BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19M-0495E

IN THE MATTER OF THE COMMISSION’S IMPLEMENTATION OF §§ 40-2.3-101 AND 102, C.R.S., THE COLORADO TRANSMISSION COORDINATION ACT.

JOINT REPLY COMMENTS
OF SUSTAINABLE FERC PROJECT AND SIERRA CLUB

Sustainable FERC Project and Sierra Club, by and through their undersigned counsel, respectfully file these reply comments in this proceeding in response to Commission Decision No. C19-0756. We appreciate the opportunity to provide comments responsive to other parties’ initial comments in this proceeding.

I. Areas of Consensus

Sustainable FERC Project and Sierra Club were pleased to observe many areas of consensus across most of the stakeholders that provided initial comments in this proceeding. At a high level, most parties agreed that:

- The Commission should consider both economic and environmental benefits as it evaluates the costs and benefits of organized markets.

- Broader regional coordination will be needed for Colorado to meet its ambitious clean energy goals in a way that maintains affordability.

- RTO governance structures should be transparent, provide for meaningful stakeholder participation, and provide a significant role for the state.

- Markets should facilitate and not impede state energy policy.

- The economic benefits of utility market participation should flow through to ratepayers.
• With a few exceptions, most parties agree that a full RTO may offer additional benefits not provided by an imbalance market.

• Colorado should avoid bifurcation between two market regions if possible.

We recommend that the Commission recognize the broad consensus that exists with respect to these topics and focus on how best to further investigate, and work with utilities to implement, the consensus views of the parties. The remainder of these comments focus on areas of disagreement among the parties.

II. Commission Authority

A. The Commission has sufficient authority to order utilities to participate in an organized market or prohibit it.

As Sustainable FERC Project demonstrated in initial comments, if the Commission finds that it would be in the public interest for the utilities to participate in an organized market, the Commission has the authority to order them to do so. Conversely, if the Commission finds that it would not be in the public interest, the Commission may order the utilities not to join a market. Our initial comments analyzed four distinct bases for this authority, each of which is sufficient for the Commission to find that it has jurisdiction:

• The Commission’s broad plenary authority to supervise public utilities gives the Commission the power to “do all things” necessary to ensure that utility rates, service, and facilities are “adequate, efficient, just, and reasonable.”

• The Colorado Transmission Coordination Act (CTCA) delegates the General Assembly’s own power to order the utilities to participate in a market to the Commission, if the Commission finds that doing so would be in the public interest.

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1 Initial Comments of Sustainable FERC Project, pp. 18-19 (quoting CRS § 40-3-102 and 101(2)).
2 Id. at p. 19.
• Directing the utilities to participate in a market is consistent with the Commission’s authority over the utilities’ resource planning process. Notably, the Commission now has such authority over Tri-State.³

• Directing the utilities to participate in a market, or prohibiting it, is consistent with the Commission’s authority over electric trading operations.⁴

As explained in more detail below, Sustainable FERC Project and Sierra Club recommend that the Commission promptly issue an interim order finding that it has sufficient authority under the CTCA to order the utilities to take the steps necessary to participate in a market, if the Commission finds that doing so is in the public interest. First, we address the arguments of the only parties that argued that the Commission does not have the authority to do so: the utilities.

B. Joining an organized market is not a managerial decision within the utility’s discretion.

Public Service and Black Hills both argue that the decision whether to join one of the market options is a managerial decision that, absent an abuse of managerial discretion, belongs to the utility.⁵ For support, both utilities cite two cases: Public Service Co. v. Public Utilities Comm’n, 653 P.2d 1117 (Colo. 1982) and Colorado Municipal League v. Pub. Utilities Comm’n, 473 P.2d 960 (Colo. 1970).

In the more recent case, Public Service Co., the Commission declined to order Public Service to divert construction funds from certain projects to the Pawnee Power Plant, which might have mitigated or avoided Public Service’s request for emergency rate relief to finish Pawnee on

³ Id. at pp. 19-21.
⁴ Id. at 21-22.
⁵ Initial Comments of Public Service, pp. 18-19; Initial Comments of Black Hills, p. 12.
schedule.⁶ In its decision, the Commission had found that the intervenors who argued for the funds to be diverted from other projects to Pawnee could not “act in the role of ‘over-the-shoulder supermanagers.’”⁷ The Commission had found that there was no evidence that Public Service had abused its managerial discretion by not reallocating construction funds to Pawnee.⁸

The utility decision not to allocate construction funds to different projects – which the Commission and the court found was not an abuse of the utility’s managerial discretion – is in no way analogous to the decision to join an organized market. Joining an organized market directly implicates the utilities’ generation resources and its retail rates, both of which are well within the Commission’s regulatory purview. While the utility decision at issue in Public Service Co. also affected utility rates, the intervenors’ position that the Commission and the court rejected was a strained counterfactual argument based on unproven facts – namely, that the utility could have theoretically reallocated sufficient funds from other construction projects to avoid the requested emergency rate relief.⁹ In other words, the Commission had found that management had not abused its discretion by not pursuing every hypothetical alternative, especially given that there was evidence in the record that the intervenors’ proposed alternative was not viable.¹⁰

When a utility proposes to build a power plant or raise its rates to collect the cost of a new plant, the Commission does not simply ask whether the utility management has abused its discretion before approving or denying the proposal, as it did with respect to the counterfactual recommendation of the intervenors in Public Service Co. Rather, pursuant to its plenary regulatory

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⁶ Public Service Co., 653 P.2d at 1123.
⁷ Id. (quoting Decision No. C80-1039).
⁸ Id. (citing Colorado Mun. League, 473 P.2d 960).
⁹ Id.
¹⁰ 653 P.2d at 1123.
authority, the Commission examines all aspects of the proposal and either approves, rejects, or modifies the proposal. The standard by which the Commission evaluates proposals for new generation resources or for increased rates is the just and reasonable standard, which is very different from a more limited "abuse of managerial discretion" standard.\textsuperscript{11}

An organized market is essentially a platform for facilitating energy trades using a utility's generation and transmission resources that the Commission has approved for other purposes (meeting native load). Public Service and Black Hills recover the cost of wholesale market purchases, offset by revenue from market sales, through their retail rates, which are set by the Commission.\textsuperscript{12} It is disingenuous for Public Service to deny that the Commission has authority to require it to join a market while acknowledging that it would need to seek Commission approval to recover the costs of joining a market if it chose to do so.\textsuperscript{13} If a utility sought approval to recover the costs of joining a market, the Commission would be well within its authority to examine whether the underlying decision to join a market was just and reasonable and ask whether the utility should have pursued a different market option. Just as the Commission currently oversees utility wholesale transactions that involve resources approved to meet native load\textsuperscript{14} and sets the utility's rates, participation in a market is well within the Commission's authority rather than the utility's managerial discretion.

\textsuperscript{11} CRS § 40-3-101(1) and (2).

\textsuperscript{12} As discussed more below, the Commission also exercises authority over some aspects of Tri-State's rates.

\textsuperscript{13} Initial Comments of Public Service, pp. 18-19.

\textsuperscript{14} For example, through Public Service's Commission-approved Policy for Resource Management and Cost Assignment for Short-Term Electric Energy Transactions Business Rules, (Proceeding Nos. 04A-0505E and 13A-0689E). We recognize that the Commission does not set wholesale rates, which are FERC jurisdictional.
For these reasons, the Commission should find that the decision to join an organized market is not a decision that lies exclusively within the managerial discretion of the utilities, but rather is a decision that falls well within the Commission's regulatory purview.

C. **Alternatively, even if the decision to join a market is a managerial decision, the Commission has the authority to find that not joining a well-designed market is an abuse of managerial discretion.**

Alternatively, if the Commission finds that joining a market is a managerial decision, the Commission should further find that it would be an abuse of that discretion for the utilities not to join a well-designed market despite evidence that doing so would be in the public interest, consistent with *Colorado Municipal League*. Similarly, the Commission could also find that it would be an abuse of discretion for the utilities to join a poorly designed market that did not provide net benefits to ratepayers.

In *Colorado Municipal League*, the court stated:

Courts and commissions should respect the decisions of management and, in general, not succumb to the temptation of assuming the role of management. However, no matter how much deference we have and should have for highly-trained management, when that management abuses its managerial discretion to the detriment of its customers, our regulatory commissions have a duty to declare the abuse and make such orders as will give to ratepayers the advantage of those economies of which management has failed to avail itself.\(^{15}\)

These statements from the court were made in the context of examining whether the utility had abused its discretion in its choice of depreciation methods in preparing its taxes.\(^{16}\) Though the court overturned several of the Commission's underlying decision points in *Colorado Municipal League*, the court did not find that the Commission had exceeded its authority when it found that

\(^{15}\) *Colorado Mun. League*, 473 P.2d at 967.

\(^{16}\) Id.
the utility should have used a different depreciation method. In other words, the court found that the Commission had the authority to correct an abuse of managerial discretion that had resulted in ratepayers not realizing the benefit of a more beneficial tax treatment.

Even if joining a market is considered a managerial decision, the Commission has the authority to find that not joining an organized market, or joining a poorly designed market, can be an abuse of managerial discretion. As described in Sustainable FERC Project’s Initial Comments (and the comments of other parties), organized markets have a track record of reducing costs, improving access to clean energy, and saving ratepayers money. However, some problematic market designs or governance structures could undermine the potential economic and environmental benefits. If the Commission finds that ratepayers would benefit from the utilities joining a well-designed organized market but the utilities refused, the Commission would have authority under Colorado Municipal League to find that such refusal was an abuse of managerial discretion. As the court stated in that case, the Commission would then “have a duty to declare the abuse and make such orders as are necessary” to ensure that ratepayers realize the benefits that they would have received absent the abuse of managerial discretion.

The most effective way for ratepayers to realize the benefits of utility market participation is, of course, for the utilities to join a market. If despite the arguments in favor of Commission authority on this issue the Commission finds that it does not have authority to order the utilities to participate in a market, under Colorado Municipal League and its ratemaking authority the Commission could require the utilities to reduce their rates to a level equivalent to what they would

\[17\] Id.
\[18\] Id.
\[19\] Initial Comments of Sustainable FERC Project, pp. 3-6.
\[20\] Colorado Mun. League, 473 P.2d at 967.
be if the utilities were actually participating in the market. At that point, the utilities would likely prefer to actually join the market, rather than simply charge rates that mimic market participation.

D. **Contrary to Tri-State’s arguments, the Commission has authority to order Tri-State to participate in a market.**

Tri-State “does not believe the Commission has the authority to order it to enter into a particular market option.”21 For support, Tri-State cites CRS § 40-9.5-101, *et. seq.* However, these sections of Colorado statute describe the process by which *retail* cooperative electric associations may exempt themselves from Commission regulation. CRS § 40-9.5-102 makes clear that this exemption process is not available to “nonprofit generation and transmission electric corporations or associations” such as Tri-State. The Commission should find that Tri-State has failed to demonstrate that the Commission does not have authority to order it to join a market.

The General Assembly recently directed the Commission to require Tri-State to submit resource plans to the Commission.22 As discussed above, participation in an organized market directly implicates a utility’s resource planning process. Consistent with the Commission’s authority over Tri-State’s resource planning process, the Commission can require Tri-State to meet some portion of its resource needs through economic market purchases.23

Although Tri-State does not file rate cases with this Commission, the Commission recently found that its ratemaking authority provided it with jurisdiction to hear Delta-Montrose Electric Association’s (DMEA’s) complaint against Tri-State regarding exit fees in Proceeding No. 18F-0866E.24 In its jurisdictional analysis, among other statutory provisions, the Commission relied on

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21 Initial Comments of Tri-State, p. 10.
22 Initial Comments of Sustainable FERC Project, p. 21; CRS § 40-2-134.
23 Initial Comments of Sustainable FERC Project, p. 21.
24 Decision No. C19-0297-I.
CRS § 40-3-101(1), which provides: “Nothing in this subsection (1) shall limit or restrict the commission’s authority to regulate rates and charges, correct abuses, or prevent unjust discrimination.”25 Here again, because utilities (including Tri-State) recover the cost of wholesale purchases through rates, the Commission has oversight authority over the wholesale purchases themselves. The Commission can therefore use its ratemaking authority to direct that such wholesale purchases be made through an organized market.

E. The Commission should assert its authority to review and approve utility decisions on whether to participate in a market.

The utilities clearly believe that the Commission cannot order them to participate in a market. By implication, it is also clear that the utilities believe that if they want to participate in a market, it is entirely up to them to choose which one. Indeed, Tri-State has already signed a contract with SPP to join SPP’s Western Energy Imbalance Service (WEIS).26 Tri-State did not seek Commission approval prior to doing so and its comments indicate no intent to do so at a later date. Similarly, it is possible that Public Service and Black Hills may join either SPP’s WEIS or CAISO’s Western Energy Imbalance Market (WEIM) without seeking the Commission’s approval beforehand. Indeed, Public Service says it intends to decide whether to join an imbalance market “by the end of 2019.”27

The purpose of this proceeding is for the Commission, along with stakeholders, “to collect comments and information helpful in analyzing the potential advantages and disadvantages of joining an energy market,” consistent with the statutory directives of the CTCA.28

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25 See id. at ¶ 20.
26 Initial Comments of Tri-State, pp. 4-5.
27 Initial Comments of Public Service, p. 2.
28 Decision No. C19-0756.
requires the Commission to make a finding, based on its investigation, as to whether utility participation in an organized market would be in the public interest and, if so, direct the utilities to take the steps necessary to do so.\textsuperscript{29} If the utilities make their own decisions on whether to join a market and which market to join without Commission oversight, it would moot this investigative proceeding and the required Commission decisions. Such utility decisions, if permitted, would frustrate the General Assembly’s directives and purpose in ordering the Commission to open this investigation.

The Commission should not allow the utilities to moot its investigative process that has been duly authorized by the General Assembly. To avoid this possibility, the Commission should issue an interim order in this proceeding finding that it has the authority to direct the utilities to participate in an organized market, or to prevent them from doing so. Sustainable FERC Project and Sierra Club recommend that the Commission issue such an order to this effect in the near term prior to expending significant additional resources on other aspects of its investigation.

In addition to finding that it has the authority to direct the utilities to participate in a market, the Commission should find that it has the authority to order the utilities to join a \textit{particular} market. Such authority is consistent with the Commission’s authority to direct the utilities to participate in market if the Commission finds that doing so would be in the public interest under the CTCA, its authority to condition market participation,\textsuperscript{30} its authority to modify a utility’s resource plan,\textsuperscript{31} and its ratemaking authority, which empowers the Commission to disallow utility cost recovery for imprudent utility decisions.\textsuperscript{32}

\textsuperscript{29} CRS § 40-2.3-102(3) and (4).
\textsuperscript{30} See Initial Comments of Sustainable FERC Project, p. 22.
\textsuperscript{31} \textit{Id.} at pp. 19-21.
\textsuperscript{32} CRS § 40-3-102.
It is important for the Commission to find that it has comprehensive authority to not only order utility market participation but to order participation in a particular market because the Commission’s determination of whether market participation is in the public interest must reflect analysis specific to particular market offerings or RTO characteristics such as governance. The authority to order, or prohibit, participation in a particular market is also important should the Commission conclude that having Colorado becoming bifurcated between two separate markets would not maximize the benefits of utility market participation. Without such a finding, each utility could seek to join the market of its choice without regard to the implications of its choice on the state as a whole. Such implications could include forgoing substantial benefits that may not be realized if Colorado becomes a bifurcated state.


A. The Commission should ensure that any recommendations it makes will help, not hinder, utilities to achieve the statutory mandates to reduce GHG emissions.

As the Commission is well aware, two laws from the 2019 legislative session mandate specific reductions in greenhouse gas emissions (GHGs). HB 19-1261 requires statewide GHG emissions to be reduced 26% by 2025, 50% by 2030, and 90% by 2050 relative to 2005 emission levels.\textsuperscript{33} HB 19-1261 does not specify the reductions that individual electric utilities, or the electric sector as a whole, must achieve in order for the state to meet these targets. However, SB 19-236 requires Public Service to reduce its GHG emissions 80% by 2030 relative to 2005 levels.\textsuperscript{34} Taken together, these two statutes will require each electric utility in Colorado to make significant changes to how it serves customers. Given the scale of the changes required by these statutes, the

\textsuperscript{33} § 25-7-102(2)(g), C.R.S.

\textsuperscript{34} § 40-2-125.5(3)(a)(l), C.R.S.
Commission should ensure that any recommendations it makes in this docket help, rather than hinder, utilities’ ability to meet the statutory GHG reduction targets.

The legislature directed the Air Quality Control Commission (AQCC) to implement HB 19-1261.\textsuperscript{35} However, as discussed, this Commission regulates resource planning for Tri-State, Black Hills, and Public Service, which collectively serve most of the electric load in Colorado and generate the majority of the GHG emissions from the electric sector. While the legislature set a specific GHG reduction target for Public Service to meet by 2030,\textsuperscript{36} it tasked the AQCC with issuing rules for utilities such as Tri-State and Black Hills.\textsuperscript{37} While the AQCC has not yet issued such rules, the AQCC has stated that the electric sector as a whole will likely need to reduce GHG emissions by at least 80\% by 2030 in order to achieve the statutory target of reducing statewide GHG emissions 50\% by 2030.\textsuperscript{38}

When the Commission reviews Black Hills’ and Tri-State’s resource plans, the Commission will need to consider whether those plans are consistent with achieving the GHG reduction targets in HB 19-1261.\textsuperscript{39} For the purposes of this proceeding, the Commission does not need to know exactly what GHG reductions will be needed from each utility over what time interval. Instead, it is sufficient to know that each utility will need to make significant cuts in its GHG emissions over time, and that the AQCC currently forecasts the electric sector as a whole

\textsuperscript{35} § 25-7-105(1), C.R.S.
\textsuperscript{36} § 40-2-125.5(3)(a)(I), (4)(a), C.R.S.
\textsuperscript{37} § 25-7-105(1), C.R.S.
\textsuperscript{38} Proceeding No. 19R-0096E, Comments of the Colorado Department of Public Health and Environment at 2 (Oct. 21, 2019) ("[I]t is likely that the state will need 80 percent or greater emissions reductions from electric utilities by 2030 to meet the 50 percent reduction target in H.B. 1261.").
\textsuperscript{39} See 4 CCR 723-3-3610(c) ("The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.").
will need to reduce GHG emissions 80% by 2030. Given the AQCC’s prediction that utilities such as Black Hills and Tri-State will need to make deep reductions in GHG emissions, the Commission should ensure that its recommendations in this docket facilitate utilities’ compliance with HB 19-1261.

As noted above, SB 19-236 makes Public Service subject to different requirements than other electric utilities. The legislature directed Public Service to reduce GHG emissions 80% by 2030 relative to 2005 levels.\textsuperscript{40} Moreover, when Public Service submits its next Electric Resource Plan (ERP) to this Commission, the ERP must contain a plan (called a “Clean Energy Plan”) for achieving this 80% GHG reduction by 2030.\textsuperscript{41} Under SB 19-236, the Commission will review Public Service’s Clean Energy Plan. The Commission should therefore ensure that its investigation and decisions in this docket facilitate a Clean Energy Plan from Public Service that complies with the statute and achieves an 80% GHG reduction by 2030.

B. The Commission should evaluate the benefits and costs of participation in specific markets, with an emphasis on how markets will affect compliance with GHG emission reduction mandates.

As Sustainable FERC Project explained in initial comments, the Commission must investigate how market participation would affect GHG emissions from the state’s electric sector, in order to understand whether market participation will enhance or impede Colorado’s ability to achieve its ambitious emission reduction mandates. It cannot simply be assumed that market participation will reduce emissions. Although markets have the potential to decrease generation from carbon-emitting sources, whether that actually occurs will depend on a number of factors including market design, transmission system capacity, the production costs of other generators in

\textsuperscript{40} § 40-2-125.5(3)(a)(I), C.R.S.

\textsuperscript{41} § 40-2-125.5(4)(a), C.R.S.
the market, overall and system peak loads, and others. Well-designed markets are more likely to result in emission reductions, especially if they restrict self-scheduling for thermal units, fully incorporate demand response and price responsive-demand, eliminate barriers to small and distributed resources, integrate energy storage, and have a functional transmission planning process. The Commission should evaluate any market option through this lens and should be closely involved in the design of any new market to ensure that it includes these market design features.

The Commission should also be cognizant that market participation does not guarantee market commitment or economic dispatch of generation resources. The SPP Market Monitoring Unit recently published an analysis indicating that “nearly half of the total megawatt volume generated from March 2014 through August 2019” consisted of self-committed resources – that is, generation units that do not respond to market price signals, but instead operate as price takers.42 This study confirms earlier research showing that self-commitment by utility-owned generators results in coal-burning power plants operating nearly 10% more than they would if economically dispatched, leading to higher emissions.43 Where market rules permit self-dispatch and self-commitment, the Commission must nevertheless continue to oversee utilities’ decisions in order to realize the benefits of market competition.

It is likely that development and generation of renewable energy will increase in a well-designed organized market. But this does not necessarily mean that Colorado-based carbon-emitting generation will dispatch down to an equivalent degree, since both renewable and carbon-


emitting generation sources will be competing to serve a larger load in a broader region. As a result, effective modeling of different system designs is necessary to assess the actual emissions outcomes, particularly the change in emissions for Colorado.

At this point, we do not have the data to take a definitive position on which specific market offerings would best help Colorado utilities meet the GHG reduction targets in HB 19-1261 and SB 19-236. Several studies have concluded that with more market integration, electric utilities can achieve greater GHG reductions in a given period of time, and/or achieve GHG reductions at a lower cost. However, we are not aware of such a study where the results have been disaggregated and presented for Colorado utilities as a whole, or for particular Colorado utilities.

The State of Colorado is currently collaborating with other states on a study of market options. That study should evaluate GHG impacts, similar to how the Energy Strategies study for the Western Interstate Energy Board is modeling GHG reductions across different scenarios, and to be most useful for Colorado’s purposes, should present GHG reductions by state. We are also aware that several Colorado utilities have retained the Brattle Group to examine certain market options. As discussed further below, we would urge those utilities to ensure that the final report, or a separate additional report, analyzes GHG reductions across the different scenarios that are modeled.

Once the Commission has modeling studies examining the impact of market mechanisms on Colorado utilities’ GHG emissions, the Commission and the parties will be in a position to decide which market offerings would best facilitate compliance with Colorado’s GHG emission reduction targets.

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The Commission’s investigation should consider both short-term impacts – those relevant to Colorado’s ability to meet its 2025 GHG emission reduction goals – and longer-term impacts. The short-term impacts would be determined primarily by current market rules, transmission system, and generation fleet, as these factors can be slow to change. Many of the potential benefits of markets, such as transparent nodal energy market prices and increased merchant clean energy development due to lower transmission-related barriers to entry, would take some time to be realized. And while participation in a market covering a broader geographic region facilitates integration of variable renewable generation, this benefit may not be immediately relevant given Colorado and its neighboring states’ current levels of variable generation sources. We raise these issues not to downplay these very real benefits of market participation, but simply to note that not all of these benefits are relevant over the timeframe needed to realize the state’s near-term GHG emission targets.

The Commission’s assessment of the costs and benefits of market participation, especially the impact on GHG emissions, must be specific to particular markets, rather than resting on high-level concepts or theories of markets. What specific market services are currently available, or may be soon, depending on whether Colorado utilities look to SPP versus CAISO? What are the resource mix and load characteristics of those systems that would affect how much Colorado’s carbon-emitting units run? What is the availability of transmission links between Colorado utilities and the markets in which they seek to participate, which have an enormous practical effect on how much market dispatch would alter the status quo?

45 See, e.g., Initial Comments of Guzman Energy, LLC at 3-5.
C. The Commission should consider how utilities participating in a market would ensure they comply with GHG emission reduction targets.

In addition to considering whether market mechanisms would help utilities achieve statutory mandates to reduce GHG emissions, the Commission should consider how it and the AQCC would measure and track compliance with GHG targets under various market mechanisms. The Commission should consider mechanisms for ensuring compliance with GHG targets under market mechanisms in general, and also how account for GHG emissions produced out of state if market participation leads to greater reliance on out-of-state resources.

These two issues will become more important over time, particularly if utilities and the Commission consider RTO membership. In the short run, utilities seem focused on whether to join an imbalance market, which generally is used to procure a small percentage of a utility’s overall resources needed to serve load. But if utilities and the Commission move towards RTO membership, a much larger percentage of resources would likely be dispatched according to market mechanisms.

The first issue for the Commission and the AQCC to consider is how ensure compliance with GHG reduction targets, such as through accounting mechanisms to track or reflect market transactions. There will need to be clear rules for assigning GHG emissions to entities to avoid double counting emissions from market transactions. Second, expanded market participation means that there may be more market transactions in which out-of-state resources are used to serve Colorado load. Thus, it is critical that both the Commission and the AQCC count and track out-of-state emissions attributable to Colorado load.

For example and as discussed above, in its next ERP Public Service is required to present a plan for reducing its GHG emissions 80% by 2030. The Division of Administration, in consultation with the AQCC, is required to determine the GHG reductions that a Clean Energy
Plan would achieve, and this Commission is then tasked with reviewing the Clean Energy Plan. The AQCC and this Commission should ensure that Public Service models how market participation – for example, participation in an imbalance market – would change the resources used to serve load, and the resulting GHG emissions.

Finally, we urge the Commission to raise these issues with the AQCC. This Commission is the agency with the most expertise in the electric sector. The AQCC may not be fully apprised of utilities’ current plans to join markets (e.g., Tri-State’s stated plans to join an imbalance market) and utilities’ consideration of joining markets. It would be helpful for the AQCC to understand how various market mechanisms could affect the resources used to serve Colorado customers and the resulting GHG emissions. Thus, we urge the Commission, and Commission staff, to work with the AQCC to make sure that utilities’ participation in markets is considered by the AQCC as it promulgates GHG inventory, accounting, and compliance rules.

To enhance the Commission’s and the parties’ understanding of how GHG emissions can be tracked and accounted for in a market construct, we suggest that a workshop or portion of a workshop be used to explore this topic.

IV. Transmission development to access low cost renewables

In their initial comments, several parties addressed the issue of transmission, with some parties urging the Commission to consider all of the benefits that transmission development can bring when evaluating its cost, while others expressing skepticism about the ability of new transmission to benefit Colorado at all.

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46 § 40-2-125.5(4)(b),(c), C.R.S.
47 § 40-2-125.5(4)(d), C.R.S.
48 Initial Comments of Colorado Energy Office, pp. 10-11; Initial Comments of AEE Institute, p. 9.
49 Initial Comments of AARP, pp. 3 and 6.
Transmission is key to accessing an affordable and reliable supply of electricity for customers – especially from remotely located resources such as wind and solar power. As a general premise, transmission improves power transfer between local resource zones, allowing for improved pooling of resources to respond to a range and variety of system stresses. Improved interconnections between local resource zones extends the transmission system’s life, increases the system’s flexibility to use any and all of the resources in a regional footprint to respond to system stress, and therefore delivers benefits over the very long term.

Transmission planning should be considered as a subset of the total system planning process, encompassing the whole of supply, demand, transmission infrastructure, and the integration with state-jurisdictional distribution systems. In theory, and as their name suggests, RTOs should be ideally suited to plan for the system’s regional needs. The bulk power system increasingly connects generation sources located farther away from load centers, especially weather-influenced (yet dispatchable) renewable energy resources. Also, the rise of distributed energy resources, especially electric vehicles and other energy storage sources of both load and supply, will add new and variable flows into the system, creating new challenges for a system designed around centralized dispatch. For these and other reasons, the grid increasingly will need to: operate more flexibly than the current system; capture the benefits of large-scale geographic diversity to manage supply integration challenges and costs, while avoiding duplicative and costlier local infrastructure; integrate new technologies to enhance resilience and system coordination; and ultimately link the asynchronous East and West interconnections. A well-run RTO can much more quickly and cost-effectively address these concerns and needs than individual balancing areas.
In our experience in other RTOs, the hallmarks of an effective transmission planning process include:

1. Accounting for all of the system and public policy benefits of transmission development, rather than narrowly focusing on only production cost savings. These benefits include:
   a. Adjusted production cost,
   b. Avoided or delayed reliability projects,
   c. Reduced costs of meeting public policy goals (e.g., avoided capital costs of wind and solar installations in lower resource areas),
   d. Avoided carbon and other pollution,
   e. Savings from lower minimum required capacity margins,
   f. Ancillary services savings,
   g. Marginal energy losses benefits,
   h. Avoided reliability must run costs,
   i. Increase in available transmission capability, and
   j. Mitigation of transmission outage costs.

2. Consolidation of smaller, typically “local” projects into larger projects where the cost savings and other benefits are clear. For example, as discussed in Sustainable FERC Project’s Initial Comments, MISO found that its 17 “multi-value projects” addressing economic, public policy, and reliability needs were technically effective and more efficient than 650 local “patch quilt” projects.50

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3. A hierarchical assessment of meeting system needs that includes full consideration of non-wires solutions, upgrades to existing infrastructure, and new transmission facilities.

4. Full consideration of using energy storage as a transmission asset.

5. Fair allocation of costs reflecting the FERC-mandated beneficiary pays approach, while ensuring that all system and customer benefits are accounted for.

6. Accurate load forecasts that account for all embedded and programmatic energy efficiency and other load-reducing measures.

7. Close coordination of interconnection upgrade planning and system planning to ensure sufficient network capacity is available for generators to interconnect with a minimum of delay. In MISO, for example, long-term system planning has fallen behind current generator interconnection needs, causing many gigawatts of wind and solar projects to be cancelled.

8. Active participation of the states in transmission planning processes.

Effective regional transmission planning can deliver significant customer savings if correctly done. It can facilitate the economic retirement of costly thermal generation and connect remote wind and solar resources. It can help meet Colorado’s reliability and resource adequacy needs by allowing the regional sharing of energy and reserves, and consideration of the full range of transmission and non-transmission solutions on a regional basis to meet system needs driven by the transition to a cleaner energy supply.

Admittedly, some elements of regional and interregional planning are not working to their full potential. For example, transmission-owning utilities sometimes resist supporting the development of larger projects if they will be subject to a competitive bidding process. Planning
and cost allocation often reflects only some of the benefits of projects. Effective consideration of non-transmission alternatives is often illusory. The continuing inability of the country’s RTOs and planning regions to jointly plan for and approve cost allocation for interregional transmission projects is a major barrier to the ability of high-value renewable energy to access markets and customers. In the worst case, local utility transmission plans are simply “rolled up” into a regional plan without meaningful consideration of a more inclusive range of regional solutions. However, these flaws are fixable, and the many other benefits of a regional planning system would not be possible without the creation of an RTO. The Commission should carefully consider the strengths and weaknesses of the transmission planning processes in any RTO that Colorado utilities might join as part of this proceeding.

V. The Commission Must Evaluate the Costs and Benefits of Specific Market Options Available to Colorado Utilities.

A. The Commission should continue to analyze the WEIM and the WEIS as potential near-term options.

As discussed, Public Service stated that it and the other JDA participants are evaluating and comparing CAISO’s WEIM and SPP’s WEIS. Meanwhile, Tri-State has signed a contract with SPP to participate in the WEIS. As also discussed earlier, whether to join a market and which market to join are decisions that belong to the Commission, not to the utilities. However, Sustainable FERC Project and Sierra Club agree that the two most viable market options in the near-term are the WEIM and the WEIS.

It is critical for the Commission to carefully compare imbalance market offerings as they exists today and may develop in the near future. We have reviewed the comparative analysis of the EIM and the WEIS presented in the reply comments of Western Resource Advocates (WRA), Western Grid Group (WGG), and Natural Resources Defense Council (NRDC) and we support
their analyses with respect to the topics analyzed therein. The Commission may want to build upon their analyses through technical workshops or other means.

B. The Commission should examine the Brattle Group study of imbalance market options.

In its initial comments, Public Service described the study that it, along with the other participants to the Joint Dispatch Agreement (JDA),\(^{51}\) is currently undertaking to examine the benefits and costs of participating in either SPP’s WEIS or CAISO’s WEIM.\(^{52}\) It is our understanding that the JDA participants have retained the Brattle Group to perform this study. Sustainable FERC Project and Sierra Club were pleased that Public Service also stated that it planned to “provide the results of the EIM study to the Commission in this docket.”

This Brattle Group study will likely serve as a valuable resource for the Commission and stakeholders as this investigatory proceeding progresses. For that reason, Sustainable FERC Project and Sierra Club recommend that the Commission require the entire study and underlying data to be filed into the docket, and not just the results. It is our understanding that ratepayers funded this study, so it is appropriate for the public to have the benefit of the full study and underlying data. Further, the Commission should invite the authors of the Brattle Group study to present the study at a Commissioner Information Meeting where the Commissioners and their staff can ask the authors questions.

If the Commission finds the Brattle Group study to be valuable, the Commission should consider it, along with the robust record in this proceeding and other studies discussed in the initial

\(^{51}\) The parties to the JDA are Public Service, Black Hills, Colorado Springs Utilities, and Platte River Power Authority.

\(^{52}\) Initial Comments of Public Service, p. 13.
comments of parties, including the DOE-funded study being led by the Utah Energy Office.\textsuperscript{53} According to Public Service’s description, the Brattle Group study will focus on potential production cost savings.\textsuperscript{54} The Commission should ensure that, in addition to studying economic benefits, the record of this proceeding contains a robust study of the environmental benefits of market participation and how such benefits compare between the various market options. The underlying data of the Brattle Group study may allow Brattle Group or another entity to perform this analysis in an efficient manner.

VI. Conclusion and recommended next steps.

Sustainable FERC Project and Sierra Club recommend that the Commission take the following next steps in this proceeding:

- As soon as practical, issue an interim order finding that the Commission has the authority to direct the utilities to participate in an organized market if it finds that doing so would be in the public interest and the authority to determine in which market the utilities should participate. Pursuant to such findings, the Commission should instruct the utilities to pause any ongoing processes to join an organized market until further notice and instruction from the Commission.

- Hold a series of technical workshops consistent with the recommendations of Western Resource Advocates, Western Grid Group, and Natural Resources Defense Council, \textsuperscript{55} with the addition of a workshop or portion of a workshop regarding GHG emission tracking mechanisms suitable for wholesale market participants.

\textsuperscript{53} Initial Comments of Colorado Energy Office, pp. 3-4.

\textsuperscript{54} Id.

\textsuperscript{55} Initial Comments of Western Resource Advocates, Western Grid Group, and Natural Resources Defense Council, pp. 27-28.
• When the Brattle Group study of the WEIM and the WEIS is complete, require the complete report to be filed into the record of this proceeding and invite the authors of the study to present the study and answer questions at a Commissioner Information Meeting.

• Evaluate the GHG emission impacts of participating in specific markets available to Colorado utilities, and determine whether such market participation would help or hinder Colorado’s ability to meet its greenhouse gas emission reduction targets.

Sustainable FERC Project and Sierra Club again thank the Commission for the opportunity to submit responsive comments and look forward to continued engagement in this proceeding.

Respectfully submitted on December 16, 2019,

BY: /s/ Scott F. Dunbar
Scott F. Dunbar (44521)
Keyes & Fox LLP
1580 Lincoln St., Suite 880
Denver, CO 80203
Phone: (949) 525-6016
sdunbar@keyesfox.com

Counsel to Sustainable FERC Project

John Moore
Senior Attorney and Director, Sustainable FERC Project
Natural Resources Defense Council
20 N. Upper Wacker Drive, Suite 1600
Chicago, Illinois 60606
312-651-7927
moore.fercproject@gmail.com

and
Casey Roberts (51801)
Senior Attorney
Sierra Club Environmental Law Program
1536 Wynkoop St., Suite 200
Denver, CO 80202
(303) 454-3355
casey.roberts@sierraclub.org

Matthew Gerhart (50908)
Staff Attorney
Sierra Club Environmental Law Program
1536 Wynkoop St., Suite 200
Denver, CO 80202
(303) 454-3346
matt.gerhart@sierraclub.org

Counsel to Sierra Club
CERTIFICATE OF SERVICE

I hereby certify that I have on December 16, 2019, I have duly served a true and correct copy of the foregoing REPLY COMMENTS OF SUSTAINABLE FERC PROJECT AND SIERRA CLUB upon all parties via the Public Utilities Commission’s E-Filing system and thereby to be served electronically and automatically on any persons for whom such automatic electronic filing is provided by the Commission’s e-filing system in this docket on this date.

/s/ Scott Dunbar
Scott Dunbar