State of Oregon Department of Environmental Quality

Written Comments

Sept. 24 2020, Clean Fuels Program Electricity 2021 Rulemaking Advisory Committee Meeting

Commenters

ACT Commodities

Center for Resource Solutions

Oregon Municipal Electric Utilities

Association Port of Portland

Commentary on Oregon's CFS Electrification Discussion Paper

1 October 2020

By ACT Commodities

Introduction

As a member of IETA (International Emission Trading Association), ACT Commodities (ACT) is a global leader in trading energy and environmental commodities. We provide solutions to over 5000 clients worldwide who need to meet environmental compliance requirements and voluntary sustainability goals. Over the past decade, ACT has developed its knowledge on the global carbon market, including emission trading mechanisms in Europe, South America, Africa, Asia, and voluntary standards such as the Verified Carbon Standard (Verra). In North America, ACT is a leader in renewable energy certificates and renewable fuels credit markets. ACT is active in the Oregon RPS and CFS and even more so in California's RPS and LCFS as well as the Federal Renewable Fuels Standard.

ACT would like to take this opportunity to comment on the **Clean Fuels Program Electricity 2021 Rulemaking Discussion Paper**, released in September 2020. Please see comments below:

Increasing the frequency of residential Electric Vehicle (EV) crediting (1.1)

ACT supports the efforts to accelerate the issuance of electric vehicle CFS credits from once a year to a minimum of twice annually. ACT further supports a quarterly issuance especially upon the inclusion of incremental credits. For example, consider the cash-flow constraints of smaller entities which hope to participate in the added benefits of REC retirement but are hesitant since they cannot reliably recover the cost until the resulting CFS credits have been issued and sold.

Directing revenue from the sale of electricity credits (1.2)

ACT understands the importance of such guidelines as it pertains to the reliability of the program. However, ACT cautions DEQ from conforming all entities to specified allowable uses for expenditures. While ACT believes this is fit for utilities, residential, and base crediting, innovation (i.e. incremental, smart-charging) beyond a baseline should not be limited to certain entities or reinvestment opportunities. There is legitimate concern some stations/networks could look at restrictions as another barrier for entry.

Incremental credits (1.3)

ACT strongly supports the inclusion of incremental crediting provisions. It is a direct pathway to promote the low carbon fuel transition and transportation electrification.

Adopting new EERs (2.1) / Administrative process to adopt EERs (2.2)

ACT is supportive of the new eOGV and eCHE EERs proposed in this amendment. Additionally, ACT agrees that an administrative, non-rulemaking, and non-individual EER adjusted CI, is the preferred solution to accommodate emerging technologies reliably and timely.

Adjusting what constitutes the statewide grid mix (3.1.2)

The current statewide grid carbon intensity does not reflect the reality of the life-cycle carbon intensity of electricity in non-utility specific CI regions of the state. For this reason, ACT is of the opinion that the DEQ must amend the current strategy for assessing the statewide carbon intensity as suggested in this amendment. If it is not corrected the CFS is effectively creating incentives for heavy emitting regions much like if a highly carbon intensive liquid fuel plant was able to default to the average carbon intensity of their industry. By removing utility-specific load from the statewide mix the CFS will correctly reflect credit generation capabilities for the fuel source.

Elise Miller

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Allowing for non-contiguous renewable electricity (3.2)

Along with incremental crediting ACT backs the concept of non-contiguous renewable electricity permitting. REC retirement is a mainstream and reliable way to audit the consumption of renewable energy. Including this mechanism in the amendment will accomplish the goal of accelerating the generation and aggregation of clean fuel credits.

Which sources of renewable electricity should be eligible? (3.2.1)

ACT supports categorically eligible zero carbon sources (i.e. wind, solar photovoltaic and solar thermal electricity, wave, tidal, small hydro, ocean thermal electricity, and geothermal) to be considered as look-up table pathways. ACT further suggests geographic eligibility to be limited to power delivered to the Bonneville Power Administration (BPA) service territory as BPA is a reliable reference for all Pacific Northwest electric service areas.

Should there be a limit to the temporal eligibility of renewable electricity? (3.2.2)

ACT recommends a timespan of 2 years to claim that electricity generated was retired for a dispensed MWh at an EV station. Since that temporal limitation may not align with existing green tariffs ACT does not recommend their inclusion as an eligible mechanism for incremental credit generation. Furthermore, ACT cautions against limiting a generator's start date as there is no comparable restraint on liquid fuel producers.

Who should be eligible to claim that renewable electricity is going into an EV? (3.2.3)

ACT challenges DEQ to consider allowing third-parties to assist EV charging stations/networks for incremental crediting purposes. Not all EV charging stations are participants in established statewide REC markets like the RPS which can be a barrier to entry and reliable pricing. For that reason ACT proposed that EV stations/networks can designate a third party to manage incremental crediting. Third parties can retire RECs in a designated WREGIS account for the EV station/network in accordance with the exact MWh dispensed. While the network/station itself can benefit from the revenue of base credits all participating parties in the value chain should have a share of added revenue opportunities for retiring RECs on behalf of MWh dispensed in a vehicle. Furthermore, third parties reliably enhance competition and prevent monopolistic markets from forming. Private business contracts will establish a fair market price for renewable energy producers, liquidity providers, and stations. ACT is proposing a similar structure adopted by Bio-CNG/LNG contracts already operating in CFS programs.

Advanced Crediting (4.1)

ACT is encouraged by the DEQ's innovation as it pertains to the advanced crediting provision. As we know the hurdle of initial investment is a universal obstacle to alternative fuel adoption and for that reason ACT proposes the broad inclusion of private, public, small, and large fleets. However, to ensure stability in the credit market ACT proposes there is a cap to available advanced credits annually. ACT also encourages the DEQ to remain technology neutral and expand the advanced crediting opportunities to all zero emission fuel pathways including electricity, hydrogen, and bio-CNG/LNG. Any guidelines should specify the requirement of fueling with a 0 gCO_2e/MJ or negative fuel source for the entirety of the 'payback period". This will ensure the technology neutral promotion of clean fuels in the state.

Conclusion

The DEQ is poised to accomplish the directive set out by Governor Kate Brown's Executive Order 20-04. Although there are various resolutions to the questions proposed ACT believes this commentary aligns with the goals set out by Senate Bill 1044. ACT has also used this opportunity to remind the DEQ to make decisions that uphold the technology-neutral stance adopted at the onset of the Program.

Finally, ACT reiterates the inclusion of third parties to provide services and relieve barriers of entry for smaller entities. Allowing EV stations/networks to outsource incremental credit generation to a third-party REC source will limit disruptions to existing renewable electricity markets and support the market-based approach already adopted by Bio-CNG/LNG pathways.

Elise Miller

October 2, 2020

Cory Ann Wind
Oregon Department of Environmental Quality (DEQ)
700 NE Multnomah Street, Suite 600
Portland, OR 97232-4100

RE: COMMENTS OF CENTER FOR RESOURCE SOLUTIONS (CRS) ON THE RULEMAKING ADVISORY COMMITTEE #1 DISCUSSION PAPER FOR THE SEPTEMBER 24, 2020 ADVISORY COMMITTEE MEETING FOR THE CLEAN FUELS PROGRAM ELECTRICITY 2021 RULEMAKING

Dear Ms. Wind:

CRS appreciates this opportunity to submit comments on the *Rulemaking Advisory Committee #1 Discussion Paper* ("Discussion Paper") for the September 24, 2020 Rulemaking Advisory Committee (RAC) Meeting #1 ("September 24 Meeting") as a part of The Clean Fuels Program (CFP) Electricity 2021 Rulemaking. Our comments are organized by topic area below. We also provide responses to consultation questions in the Discussion Paper and discussion questions from the September 24 Meeting.

BACKGROUND ON CRS AND GREEN-E®

CRS is a 501(c)(3) nonprofit organization that creates policy and market solutions to advance sustainable energy. CRS provides technical guidance to policymakers and regulators at different levels on renewable energy policy design, accounting, tracking and verification, market interactions, and consumer protection. CRS also administers the Green-e® programs. For over 20 years, Green-e® has been the leading independent certification for voluntary renewable electricity products in North America. In 2018, Green-e® certified retail sales of over 62 million megawatt-hours (MWh), serving over 1.2 million retail purchasers of Green-e® certified renewable energy, including 61,000 businesses.[1]

[1] See the 2019 (2018 Data) Green-e® Verification Report here for more information: https://resource-solutions.org/g2019/.

COMMENTS

<u>Expansion of the CFP to include utility green tariff programs and renewable energy credits (RECs)</u>

1. The CFP should allow electric vehicles (EVs) to charge with renewable electricity through utility green tariff programs and the retirement of RECs.

Clean transportation markets present opportunities to dramatically grow green power markets and demand for green power from EV users while also transforming the transportation sector. This change would provide renewable generators and suppliers access to this new market and potentially increase the importance of EV crediting and electrification as a compliance pathway under the CFP, which may provide substantial benefits over the next best alternative transportation fuel option.

2. Additional requirements and verification procedures should be added to protect against double counting onsite behind the meter (BTM) renewable energy (RE).

Whereas the CFP currently recognizes onsite BTM RE at the charging station for non-residential EV charging, it is our understanding that REC retirement for this generation is only required and verified where the facilities are registered in the Western Renewable Energy Generation Information System (WREGIS). However, since most of these facilities will not be so registered due to their size, we recommend that additional requirements be added and verification performed to ensure that RE attributes (i.e. RECs) are retained in perpetuity by these facilities. At the very least, DEQ could require an attestation to that effect by facility owners.

<u>Calculating the statewide and utility-specific mixes</u>

3. CRS supports the existing use of utility-specific mixes to determine the carbon intensity (CI) of electricity used to charge EVs for CFP crediting, and the proposal to adjust the statewide grid mix and CI to exclude energy and emissions associated with the utilities that have opted to use utility-specific CIs.

Adjusting the existing policy in line with this proposal will result in a more precise calculation of reductions and CFP credits for EV charging. The CFP accounts for greenhouse gas (GHG) emissions delivered to EV load. These emissions can be calculated using either "location-based" or "market-based" accounting—where market-based accounting reflects contractual use and purchasing of specified generation, including the use of RECs for RE, and location-based accounting does not.[2] California's Low-carbon Fuel Standard (LCFS) uses a location-based grid average but then allows for market-based

[2] For further discussion, see Sotos, M. (2015) *GHG Protocol Scope 2 Guidance: An Amendment to the GHG Protocol Corporate Standard*. World Resources Institute. Available online: http://www.wri.org/sites/default/files/Scope_2_Guidance_Final.pdf.

purchasing of RE. It makes more sense to use retail sales data instead of total system generation and to allow utility-specific mixes if other market-based adjustments (e.g. purchasing RE) can be made. And it would also make sense to adjust the regional grid average to remove utility-specific mixes that are used (i.e. to avoid double counting in the CFP calculations) as a preferable alternative to grid averages.

4. Additional improvements should be made to utility-specific CIs used for crediting to further increase precision, including using residual mix and product-specific emissions factors.

The CFP should require that all voluntary sales be removed from both utility-specific CIs and the grid average in order to estimate "residual mix" emissions factors, to avoid double counting overall. More generally, the utility-specific CIs should be adjusted to be product-specific or at least represent the default or standard product mix. Currently, utility-specific CIs represent total retail sales—total tons over total megawatt-hours (MWh) served—which does not represent the mix or emissions factor actually used by any individual customer.

5. CRS recommends the specification of a standardized methodology for calculating utility-specific CIs, beyond DEQ's GHG Reporting Program and the guidance documents available on the CFP website.[3]

Again, utility-specific CIs calculated per DEQ's GHG Reporting Program do not necessarily represent the electricity contractually delivered to individual customers. It is not clear, for example, how RECs are treated in the calculations and whether RE included has been contractually delivered to serve retail load. The CFP can consider, for example, either developing a methodology or accepting rates calculated in conformance with and verified against The Climate Registry's (TCR's) Electric Power Sector (EPS) Protocol[4], which is consistent with the GHG Protocol and ISO 14064-1.

6. Please clarify whether or not the calculation of CFP credits for EV charging represents the assignment of attributes (e.g. a resource mix and emissions factor) to the power and a retail usage claim for the EV user.

DEQ's use of an adjusted grid average, a residual mix, or utility-specific mixes to estimate the CI of delivered electricity as a part of EV crediting in the CFP may be understood to represent the assignment of attributes to delivered power, such that the EV user may claim to be receiving electricity with those attributes (from a certain mix of sources or with a certain emissions rate). Alternatively, DEQ's use of these mixes and rates may simply be a part of a calculation to estimate emissions reductions associated with using an EV instead of a gas-powered vehicle. The difference is important for retail customers in Oregon, RE markets, and participants in the CFP. If DEQ is assigning attributes,

[3] See https://www.oregon.gov/deq/ghgp/cfp/Pages/Guidance-Documents.aspx.
[4] See https://www.theclimateregistry.org/tools-resources/reporting-protocols/electric-power-sector-protocol/.

then, for example, the issuance of base credits (for grid average electricity for residential charging) would mean that that charging cannot also be assigned to load participating in a green power program—i.e. the same load cannot be met with both the grid mix and RE. And in this case, the use of more precise emissions factors (representing residual and product-specific mixes, see comment no. 4 above) becomes even more important. However, if DEQ's estimation of the difference in emissions between a car powered with electricity vs. gasoline is not an assignment of attributes or a usage claim per se, then issuance of base credits would not conflict with an EV user's claim to 100% RE through a utility program that is not participating in the CFP. California Air Resources Board (CARB) Staff have confirmed that their estimation methods for the emissions associated with electricity used as a transportation fuel under the LCFS do not represent a retail usage claim or claim on the attributes.[5]

REC eligibility

7. CRS recommends further explanation and specificity regarding the proposal that, "RECs used under this provision or by an eligible green tariff would need to be in addition to any other requirement or program."[6]

Please clarify: additional to which programs? Is DEQ referring to regulatory programs only, or also voluntary programs? Does this also mean additional to RE that is certified by the Green-e® program?

For example, CARB has a similar requirement for the Voluntary Renewable Energy Program (VREP) under the state's cap-and-trade program, which prohibits claims on the renewable electricity or the use of RECs in any other voluntary or mandatory program, and which is referenced by the LCFS program.[7] However, CARB has recognized the distinction between having RE certified using a program like Green-e® vs. using the RE for a separate program. It considers the Green-e® program to be a part of the same "use" for voluntary RE purposes as the VREP. As a result, Green-e® certified RE may be used in the VREP.

Clarification from DEQ on this question—eligibility or ineligibility in other programs—may have other implications for the Green-e® program, however. For example, RECs used for the VREP under cap-and-trade in California cannot be used for the LCFS,[8] indirectly making those RECs ineligible for the Green-e® program (except for certain 100% renewable electricity products[9]). It may have implications for other programs as well. For example, the California Energy Commission (CEC) has determined that publicly

[5] Phone conversation with CARB Staff on January 16, 2020.
[6] Discussion Paper, pg. 8.
[7] See Section 95841.1(b)(1)(E) of the Cap-and-Trade Regulation in Title 17, CCR, and April 2019 LCFS Guidance 19-01 for Book-and-Claim Accounting for Low-CI Electricity, https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/guidance/lcfsguidance_19-01.pdf.
[8] See April 2019 LCFS Guidance 19-01**.**
[9] See https://www.green-e.org/news/062019 and Sec. IV.C1.9 of the Green-e® Energy Code of Conduct.

owned utilities (POUs) cannot exclude voluntary RE sales from Renewable Portfolio Standard (RPS) compliance obligations if that RE is used for the LCFS.[10]

Among other things, DEQ should specify the REC retirement requirements for the CFP. This alone may determine how those RECs may be used in other programs.

Regarding other potential requirements and limitations on REC eligibility, please see responses to consultation and discussion questions below.

<u>REC vintage</u>

8. A proposal to limit the vintage of eligible RECs to those generated within three quarters of when the EV charging occurs (i.e. an 18-month REC vintage window) may require an adjustment to the current CFP reporting and credit issuance schedule.

While individual utilities may find a "within three quarters" REC vintage requirement to be challenging based on their individual circumstances, in general, it would simply require that customers and utilities monitor their REC purchases, require specific vintages, and perhaps engage in quarterly reconciliation of RECs for EV charging.

However, it may require adjustments to current reporting and compliance deadlines, considering the time it takes for RECs to be issued in WREGIS, which is typically 90 days (or one quarter). Based on current issuance of CFP credits in the first quarter of the year for the prior year,[11] a "within three quarters" vintage requirement would effectively allow RECs that are up to three quarters old, but RECs with a vintage that is three quarters after charging occurs could only be used for first quarter EV charging. For charging in any other quarter, CFP credit issuance would occur before three quarters in the future. And for fourth quarter EV charging, participants would have to use entirely past-vintage RECs (a three quarter or 9-month vintage window)—current and future vintage RECs could not be used for fourth quarter charging.

In general, we suggest that DEQ seek to align reporting and vintage requirements with other existing RE programs, e.g. the Green-e® program's 21-month vintage window and June 1st annual reporting deadline, to reduce complexity for program participants.

[10] See Section 3204(b)(9) on p.19 of the Second 15-Day Language Modification of Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities: https://efiling.energy.ca.gov/GetDocument.aspx?tn=234349&DocumentContentId=67208.
[11] Discussion Paper, pg. 2.

Incremental credits for EV charging with RE

9. CRS generally supports the introduction of "incremental" credits for *residential* EV charging with RE or low-CI electricity, representing, "the delta between the CI of the renewable electricity versus the statewide grid mix."[12]

However, it is not clear from the Discussion Paper or the presentation slides from the September 24 Meeting if these incremental credits would only be for residential EV charging, as is the case, for example, in California's LCFS. If DEQ is proposing to introduce incremental credits for non-residential EV charging as well, please explain the benefits of that approach over simply awarding additional CFP credit to the same entity for non-residential charging with a lower CI. Furthermore, if DEQ proposes to issue incremental credits for residential charging only to the same utilities that can currently receive credits for residential EV charging (see comments related to credit ownership structure below), then incremental credits may not be needed for residential charging either. Again, additional credit may simply be awarded to the utility. Incremental credits are helpful to the extent that different entities may receive base versus incremental credits, which would be the case if entities other that the utility may earn incremental credits for EV charging with RE, e.g. retiring RECs.

Credit ownership structure for EV charging with RE in the CFP

10. CRS generally supports a credit ownership structure that is similar to the California LCFS program, as described in Sec. 3.2.3 of the Discussion Paper.

CRS does not see the need to change the credit ownership structure for non-residential charging. If incremental credits are introduced for residential EV charging with low-CI electricity, then the credit ownership hierarchy (based on data quality) that is used in California and described in Sec. 3.2.3 of the Discussion Paper is a reasonable and consistent approach.

Directing revenue from the sale of electricity credits

11. CRS supports the inclusion of a new requirement that revenue from selling residential EV credits should be used to promote transportation electrification and benefit current or future EV drivers. We recommend that DEQ provide guidance on what uses and activities meet this requirement that is more specific than California's guidance for its LCFS program.[13]

This requirement will help ensure that EV customers in Oregon are supporting compliance under the CFP, rather than subsidizing it. Compliance entities should be paying for EV use to comply with the

[12] *Ibid*, pg. 3.
[13] See March 2020 LCFS Guidance 20-03**.**

CFP, rather than a situation in which EV users are paying to generate compliance credits and the utility receives a windfall. The requirement that EV credit revenue should benefit current or future EV drivers should apply to revenue from both base credits and incremental credits, and it should apply not only to utilities but to other entities receiving potential incremental credits for residential charging as well.

CRS recommends that DEQ provides a more specific list of activities that would meet the electricity credit proceeds spending requirement, rather than broader principles for revenue spending or California's non-exhaustive list of examples. This will facilitate enforcement of the requirement.

<u>Incremental crediting for smart charging</u>

12. Introducing use of hourly grid mix data for crediting for smart charging may cause some confusion, particularly around the question of customer claims, and present other data availability and accounting challenges.

The availability of hourly data is uncertain. California allows reporting entities to apply for a smart charging pathway, where they have the ability to do submetering at the hourly level, for residential crediting. However, ideally, DEQ would require use of hourly residual mixes or retail mixes to avoid double counting, which may be even farther off than either consistent hourly data or annual regional residual mixes. See comment no. 4 above. In addition, this would allow for crediting based on both hourly (for smart charging) and annual matching of RE generation to load (using RE/RECs) in the CFP. This is confusing, especially if crediting represents an assignment of attributes (see comment no. 6 above).

<u>A voluntary green power EV option in Oregon, disclosure, and compensation</u>

13. DEQ can consider creating an opportunity for EV customers using RE to "opt out" of the CFP or keep the credits associated with their charging in order to preserve regulatory surplus and produce benefits outside of the CFP.

Unless there is commercial EV charging that is not participating in the CFP, all EV charging in Oregon supports the CFP, which lowers emissions in the transportation sector. There does not appear to be a way for non-commercial EV owners in Oregon to "opt out" of the CFP by acquiring or otherwise preventing credits associated with their charging from being used to meet CFP requirements. As a result, EV charging in Oregon does not reduce emissions beyond what the CFP already requires. If these emissions reductions did not come from EV customers in Oregon, fuel producers would need to create or acquire them from somewhere else in the sector under the law. EV charging does not move the needle in that respect. This may not align with consumers' expectations.

Under proposed changes, electricity suppliers, charging stations, vehicle manufacturers, and possibly others can additionally purchase RE for EV charging in order to generate more or incremental credits. EV customers cannot acquire these credits either. It is possible for these entities or the EV customer to purchase green power for EV charging and not use it to generate additional credits—effectively opting out for the additional benefits of using RE. But, EV customers may have little or no say in whether RE is used for the CFP, except by choosing to buy different or more RE for EV charging from a different supplier.

DEQ may consider the benefits of creating a voluntary EV option as a separate driver for electrification and RE for EV use outside of the CFP.

14. Disclosure to EV customers, including those using RE for EV charging, should be sufficient to communicate what the CFP is and the role of the customer's EV in supporting the CFP. Where there are requirements for use of EV credit revenue, this should be disclosed to EV customers as well.

EV customers in Oregon may not be aware that they are supporting the CFP and they may expect that their choice to buy an EV moves the needle on emissions from the transportation sector. At a minimum, they should receive sufficient disclosure about the CFP program, the role of their EV in the CFP and how it affects their environmental impact, and what happens to credits and credit revenue associated with their charging. They should also be informed of how they will be compensated for the environmental benefits that they are creating for fuel producers. Point-of-purchase rebates, for example, that are funded using EV credit revenues should be accurately disclosed as payments for the right to use the EV for compliance with state law.

15. EV customers should be compensated, either directly or indirectly, for the full value of their contributions to the CFP, such that they are in fact selling CFP credits rather than subsidizing CFP compliance for regulated entities.

See comment no. 11 above.

<u>Responses to consultation and discussion questions regarding RE</u>

We have provided brief responses to the questions on pg. 9 of the Discussion Paper below.

Should there be additional requirements for eligible renewable electricity?
It depends on program objectives, but we suggest alignment with existing standards and programs to the extent possible and balancing in-state and regional benefits. See responses below for further discussion of Green-e® certification, geographic restrictions, and vintage requirements.
Should DEQ adopt the definition of renewable electricity used in the state RPS, or is a more narrow definition appropriate?
It is unclear whether DEQ is asking specifically about eligible renewable resource types or other requirements around generation vintage, geographic eligibility, type of RE procurement, etc. See responses further below for discussion of geographic restrictions and vintage requirements. However, in general, we again suggest alignment with existing standards and programs to the extent possible and balancing in-state and regional benefits. Rather than limiting eligibility to certain renewable resource types, all renewable resources and RECs may be eligible and the CI should reflect the actual direct and lifecycle emissions of generation using that resource.
Should eligibility for renewable electricity generators be further restricted to those placed in service following the start of the CFP?
We request further explanation of the rationale and objectives behind such a restriction. Such a restriction is not necessary to accurately calculate the delta between the CI of gasoline vs. the CI of electricity or the delta between the CI of RE vs. the statewide grid mix. Use of existing RE as a transportation fuel delivers emissions reductions in the transportation sector equivalent to those delivered by use of post-2016 RE. However, if it is another objective of the program to drive new development of RE to serve EV charging through CFP crediting, then such a restriction may be justified. We also request some analysis of the benefits of determining that only new RE generators should have access to this new market for RE, in both the electricity and transportation sectors, and whether this restriction would limit use of RE for the CFP overall.
Should RECs only be allowed from renewable generators that deliver power into Oregon or an electricity balancing area that covers at least a portion of the state?
DEQ does not need to limit REC use based on generator location or transaction type (e.g. bundled vs. unbundled RE) to ensure accurate accounting. The attributes of generation (including emissions) are not physically delivered to load. If DEQ has objectives beyond accurate accounting, we suggest balancing in-state and regional benefits and objectives. If necessary, deliverability restrictions would be consistent with California, which requires that RPS Portfolio Content Category (PCC) 1 deliverability requirements be met for all RECs used for its LCFS.

Should DEQ qualify green tariffs for use in the program?
Yes. At a minimum, DEQ should ensure that eligible green tariffs actually deliver RE and retire RECs that meet eligibility requirements. DEQ could potentially reference other RE standards, like the Green-e® Standard, for all or part of a verification process. In California, Green-e® allows certain 100% renewable electricity retail products (in which RECs and energy are sold together) to include a portion of RE generation that is awarded LCFS credits for EV charging. A similar policy could be adopted for Oregon's CFP, in which case Green-e® certified programs used for the CFP would undergo a rigorous verification process. Green-e® could also incorporate additional steps to its verification process for any CFP eligibility requirements. See further discussion of use of the Green-e® program for CFP compliance below.

We have provided brief responses to the questions on slide 37 of the presentation slides from the September 24 Meeting below.

How can we ensure that actual additional reductions are achieved?
True project/activity "additionality" must be tested (using multiple tests) in accordance with best practices for emissions reductions credits (a.k.a. carbon offsets). See established methodologies/protocols used by carbon offset project verification programs for transportation electrification projects, including Verra, the Gold Standard Foundation, the American Carbon Registry, the Climate Action Reserve, as well as methodologies created for the Clean Development Mechanism. However, if DEQ is simply seeking to ensure that emissions reductions in the transportation sector due to use of RE for EV charging under the CFP are incremental to other state policies and voluntary programs, then it can require that RECs used for CFP are not used for other programs and that the RE is either not located in a capped region (e.g. California or potentially Oregon in the future) or, if it is, allowances are retired. It must also ensure that the underlying electricity is not otherwise counted toward state or voluntary RE or carbon targets, and that avoided emissions associated with RE used for the CFP are not otherwise credited, traded, or accounted for. Again, Green-e® certification could help provide these assurances. See further discussion of use of the Green-e® program for CFP compliance below
Who should be able to claim they are delivering renewable power to vehicles?
Legally, only delivery of the REC or REC retirement on behalf of the EV owner for EV load constitutes delivery of renewable power for EV charging.[14] Again, DEQ should clarify whether CFP credit issuance

[14] See Jones, T. *et al*. (2015). *The Legal Basis of Renewable Energy Certificates*. Center for Resource Solutions. https://resource-solutions.org/wp-content/uploads/2015/07/The-Legal-Basis-for-RECs.pdf.
Also see U.S. Federal Trade Commission (FTC). (February 5, 2015). Letter to Sheehey Furlong & Behm P.C. regarding Petition to Investigate Deceptive Trade Practices of Green Mountain Power Company In the Marketing of Renewable Energy to Vermont Customers. p. 3-4. http://blogs2.law.columbia.edu/climate-change-litigation/wp-content/uploads/sites/16/case-documents/2015/20150205_docket-na_letter.pdf

for EV charging with RE (or low-CI electricity) represents a claim on attributes (see comment no. 6 above). If DEQ is simply asking which entity should be able to get CFP credits for EV charging with low-CI electricity, credits should go to the non-residential charging equipment owner, and for residential charging, credits can go to the supplier of the RECs (bundled or unbundled) based on a hierarchy of charging data quality or DEQ can select certain eligible green power and REC providers (e.g. utilities). See comments related to credit ownership structure above.

Does it make sense to require that RECs retired under this provision meet a voluntary standard such as Green-e®?

Possibly. The Green-e® Standard is independent and stakeholder driven, and it is the leading standard for voluntary RE in North America. However, it may only be possible for RECs ultimately used for the CFP to be included in a certified *wholesale* (and voluntary) transaction to reporting entities (e.g. charging station owners, vehicle manufacturers, etc.), depending on a determination by the Green-e® program about whether or not RE/RECs used for Oregon's CFP can be included in a certified retail product. Green-e® certification of wholesale sales of RECs would ensure that they meet the Green-e® Standard and that the wholesale sale is verified, even if they cannot be sold in a Green-e® certified retail product to the end-EV-user. There have been other instances in which state regulatory programs (e.g. state and municipal RPS programs) have similarly recognized wholesale purchasing of voluntary Green-e® certified RE which is later used for RPS compliance (i.e. a non-voluntary retail end-use).

With exceptions, the Green-e® program has historically required that RE used to supply certified products is surplus to regulation. In California, CARB's determination that RE used for the LCFS cannot also be used for the VREP under cap-and-trade, which is required by the Green-e® program, effectively determined that RECs used for the LCFS could not also be Green-e® certified. Without a cap-and-trade program covering the electricity sector in Oregon, the Green-e® program would need to decide if RECs could be used for the CFP.

The Green-e® program has adopted a policy for 100% renewable electricity products (in which RECs and energy are sold together) allowing a portion of RE to be used for the LCFS provided that at least 25% of the product is purely voluntary and not used for compliance and with additional disclosures to the customer.[15] It seems reasonable that the program would adopt the same policy for 100% renewable electricity products sold in Oregon.

Finally, slide 36 of the presentation slides from the September 24 Meeting includes some incorrect information. The Green-e® program includes a 21-month vintage window, and geographic sourcing

Also see OR. ADMIN. R. § 330-160-0015 (16).

[15] See https://www.green-e.org/news/062019 and Sec. IV.C1.9 of the Green-e® Energy Code of Conduct.

restrictions apply only to certified renewable electricity products (in which RECs and energy are sold together), not REC products. The Green-e® program also includes many other requirements that are not shown on the slide. CRS would be happy to assist DEQ with any references to or requirements for Green-e® certification.
Should there be geographic restrictions on what renewable electricity qualifies? Should eligible generators be located in the WECC? In an electricity balancing authority that includes Oregon? In Oregon? The same utility service territory?
See our response to a similar question above. But again, it depends on DEQ's legal authority, the program's objectives, and the balance between in-state and region-wide benefits of electrification and RE generation. The Green-e® program sets geographic sourcing requirements for renewable electricity products (where RECs and energy are sold together)—RE must be sourced from the same grid region as where the customer is located[16]—based on expressed and perceived expectations of stakeholders. These expectations may be different for REC products.
Could utility green tariffs meet a vintage/temporal restriction on when renewable electricity is being generated to meet the zero carbon claim?
It may depend on individual utility circumstances. However, vintage restrictions, e.g. the Green-e® program's 21-month vintage window for annual sales, are standard practice in the voluntary market. "Tighter" vintage restrictions (e.g. the proposed six quarter or 18-month window, limited later in the year by CFP credit issuance) would mean that utilities would need to more carefully monitor REC procurements and it may require monthly or quarterly reconciliation of RECs for EV charging, which may increase administrative burden. See comment no. 8 above for important considerations regarding vintage and reporting/issuance timeframes.

Please let me know if we can provide any further information or answer any other questions.

Sincerely,

______/s/______

Todd Jones

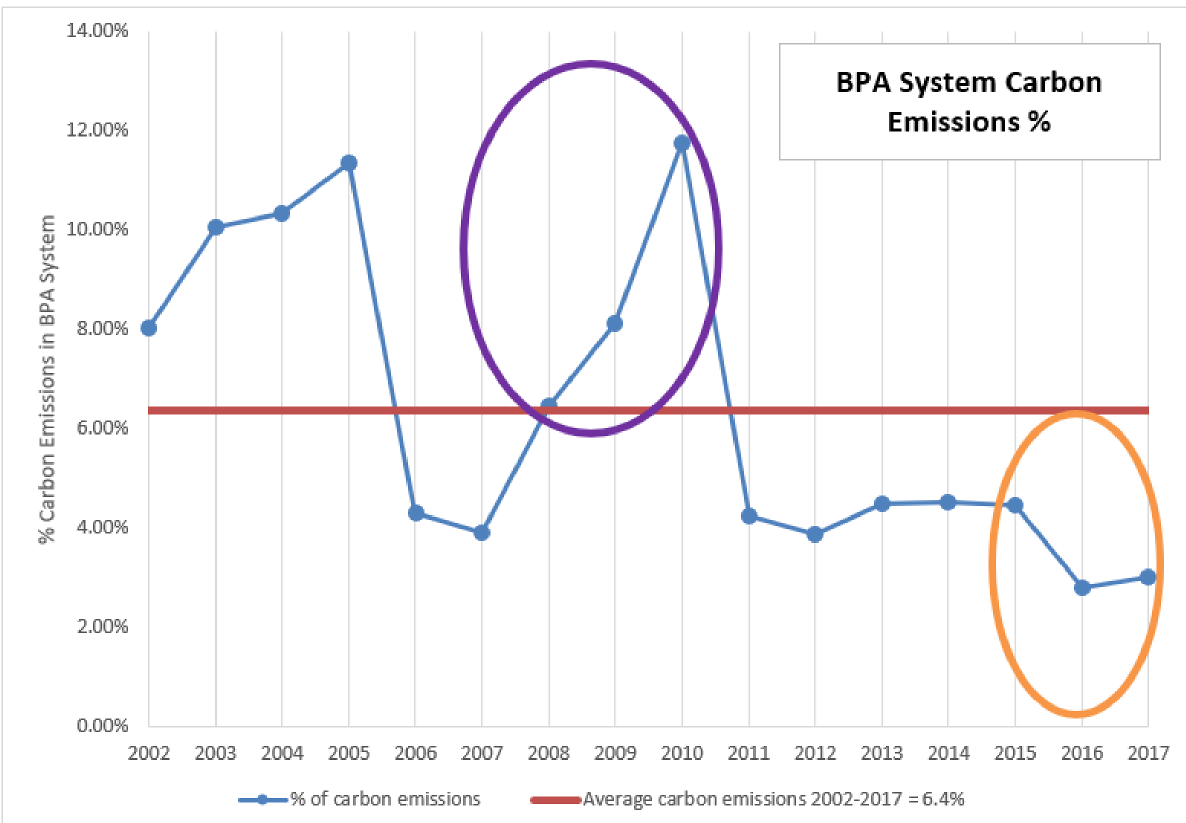
Director, Policy

[16] See Sec. IV.A of the Green-e Renewable Energy Standard for Canada and the United States v3.4.

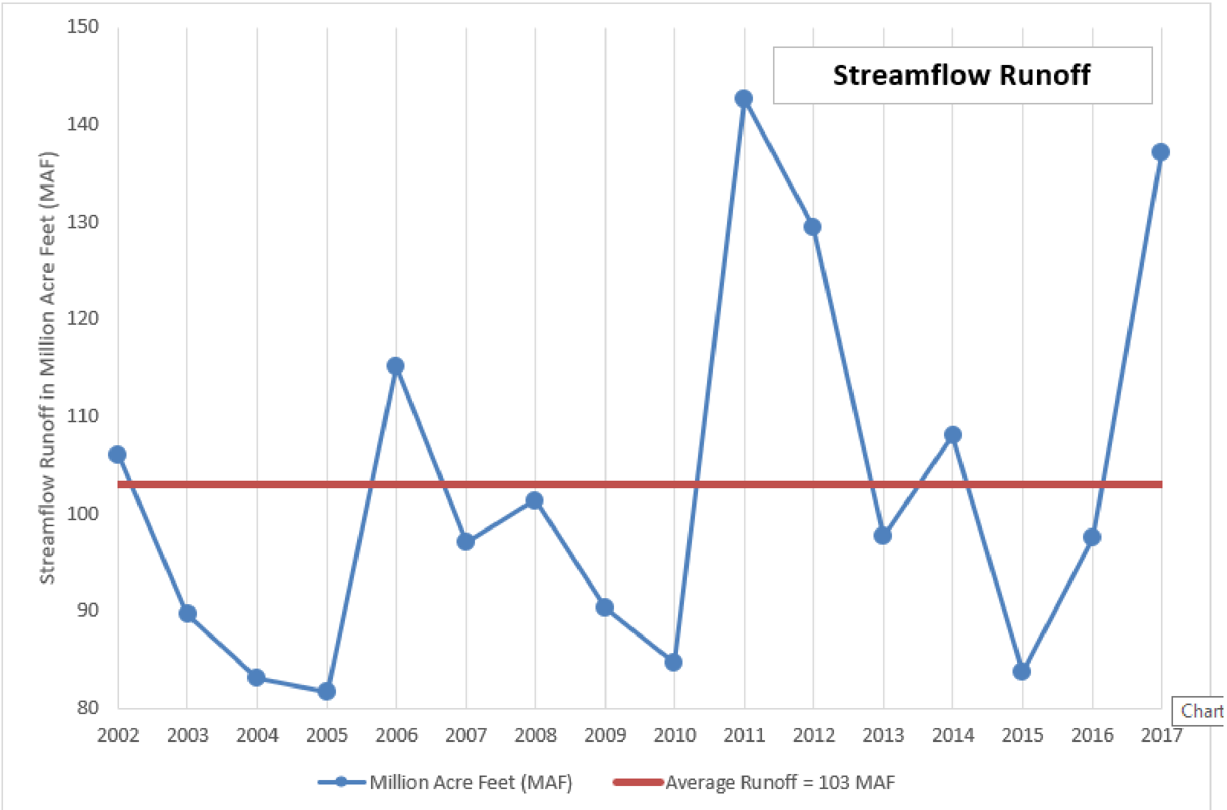
I wanted to share this spreadsheet and some graphs with you for considering whether to eliminate the 5-year rolling average. (The data below was pulled together when the Legislature was debating the Cap & Trade bill, but I think it is illustrative in this case too.)

As Greg Alderson from PGE mentioned in the workshop, the CFP does not go back too far to measure hydro variability. If you go back further, you can see that 2010 that was a pretty big swing where BPA had to rely more on market purchases.

I hope to provide some comments on this issue and some of the other items from the workshop, but I thought I would just forward this data to you separately. I am not an expert on hydro-variability, but I can connect you with one if you'd like more detail. Thanks. Have a nice weekend, Jennifer



Explanation: If the amount of allowances are based on the most recent 3 years of carbon emissions (orange circle), this is below the average amount of carbon emissions BPA has experienced over the last 15 years. Our feared outcome is that in the first 3-year compliance period, BPA's actual carbon emissions end up being more similar to the purple circle. BPA would not have nearly enough free allowances and would need to go buy allowances in the market. On average and over time, receiving allocations based on an average (such as the 15-year average shown as the red line), BPA would have sufficient allowances. *However*, the compliance periods are relatively short 3-year periods of time, and that does not bode well under the law of averages. Said differently, the risk is BPA's allowances are based on the orange circle, and then the first compliance period emissions are the purple circle and BPA has to buy allowances because it hasn't had time to bank them when the emissions are below average.



Explanation: This chart shows the streamflow runoff over the last 15 years. The red line is the 80-year average runoff – because of the extreme variability of streamflow over time, BPA uses the largest data set possible, which is currently 80 years. In over 60% of the last 15 years, streamflow runoff was below average. You will also see there isn't always a direct correlation between streamflow and carbon emissions. That is because *when* the water comes down matters a lot. Even if the water year is good overall, if there isn't sufficient water during the cold winter or hot summer, BPA has to make market purchases to continue to reliably serve loads during those times.

Jennifer Joly, Director
Oregon Municipal Electric Utilities Association
1201 Court Street NE, Suite 102
Salem, OR 97301

www.omeu.org

The BPA System Mix below is BPA's system mix as reported voluntarily consistently with state GHG reporting programs. BPA began reporting its system mix to the California Energy Commission and Washington Department of Commerce. Since then additional state agencies have requested the information: Oregon DEQ (reported in 2013 retroactively to 2010) and an additional agency in California, the California Air Resources Board. BPA's system mix is the same for all entities as reflected in this reporting.

BPA System Mix Summary Years 2002-2017

For questions, please contact Kristina Rohe (PTC) at 503.230.7528

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Biomass and Waste	0.25%	0.24%	0.26%	0.23%	0.27%	0.29%	0.09%	0.20%	0.18%	0.16%	0.09%	0.03%	0.10%	0.13%	0.05%	0.00%
Geothermal	0.00%	0.00%	0.00%	0.00%					0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Small Hydro	0.84%	0.56%	0.75%	0.70%	1.28%	1.31%	1.33%	1.26%	1.33%	1.22%	1.07%	1.01%	1.09%	0.92%	0.96%	0.91%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wind					0.46%	0.49%	0.67%	0.62%	0.60%	0.57%	0.57%	0.66%	0.65%	0.88%	0.93%	0.75%
Coal	0.00%	0.00%	0.00%	0.00%					0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Large Hydroelectric	80.36%	79.30%	77.22%	77.13%	83.65%	84.40%	80.62%	81.68%	74.70%	88.95%	85.01%	84.03%	83.19%	83.60%	84.16%	86.54%
Natural Gas	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	0.07%	0.05%	0.04%	0.06%	0.01%	0.01%
Nuclear	10.51%	9.83%	11.43%	10.57%	10.04%	9.61%	10.71%	8.13%	11.42%	4.87%	9.33%	9.74%	10.40%	9.94%	11.09%	8.78%
Non Specified purchases	8.04%	10.07%	10.33%	11.37%	4.30%	3.90%	6.47%	8.11%	11.77%	4.23%	3.87%	4.47%	4.53%	4.46%	2.80%	3.00%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Oregon Load (MWh)	13,436,276	13,436,276	13,436,276	13,436,276	13,916,873	14,312,459	14,462,845	13,872,171	13,633,933	14,139,919	13,842,745	14,045,376	13,779,415	13,648,010	13,802,403	14,506,599
Emissions (MT CO_2e)	462,429	578,983	594,035	653,909	256,114	238,680	406,385	481,518	592,958	207,577	202,242	243,266	233,837	199,807	160,522	129,730

Average emissions 2002-2017 352,624

1/ Due to changes in IT systems, calculating actual BPA-served load for customers prior to 2010 would have to be manually done. Therefore, Oregon load for 2005-2009 is metered Total Retail Load minus a conservative approximation where appropriate for COU non-federal resource amounts. BPA expects this is close to actual load. For 2002-2004, as estimation is used. Actual load amounts can be calculated by BPA staff as needed.

2/ Emissions for 2002-2009 are calculated based on CARB's unspecified resource emissions factor of 0.428 MT CO_2e per MWh.

3/ Emissions and MWh for CY 2010-2017 are per Oregon DEQ reporting and were provided by Elizabeth Elbel on 11/7/2018

From: Breen, David
Sent: Tuesday, September 29, 2020 5:38 PM
To: HDDR&R2021
Subject: CFP Rulemaking Comment

I believe that It is imperative that Oregon adopt a Tier 2 pathway application process to administratively review and approve Energy Economy Ratios (EERs) outside of rulemaking. It takes time to gather the appropriate information and data to develop credible and defensible EERs, and in many cases the product of these efforts will not align with Oregon's windows for rulemaking. This is particularly true for EERs being developed for California's LCFS that Oregon can/should take advantage of. For example, the, the California Airports Council recently solicited proposals from qualified consultants for technical consulting services to develop EERs for airside electric ground support equipment (eGSE). Oregon should rely on this work, which will develop EERs utilizing best practices developed by the California Air Resources Board and the Airport Cooperative Research Program. The timeframe for this process, however, is uncertain.

I greatly appreciate the opportunity to provide perspectives in enhancing Oregon's CFP.

Respectfully,

David Breen
Mgr, Env Air Quality & Energy
Port of Portland

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From:	Jennifer Joly
To:	CFPE2021
Cc:	Danelle Romain (dromain@theromaingroup.com); Ted Case (tcase@oreca.org); "PETERS Bill N."; WIND Cory Ann
Subject:	Feedback from OMEU, OPUDA, ORECA, re: CFP Electricity 2021 RAC Workshop #1
Date:	Wednesday, October 7, 2020 4:33:41 PM

Thank you for the opportunity to provide comment on the potential changes to the electricity provisions of the Clean Fuels Program (CFP). Given the complexity of these proposals and the agency's abbreviated timelines for comment, we reserve the right to provide further comment or revise to these preliminary impressions in subsequent workshops and during the formal rulemaking.

Directing Revenue from the Sale of Electricity Credits. As noted in the September 24th workshop, we would be concerned about the development of strict requirements for spending the proceeds of electricity credit sales by DEQ. As noted in your presentation, the PUC has developed spending principles for residential EV credits for investor-owned utilities (IOUs) in UM 1826. Likewise, as consumer-owned utilities (COUs), our governing boards have directed the spending of revenues from CFP credits. Given the variability of COU territories, some with very nascent EV adoption, we need the flexibility to develop targeted programs that match our local climate goals and realities on the ground.

That said, we do not have any objection to ensuring that CFP credit revenues are spent on purposes that accelerate transportation electrification. In fact, we testified to that in the Legislature when this issue was considered during the 2020 Legislative Session (HB 4135). We are unaware of any instances where CFP credit revenues are being used for non-EV purposes. After CFP investments are made, we would be happy to share how COUs are using these credit revenues with DEQ. In this case, it does not make sense to have overly prescriptive State requirements. As the old adage goes, if it ain't broke, don't fix it. We don't want to unnecessarily stifle local ingenuity.

Calculating the Utility-Specific and Statewide Mixes. We do not support changing the averaging period from five years to a single year—especially for the utility-specific mix, which COUs typically designate due to our much lower carbon intensity (CI) than the statewide mix. As you know, the five-year rolling average was adopted to smooth out hydroelectric variability, which is much more impactful to the COUs who have a much higher percentage of hydro compared to the IOUs. If the utility-specific mix calculation timeframe is shortened, it would introduce more year to year variability in the amount of credits COUs receive under the program. Predictability is important for EV programs, particularly customer rebates and incentives.

As was pointed out in the September 24th RAC Workshop by Greg Alderson of PGE, the CFP was launched in 2016, which is not a very long timeframe for evaluating the variability of hydro-generation. While we have not seen significant hydro variability since the start of the CFP, because of the extreme variability of streamflow over time the Bonneville Power Administration (BPA)—the primary power supplier to COUs—uses the largest data set possible for their evaluation, which is currently 80 years of average runoff. In over 60% of the last 15 years, streamflow runoff was below average. Of course, there isn't always a direct correlation between streamflow and carbon emissions because *when* the water comes down is also key. Even if the water year is good overall, if there isn't sufficient water during the cold winter or hot summer, BPA has to make market purchases, which may include natural gas, to continue to reliably serve loads during those times.

With respect to the statewide mix, we do not have objections to adjustments that reflect the retirement of fossil generation, like the Boardman coal-fired plant, at more frequent intervals than every five years. Also, given generally accepted principles of carbon accounting and the significant participation of COUs in the CFP, we support DEQ's proposal to remove the utility-specific load from the statewide mix.

Eligible Renewable Electricity Sources. Linking the definition of renewable electricity to the State's Renewable Portfolio Standard (RPS) is inconsistent with DEQ's pledge to "employ a technology and fuel-neutral approach." We are having difficulty understanding the mixing and matching of "renewables" versus "carbon free." If the goal of the CFP is to reduce carbon emissions, legacy hydro is zero carbon and should not be excluded as an eligible source if other program requirements are met. In addition to being zero-carbon, legacy hydro is a cornerstone of integrating other intermittent non-hydro renewables, like wind and solar.

Jason Heuser of Eugene Water & Electric Board (EWEB) mentioned that EWEB is considering the development of a 100% carbon free product using existing EWEB-owned hydropower, possibly in combination with EWEB-owned and contracted-for wind, and solar generation. At the option of the customer, the new 100% carbon free product would eliminate unspecified market purchases made for system balancing purposes, which may include fossil resources. Another example, in lieu of building new natural gas plants, in 2018 PGE signed a power purchase agreement with BPA for 200 MW of capacity from the federal hydro system. These types of arrangements result in "real and quantifiable GHG reductions" and should thus be eligible for incremental CFP credit generation. We disagree that the goal of the CFP should be to "incent the building of new renewables." The program should not run counter to incenting the most cost-effective choices that achieve carbon reduction for Oregon ratepayers. It makes no sense to exclude any non-carbon emitting resource from the program.

As Senator Roblan pointed out during an RPS briefing last month in the Senate Energy and Environment Committee, as long as large hydro is separate, we are not really being honest because we are extracting out a lot of the clean energy we are using. As the Senator put it, when we make these artificial determinations, the public loses trust in government. We urge

DEQ to take the same technology neutral approach that a Cap and Trade program would have.

Even using an RPS construct for incremental CFP credit generation, DEQ appears to omit incremental hydro, which is an eligible resource under the Oregon RPS. As you are likely aware, incremental hydro would be "an additional action" that would lower the CI of electricity as well, and should qualify. This way, COUs would have the option of utilizing any incremental RECs for use in the CFP (at least to the extent the RECs meet the time limits DEQ establishes).

There are also some parameters for qualifying RECs that were discussed at the September 24th workshop and that were included in the presentation. Many of the "narrower/create your own requirements," as presented in the presentation, are too narrowly tailored. It is important to keep in mind that the electrical system in the West is regional in nature and often cost-effective resources that reduce emissions may be outside of Oregon or BPA's BA. For example, COUs receive RECs for wind projects in Wyoming, which may not be located in BPA's BA.

General Comments. We support DEQ's efforts to establish more opportunities to generate CFP credits, but beyond the items identified above, such as ensuring that CFP credits are broadly spent in support of transportation electrification, we do not support amendments to the existing "base credit" program. The base program, allowing the use of a utility-specific mix with a 5-year rolling average, is functioning well to achieve the aims of the CFP. It is also important that CFP accounting not become too complex or onerous for smaller utilities to participate.

Thank you for your consideration. We look forward to the continued discussion.

Jennifer Joly, Director, Oregon Municipal Utilities Association
Danelle Romain, Lobbyist, Oregon People's Utility District Association
Ted Case, Executive Director, Oregon Rural Electric Cooperative Association