely,

Alan R.P. Journet

Alan R.P. Journet

Co-Facilitator
Southern Oregon Climate Action Now

3/26/2021

Richard Whitman, Director
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232-4100

Re: Climate Scientists and Experts Support an Ambitious Oregon Climate Protection Program

Dear Director Whitman,

We the undersigned climate scientists, public health professionals, and air quality experts are writing to urge the Department of Environmental Quality (DEQ) to adopt an ambitious Climate Protection Program. DEQ has a unique opportunity to decarbonize the state while holding emitters accountable for their global warming pollution. **We urge you to make the commitment to a cleaner and safer future for Oregon.**

The science is clear. Avoiding the worst consequences of climate change requires us as a globe to make deep emissions reductions in the next decade, and Oregon must do its part. The consequences of inaction are already being felt by Oregonians. Last year's wildfires were devastating, burning over a million acres across the state[1]. Sea levels along the Oregon coast have already risen by 2-4 inches since the 1980s[2]. And climate models project annual average temperatures will rise by 5°F to 8.5°F in the Pacific Northwest if we continue to emit heat-trapping gases[3]. Allowing the state to continue down this path risks a future plagued by extreme heat, severe flooding, and the displacement of thousands of Oregonians from their homes.

We would like to make three key recommendations regarding the program.

- **Establish an Ambitious Emission Reduction Target –** Governor Kate Brown's Executive Order 20-04 recognized the urgency of rapid decarbonization when it established a goal of an 80 percent reduction below 1990 levels by 2050. Oregon's Climate Protection Program must, at a minimum, match that commitment. DEQ should strive to go further than this baseline and ought to reduce emissions at a trajectory consistent with a national path to net-zero by 2050, consistent with the US contribution to the global emissions reductions the best available science concludes will be necessary to stay well below a 2°C increase in global average temperature above pre-industrial levels.
- **Prioritize Early Reductions –** The importance of frontloading emissions reductions is critical. DEQ must commit to EO 20-04's goal of at least a 45 percent reduction below 1990 levels by 2035 and should develop a regulation that also ensures deep reductions in the next decade. We in the scientific community have been clear about the importance of meeting interim reduction targets. These benchmarks, articulated clearly in the IPCC 1.5 report, are critical to meeting our climate goals. Focusing only on the mid-century reduction target is simply insufficient.
- **Avoid Disproportionate Impacts to Frontline Communities** – The program – particularly the way it structures alternate compliance flexibility for regulated polluters – must benefit environmental justice and low-income communities. Particular attention should be paid to

[1] Oregon Department of Forestry. 2020. ODF fire report for Monday, Oct. 12, 2020. Online at https://odfwildfire.wpengine.com/2020/10/12/odf-fire-situation-report-for-monday-oct-12/

[2] National Oceanic and Atmospheric Administration (NOAA). No date. Level trends. Online at https://tidesandcurrents.noaa.gov/sltrends, accessed December 13, 2018.

[3] Vose, R.S., D.R. Easterling, K.E. Kunkel, A.N. LeGrande, and M.F. Wehner. 2017. Temperature changes in the United States. In Climate science special report: Fourth National Climate Assessment, volume I, edited by D.J. Wuebbles, D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock. Washington, DC: US Global Change Research Program. Online at http://doi.org/10.7930/J0N29V45

avoiding regressive energy costs and driving down the emission of harmful co-pollutants which have historically burdened low-income households, tribes, and communities of color in Oregon[4]. DEQ ought to work closely with frontline and rural communities whose livelihoods are based on natural resource extraction and management. The time is now to build a broader coalition.

Thank you for considering our views on the Climate Protection Program. We appreciate your continued work to reduce emissions in Oregon and hope you share our vision for a strong and ambitious Climate Protection Program. We urge you to set Oregon on a course to a cleaner future and a safer climate.

Sincerely,

Institutional affiliations are listed for identification purposes only, and do not imply endorsement of the letter by those institutions. All signers are scientists and experts who live or work in Oregon and have expertise relevant to our understanding of climate change, its impacts, or solutions.

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Edward Kushner, Ph.D.
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Air Pollution

Frank Lippy, M.D.
Medical Research

Gabrielle Roesch-McNally, Ph.D.
National Climate Assessment Author
500 Women Scientists

[4] Oregon Health Authority. 2020. Climate and health in Oregon 2020 report. OR: Oregon Health Authority Public Health Division. Online at https://www.oregon.gov/oha/PH/HEALTHYENVIRONMENTS/CLIMATECHANGE/Documents/2020/Climate%20and%20Health%20in%20Oregon%202020%20-%20Full%20Report.pdf

From: John Hillock <john@enterprise-electric.com>
Sent: Wednesday, March 24, 2021 9:18 AM
To: Nicole.Singh@state.or.us
Subject: forestry

CCI should help fund community forest see page 6 section 2 2.3

https://static1.squarespace.com/static/59c554e0f09ca40655ea6eb0/t/5a0a11544192029150c0ec8d/1510609238223/2020+Roadmap+Forestry.pdf

DIRECTIVE TO THE OREGON GLOBAL WARMING COMMISSION ON NATURAL AND WORKING LANDS:

"In coordination with the Oregon Department of Agriculture, Oregon Department of Forestry and Oregon Watershed Enhancement Board, the Oregon Global Warming Commission is directed to submit a proposal to the Governor for consideration of adoption of state goals for carbon sequestration and storage by Oregon's natural and working landscapes, including forests, wetlands and agricultural lands, based on best available science. The proposal shall be submitted no later than June 30, 2021." See full Executive Order 20-04 here.

Working lands/ community forest are the best solution to climate change for Eastern Oregon, Community ownership could Enhance these investment creating jobs and protecting water sheds.

Commissioner Hillock

March 26, 2021

Oregon Department of Environmental Quality
Office of Greenhouse Gas Programs
700 NE Multnomah St., Suite 600
Portland, OR 97232

Re: WSPA Comments on DEQ Cap and Reduce RAC Meeting #3

Western States Petroleum Association (WSPA) is a trade association that proudly represents companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas, and other energy supplies in Oregon and four other western states.

The way the world produces and consumes energy is evolving. And the members of WSPA are on the cutting edge of those changes, investing in and developing the affordable, reliable, and ever cleaner energy sources and technologies of the future. We believe that, working together, we can rise to the challenge of a changing climate. As such, we appreciate the opportunity to comment DEQ's third RAC meeting on the proposed cap-and-reduce program.

Community Compliance Instruments

On several occasions, we have commented on the need to ensure there is an adequate pathway to compliance (beyond the state forcing a constraint on fuel supplies). We want to continue to underscore the importance of creating a viable and adequate means of compliance.

We believe that developing a pool of Community Compliance Instruments (CCIs) could be a step in the right direction, and we would encourage DEQ to consider allowing for a high percentage of compliance through the CCI mechanism. The modeling of 5-25% will be informative, but it will be important to understand the maximum percentage allowable earlier in the RAC process versus later in rulemaking process. The two key variables for consideration are percentage and price.

However, we note that DEQ should also exercise caution in developing this mechanism, as it will be vital that the state can demonstrate that emission reductions associated with CCI projects are additive and cost-effective.

- ***Emission Reductions Should Be Additive.*** Existing state and federal programs currently focus on reducing emissions in Oregon's disadvantaged communities.

For example, the federal LIHEAP program which funds a portion of Oregon's Energy and Weatherization program (under the Oregon Housing and Community Services) serves to reduce GHG emissions in low-income communities. Therefore, it would be inappropriate for CCI projects to fund these types of projects unless it is determined that additional funding could be leveraged for additional GHG benefit. But the key is to ensure that the benefit would be additive and that CCI projects would not "crowd out" already existing programs.

- ***CCI Projects Should Be Cost-Effective***. In evaluating CCI projects, DEQ should develop and adhere to a cost-effectiveness evaluation as a mechanism for providing cost containment.
- ***CCIs Should Have Well-Defined Price Structure.*** There was minimal discussion on how the price of a CCI credit will be determined. That will be critical to our evaluation of the feasibility and effectiveness of this compliance option. We recommend that be discussed and established early in the RAC process.

Threshold for Inclusion

DEQ's working paper lays out an explanation for excluding smaller fuel providers below a de minimis threshold. While we would typically argue in favor of streamlining and reducing administrative burden, in this case WSPA finds it necessary to flag some serious concerns.

First, by setting the threshold at a high value, DEQ would, at best, be encouraging fuel shuffling which does not result in any emissions reductions, but in this case may likely result in no longer capturing some emissions that would have been "caught" otherwise. The environmental impact of doing so is not minimal. Second, the current system of delivery via the Cascadia pipeline is more efficient from a GHG perspective than the alternative which likely mean increased truck trips and VMT. Lastly, as suggested by some stakeholders, this type of structure could inadvertently incentivize smaller fuel suppliers to game the system. Ultimately, if that were to occur, it could result in additional truck trips and VMT across the border. As part of its analysis, DEQ should consider what the unintended environmental consequences could be of such an arrangement.

Scenario Modeling

DEQ made an assumption in their scenario modeling that in all three scenarios, adequate supply of compliance instruments would be available to the market, up to the limit allowable. It is unclear how DEQ can make this assumption without proper analysis that demonstrates real-world availability of projects that also includes the cost per metric ton for projects.

Cost Containment

We continue to recommend that DEQ pursue as broad a market as possible in order to somewhat mitigate the potential for volatility. The small market and potential volatility in carbon price underscores the need for strong cost containment elements. The discussed features of banking, trading, multi-year compliance periods and alternative compliance instruments may help but could ultimately prove insufficient. We recommend consideration of other design features such as access to offset registries and price triggers where, if the market price (e.g. a transparent trading price for compliance credits) reaches assigned price points, it would trigger program adjustments. Such features could soften the impact on Oregon consumers. Similar features exist in Oregon's Clean Fuels Program.

Thank you again for the opportunity to comment. If you have any questions, please feel free to contact me at troberts@wspa.org. We look forward to meeting with you to further discuss these ideas and welcome an open dialogue with you.

Sincerely,

Tiffany Krista Roberts

Tiffany Roberts
VICE PRESIDENT, REGULATORY AFFAIRS
WSPA