

To: Senate Transportation and Energy Committee Members
Cc: Senator Hansen, Senator Coram, and Representative A. Valdez
From: Larry Miloshevich of Lafayette (larry.miloshevich@gmail.com)
Re: Proposed amendment to SB21-072

Dear Committee Members, Sen. Hansen, Sen. Coram, and Rep. Valdez:

Colorado's transmission system is "dumb" (lacking in modern technologies), and it would be contrary to the public interest to build new "dumb" transmission when we could insist upon the evaluation and deployment of a set of modern hardware and software technologies collectively known as "Advanced Transmission Technologies" (ATT).

Please require that these Advanced Transmission Technologies be evaluated for all new transmission projects, and adopted if found to be in the public interest.

The Colorado PUC has indicated its strong interest in these technologies, as described below. A recent study of the potential value of ATT on the Southwest Power Pool (SPP) transmission system found that these technologies could double the available capacity of the system at low cost, and thereby enable massive new renewable energy integration quickly and cost-effectively.

Utilities will not seriously consider these technologies voluntarily because ATT are less profitable than traditional "dumb" transmission solutions. Therefore, utilities need a clear mandate to ensure that these common-sense and cost-effective technologies are considered, including for the newly proposed \$1.7B Power Pathway project.

1. BACKGROUND

Advanced Transmission Technologies include:

- **Dynamic Line Ratings (DLR):** Line capacity ratings can be adjusted in real time by measuring the line's actual capacity under ambient conditions (temperature, windspeed, humidity, irradiance, precipitation) using monitoring devices and forecasts. The dynamic line rating almost always allows for more capacity than the traditional fixed rating that is based on worst-case conditions. For example, line capacity will be greater on windy days, just when greater capacity is needed for wind farms producing maximum output, allowing for greater wind energy generation to be interconnected on those lines.
- **Advanced Power Flow Control (APFC):** Refers to devices that apportion power flow to different lines as needed to prevent congestion on any single line. A PG&E pilot study showed that scale deployment of APFC would be "*significantly less costly than a traditional transmission upgrade to increase capacity in most scenarios.*"¹

¹ *Smart transmission: How FERC can spur modernization of the bulk power system.* Herman Trabish. Utility Dive. March 26, 2018. <https://www.utilitydive.com/news/smart-transmission-how-ferc-can-spur-modernization-of-the-bulk-power-syste/519901/>

- **Topology Optimization:** Refers to software that automatically reconfigures power flow around congestion by distributing power more evenly across the system, increasing the transmission capacity of the grid as a whole and reducing congestion charges.

Brattle Group study of ATT on the SPP transmission system:²

The results of this study are remarkable. The study showed that implementing ATT in Oklahoma and Kansas could double the amount of renewable energy connected to the system (thereby reducing interconnection queues), at a cost that is paid for by the benefits within 6 months (i.e., dirt cheap), with substantial ongoing economic benefits. The technologies can be deployed far more rapidly than traditional transmission solutions, with major implications for the rate and cost of decarbonization. Although benefits may not be as large in Colorado as seen in the SPP study, evaluation of ATT on the Colorado transmission system is certainly warranted. And since utilities refuse to do so voluntarily – as evidenced by ignoring these technologies in all past "PUC Rule 3627" Transmission Planning proceedings, as well as the new \$1.7B Power Pathway project³ – legislative direction to evaluate and deploy ATT is needed.

The timing is right to move forward on evaluating and implementing ATT broadly across the Colorado transmission system, in light of:

- Strong Commission interest in these technologies, as indicated by their convening of a Commissioners' Information Meeting (CIM) on this topic in October 2020.⁴
- Commission Decision No. R21-0073 in Rule 3627 Transmission Planning Proceeding No. 20M-0008E, which requires utilities to evaluate ATT in all future 10-year transmission plans (summarized in paragraph 45 of the Decision).⁵
- The immediate need for more available transmission capacity on the existing transmission system in order to reduce the interconnection queue and bring more renewable energy online quickly and cost-effectively.

² *Unlocking the Queue with Grid-Enhancing Technologies: Case study of the Southwest Power Pool.* T. Bruce Tsuchida, Stephanie Ross and Adam Bigelow. Brattle Group. Feb. 1, 2021.

Full report: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle_Unlocking-the-Queue-with-Grid-Enhancing-Technologies_Final-Report_Public-Version.pdf90.pdf

Release page: <https://watt-transmission.org/2021/02/22/unlocking-the-queue/>

GTM article: *Report: 'Grid-Enhancing Technologies' Could Save \$5B per Year by Boosting US Renewables Capacity.* Jeff St. John. Greentech Media. Feb. 24, 2021. <https://www.greentechmedia.com/articles/read/report-grid-enhancing-technologies-could-save-5b-per-year-double-u.s-renewables-capacity-growth>

³ *Xcel proposes \$1.7B transmission investment in Colorado to unlock nearly 5.5 GW new renewables.* Catherine Morehouse, Utility Dive. March 4, 2021. <https://www.utilitydive.com/news/xcel-proposes-17b-transmission-investment-in-colorado-to-unlock-nearly-5/596093/>

⁴ CIM on Advanced Transmission Technologies, Oct. 22, 2020.

Presentations: https://drive.google.com/drive/folders/1BEpdL9aTvpSuMgKivEmRRcCx_tzaLZ-U

Audio: <https://drive.google.com/file/d/1kvidyaHLxz56GYqqPdWfWB5aBiYQDV6i/view>

Summary: <https://energycentral.com/c/pip/shining-light-advanced-transmission-technologies>

⁵ PUC Decision No. R21-0073_20M-0008E. See paragraph 45. https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=940011

- The imminent consideration of the new \$1.7B Power Pathway transmission project, which has not been evaluated for the potential benefits of ATT. ATT could either enable more renewable energy to be interconnected on the proposed system, or ATT could reduce the size and cost of the proposed system while maintaining the same real-life capacity. To proceed with such a costly new development without first evaluating the adoption of ATT would amount to building archaic and inefficient 20th century transmission in the 21st century, to the detriment of ratepayers, renewable energy developers, and the public's interest in rapid and cost-effective decarbonization.

A proposal entitled "*Evaluation of Advanced Transmission Technologies on the Colorado Transmission System*" was submitted by me to the Colorado Coordinated Planning Group (CCPG) with the intent of initiating a broad study of ATT, toward implementing these technologies system-wide at this critical time (the CCPG proposal is available upon request). While it is a requirement of Rule 3627 that the CCPG must consider and respond to this stakeholder proposal, past evidence suggests that it will go nowhere. **Legislative motivation is needed!**

2. PROPOSED AMENDMENT TO SB21-072

There are two main approaches that an amendment could take, and there are several Stakeholders who are interested in this idea, including myself, that the Bill Sponsors could consult regarding specific approaches and redline language (the names of interested stakeholders are available upon request):

- **At a minimum**, all new-build transmission in the State of Colorado – including the \$1.7B Power Pathway project – should be required to seriously evaluate the impact of deploying ATT on the lines (especially DLR which is a no-brainer) and to adopt those measures that are found (**by an independent evaluator**) to be cost-effective or otherwise in the public interest. One possibility is to include this requirement in the PUC's CPCN (Certificate of Public Convenience and Necessity) process for evaluating and approving significant capital assets. However, this requirement needs to apply to all Colorado transmission owners/developers, not just investor-owned utilities. Allowing new "dumb" transmission like Power Pathway to go forward without such an assessment harms ratepayers and renewable energy developers, and slows the rate of decarbonization of Colorado's electric system.
- **More desirable and more effective** would be a system-wide study of the Colorado transmission system along the lines of that described in the aforementioned CCPG proposal, in order to identify and characterize the full benefit of these modern technologies on our system. ATT would open up more capacity for rapidly adding additional renewable energy generation on existing lines, and would reduce curtailment of renewable energy, and reduce present or future congestion and associated congestion charges. The Brattle SPP study provides a good example of the type of evaluation that Colorado needs. While the study could be funded from the PUC Fixed Utility Fund, it could also be funded by a rider on ratepayer bills given that ratepayers will receive the economic benefits of ATT deployment. Transmission owners should be

required to implement any technologies that are found (by an independent evaluator) to be cost-effective or otherwise in the public interest, with full cost recovery of course.

It is relevant to note that a system-wide assessment of the potential impact of ATT is desirable in order to better understand where, and how much, new transmission is needed to meet state policy goals such as 80x30. Therefore, it is desirable to have a baseline system-wide study in hand for the purpose of informing consideration of any new transmission project being considered in a CPCN proceeding.

Possible location for amendment language in SB21-072 (Introduced version):

On page 4, after line 9, add an item (III) that requires the PUC to:

- 1) evaluate the impact of ATT on the existing transmission system before any new transmission project is evaluated, in order to better understand the needed characteristics of any proposed new transmission; and
- 2) require an evaluation of the impact of ATT on any new transmission project, and require implementation of the technologies that are found to be cost-effective or otherwise in the public interest, as determined by an independent evaluator, as a condition of approving a CPCN.

Thank you for your consideration!

Senate Bill 21-072, March 9, 2 pm, SCR 357
Senate Transportation & Energy
Testimony of Bill Levis, AARP Colorado

I am Bill Levis, a volunteer advocate for AARP Colorado. I was Consumer Counsel representing consumers before the Public Utilities Commission in energy and telecom proceedings from 2009-2013 as well as interim director of the National Association of State Utility Consumer Advocates. As public policy director at MCI for nearly 20 years, I appeared before public utility commissions and legislatures in 20 states.

On behalf of our nearly 700,000 members in Colorado, AARP supports cost-effective “efforts to increase the percentage of electricity produced from renewable sources. Sustainable energy policies should ensure all consumers can afford enough energy to meet their basic needs..”

SB21-072 is a solution looking for a problem that does not exist.

SB19-236, section 12, the Colorado Transmission Coordination Act, C.R.S. 40-2.3-102, already requires the PUC to open a proceeding by January 2020 to investigate costs and benefits of energy imbalance markets, regional transmission organizations, power pools and joint tariffs. The Commission is to hold hearings by July 2021 and to issue a decision by December 2021 whether participation in an EIM or RTO is in the public interest. Assuming the PUC decides electric utility participation is in the public interest, the Commission is to direct by July 2022 that utilities take appropriate action including joining an EIM or RTO.

Unlike Texas where 4 million customers were without electricity last month during the week-long cold snap, our state didn't have brown or blackouts. Texas' electric and natural gas markets have been basically exempt from regulation for 20 years. California suffered similar blackouts last summer.

Colorado's utilities either are regulated by the PUC pursuant to article XXV of our state constitution and title 40 of our statutes or by municipalities or rural electric associations.

Colorado, part of the Western Interconnect, has an abundance of electricity. When Aquila, serving Pueblo, was sold to Black Hills, Xcel chose not to continue providing electricity so Black Hills had to build several natural gas plants. Only after Black Hills committed to natural gas did Xcel offer to sell it electricity because its own electric use was not growing. Both Xcel, headquartered in Minneapolis, and Black Hills, in Rapid City, are in 8 states. In addition, Tri-State, the wholesale power provider for many REAs in Colorado, is in 4 states.

Colorado utilities already are members of two imbalance markets with other states. During the February cold snap, both Southwest Power Pool, a majority of whose power is coal, and MISO, the midwest RTO, imposed rolling blackouts in their states, something not necessary

in Colorado. Commission oversight ensured that Colorado did not suffer similar power outages, even though the temperatures in Denver dipped to -10°.

Our wind turbines have necessary heaters for cold weather, our natural gas lines are buried at sufficient depths to protect from freezing and power plants are protected from extreme cold.

When a state joins an RTO, transmission control transfers to the Federal Energy Regulatory Commission. Decisions are made by the FERC even if it does not benefit your state. States such as CT, IL, MD and NJ are considering leaving RTOs because they don't see the benefits in paying for power in other states.

In MISO, state commission staff attend up to 700 meetings a year adding costs for the states and their consumers. The return on equity the FERC approves is significantly higher than what a state commission would approve. FERC even gives a bonus ROE for being in an RTO. No wonder they are so popular with utilities. All this is bad news for consumers as at one point FERC was allowing returns as high as 11.74%--far greater than allowed by state PUCs like ours.

An RTO also means additional multi-state transmission lines with socialized costs. When a proposal was made to run a line from the San Luis Valley to Pueblo, residents reacted negatively. Imagine the reaction if Colorado joined an RTO, requiring lines west to Utah, north to Wyoming, south to New Mexico, east to Kansas. And the legislation even says land can be condemned for "regional" benefit.

Our state doesn't need to mandate that state utilities join an RTO by 2030. It is a solution without a problem.

Thank you.



Support for Senate Bill 21-072: Public Utilities Commission Modernize Electric Transmission Infrastructure

I am Jeffrey C. Wadsworth, President and CEO of Poudre Valley Rural Electric Association (PVREA), a member-owned electric distribution cooperative serving approximately 120,000 people and more than 48,000 homes and businesses in northern Colorado. Our service territory spans 2,000 square miles across Larimer, Weld and Boulder counties.

PVREA strongly supports SB 21-072 as we believe a robust Regional Transmission Organization (RTO) is crucial to our ability to meet our goal of providing our members with 80% renewable energy by 2030.

As we work towards our environmental commitments, we remain steadfast in our focus to ensure the electricity we deliver to our members is reliable and affordable, both pillars of our cooperative business model.

We believe RTOs play an important role in making the electric grid more resilient by allowing for the maximization of an integrated grid to draw on all available resources across a much larger geographical footprint.

An RTO structure would also allow for regionally coordinated market access resulting in lower electricity costs and greater reliability not just for PVREA, but for all residents of Colorado; spurring new renewable energy and storage projects while addressing reliability concerns as we transition to a carbon-free future.

In closing, PVREA respectfully urges the committee to pass SB 21-072 so that we can keep Colorado's electricity affordable, reliable, and increasingly clean. I appreciate the opportunity to testify on this important issue.



March 5, 2021

Senate Transportation and Energy Committee
Colorado General Assembly
200 E. Colfax Avenue
Denver, CO 80203

RE: HB21-072– Public Utilities Commission Modernize Electric Transmission Infrastructure

Dear Members of the Senate Transportation and Energy Committee:

My name is Ann Sutton living in Westminster CO. This testimony represents the position of the League of Women Voters of Colorado on this bill to modernize electric transmission infrastructure. The League supports expansion of renewable energy and contribution to our transition away from dependence on fossil fuels for electricity generation.

Several recently published studies have demonstrated that electric transmission build-out with interstate coordination can result in lowering the cost of decarbonizing the electric grid, reducing the need for storage capacity, and offering more efficient siting for wind and solar.

https://www.utilitydive.com/news/new-transmission-approaches-can-cut-billions-in-decarbonization-costs-mit/593240/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202021-01-13%20Utility%20Dive%20Newsletter%20%5Bissue:31855%5D&utm_term=Utility%20Dive

<https://www.greentechmedia.com/articles/read/study-transmission-is-the-key-to-a-low-cost-decarbonized-u.s-grid>

There are large benefits to power-sharing across regions with variable wind and solar generation, reducing the need for storage such as batteries or other systems. Further, remote renewable power sources can be connected to electricity load centers- areas of power demand by consumers- rather than building solar and wind arrays near to cities, which may be more expensive and disruptive to existing urban development.

Transmission developments have slowed in recent years due to complexities of building massive projects across multiple jurisdictions ...through legal or regulatory challenges. In the current bill, CETA may help reduce complex challenges in funding, building, and regulations.

A further, parallel benefit in this bill is supporting expansion of broadband within Colorado by using transmission easements for building broadband infrastructure. The Pandemic has dramatically revealed our state's deficiencies in providing this service, especially to rural or under-resourced areas. The League supports social and economic justice for all Coloradans.

Thank you for considering this important issue.

Respectfully,

Ann Sutton, Volunteer Lobbyist
League of Women Voters of Colorado
1410 Grant Street, Suite B-204
Denver, CO 80203



TO: Colorado Senate Transportation and Energy Committee

FROM: The Colorado Renewable Energy Society (CRES)

DATE: March 11, 2021

REGARDING: SB21-072

Dear Members of the Colorado Senate Transportation and Energy Committee:

CRES would like to thank the sponsors of SB21-072 for the hard work that has gone into advancing this bill related to developing electric transmission facilities in Colorado. Ensuring the availability of adequate transmission infrastructure for renewable clean energy is critical for Colorado to meet its clean energy goals. CRES supports the creation of the Colorado Electric Transmission Authority; CETA's power to issue lower interest revenue bonds¹ and joining a regional transmission authority when the time is right. This new type of state transmission authority is working in New Mexico and has lowered their costs and enabled \$1 billion of investments in renewable energy in NM.² To this end, we are in support of the proposed bill, but ask for consideration of the amendments below.

CRES recognizes that this issue is complicated. Changes such as those proposed in the bill are rarely easy, especially with the many parties involved that will have their own perspective. We thank the bill sponsors for their thoughtful approach which promotes more efficient planning and less expensive transmission by using a state funding authority.

We respectfully request consideration of the following amendments, which we believe will provide clarity to those who will have the responsibility to implement the directive of the bill:

1. Allow the PUC 270 days instead of 180 days for decision making (Section 1, CRS 40-2-126 (4), page 4, line 15). The determination of need and the assessment of design for new transmission facilities is a complex process. It would not be prudent to have the PUC time-pressured into making decisions which might not have been fully vetted. Worse yet would be approval by default of expensive transmission facilities that may not be needed or may not serve the public interest.

¹ Likely lower interest than paying for investor owned utility transmission projects approved through the PUC.

² See:

<https://www.nmlegis.gov/handouts/WNR%20072618%20Item%208%20NM%20RETA%20Presentation.pdf>

2. Add language to ensure that over-building of transmission facilities does not occur, and that forward-looking consideration is given to alternatives, including the impact to load from electric vehicles (EVs). We suggest the following addition:

Section 1, CRS 40-2-126 (3) (a), page 4, after line 9, add (III) as follows:

(III) IS A COST-EFFECTIVE USE OF RATE PAYER MONEY AND WILL BE IN THE LONG-TERM PUBLIC INTEREST IN LIGHT OF ALTERNATIVES INCLUDING INCREASING DEPLOYMENTS OF DISTRIBUTED GENERATION AND NON-TRANSMISSION ALTERNATIVES, THE ADDITION OF ADVANCED TRANSMISSION TECHNOLOGIES TO EXISTING AND PLANNED TRANSMISSION LINES, AND THE CAPACITY THAT WILL BE OPENED UP BY THE RETIREMENT OF EXISTING GENERATION INCLUDING COAL AND NATURAL GAS PLANTS

3. Improve the bill by referencing a requirement for all new electric transmission facilities to have current state-of-the-art cybersecurity installed. While this may seem obvious or redundant, it is a significant risk that we believe is best addressed directly in the bill.

CRES is supportive of the requirement for transmission utilities to join regional transmission organizations (RTOs) by January 1, 2030. Recent studies have shown that RTOs bring significant cost savings, job creation, and reduce greenhouse gases.³ For ease of implementation, we suggest limiting the RTO definition section in the bill to only those items that describe what an RTO is, and striking the many auxiliary criteria listed. We believe the RTO requirement is a cornerstone of the bill. If it is removed, then we recommend a suitable replacement such as requirements to join an Energy Imbalance Market. In this regard, Colorado's current system must be changed to get us to our goals as put forth in the state's 2019 Climate Action Plan.

Again, CRES thanks the sponsors of this bill for their hard work and their dedication to improving the transmission network in Colorado. We appreciate your service to our state.

Sincerely,



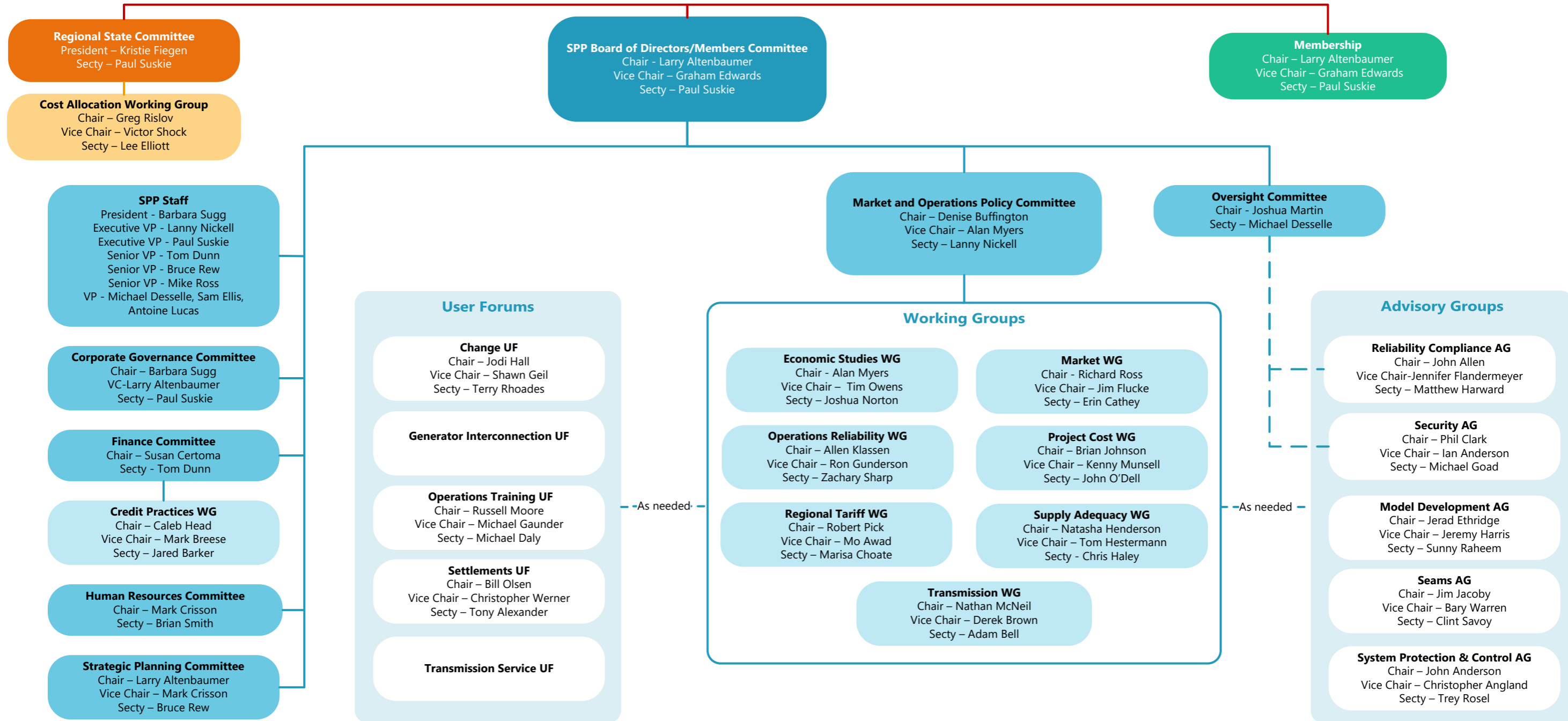
Vincent P. Calvano

Chair: CRES Policy Committee

Colorado Renewable Energy Society

³ See : [Study: Multiple benefits to coordinated wholesale market \(irea.coop\)](#)).

Group Organizational Chart



Decision No. C19-0756

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.

**COMMISSION DECISION OPENING A PROCEEDING,
DESIGNATING COMMISSIONER KONCILJA
AS HEARING COMMISSIONER, AND SOLICITING
INPUT FROM INTERESTED PARTICIPANTS**

Mailed Date: September 17, 2019
Adopted Date: September 11, 2019

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- A. The Commission Orders That:18
- B. ADOPTED IN COMMISSIONERS’ WEEKLY MEETING September 11, 2019.20

I. BY THE COMMISSION

A. Statement

1. Pursuant to the Colorado Transmission Coordination Act of 2019, §§ 40-2.3-101 and 102, C.R.S. (CTCA),¹ the Public Utilities Commission (Commission or PUC) opens this proceeding to collect comments and other information helpful in analyzing the potential advantages and disadvantages in joining one of the types of energy markets identified.² The Commission designates Commissioner Frances Koncilja as Hearing Commissioner,³ pursuant to § 40-6-101(2)(a), C.R.S., to work with the Staff of the Colorado Public Utilities Commission (Staff), stakeholders, and other interested participants to collect and organize information, conduct public comment hearings, and make recommendations to the full Commission as to possible next steps in conducting the analysis required by § 40-2.3-102(2), C.R.S., and to aid the Commission in its determination of the public interest as required by § 40-2.3-102(3), C.R.S.

2. CTCA directs the Commission to investigate the costs and benefits to electric utilities, other generators, and Colorado electric utility customers resulting from electric utility participation in energy imbalance markets (EIMs), regional transmission organizations (RTOs), power pools, or joint tariffs. Electric utilities are defined in § 40-1-103(2)(a), C.R.S., to include

¹ CTCA, attached as Exhibit A

² Section 40-2.3-102(1)-(4), C.R.S., refer to energy imbalance markets, regional transmission organizations, power pools and joint tariffs.

³ At the Commissioners’ Weekly Meeting on June 26, 2019, the Commissioners agreed to divide responsibilities for the first stages of implementation of the new obligations in the PUC Sunset Bill, Senate Bill 19-236 with Chairman Ackermann having responsibility for Distribution Resource Planning, Commissioner Gavan for Performance Based Ratemaking, and Commissioner Koncilja for CTCA.

“[e]very cooperative electric association, or nonprofit electric corporation or association, and every other supplier of electric energy, whether supplying electric energy for the use of the public or for the use of its own members.” The CTCA directs the Commission to consider the impact of these four different market constructs on retail and wholesale electricity rates for both participating and non-participating entities, transmission rates, the commitment and dispatch of generation, operating costs, reserve requirements, renewable integration, and regional infrastructure investment. The interaction of these market options with system reliability must necessarily be included in this investigation.

3. CTCA sets deadlines for four specific Commission actions:

- **January 1, 2020** – “The Commission shall open a proceeding to investigate the potential costs and benefits to electric utilities, other generators, and Colorado electricity customers that would arise from electric utilities” participating in a regional electricity market,⁴
- **July 1, 2021** – “The Commission shall hold a hearing for public comment to consider the information received during the Commission’s investigation...”⁵
- **December 1, 2021** – “The Commission shall issue a decision determining whether electric utilities participating in [an electricity market] is in the public interest.”⁶
- **July 1, 2022** – If the Commission determines that electric utility participation in a one of the specified types of markets is in the public interest the Commission “shall direct electric utilities to take appropriate actions and conduct such proceedings as the commission deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.”⁷

4. We open this miscellaneous proceeding to conduct the investigation contemplated in the first Commission obligation above. We choose to proceed through a miscellaneous

⁴ § 40-2.3-102(1), C.R.S.

⁵ § 40-2.3-102(2), C.R.S.

⁶ § 40-2.3-102(3), C.R.S.

⁷ § 40-2.3-102(4), C.R.S.

proceeding in order to allow the Hearing Commissioner to issue orders and make recommendations to the full Commission as to next steps. This proceeding will serve as a repository for the filing of comments, studies and analyses, and will serve as a platform from which to conduct workshops, hold public hearings, pose questions, discuss processes, and issue orders.

5. In order to build on information from other Commission proceedings and regional market studies and experience, Staff is directed to file the most current and relevant documents into this proceeding as described below.

6. Through the course of this miscellaneous proceeding, we will invoke, pursuant to Rule 4 Code of Colorado Regulations 723-1-1111 of the Commission's Rules of Practice and Procedure, the "Permit, but Disclose" process. Interested persons may schedule *ex parte* presentations to a Commissioner that shall include Commission Staff provided that the contacts relate solely to the CTCA investigation, and do not concern any matter pending before the Commission in another proceeding. Within two business days following a permitted presentation, the person requesting the meeting is required to file in this Proceeding a letter disclosing the contact with a copy of materials provided to the Commissioner during the meeting.

7. We will attempt to accommodate all reasonable requests for *ex parte* meetings, subject to the schedule and availability of each Commissioner. To schedule an *ex parte* presentation with a Commissioner, an interested person should contact the Executive Assistants to the Commissioners and should clarify that the presentation is associated with this Proceeding.

8. We encourage stakeholders to file a statement of interest in participating in this proceeding. Participants should submit initial comments no later than November 15, 2019. Comments responsive to those initial filings may be made no later than December 15, 2019.

II. BACKGROUND

A. Commission History Investigating and Implementing Markets.

9. Evaluation of markets and participation by the investor owned utilities in Colorado in various types of markets is not new to the Commission. The Commission has been involved in implementing and analyzing the benefits and detriments of market participation by Colorado investor owned electric utilities since at least 2011.

10. The Commission examined the “implications of a potential regional Energy Imbalance Market (EIM) that may include Colorado electric utilities” in Decision No. C11-1347 in Proceeding No. 11M-998E issued December 15, 2011 at p. 1. More recently, the Commission has been monitoring the benefits to Colorado utilities of short-term imbalance energy trading through the participation of Public Service Company of Colorado (Public Service) and Black Hills in the Joint Dispatch Agreement (Proceeding No. 16A-0276E).⁸

11. In addition, Public Service has decades of experience in bilateral market transactions pursuant to their Trading Rules, which were originally approved by the Commission in 2000 and most recently updated in Proceeding No. 13A-0689E (Settlement between Public Service, Staff, and the Office of Consumer Counsel).

12. In October 2016, Decision No. C16-1002 opened Investigatory Proceeding No. 16I-0816E to “receive and develop information and analysis related to the activities of the

⁸ Public Service filed a semiannual report in Proceeding No. 16A-0276E. This report details “Generation Cost Savings,” “Energy Sales Margins,” and “Net change in carbon emissions” by participating entity.

Mountain West Transmission Group (MWTG).” MWTG was comprised of nine transmission owners (Basin Electric Power Cooperative, Black Hills Colorado Electric, LLC, Black Hills Power, Inc., Cheyenne Light Fuel & Power Company, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Association, Inc., Western Area Power Administration, Loveland Area Projects and Western Area Power Administration, Colorado River Storage Projects).

13. Between March 2017 and March 2018, the Commission held five Commission Information Meetings (CIMs) to investigate issues related to MWTG joining the Southwest Power Pool (SPP). In addition to active participation by more than a dozen entities and reports from MWTG utilities regarding the status of their negotiations and proposed market operation, the Commission heard stakeholders present and discuss information related to the benefits of markets for renewables, ratepayer risks and concerns, reliability coordination, transmission rates, planning and cost allocation, RTO governance, Federal Energy Regulatory Commission (FERC) process and jurisdiction, and cost benefit categories. The CIM presentations, as well as comments and recommendations from stakeholders and a variety of white papers and market-related reports are all available in the MWTG Investigatory Proceeding (16I-0816E). Staff will file a subset of those documents that are the most current and relevant to the instant investigation in this new proceeding for ease of reference.

14. Public Service announced in April 2018 that it was withdrawing from the negotiations to join SPP, citing limited benefits and uncertain costs. This effectively ended the

MWTG effort and the Commission's investigation.⁹ However, the MWTG Investigatory Proceeding is an invaluable resource to this current market investigation effort.

III. CURRENT STATUS OF RELIABILITY CO-ORDINATION

15. In January 2018, amidst the MWTG effort to join the SPP, the California Independent System Operator (CAISO) announced that it would leave Peak Reliability, become its own reliability coordinator (RC) – to be known as “RC West” – and also offer that service to other utilities. Although the MWTG effort ended soon thereafter, SPP separately offered to provide RC services as a non-membership option for any interested western utilities. To date, 39 balancing authorities and transmission owners have finalized service agreements with RC West¹⁰ and 14 utilities (including those within the Public Service balancing authority) have committed to SPP's RC service. The full transition from Peak Reliability will be completed by the end of 2019.¹¹

IV. CURRENT AND PROPOSED MARKET OFFERINGS IN THE WESTERN INTERCONNECTION

16. Several of the transmission operators within Colorado are currently considering joining an imbalance market. Both CAISO and SPP are offering imbalance services in Colorado.¹²

⁹ The MWTG proceeding was closed on October 17, 2018.

¹⁰ <http://www.aiso.com/informed/Pages/RCWest/Default.aspx>

¹¹ <https://www.wecc.org/EventAnalysisSituationalAwareness/Pages/Certification.aspx>

¹² On August 30, 2019, Xcel Energy issued a press release indicating that Xcel Energy, Black Hills Energy, Colorado Springs Utilities, and Platte River Power Authority (*i.e.*, current JDA members) have “launched an in-depth study to determine the best course of action” related to joining an energy imbalance market. They have hired a consulting firm to evaluate the benefits and costs of participation in either SPP's WEIS or CAISO's WEIM. The study results are expected by the end of September and a decision is expected by the end of the year.

17. The CAISO-administered Western EIM was established in 2014 with Pacificorp as the first participant outside California.¹³ Additional utilities have joined in each year since then and by 2022, greater than 70 percent of the Western Interconnection's load will be participating in the Western EIM.¹⁴ CAISO has also proposed to develop an Extended Day-Ahead Market (EDAM) for EIM participants and is currently conducting a feasibility analysis and discussing issues with stakeholders.¹⁵

18. Citing its expanded role as a Western RC, on April 4, 2019, SPP announced its interest in offering a Western Energy Imbalance Service (WEIS) to utilities in the Western Interconnection. On June 17, 2019, it released its specific WEIS proposal.¹⁶ SPP requested action on or before September 3rd regarding its WEIS offering. If it receives sufficient commitments by then, SPP proposes to have the EIS up and running by February 2021. On September 9, 2019, Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, Inc., and the Western Area Power Administration announced their decision to join SPP's Western Energy Imbalance Service.¹⁷

¹³ WEIM is a voluntary 15-minute and 5-minute real-time energy market operated by the CAISO. The WEIM utilizes transmission capacity made available to the EIM and security-constrained economic dispatch (SCED) to optimize real-time energy dispatch and resolve energy and load imbalances across the footprint.

¹⁴ Current map available here: <https://www.westerneim.com/Pages/About/default.aspx>

¹⁵ See <http://www.caiso.com/informed/Pages/StakeholderProcesses/Day-AheadMarketEnhancements.aspx>. If pursued, the EDAM would likely be a voluntary additional market option for entities participating in the WEIM.

¹⁶ See <https://www.spp.org/weis>. This market's construct is still being developed but would likely be very similar to the Western EIM and would utilize SCED to optimize real-time energy dispatch and resolve imbalances. Most likely participants appear to be in Colorado, and parts of Wyoming, New Mexico, and Arizona (and are mostly comprised of former participants in the MWTG effort).

¹⁷<https://www.tristate.coop/three-regional-utilities-announce-decision-join-southwest-power-pool-market>

A. Discussion

19. The Commission needs to understand how utility market participation may change whether Colorado is an importer or exporter of electricity at different times of the day and/or year; what the fuel source is for the electricity being imported and exported; how these imports and exports may change over time; information on the geographic footprint of Colorado's trading partners; the impact this market activity has on the ultimate electricity bill paid by Colorado consumers; and who determines how the potential cost of new transmission is paid for.

20. As noted above, the purpose of this investigation is to help inform the Commission of the costs and benefits, impacts to ratepayers, regulatory and policy implications, and impact on renewable integration of different levels of regional market participation. As part of this investigation, the Commission seeks to determine the conditions under which these costs, benefits, and impacts materialize. This investigation should assist an ultimate Commission determination of what is in the public interest and how to proceed with the next steps.

1. Colorado Energy Policy

21. The CTCA is part of a broader set of recent statutory changes, many of which articulate state environmental policy goals pertinent to the electric utility industry. As explained in more detail below, the 2019 legislative session made substantive changes to the energy policies of the State of Colorado.

22. In addition to statutory changes, recently elected Governor Jared Polis has issued executive orders and made public statements regarding Colorado's renewable energy goals. In

these statement, the Polis administration “has set a goal of 100% renewable electricity by 2040.”¹⁸

23. In recent years, Colorado has been working under the Renewable Energy Standard laid out in § 40-2-124, C.R.S. This statute requires 30 percent of retail electricity sales to be supplied by renewable energy by 2020 for Investor Owned Utilities.¹⁹ The Renewable Energy Standard for most electric cooperatives is 20 percent and for other cooperatives and large municipal utilities the standard is 10 percent.

24. Two bills from the 2019 legislative session extend these utility environmental targets. The first bill, House Bill (HB) 19-1261, established statewide goals to reduce 2025 greenhouse gas emissions from the 2005 baseline by at least 26 percent, 2030 emissions by 50 percent, and 2050 emissions by 90 percent. The goals in HB19-1261 apply economy wide, not just to the electric sector. The second bill, Senate Bill 19-236, directed “electric [utilities] with greater than five hundred thousand customers in the state or any other electric utility that opts in...” to file a Clean Energy Plan to reduce carbon emissions to 80 percent below 2005 levels by 2030 and reduce atmospheric carbon emissions by 100 percent by 2050.²⁰

25. The West is not homogeneous in regard to state environmental and other policy goals or in regard to existing fossil and renewable generation assets. Electricity service providers in other states that might participate in electric markets and with whom Colorado utilities may

¹⁸ See: <https://www.colorado.gov/governor/environment-and-renewables> and <https://www.colorado.gov/governor/2019-executive-orders>

¹⁹ See § 40-2-124(1)(c), C.R.S.

²⁰ Currently, only Public Service is obligated to file a Clean Energy Plan based on the statutory definition of a “qualifying retail utility.”

trade, could have less or more demanding decarbonization and/or renewable energy goals. These factors need to be considered in approaching the evaluation of the potential costs and benefits of electricity market regionalization in Colorado and the impact of regionalization in supporting Colorado's policy goals.

2. Colorado's Transmission Infrastructure

26. Colorado is electrically located on the edge of the Western Interconnect with limited DC ties to the East and limited AC ties to the West. Colorado is surrounded by states of relatively low load density with large geologic barriers between them. In recognition of this lack of interconnection, both the 2017/2018 SPP proposal to provide RTO services to the MWTG and the current energy imbalance service offerings treat the MWTG footprint (or portions of the MWTG footprint) as a geographic market distinct from either the rest of SPP or other CAISO EIM participants in the West.

27. One benefit that may be considered in this investigation of regional market participation is the potential for increased access to renewable generation from other geographic regions and the potential to export local excess renewable generation to other geographic regions without paying fees to multiple transmission providers. Regional diversity of renewable generation may help compensate for the inherently intermittent nature of individual renewable resources. This investigation should evaluate the degree to which this geographic diversity could help support the state's statutory requirements and energy policy goals.

28. The Commission is concerned that Colorado has limited transmission interconnection with the rest of the Western Electricity Coordinating Council region (WECC) and with SPP states to the East and that this lack of interconnection may limit the benefits of

regional markets absent significant infrastructure investment. More than one stakeholder has observed that “if you love wind generation, you must love transmission.” The Commission will need to assess the costs, benefits, feasibility, cost recovery, and other implications of major transmission investment as part of this market investigation.

3. Current and Future Role of Storage

29. In Public Service’s most recent electric resource plan Proceeding No. 16A-0396E, the Commission approved the acquisition of 275 megawatts of battery storage (configured as “solar plus storage” facilities) on September 10, 2018 in Decision No. C18-0761. These battery projects provide four-hour storage capability. Adding these batteries will provide an opportunity to determine how to utilize storage resources most effectively for integrating higher penetrations of variable renewable generation. It is not clear what role storage will play in renewable integration in the medium to long-term and to what extent batteries could reduce the overall need for regional transmission. This will depend in part on how quickly storage technology advances, particularly in the development of long-term (seasonal) storage, and how much costs decline.

4. Joint Dispatch Agreement (JDA)

30. In 2016, Public Service, Black Hills Colorado Electric, LLC, and Platte River Power Authority entered into a Joint Dispatch Agreement (JDA) to dispatch their generating units on a sub-hourly basis to serve their combined load with the most economic resources. Similar to participants in other energy imbalance markets, participants in the JDA realize short-term production cost savings and earn margins from additional sales. The combined annual benefit for JDA participants has ranged from approximately \$2 million to \$3.7 million in the first

years of operation.²¹ The JDA is currently in the process of expanding to include the City of Colorado Springs Utility.

31. In a letter agreement between Public Service and former Commission Chairman Joshua Epel, dated August 21, 2015,²² Public Service agreed to a number of provisions regarding the reporting and administration of the JDA. In this agreement, Public Service committed that “[i]n the event [Public Service] intends to file with the FERC a proposal to establish an energy imbalance market, or another related or similar construct, [Public Service] agrees to notify the [Commission] at least ninety (90) days in advance of such a filing. [Public Service] also agrees to provide the [Commission] with a confidential briefing of such proposal at least thirty (30) days in advance of filing with the FERC.” This advance notice will allow the Commission to consider the procedural complexities such a filing would introduce.

5. Mountain West Transmission Group Conclusions

32. During the MWTG negotiation, several consulting firms were used to model the costs and benefits of market participation. MWTG consultants performed production cost modeling of both the joint tariff and full RTO constructs.²³ Based on the preliminary modeling results, the MWTG concluded that a joint transmission tariff alone would not produce enough savings to justify the effort, but that RTO participation was worth pursuing. At the time, energy imbalance market and day ahead market constructs were not evaluated. The Commission

²¹ See “Semiannual JDA Reports” filed in Proceeding No. 16A-0276E.

²² See Attachment SLP-2 to the Answer Testimony of Staff witness Sharon Podein in Proceeding No. 16A-0276E.

²³ The Joint tariff was modeled for 2016 only. Full RTO was modeled for 2016 and 2024 and examined current trends, high natural gas prices, and “market stress” scenarios. Both sets of results were compared to a status quo bilateral market analysis. The report points out that the production cost modeling did not include simulation of intra-day and real-time operations and thus was missing potential benefits achieved through such coordination.

proposes to build on the preliminary findings of the MWTG regarding joint tariffs and full RTO in conducting this investigation into the benefits of regional market participation.

33. In a report to SPP stakeholders dated March 19, 2018, SPP indicated that the cost of coal generation in Colorado was less expensive than the cost of coal generation in SPP and forecast increased Colorado coal generation if the MWTG were to join SPP.²⁴ This observation raises questions regarding the impact of market participation on generation mix, particularly as Colorado accesses markets with substantially different generation fleets and state environmental goals.

6. Department of Energy Market Investigation (DOE Study) and Other Market Studies of Interest

34. Four Western states, including Colorado, recently received funding from the U. S. Department of Energy (DOE) to perform an investigation into the benefits of greater integration in Western electricity markets. The four participating states are Utah, Montana, Idaho, and Colorado with the Utah Energy Office functioning as the Principal Investigator. This study includes a consultant (Energy Strategies) performing utility-grade production cost modeling of several potential market footprints.

35. The draft project schedule calls for modeling results to be available the third quarter of 2020 and additional deliverables to be completed in early 2021. This modeling effort is currently in the stage of scoping the market constructs, geographic footprints, and scenarios to be evaluated. Staff will have more insight into the extent of overlap between the CTCA and this

²⁴ SPP Staff report *10-year Costs and Benefits to SPP Members of Integrating Mountain West Transmission Group: Quantitative Analysis of Costs and Benefits*, March 19, 2018, pp. 16-17.

modeling effort in the next few months. Staff is directed to file into this proceeding updates from the DOE Study as they become available.

36. As a preliminary step in the Utah-led DOE-funded investigation, Energy Strategies compiled a list of other recent market studies, many of which may offer insights into the issues, costs, and benefits that should be considered in the Commission's evaluation. In addition to the MWTG studies, Staff is directed to collect pertinent information from those analyses and to file them into this proceeding.²⁵

7. Reliability Concerns that Must Be Addressed in this Proceeding

37. Although not specifically identified in the CTCA, the Commission considers reliability a key consideration in any major shift in utility operations and governance such as joining an organized market.²⁶ The WECC region is currently transitioning from essentially two Reliability Coordinators (Peak Reliability and the Alberta Electric System Operator) to a total of five RCs (California Independent System Operator's RC West, Southwest Power Pool, BC Hydro, Gridforce Energy Management, LLC, and the Alberta Electric System Operation). Reliability considerations should play a significant role in any evaluation of joining or forming a new market construct. Staff is closely following the activities of the Western Interconnection Regional Advisory Body (WIRAB), which advises the North American Electricity Reliability

²⁵ These studies include Western EIM service evaluations including quarterly benefits estimates/reports, individual utility evaluations regarding Western EIM participation, and California's Senate Bill 350 study evaluating the impacts of a regional market.

²⁶ The Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, require jurisdictional utilities to address reliability in Electric Resource Planning (3600 through 3619), Transmission Planning (Rules 3625 through 3627), the Renewable Energy Standard (Rules 3650 through 3668) and utility Applications (Rule 3703) and establish standards for "Operating Reliability and Safety" (Rules 3910 through 3929). In addition, the Commission's Rules require utilities to report major events resulting in a loss of service (Rules 3250 through 3253).

Council, FERC, and WECC on reliability issues.²⁷ Staff is directed to file into this proceeding relevant information developed in WIRAB proceedings.

8. Market Definitions and Solicitation of Comments

38. The Commission proposes to use the following more detailed definitions of the various market options in this proceeding and invites comments on these definitions:

- a) *Power Pool* – Power Pool refers to a system of trading wholesale electricity that determines which of a set of pooled generators are most economic to serve load and set the price for that period. The Joint Dispatch Agreement (JDA) operating today is an example of a power pool and serves as the base case market construct. Parties to the Joint Dispatch Agreement pool generating resources to meet their combined load using the least cost dispatch.
- b) *Joint Tariffs* – Joint Tariff refers to a single rate that applies for transmission service over the routes or lines of two or more transmission providers. This market construct was studied during the Mountain West Transmission Group (MWTG) investigation.
- c) *Energy Imbalance Market (EIM)* – An EIM refers to a real-time bulk power trading market that allows participants to buy and sell unscheduled energy using available/unscheduled transmission. The California ISO (CAISO) is currently operating an EIM in the West (the WEIM) and has offered to stand up an EIM market to serve Colorado entities. The Southwest Power Pool (SPP) is currently working with interested parties to develop a Western Energy Imbalance Service (WEIS) market.
- d) *Regional Transmission Organization (RTO)* – An RTO refers to an independent electric transmission operator that provides wholesale transmission services to more than one provider of electric services. An RTO incorporates centralized real-time dispatch and day ahead unit commitment with a joint transmission tariff, An RTO also consolidates reliability obligations, transmission planning and cost allocation, and transfers operational control of the transmission system to the system operator. An RTO introduces new sources of potential benefits but also the potential for substantial additional costs and a host of governance issues that other market constructs largely avoid.
- e) *Extended Day Ahead Market (EDAM)* – The EDAM is an initiative conceptualized by the CAISO and Western EIM entities to extend the benefits of the EIM to the day-ahead market. EDAM would enable day-ahead unit commitment and dispatch across the participating footprint, but would not encompass transfer of operational control or any planning responsibilities to the CAISO. While this market construct could have significant benefits beyond the EIM, it does start to raise governance and market power/monitoring issues. While the EDAM was not specifically identified for

²⁷ WIRAB was created by Western Governors under Section 215(j) of the Federal Power Act. Section 215 of the FPA provides for the establishment of a federal regulatory system of mandatory and enforceable electric reliability standards for the nation's bulk power system. WIRAB's membership is composed of representatives from all states and international provinces that have load within the Western Interconnection. See <https://westernenergyboard.org/wirab/who-what/>

investigation by the Colorado Transmission Coordination Act, PUC Staff believe this market construct would be appropriate to include in this investigatory effort.

39. We also invite comments on any or all of the following questions and issues:

- a) *Costs and Benefits* – Modeling studies to date have primarily addressed the savings attributable to generation commitment and dispatch optimization provided by integrated markets (as determined by production cost modeling). What other costs and benefits should be quantified for purposes of this investigation? What other costs and benefits cannot be quantified but should be taken into account and how can those be factored into an evaluation of market constructs? How do these change over time and with differing levels of resource and transmission investment?
- b) *Ratepayer Benefits* – What are the mechanisms by which ratepayers realize the benefits from greater market integration? What kind of benefits and costs impact retail energy rates? How does the Commission ensure that benefits flow to ratepayers?
- c) *Governance* – How should the Commission evaluate the potential governance structures of the four identified market structures and the subsequent potential for changes in regulatory authority? How should the Commission consider such non-quantifiable governance issues as the independence of market service providers, transparency in market decision-making, the representation of consumer interests, and the role of FERC in market oversight?
- d) *Risks* – What risks should the Commission consider in its evaluation of markets? How do these risks change depending on market construct? What factors influence the level of risk borne by Colorado entities?²⁸
- e) *Quantitative Analysis* – What kind(s) of modeling efforts or other analyses should the Commission be pursuing?
- f) *Footprints* – What geographic market footprints should the Commission consider in its market evaluation? Footprint options could include the state of Colorado, the Mountain West Transmission Group, or a larger regional area.
- g) *New Transmission* – To what extent is additional transmission access/investment needed in order to realize the benefits of market participation? What is the potential cost and or range of costs of new transmission build needed to enable the full benefits of an RTO? What are the barriers to the development of new transmission resources within the state of Colorado and elsewhere?
- h) *Transmission Pricing and Cost Treatment* – How should transmission be priced under different market structures? How should the Commission consider transmission cost allocation issues and the impact on rates for both new and existing transmission infrastructure?
- i) *Other Market Services* – How should the Commission consider other market functions such as reserve planning, resource adequacy, GHG policies, ancillary services, and capacity markets?
- j) *Timeframe* – What period of time should be covered by the Commission’s quantitative analysis?

²⁸ Some risks the Commission might consider include the potential for stranded costs, reduction in opportunities for bilateral transactions for non-participating entities, potential market exit fees, etc.

- k) *State Environmental Goals* – How should the state’s statutory requirements and/or environmental goals pertaining to the state’s electric utilities be considered in the Commission’s analysis? What implications do different market constructs have for greater renewable penetration and the economics of renewable generation? How do the impacts change over time and depending on technological development?
- l) *Imports/Exports* – How should an evaluation of public interest consider the potential impact of markets on the exports of high-GHG emission generation to other states?

40. We invite comments regarding the regulatory process and specific authority of the

PUC as regards market regionalization efforts:

- a) *Stakeholder Process* – The Commission envisions holding a series of workshops and a public hearing to address specific issues related to its CTCA investigation. What topics and workshop structure would be most productive?
- b) *Ordering Authority under the CTCA* – Does the Commission have authority to order Electric Service Providers within the state of Colorado to enter into one of the market options discussed in the CTCA?
- c) *Legislative Clarification* – Should the General Assembly clarify and or amplify the jurisdiction of the PUC to order these entities to participate in a market?
- d) *Imbalance Market Regulatory Process* – If Colorado jurisdictional utilities decide to pursue either CAISO or SPP energy imbalance services, what would they need to file at the PUC and when would that occur? How does this relate to when the costs to join such a market would begin to be incurred? When would FERC filings be made and what would be included in those FERC filings? To what extent do decisions regarding imbalance market participation restrict future regional market options?
- e) *Bifurcated State* – What are the implications, both regarding regulatory processes and costs and benefits, of different Colorado Electric Service Providers pursuing different market constructs or different market operators?

V. **ORDER**

A. **The Commission Orders That:**

1. The Commission opens this Miscellaneous Proceeding to collect comments and information helpful in analyzing the potential advantages and disadvantages of joining an energy market, pursuant to §§ 40-2.2-101 and 102, C.R.S., consistent with the discussion above.

2. This proceeding shall serve as a platform to conduct the statutorily required investigation specified in § 40-2.2-102(1), C.R.S., and will serve as a platform from which to conduct workshops, pose questions, hold public hearings, file investigation results, issue orders

and make recommendation as to how to proceed with the next steps in the Colorado Transmission Coordination Act of 2019.

3. This Proceeding is designated as an administrative proceeding under 4 *Code of Colorado Regulations* 723-1-1004(b).

4. This Proceeding will follow the “Permit, but Disclose” process pursuant to Rule 1111 of the Commission’s Rules of Practice and Procedure 4 *Code of Colorado Regulations* 723-1.

5. The Commission designates Commissioner Frances Koncilja as the Hearing Commissioner.

6. Persons interested in participating in this proceeding shall file a notice of participation by November 15, 2019.

7. Interested stakeholders shall submit initial comments in response to this Decision no later than November 15, 2019.

8. Responsive comments shall be filed by December 15, 2019.

9. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING
September 11, 2019.**

(S E A L)



ATTEST: A TRUE COPY

A handwritten signature in cursive script that reads "Doug Dean".

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

FRANCES A. KONCILJA

JOHN GAVAN

Commissioners

SB 72—Massive Transfer of Power from Local Communities and the Colorado Public Utilities Commission to FERC and a New Authority Answerable to No One

How do you feel about a transmission line 50 feet from your back door? “Ha” you say. “Cannot happen because I have local zoning and permitting processes that will stop that.” If Senate Bill 72 (“SB72”) passes, those local protections do not apply. “Ha” you say again. “My land is protected by a conservation easement.” You are wrong again. If SB72 passes, this new Transmission Authority (Authority) has the sole discretion to build transmission lines anywhere they want, with no notice to you and no way for you to participate in the decision. The Authority will have the power of eminent domain but not to worry, the Authority will pay you for the value of that sliver of land without the conservation easement on the property. So, the first time you will find out about the new transmission line 50 feet from you backdoor or across that pristine vista, is when the Authority knocks on your door and tells you they are taking your land. The Authority will make a take it or fight it offer to pay you for the land. Your only remedy is to hire a lawyer to represent you in the condemnation proceeding and the only issue you can raise is the value of your property the Authority has taken.

How do you feel about a huge transmission charges on your electric bill? “Ha” you say again, “I can participate in rate cases at the Colorado Public Utilities Commission (“PUC”) and challenge the outrageous amount.” You are wrong again. IF SB72 passes, you will have the “opportunity” to challenge the amount at the Federal Energy Regulatory Commission (“FERC”). As a former PUC Commissioner, I was, at times, critical of the complicated PUC processes and the expense in participating at the PUC. The FERC processes make the PUC look easy and simple to navigate. For example, FERC Order 1000 that governs the transmission issues is over 620 pages. Lawyers who handle matters at FERC, located in Washington D.C, are very expensive. Tariffs at FERC are usually 1500 pages or more. So, you will need to hire a high-priced K street lawyer who understands the orders, the tariffs, and the processes. The cost and the distance will limit if not eliminate your ability to fight the charges.

How do you feel about another large charge on your bill for the expense of your utility becoming a member of a Regional Transmission Authority (“RTO”)? “Ha” you say again, “the PUC is studying whether or not joining an RTO is in the best interests of the citizens of Colorado and as required by 2019 legislation they have hired the consultant, paid the consultant \$500,000. I have submitted comments. The report will issue on

May 1. I can submit more comments.” You are wrong again. SB72 **ORDERS** the PUC to **ORDER** Colorado utilities to join an RTO by 2030, UNLESS the PUC decides that joining an RTO is “against” the public interest of the citizens of Colorado. So, SB72 creates a presumption that the Colorado utilities will join an RTO and the PUC, the regulatory agency, must rebut the presumption, taking into account the needs for transmission for other states. How is that for turning the regulatory process on its head? The current study is looking at the costs and benefits of joining an RTO. So that \$500,000 study that is almost completed will be worthless because SB72 makes the decision, then changes the criteria and the standard the study is based on.

RTOs are very complex organizations. Each of them spends about a quarter of a BILLION dollars a year to operate. Those costs flow down to electric customers. The environmental community, bless their hearts, are wildly enthusiastic about RTOs. They continually say that an RTO “increases the penetration of renewable energy.” The important question, however, is what are the costs and benefits for the citizens of Colorado. That is what the PUC is currently studying. Without even considering the study SB72 makes the decision—join.

We have all seen how badly the RTOS have operated this last year. ERCOT is a disaster, brought to you by the same folks who brought you ENRON. (Those expensive “Market Monitors” paid for by electric customers missed the obvious.) The California Independent System Operator (“CAISO”), another golden child in the environmental world, had rolling black outs in August. Southwest Power Pool (“SPP”) the other nearby RTO had black outs during the extreme weather in February.

SB72 is so detailed in the requirements for an eligible RTO that the PUC must order the Colorado utilities to join, that one must conclude that the backers of SB72 have already decided which RTO Colorado should join. SB72 ignores whether the PUC has the legal authority to order a utility to join an RTO and turn over its transmission assets to the RTO—there is this annoying due process clause that requires due process before property rights are taken. SB72 contains other hidden minefields, too numerous to review here.

This new Authority can plan, build, own and finance transmission lines, enter into contracts and leases, operate the transmission lines, hire an operator, and issue revenue bonds. The Authority will be run by a board of 7—not elected, but appointed, part time and not paid, which means they will be captive to the unregulated independent transmission builders-- the out of state hedge funds who want to make as

much profit as they can from transmission and the environmental organizations who want new transmission, regardless of the cost and regardless of the benefits for Colorado citizens.

This new Authority is not any agency of the state, not subject to administrative direction from the state and not subject to the personnel rules, so they can pay their executive director whatever they want--\$300,000? \$400,000. I wonder who the candidate waiting in the wings for this plum assignment to be the King or Transmission Dictator is? This Authority and its Transmission Dictator will be answerable to no elected official—not the Governor and not the General Assembly.

To add insult to injury, SB72 will raid the fixed utility fund (which Colorado electric and gas customers fund) for at least a half million dollars to create this Authority. I predict this \$500,000 is only a first installment because \$500,000 is not enough to run this Authority. (If the backers of SB72 really thought it could fund itself, they would set up the Authority as an enterprise.) The Authority will drain the PUC of the resources the PUC needs to adequately regulate the investor-owned utilities in this complex environment. You may not always agree with the PUC (I know I did not and wrote dissenting opinions), but the PUC does its best to limit the return on equity meaning the profit that the utility can make and require that the utility follow the public policies of the state, including hiring union workers. If SB72 passes, you will never know how much the hedge funds are making from transmission in this state, unless you have enough money to invest in them. Independent transmission builders are not subject to Best Value Employment Metrics, and will only care about their bottom line, not Colorado workers or Colorado ratepayers.

SB 72 is one of the largest transfers of power from the towns and communities in Colorado and Colorado PUC to an Authority that is accountable to no one. The transfer of Colorado decision making to this Authority and FERC is not in the public interest of the citizens of Colorado. It will only benefit unregulated out of state transmission builders and the hedge funds who finance them and some environmental organizations. (Did I mention that the out of state hedge fund has the same lobbying firm as many of the environmental organizations?). Decisions concerning where to build and how much to pay for new transmission should be made by local towns and the Colorado PUC who will consider your costs, your backyards, who benefits and how much they benefit. This bill should be killed.

Submitted by Frances A Koncilja, a Denver lawyer and lifetime Colorado resident who served as a Commissioner on the PUC from 2016 to 2020, now at Koncilja Public Utility Law and Strategy, LLLC and can be reached at fkoncilja@koncilja.com

TESTIMONY BEFORE COLORADO SENATE
TRANSPORTATION AND ENERGY COMMITTEE
AGAINST SENATE BILL 72

SUBMITTED BY FRANCES A. KONCILJA
FORMER COMMISSIONER, COLORADO PUBLIC
UTILITIES COMMISSION

MARCH 16, 2021

My name is Frances Koncilja. I grew up in Pueblo, practiced law in Denver for more years than I care to remember. Governor Hickenlooper appointed me to the Colorado Public Utilities Commission in 2016. My term expired last year. I am not representing a client today. I am not being paid for my testimony or for writing the opinion column published by Colorado Politics. I am here testifying as a citizen who developed some knowledge and expertise in markets and transmission while I served on the PUC and I want to share some of that information with you.

I will not repeat here the arguments I made against the proposed Transmission Authority, other than to say it is a mistake to take power and authority over placement of transmission lines from local permitting and to give this new Transmission Authority the power of eminent domain. My other concerns are covered in the Colorado Politics opinion piece.

My primary focus today will be on the requirement that Colorado utilities join a regional transmission authority ("RTO").

Why should you take my opinions into consideration?

I was the Commissioner who spent almost 3 years leading the two dockets before the Commission which studied the proposed Mountain West Transmission Group as well as the Hearing Commissioner to preside over the Transmission Co-ordination study required by the 2019 legislation. I presided over five commission information meetings with dozens of participants who filed comments and submitted position papers and detailed studies. In opening the docket to conduct the study you required in 2019, PUC staff and I prepared a 20page order detailing the history of power pools, trading rules, joint dispatch agreements and energy imbalance markets in Colorado and requested comments from stakeholders on specific questions as to how to conduct the study. I am including in my testimony that order so that you can see the level of detail required and the care necessary to conduct the study requested by the 2019 General Assembly. The study will be completed May 1, followed by time for stakeholders to comment and a final decision by the Commission on December 1.

Joining an RTO is a serious decision, but similar to checking into the Hotel California—great on check in but impossible to leave because of the exit charges.

There are two current options to be the RTO for Colorado utilities—CAISO and SPP. CAISO is not really an option because of what we call the “governance” problem. CAISO is directed and controlled by the state of California. Liberal Democrat though I am, I would never want California making decisions for Colorado. So, even though their office in Folsom California is beautiful (I have included a photo—LEEDs certified by the way), let’s take CAISO off the table.

Let’s look at what life is like if you pass SB 72 and you force the Colorado utilities to join SPP—another very nice (expensive) office building for their 600 employees in Little Rock, Arkansas.

SPP is a 501(C)(6) organization meaning it is designed to assert and protects the interest of its members. SPP’s members are Transmission Owners, Transmission Users and Transmission Customers. SPP owes a duty to its members, not to the citizens of the state of Colorado, or any state. SPPS’ articles make no mention of the public interest and it has no legal requirement to act in the public interest.

SPPS budget last year was \$185 million. (CAISO’s was \$204 million). These are expensive entities to operate and ultimately electric customers pay for all of the costs.

There is little to no opportunity for Colorado interests to be taken into account at SPP. There are about 30 committees for the various members and 300 to 400 meetings a year. The only “voice” for a state is through membership in the Regional States Committee. The State Committee has NO independent staff or attorney, no independent budget, no ability to gather information or conduct investigations or make filings at FERC. I am including in my testimony an organizational chart of SPP. You can see that the state committee, the only place the citizens of Colorado will be represented is an island in the upper left- hand corner. So, decisions will be made by the transmission owners, transmission customers and users. Membership is very expensive and it is likely that the office of consumer

counsel and the environmental groups will not be able to afford membership and a vote in SPP.

RTO's are unregulated clearing houses for the settlement of financial transactions. The unregulated part became very clear with the ERCOTT problems. The products that are sold through this clearing house are complex and only the transmission owners and the traders understand them. There are charges for transmission services, for ancillary services, grid management charges, market services charges, system operator charges, CRR service charges, ancillary service capacity charges in day ahead and real time markets, required access charges, wheeling charges, intermittent resource charges and reliability co-ordination charges, to name a few.

All the RTOs have had serious problems in delivering electricity in the last several years. As I said in my Colorado Politics piece—ERCOT has been a disaster, with CAISO not far behind and SPP had blackouts during the extreme weather in February.

The economic theory behind an RTO is that price signals will drive the efficient use of transmission and sources of energy. So, if you force the utilities to join SPP, does that lead to faster decarbonization or reduced emissions? Probably not. In 2018, when SPP was trying to get its members to agree to the Mountain West Transmission Group, SPP pointed out that the cost of coal generation in Colorado was less expensive than the cost of coal generation in SPP and they forecasted an increased market for coal generation if SPP accepted MWTG because they would buy more of Colorado's coal generation. (See page 14, paragraph 33 of the Order I have attached to my testimony.)

Requiring Colorado utilities to join any RTO without the benefit of the \$500,000 study that you required in 2019 is not in the public interest and will likely, in my opinion, damage the interests of Colorado. Utilities, before entering an RTO have the ability to negotiate numerous items. SB 72 takes away this leverage as the RTO will know the General Assembly has already made the decision the utilities must join.

One additional comment about hedge funds and their ability under SB 72 to control transmission building. I suggest you read the March 8, 2021 article in the New Yorker by Sheelah Kolkatkar— “What Happens when Investment Firms Acquire Trailer Parks.” In their never-ending quest for higher returns, hedge funds win and regular people suffer.

Hedge funds are unregulated. As a Commissioner, I could see and question and reduce the return on equity for utilities. No one has this power over hedge funds. Same with best value employment practices and safety practices.

I want to conclude by making some observations about the PUC staff and Public Service. My reputation at the Commission was one of cynicism with respect to the utilities and my focus was on protecting rate payers. Around the country and in Colorado, there are numerous utilities engaging in public “green washing” --assigning interests in dirty plants and buying renewable credits or planting trees. PSCO, however, is the real deal in decarbonizing. They have supported the Governor’s initiatives and are implementing House Bill 1261 and SB 236. They filed a \$1.7 billion transmission plan which will tie into their clean energy electric resource plan which will be filed in two weeks with a cost of about \$8 billion. Why slow down all of this progress with a requirement to join an TRO and setting up a Transmission Authority now? Let’s see what these plans look like, what stakeholders, who will have a full voice at the PUC say about the plans and let’s see how the Energy Imbalance Market works, before the General Assembly imposes new and costly requirements. If you enact SB 72, you will be telling utilities around the country that no good comes from supporting reduced emissions and the PSCO model of leadership in attaining a clean energy future is a failure.

I think the SB 72 will also be demoralizing to staff at the PUC. They have put hours into the study that you ordered and what you are saying to them, is that their work and dedication does not count and is not respected. Colorado is very lucky to have some incredible staff at the PUC, people (a lot of women) who could earn much more in the private sector, who day after day do the tough business of regulation because they care about good public policy and good results for rate payers. Show your respect for their hard work and table SB 72 this year.

In 2019, the General Assembly and the Governor put Colorado on a path to reduce emissions. The PUC, with limited and overworked staff, is thoughtfully and judiciously implementing those directives. To distract the Commission, PUC staff, the office of Consumer Counsel and the utilities with new initiatives and directives is not wise and in fact counter-productive.

I urge you to vote against allowing SB 72 out of your committee.
Thank you.



Decision No. C19-0756

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.

**COMMISSION DECISION OPENING A PROCEEDING,
DESIGNATING COMMISSIONER KONCILJA
AS HEARING COMMISSIONER, AND SOLICITING
INPUT FROM INTERESTED PARTICIPANTS**

Mailed Date: September 17, 2019
Adopted Date: September 11, 2019

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- A. The Commission Orders That:18
- B. ADOPTED IN COMMISSIONERS’ WEEKLY MEETING September 11, 2019.20

I. BY THE COMMISSION

A. Statement

1. Pursuant to the Colorado Transmission Coordination Act of 2019, §§ 40-2.3-101 and 102, C.R.S. (CTCA),¹ the Public Utilities Commission (Commission or PUC) opens this proceeding to collect comments and other information helpful in analyzing the potential advantages and disadvantages in joining one of the types of energy markets identified.² The Commission designates Commissioner Frances Koncilja as Hearing Commissioner,³ pursuant to § 40-6-101(2)(a), C.R.S., to work with the Staff of the Colorado Public Utilities Commission (Staff), stakeholders, and other interested participants to collect and organize information, conduct public comment hearings, and make recommendations to the full Commission as to possible next steps in conducting the analysis required by § 40-2.3-102(2), C.R.S., and to aid the Commission in its determination of the public interest as required by § 40-2.3-102(3), C.R.S.

2. CTCA directs the Commission to investigate the costs and benefits to electric utilities, other generators, and Colorado electric utility customers resulting from electric utility participation in energy imbalance markets (EIMs), regional transmission organizations (RTOs), power pools, or joint tariffs. Electric utilities are defined in § 40-1-103(2)(a), C.R.S., to include

¹ CTCA, attached as Exhibit A

² Section 40-2.3-102(1)-(4), C.R.S., refer to energy imbalance markets, regional transmission organizations, power pools and joint tariffs.

³ At the Commissioners’ Weekly Meeting on June 26, 2019, the Commissioners agreed to divide responsibilities for the first stages of implementation of the new obligations in the PUC Sunset Bill, Senate Bill 19-236 with Chairman Ackermann having responsibility for Distribution Resource Planning, Commissioner Gavan for Performance Based Ratemaking, and Commissioner Koncilja for CTCA.

“[e]very cooperative electric association, or nonprofit electric corporation or association, and every other supplier of electric energy, whether supplying electric energy for the use of the public or for the use of its own members.” The CTCA directs the Commission to consider the impact of these four different market constructs on retail and wholesale electricity rates for both participating and non-participating entities, transmission rates, the commitment and dispatch of generation, operating costs, reserve requirements, renewable integration, and regional infrastructure investment. The interaction of these market options with system reliability must necessarily be included in this investigation.

3. CTCA sets deadlines for four specific Commission actions:

- **January 1, 2020** – “The Commission shall open a proceeding to investigate the potential costs and benefits to electric utilities, other generators, and Colorado electricity customers that would arise from electric utilities” participating in a regional electricity market,⁴
- **July 1, 2021** – “The Commission shall hold a hearing for public comment to consider the information received during the Commission’s investigation...”⁵
- **December 1, 2021** – “The Commission shall issue a decision determining whether electric utilities participating in [an electricity market] is in the public interest.”⁶
- **July 1, 2022** – If the Commission determines that electric utility participation in a one of the specified types of markets is in the public interest the Commission “shall direct electric utilities to take appropriate actions and conduct such proceedings as the commission deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.”⁷

4. We open this miscellaneous proceeding to conduct the investigation contemplated in the first Commission obligation above. We choose to proceed through a miscellaneous

⁴ § 40-2.3-102(1), C.R.S.

⁵ § 40-2.3-102(2), C.R.S.

⁶ § 40-2.3-102(3), C.R.S.

⁷ § 40-2.3-102(4), C.R.S.

proceeding in order to allow the Hearing Commissioner to issue orders and make recommendations to the full Commission as to next steps. This proceeding will serve as a repository for the filing of comments, studies and analyses, and will serve as a platform from which to conduct workshops, hold public hearings, pose questions, discuss processes, and issue orders.

5. In order to build on information from other Commission proceedings and regional market studies and experience, Staff is directed to file the most current and relevant documents into this proceeding as described below.

6. Through the course of this miscellaneous proceeding, we will invoke, pursuant to Rule 4 Code of Colorado Regulations 723-1-1111 of the Commission's Rules of Practice and Procedure, the "Permit, but Disclose" process. Interested persons may schedule *ex parte* presentations to a Commissioner that shall include Commission Staff provided that the contacts relate solely to the CTCA investigation, and do not concern any matter pending before the Commission in another proceeding. Within two business days following a permitted presentation, the person requesting the meeting is required to file in this Proceeding a letter disclosing the contact with a copy of materials provided to the Commissioner during the meeting.

7. We will attempt to accommodate all reasonable requests for *ex parte* meetings, subject to the schedule and availability of each Commissioner. To schedule an *ex parte* presentation with a Commissioner, an interested person should contact the Executive Assistants to the Commissioners and should clarify that the presentation is associated with this Proceeding.

8. We encourage stakeholders to file a statement of interest in participating in this proceeding. Participants should submit initial comments no later than November 15, 2019. Comments responsive to those initial filings may be made no later than December 15, 2019.

II. BACKGROUND

A. Commission History Investigating and Implementing Markets.

9. Evaluation of markets and participation by the investor owned utilities in Colorado in various types of markets is not new to the Commission. The Commission has been involved in implementing and analyzing the benefits and detriments of market participation by Colorado investor owned electric utilities since at least 2011.

10. The Commission examined the “implications of a potential regional Energy Imbalance Market (EIM) that may include Colorado electric utilities” in Decision No. C11-1347 in Proceeding No. 11M-998E issued December 15, 2011 at p. 1. More recently, the Commission has been monitoring the benefits to Colorado utilities of short-term imbalance energy trading through the participation of Public Service Company of Colorado (Public Service) and Black Hills in the Joint Dispatch Agreement (Proceeding No. 16A-0276E).⁸

11. In addition, Public Service has decades of experience in bilateral market transactions pursuant to their Trading Rules, which were originally approved by the Commission in 2000 and most recently updated in Proceeding No. 13A-0689E (Settlement between Public Service, Staff, and the Office of Consumer Counsel).

12. In October 2016, Decision No. C16-1002 opened Investigatory Proceeding No. 16I-0816E to “receive and develop information and analysis related to the activities of the

⁸ Public Service filed a semiannual report in Proceeding No. 16A-0276E. This report details “Generation Cost Savings,” “Energy Sales Margins,” and “Net change in carbon emissions” by participating entity.

Mountain West Transmission Group (MWTG).” MWTG was comprised of nine transmission owners (Basin Electric Power Cooperative, Black Hills Colorado Electric, LLC, Black Hills Power, Inc., Cheyenne Light Fuel & Power Company, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Association, Inc., Western Area Power Administration, Loveland Area Projects and Western Area Power Administration, Colorado River Storage Projects).

13. Between March 2017 and March 2018, the Commission held five Commission Information Meetings (CIMs) to investigate issues related to MWTG joining the Southwest Power Pool (SPP). In addition to active participation by more than a dozen entities and reports from MWTG utilities regarding the status of their negotiations and proposed market operation, the Commission heard stakeholders present and discuss information related to the benefits of markets for renewables, ratepayer risks and concerns, reliability coordination, transmission rates, planning and cost allocation, RTO governance, Federal Energy Regulatory Commission (FERC) process and jurisdiction, and cost benefit categories. The CIM presentations, as well as comments and recommendations from stakeholders and a variety of white papers and market-related reports are all available in the MWTG Investigatory Proceeding (16I-0816E). Staff will file a subset of those documents that are the most current and relevant to the instant investigation in this new proceeding for ease of reference.

14. Public Service announced in April 2018 that it was withdrawing from the negotiations to join SPP, citing limited benefits and uncertain costs. This effectively ended the

MWTG effort and the Commission's investigation.⁹ However, the MWTG Investigatory Proceeding is an invaluable resource to this current market investigation effort.

III. CURRENT STATUS OF RELIABILITY CO-ORDINATION

15. In January 2018, amidst the MWTG effort to join the SPP, the California Independent System Operator (CAISO) announced that it would leave Peak Reliability, become its own reliability coordinator (RC) – to be known as “RC West” – and also offer that service to other utilities. Although the MWTG effort ended soon thereafter, SPP separately offered to provide RC services as a non-membership option for any interested western utilities. To date, 39 balancing authorities and transmission owners have finalized service agreements with RC West¹⁰ and 14 utilities (including those within the Public Service balancing authority) have committed to SPP's RC service. The full transition from Peak Reliability will be completed by the end of 2019.¹¹

IV. CURRENT AND PROPOSED MARKET OFFERINGS IN THE WESTERN INTERCONNECTION

16. Several of the transmission operators within Colorado are currently considering joining an imbalance market. Both CAISO and SPP are offering imbalance services in Colorado.¹²

⁹ The MWTG proceeding was closed on October 17, 2018.

¹⁰ <http://www.aiso.com/informed/Pages/RCWest/Default.aspx>

¹¹ <https://www.wecc.org/EventAnalysisSituationalAwareness/Pages/Certification.aspx>

¹² On August 30, 2019, Xcel Energy issued a press release indicating that Xcel Energy, Black Hills Energy, Colorado Springs Utilities, and Platte River Power Authority (*i.e.*, current JDA members) have “launched an in-depth study to determine the best course of action” related to joining an energy imbalance market. They have hired a consulting firm to evaluate the benefits and costs of participation in either SPP's WEIS or CAISO's WEIM. The study results are expected by the end of September and a decision is expected by the end of the year.

17. The CAISO-administered Western EIM was established in 2014 with Pacificorp as the first participant outside California.¹³ Additional utilities have joined in each year since then and by 2022, greater than 70 percent of the Western Interconnection's load will be participating in the Western EIM.¹⁴ CAISO has also proposed to develop an Extended Day-Ahead Market (EDAM) for EIM participants and is currently conducting a feasibility analysis and discussing issues with stakeholders.¹⁵

18. Citing its expanded role as a Western RC, on April 4, 2019, SPP announced its interest in offering a Western Energy Imbalance Service (WEIS) to utilities in the Western Interconnection. On June 17, 2019, it released its specific WEIS proposal.¹⁶ SPP requested action on or before September 3rd regarding its WEIS offering. If it receives sufficient commitments by then, SPP proposes to have the EIS up and running by February 2021. On September 9, 2019, Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, Inc., and the Western Area Power Administration announced their decision to join SPP's Western Energy Imbalance Service.¹⁷

¹³ WEIM is a voluntary 15-minute and 5-minute real-time energy market operated by the CAISO. The WEIM utilizes transmission capacity made available to the EIM and security-constrained economic dispatch (SCED) to optimize real-time energy dispatch and resolve energy and load imbalances across the footprint.

¹⁴ Current map available here: <https://www.westerneim.com/Pages/About/default.aspx>

¹⁵ See <http://www.caiso.com/informed/Pages/StakeholderProcesses/Day-AheadMarketEnhancements.aspx>. If pursued, the EDAM would likely be a voluntary additional market option for entities participating in the WEIM.

¹⁶ See <https://www.spp.org/weis>. This market's construct is still being developed but would likely be very similar to the Western EIM and would utilize SCED to optimize real-time energy dispatch and resolve imbalances. Most likely participants appear to be in Colorado, and parts of Wyoming, New Mexico, and Arizona (and are mostly comprised of former participants in the MWTG effort).

¹⁷<https://www.tristate.coop/three-regional-utilities-announce-decision-join-southwest-power-pool-market>

A. Discussion

19. The Commission needs to understand how utility market participation may change whether Colorado is an importer or exporter of electricity at different times of the day and/or year; what the fuel source is for the electricity being imported and exported; how these imports and exports may change over time; information on the geographic footprint of Colorado's trading partners; the impact this market activity has on the ultimate electricity bill paid by Colorado consumers; and who determines how the potential cost of new transmission is paid for.

20. As noted above, the purpose of this investigation is to help inform the Commission of the costs and benefits, impacts to ratepayers, regulatory and policy implications, and impact on renewable integration of different levels of regional market participation. As part of this investigation, the Commission seeks to determine the conditions under which these costs, benefits, and impacts materialize. This investigation should assist an ultimate Commission determination of what is in the public interest and how to proceed with the next steps.

1. Colorado Energy Policy

21. The CTCA is part of a broader set of recent statutory changes, many of which articulate state environmental policy goals pertinent to the electric utility industry. As explained in more detail below, the 2019 legislative session made substantive changes to the energy policies of the State of Colorado.

22. In addition to statutory changes, recently elected Governor Jared Polis has issued executive orders and made public statements regarding Colorado's renewable energy goals. In

these statement, the Polis administration “has set a goal of 100% renewable electricity by 2040.”¹⁸

23. In recent years, Colorado has been working under the Renewable Energy Standard laid out in § 40-2-124, C.R.S. This statute requires 30 percent of retail electricity sales to be supplied by renewable energy by 2020 for Investor Owned Utilities.¹⁹ The Renewable Energy Standard for most electric cooperatives is 20 percent and for other cooperatives and large municipal utilities the standard is 10 percent.

24. Two bills from the 2019 legislative session extend these utility environmental targets. The first bill, House Bill (HB) 19-1261, established statewide goals to reduce 2025 greenhouse gas emissions from the 2005 baseline by at least 26 percent, 2030 emissions by 50 percent, and 2050 emissions by 90 percent. The goals in HB19-1261 apply economy wide, not just to the electric sector. The second bill, Senate Bill 19-236, directed “electric [utilities] with greater than five hundred thousand customers in the state or any other electric utility that opts in...” to file a Clean Energy Plan to reduce carbon emissions to 80 percent below 2005 levels by 2030 and reduce atmospheric carbon emissions by 100 percent by 2050.²⁰

25. The West is not homogeneous in regard to state environmental and other policy goals or in regard to existing fossil and renewable generation assets. Electricity service providers in other states that might participate in electric markets and with whom Colorado utilities may

¹⁸ See: <https://www.colorado.gov/governor/environment-and-renewables> and <https://www.colorado.gov/governor/2019-executive-orders>

¹⁹ See § 40-2-124(1)(c), C.R.S.

²⁰ Currently, only Public Service is obligated to file a Clean Energy Plan based on the statutory definition of a “qualifying retail utility.”

trade, could have less or more demanding decarbonization and/or renewable energy goals. These factors need to be considered in approaching the evaluation of the potential costs and benefits of electricity market regionalization in Colorado and the impact of regionalization in supporting Colorado's policy goals.

2. Colorado's Transmission Infrastructure

26. Colorado is electrically located on the edge of the Western Interconnect with limited DC ties to the East and limited AC ties to the West. Colorado is surrounded by states of relatively low load density with large geologic barriers between them. In recognition of this lack of interconnection, both the 2017/2018 SPP proposal to provide RTO services to the MWTG and the current energy imbalance service offerings treat the MWTG footprint (or portions of the MWTG footprint) as a geographic market distinct from either the rest of SPP or other CAISO EIM participants in the West.

27. One benefit that may be considered in this investigation of regional market participation is the potential for increased access to renewable generation from other geographic regions and the potential to export local excess renewable generation to other geographic regions without paying fees to multiple transmission providers. Regional diversity of renewable generation may help compensate for the inherently intermittent nature of individual renewable resources. This investigation should evaluate the degree to which this geographic diversity could help support the state's statutory requirements and energy policy goals.

28. The Commission is concerned that Colorado has limited transmission interconnection with the rest of the Western Electricity Coordinating Council region (WECC) and with SPP states to the East and that this lack of interconnection may limit the benefits of

regional markets absent significant infrastructure investment. More than one stakeholder has observed that “if you love wind generation, you must love transmission.” The Commission will need to assess the costs, benefits, feasibility, cost recovery, and other implications of major transmission investment as part of this market investigation.

3. Current and Future Role of Storage

29. In Public Service’s most recent electric resource plan Proceeding No. 16A-0396E, the Commission approved the acquisition of 275 megawatts of battery storage (configured as “solar plus storage” facilities) on September 10, 2018 in Decision No. C18-0761. These battery projects provide four-hour storage capability. Adding these batteries will provide an opportunity to determine how to utilize storage resources most effectively for integrating higher penetrations of variable renewable generation. It is not clear what role storage will play in renewable integration in the medium to long-term and to what extent batteries could reduce the overall need for regional transmission. This will depend in part on how quickly storage technology advances, particularly in the development of long-term (seasonal) storage, and how much costs decline.

4. Joint Dispatch Agreement (JDA)

30. In 2016, Public Service, Black Hills Colorado Electric, LLC, and Platte River Power Authority entered into a Joint Dispatch Agreement (JDA) to dispatch their generating units on a sub-hourly basis to serve their combined load with the most economic resources. Similar to participants in other energy imbalance markets, participants in the JDA realize short-term production cost savings and earn margins from additional sales. The combined annual benefit for JDA participants has ranged from approximately \$2 million to \$3.7 million in the first

years of operation.²¹ The JDA is currently in the process of expanding to include the City of Colorado Springs Utility.

31. In a letter agreement between Public Service and former Commission Chairman Joshua Epel, dated August 21, 2015,²² Public Service agreed to a number of provisions regarding the reporting and administration of the JDA. In this agreement, Public Service committed that “[i]n the event [Public Service] intends to file with the FERC a proposal to establish an energy imbalance market, or another related or similar construct, [Public Service] agrees to notify the [Commission] at least ninety (90) days in advance of such a filing. [Public Service] also agrees to provide the [Commission] with a confidential briefing of such proposal at least thirty (30) days in advance of filing with the FERC.” This advance notice will allow the Commission to consider the procedural complexities such a filing would introduce.

5. Mountain West Transmission Group Conclusions

32. During the MWTG negotiation, several consulting firms were used to model the costs and benefits of market participation. MWTG consultants performed production cost modeling of both the joint tariff and full RTO constructs.²³ Based on the preliminary modeling results, the MWTG concluded that a joint transmission tariff alone would not produce enough savings to justify the effort, but that RTO participation was worth pursuing. At the time, energy imbalance market and day ahead market constructs were not evaluated. The Commission

²¹ See “Semiannual JDA Reports” filed in Proceeding No. 16A-0276E.

²² See Attachment SLP-2 to the Answer Testimony of Staff witness Sharon Podein in Proceeding No. 16A-0276E.

²³ The Joint tariff was modeled for 2016 only. Full RTO was modeled for 2016 and 2024 and examined current trends, high natural gas prices, and “market stress” scenarios. Both sets of results were compared to a status quo bilateral market analysis. The report points out that the production cost modeling did not include simulation of intra-day and real-time operations and thus was missing potential benefits achieved through such coordination.

proposes to build on the preliminary findings of the MWTG regarding joint tariffs and full RTO in conducting this investigation into the benefits of regional market participation.

33. In a report to SPP stakeholders dated March 19, 2018, SPP indicated that the cost of coal generation in Colorado was less expensive than the cost of coal generation in SPP and forecast increased Colorado coal generation if the MWTG were to join SPP.²⁴ This observation raises questions regarding the impact of market participation on generation mix, particularly as Colorado accesses markets with substantially different generation fleets and state environmental goals.

6. Department of Energy Market Investigation (DOE Study) and Other Market Studies of Interest

34. Four Western states, including Colorado, recently received funding from the U. S. Department of Energy (DOE) to perform an investigation into the benefits of greater integration in Western electricity markets. The four participating states are Utah, Montana, Idaho, and Colorado with the Utah Energy Office functioning as the Principal Investigator. This study includes a consultant (Energy Strategies) performing utility-grade production cost modeling of several potential market footprints.

35. The draft project schedule calls for modeling results to be available the third quarter of 2020 and additional deliverables to be completed in early 2021. This modeling effort is currently in the stage of scoping the market constructs, geographic footprints, and scenarios to be evaluated. Staff will have more insight into the extent of overlap between the CTCA and this

²⁴ SPP Staff report *10-year Costs and Benefits to SPP Members of Integrating Mountain West Transmission Group: Quantitative Analysis of Costs and Benefits*, March 19, 2018, pp. 16-17.

modeling effort in the next few months. Staff is directed to file into this proceeding updates from the DOE Study as they become available.

36. As a preliminary step in the Utah-led DOE-funded investigation, Energy Strategies compiled a list of other recent market studies, many of which may offer insights into the issues, costs, and benefits that should be considered in the Commission's evaluation. In addition to the MWTG studies, Staff is directed to collect pertinent information from those analyses and to file them into this proceeding.²⁵

7. Reliability Concerns that Must Be Addressed in this Proceeding

37. Although not specifically identified in the CTCA, the Commission considers reliability a key consideration in any major shift in utility operations and governance such as joining an organized market.²⁶ The WECC region is currently transitioning from essentially two Reliability Coordinators (Peak Reliability and the Alberta Electric System Operator) to a total of five RCs (California Independent System Operator's RC West, Southwest Power Pool, BC Hydro, Gridforce Energy Management, LLC, and the Alberta Electric System Operation). Reliability considerations should play a significant role in any evaluation of joining or forming a new market construct. Staff is closely following the activities of the Western Interconnection Regional Advisory Body (WIRAB), which advises the North American Electricity Reliability

²⁵ These studies include Western EIM service evaluations including quarterly benefits estimates/reports, individual utility evaluations regarding Western EIM participation, and California's Senate Bill 350 study evaluating the impacts of a regional market.

²⁶ The Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, require jurisdictional utilities to address reliability in Electric Resource Planning (3600 through 3619), Transmission Planning (Rules 3625 through 3627), the Renewable Energy Standard (Rules 3650 through 3668) and utility Applications (Rule 3703) and establish standards for "Operating Reliability and Safety" (Rules 3910 through 3929). In addition, the Commission's Rules require utilities to report major events resulting in a loss of service (Rules 3250 through 3253).

Council, FERC, and WECC on reliability issues.²⁷ Staff is directed to file into this proceeding relevant information developed in WIRAB proceedings.

8. Market Definitions and Solicitation of Comments

38. The Commission proposes to use the following more detailed definitions of the various market options in this proceeding and invites comments on these definitions:

- a) *Power Pool* – Power Pool refers to a system of trading wholesale electricity that determines which of a set of pooled generators are most economic to serve load and set the price for that period. The Joint Dispatch Agreement (JDA) operating today is an example of a power pool and serves as the base case market construct. Parties to the Joint Dispatch Agreement pool generating resources to meet their combined load using the least cost dispatch.
- b) *Joint Tariffs* – Joint Tariff refers to a single rate that applies for transmission service over the routes or lines of two or more transmission providers. This market construct was studied during the Mountain West Transmission Group (MWTG) investigation.
- c) *Energy Imbalance Market (EIM)* – An EIM refers to a real-time bulk power trading market that allows participants to buy and sell unscheduled energy using available/unscheduled transmission. The California ISO (CAISO) is currently operating an EIM in the West (the WEIM) and has offered to stand up an EIM market to serve Colorado entities. The Southwest Power Pool (SPP) is currently working with interested parties to develop a Western Energy Imbalance Service (WEIS) market.
- d) *Regional Transmission Organization (RTO)* – An RTO refers to an independent electric transmission operator that provides wholesale transmission services to more than one provider of electric services. An RTO incorporates centralized real-time dispatch and day ahead unit commitment with a joint transmission tariff, An RTO also consolidates reliability obligations, transmission planning and cost allocation, and transfers operational control of the transmission system to the system operator. An RTO introduces new sources of potential benefits but also the potential for substantial additional costs and a host of governance issues that other market constructs largely avoid.
- e) *Extended Day Ahead Market (EDAM)* – The EDAM is an initiative conceptualized by the CAISO and Western EIM entities to extend the benefits of the EIM to the day-ahead market. EDAM would enable day-ahead unit commitment and dispatch across the participating footprint, but would not encompass transfer of operational control or any planning responsibilities to the CAISO. While this market construct could have significant benefits beyond the EIM, it does start to raise governance and market power/monitoring issues. While the EDAM was not specifically identified for

²⁷ WIRAB was created by Western Governors under Section 215(j) of the Federal Power Act. Section 215 of the FPA provides for the establishment of a federal regulatory system of mandatory and enforceable electric reliability standards for the nation's bulk power system. WIRAB's membership is composed of representatives from all states and international provinces that have load within the Western Interconnection. See <https://westernenergyboard.org/wirab/who-what/>

investigation by the Colorado Transmission Coordination Act, PUC Staff believe this market construct would be appropriate to include in this investigatory effort.

39. We also invite comments on any or all of the following questions and issues:

- a) *Costs and Benefits* – Modeling studies to date have primarily addressed the savings attributable to generation commitment and dispatch optimization provided by integrated markets (as determined by production cost modeling). What other costs and benefits should be quantified for purposes of this investigation? What other costs and benefits cannot be quantified but should be taken into account and how can those be factored into an evaluation of market constructs? How do these change over time and with differing levels of resource and transmission investment?
- b) *Ratepayer Benefits* – What are the mechanisms by which ratepayers realize the benefits from greater market integration? What kind of benefits and costs impact retail energy rates? How does the Commission ensure that benefits flow to ratepayers?
- c) *Governance* – How should the Commission evaluate the potential governance structures of the four identified market structures and the subsequent potential for changes in regulatory authority? How should the Commission consider such non-quantifiable governance issues as the independence of market service providers, transparency in market decision-making, the representation of consumer interests, and the role of FERC in market oversight?
- d) *Risks* – What risks should the Commission consider in its evaluation of markets? How do these risks change depending on market construct? What factors influence the level of risk borne by Colorado entities?²⁸
- e) *Quantitative Analysis* – What kind(s) of modeling efforts or other analyses should the Commission be pursuing?
- f) *Footprints* – What geographic market footprints should the Commission consider in its market evaluation? Footprint options could include the state of Colorado, the Mountain West Transmission Group, or a larger regional area.
- g) *New Transmission* – To what extent is additional transmission access/investment needed in order to realize the benefits of market participation? What is the potential cost and or range of costs of new transmission build needed to enable the full benefits of an RTO? What are the barriers to the development of new transmission resources within the state of Colorado and elsewhere?
- h) *Transmission Pricing and Cost Treatment* – How should transmission be priced under different market structures? How should the Commission consider transmission cost allocation issues and the impact on rates for both new and existing transmission infrastructure?
- i) *Other Market Services* – How should the Commission consider other market functions such as reserve planning, resource adequacy, GHG policies, ancillary services, and capacity markets?
- j) *Timeframe* – What period of time should be covered by the Commission’s quantitative analysis?

²⁸ Some risks the Commission might consider include the potential for stranded costs, reduction in opportunities for bilateral transactions for non-participating entities, potential market exit fees, etc.

- k) *State Environmental Goals* – How should the state’s statutory requirements and/or environmental goals pertaining to the state’s electric utilities be considered in the Commission’s analysis? What implications do different market constructs have for greater renewable penetration and the economics of renewable generation? How do the impacts change over time and depending on technological development?
- l) *Imports/Exports* – How should an evaluation of public interest consider the potential impact of markets on the exports of high-GHG emission generation to other states?

40. We invite comments regarding the regulatory process and specific authority of the

PUC as regards market regionalization efforts:

- a) *Stakeholder Process* – The Commission envisions holding a series of workshops and a public hearing to address specific issues related to its CTCA investigation. What topics and workshop structure would be most productive?
- b) *Ordering Authority under the CTCA* – Does the Commission have authority to order Electric Service Providers within the state of Colorado to enter into one of the market options discussed in the CTCA?
- c) *Legislative Clarification* – Should the General Assembly clarify and or amplify the jurisdiction of the PUC to order these entities to participate in a market?
- d) *Imbalance Market Regulatory Process* – If Colorado jurisdictional utilities decide to pursue either CAISO or SPP energy imbalance services, what would they need to file at the PUC and when would that occur? How does this relate to when the costs to join such a market would begin to be incurred? When would FERC filings be made and what would be included in those FERC filings? To what extent do decisions regarding imbalance market participation restrict future regional market options?
- e) *Bifurcated State* – What are the implications, both regarding regulatory processes and costs and benefits, of different Colorado Electric Service Providers pursuing different market constructs or different market operators?

V. **ORDER**

A. **The Commission Orders That:**

1. The Commission opens this Miscellaneous Proceeding to collect comments and information helpful in analyzing the potential advantages and disadvantages of joining an energy market, pursuant to §§ 40-2.2-101 and 102, C.R.S., consistent with the discussion above.

2. This proceeding shall serve as a platform to conduct the statutorily required investigation specified in § 40-2.2-102(1), C.R.S., and will serve as a platform from which to conduct workshops, pose questions, hold public hearings, file investigation results, issue orders

and make recommendation as to how to proceed with the next steps in the Colorado Transmission Coordination Act of 2019.

3. This Proceeding is designated as an administrative proceeding under 4 *Code of Colorado Regulations* 723-1-1004(b).

4. This Proceeding will follow the “Permit, but Disclose” process pursuant to Rule 1111 of the Commission’s Rules of Practice and Procedure 4 *Code of Colorado Regulations* 723-1.

5. The Commission designates Commissioner Frances Koncilja as the Hearing Commissioner.

6. Persons interested in participating in this proceeding shall file a notice of participation by November 15, 2019.

7. Interested stakeholders shall submit initial comments in response to this Decision no later than November 15, 2019.

8. Responsive comments shall be filed by December 15, 2019.

9. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING
September 11, 2019.**

(S E A L)



ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

FRANCES A. KONCILJA

JOHN GAVAN

Commissioners

SB 72—Massive Transfer of Power from Local Communities and the Colorado Public Utilities Commission to FERC and a New Authority Answerable to No One

How do you feel about a transmission line 50 feet from your back door? “Ha” you say. “Cannot happen because I have local zoning and permitting processes that will stop that.” If Senate Bill 72 (“SB72”) passes, those local protections do not apply. “Ha” you say again. “My land is protected by a conservation easement.” You are wrong again. If SB72 passes, this new Transmission Authority (Authority) has the sole discretion to build transmission lines anywhere they want, with no notice to you and no way for you to participate in the decision. The Authority will have the power of eminent domain but not to worry, the Authority will pay you for the value of that sliver of land without the conservation easement on the property. So, the first time you will find out about the new transmission line 50 feet from you backdoor or across that pristine vista, is when the Authority knocks on your door and tells you they are taking your land. The Authority will make a take it or fight it offer to pay you for the land. Your only remedy is to hire a lawyer to represent you in the condemnation proceeding and the only issue you can raise is the value of your property the Authority has taken.

How do you feel about a huge transmission charges on your electric bill? “Ha” you say again, “I can participate in rate cases at the Colorado Public Utilities Commission (“PUC”) and challenge the outrageous amount.” You are wrong again. IF SB72 passes, you will have the “opportunity” to challenge the amount at the Federal Energy Regulatory Commission (“FERC”). As a former PUC Commissioner, I was, at times, critical of the complicated PUC processes and the expense in participating at the PUC. The FERC processes make the PUC look easy and simple to navigate. For example, FERC Order 1000 that governs the transmission issues is over 620 pages. Lawyers who handle matters at FERC, located in Washington D.C, are very expensive. Tariffs at FERC are usually 1500 pages or more. So, you will need to hire a high-priced K street lawyer who understands the orders, the tariffs, and the processes. The cost and the distance will limit if not eliminate your ability to fight the charges.

How do you feel about another large charge on your bill for the expense of your utility becoming a member of a Regional Transmission Authority (“RTO”)? “Ha” you say again, “the PUC is studying whether or not joining an RTO is in the best interests of the citizens of Colorado and as required by 2019 legislation they have hired the consultant, paid the consultant \$500,000. I have submitted comments. The report will issue on

May 1. I can submit more comments.” You are wrong again. SB72 **ORDERS** the PUC to **ORDER** Colorado utilities to join an RTO by 2030, UNLESS the PUC decides that joining an RTO is “against” the public interest of the citizens of Colorado. So, SB72 creates a presumption that the Colorado utilities will join an RTO and the PUC, the regulatory agency, must rebut the presumption, taking into account the needs for transmission for other states. How is that for turning the regulatory process on its head? The current study is looking at the costs and benefits of joining an RTO. So that \$500,000 study that is almost completed will be worthless because SB72 makes the decision, then changes the criteria and the standard the study is based on.

RTOs are very complex organizations. Each of them spends about a quarter of a BILLION dollars a year to operate. Those costs flow down to electric customers. The environmental community, bless their hearts, are wildly enthusiastic about RTOs. They continually say that an RTO “increases the penetration of renewable energy.” The important question, however, is what are the costs and benefits for the citizens of Colorado. That is what the PUC is currently studying. Without even considering the study SB72 makes the decision—join.

We have all seen how badly the RTOS have operated this last year. ERCOT is a disaster, brought to you by the same folks who brought you ENRON. (Those expensive “Market Monitors” paid for by electric customers missed the obvious.) The California Independent System Operator (“CAISO”), another golden child in the environmental world, had rolling black outs in August. Southwest Power Pool (“SPP”) the other nearby RTO had black outs during the extreme weather in February.

SB72 is so detailed in the requirements for an eligible RTO that the PUC must order the Colorado utilities to join, that one must conclude that the backers of SB72 have already decided which RTO Colorado should join. SB72 ignores whether the PUC has the legal authority to order a utility to join an RTO and turn over its transmission assets to the RTO—there is this annoying due process clause that requires due process before property rights are taken. SB72 contains other hidden minefields, too numerous to review here.

This new Authority can plan, build, own and finance transmission lines, enter into contracts and leases, operate the transmission lines, hire an operator, and issue revenue bonds. The Authority will be run by a board of 7—not elected, but appointed, part time and not paid, which means they will be captive to the unregulated independent transmission builders-- the out of state hedge funds who want to make as

much profit as they can from transmission and the environmental organizations who want new transmission, regardless of the cost and regardless of the benefits for Colorado citizens.

This new Authority is not any agency of the state, not subject to administrative direction from the state and not subject to the personnel rules, so they can pay their executive director whatever they want--\$300,000? \$400,000. I wonder who the candidate waiting in the wings for this plum assignment to be the King or Transmission Dictator is? This Authority and its Transmission Dictator will be answerable to no elected official—not the Governor and not the General Assembly.

To add insult to injury, SB72 will raid the fixed utility fund (which Colorado electric and gas customers fund) for at least a half million dollars to create this Authority. I predict this \$500,000 is only a first installment because \$500,000 is not enough to run this Authority. (If the backers of SB72 really thought it could fund itself, they would set up the Authority as an enterprise.) The Authority will drain the PUC of the resources the PUC needs to adequately regulate the investor-owned utilities in this complex environment. You may not always agree with the PUC (I know I did not and wrote dissenting opinions), but the PUC does its best to limit the return on equity meaning the profit that the utility can make and require that the utility follow the public policies of the state, including hiring union workers. If SB72 passes, you will never know how much the hedge funds are making from transmission in this state, unless you have enough money to invest in them. Independent transmission builders are not subject to Best Value Employment Metrics, and will only care about their bottom line, not Colorado workers or Colorado ratepayers.

SB 72 is one of the largest transfers of power from the towns and communities in Colorado and Colorado PUC to an Authority that is accountable to no one. The transfer of Colorado decision making to this Authority and FERC is not in the public interest of the citizens of Colorado. It will only benefit unregulated out of state transmission builders and the hedge funds who finance them and some environmental organizations. (Did I mention that the out of state hedge fund has the same lobbying firm as many of the environmental organizations?). Decisions concerning where to build and how much to pay for new transmission should be made by local towns and the Colorado PUC who will consider your costs, your backyards, who benefits and how much they benefit. This bill should be killed.

Submitted by Frances A Koncilja, a Denver lawyer and lifetime Colorado resident who served as a Commissioner on the PUC from 2016 to 2020, now at Koncilja Public Utility Law and Strategy, LLLC and can be reached at fkoncilja@koncilja.com

TESTIMONY BEFORE COLORADO SENATE
TRANSPORTATION AND ENERGY COMMITTEE
AGAINST SENATE BILL 72

SUBMITTED BY FRANCES A. KONCILJA
FORMER COMMISSIONER, COLORADO PUBLIC
UTILITIES COMMISSION

MARCH 16, 2021

My name is Frances Koncilja. I grew up in Pueblo, practiced law in Denver for more years than I care to remember. Governor Hickenlooper appointed me to the Colorado Public Utilities Commission in 2016. My term expired last year. I am not representing a client today. I am not being paid for my testimony or for writing the opinion column published by Colorado Politics. I am here testifying as a citizen who developed some knowledge and expertise in markets and transmission while I served on the PUC and I want to share some of that information with you.

I will not repeat here the arguments I made against the proposed Transmission Authority, other than to say it is a mistake to take power and authority over placement of transmission lines from local permitting and to give this new Transmission Authority the power of eminent domain. My other concerns are covered in the Colorado Politics opinion piece.

My primary focus today will be on the requirement that Colorado utilities join a regional transmission authority ("RTO").

Why should you take my opinions into consideration?

I was the Commissioner who spent almost 3 years leading the two dockets before the Commission which studied the proposed Mountain West Transmission Group as well as the Hearing Commissioner to preside over the Transmission Co-ordination study required by the 2019 legislation. I presided over five commission information meetings with dozens of participants who filed comments and submitted position papers and detailed studies. In opening the docket to conduct the study you required in 2019, PUC staff and I prepared a 20page order detailing the history of power pools, trading rules, joint dispatch agreements and energy imbalance markets in Colorado and requested comments from stakeholders on specific questions as to how to conduct the study. I am including in my testimony that order so that you can see the level of detail required and the care necessary to conduct the study requested by the 2019 General Assembly. The study will be completed May 1, followed by time for stakeholders to comment and a final decision by the Commission on December 1.

Joining an RTO is a serious decision, but similar to checking into the Hotel California—great on check in but impossible to leave because of the exit charges.

There are two current options to be the RTO for Colorado utilities—CAISO and SPP. CAISO is not really an option because of what we call the “governance” problem. CAISO is directed and controlled by the state of California. Liberal Democrat though I am, I would never want California making decisions for Colorado. So, even though their office in Folsom California is beautiful (I have included a photo—LEEDs certified by the way), let’s take CAISO off the table.

Let’s look at what life is like if you pass SB 72 and you force the Colorado utilities to join SPP—another very nice (expensive) office building for their 600 employees in Little Rock, Arkansas.

SPP is a 501(C)(6) organization meaning it is designed to assert and protects the interest of its members. SPP’s members are Transmission Owners, Transmission Users and Transmission Customers. SPP owes a duty to its members, not to the citizens of the state of Colorado, or any state. SPPS’ articles make no mention of the public interest and it has no legal requirement to act in the public interest.

SPPS budget last year was \$185 million. (CAISO’s was \$204 million). These are expensive entities to operate and ultimately electric customers pay for all of the costs.

There is little to no opportunity for Colorado interests to be taken into account at SPP. There are about 30 committees for the various members and 300 to 400 meetings a year. The only “voice” for a state is through membership in the Regional States Committee. The State Committee has NO independent staff or attorney, no independent budget, no ability to gather information or conduct investigations or make filings at FERC. I am including in my testimony an organizational chart of SPP. You can see that the state committee, the only place the citizens of Colorado will be represented is an island in the upper left- hand corner. So, decisions will be made by the transmission owners, transmission customers and users. Membership is very expensive and it is likely that the office of consumer

counsel and the environmental groups will not be able to afford membership and a vote in SPP.

RTO's are unregulated clearing houses for the settlement of financial transactions. The unregulated part became very clear with the ERCOTT problems. The products that are sold through this clearing house are complex and only the transmission owners and the traders understand them. There are charges for transmission services, for ancillary services, grid management charges, market services charges, system operator charges, CRR service charges, ancillary service capacity charges in day ahead and real time markets, required access charges, wheeling charges, intermittent resource charges and reliability co-ordination charges, to name a few.

All the RTOs have had serious problems in delivering electricity in the last several years. As I said in my Colorado Politics piece—ERCOT has been a disaster, with CAISO not far behind and SPP had blackouts during the extreme weather in February.

The economic theory behind an RTO is that price signals will drive the efficient use of transmission and sources of energy. So, if you force the utilities to join SPP, does that lead to faster decarbonization or reduced emissions? Probably not. In 2018, when SPP was trying to get its members to agree to the Mountain West Transmission Group, SPP pointed out that the cost of coal generation in Colorado was less expensive than the cost of coal generation in SPP and they forecasted an increased market for coal generation if SPP accepted MWTG because they would buy more of Colorado's coal generation. (See page 14, paragraph 33 of the Order I have attached to my testimony.)

Requiring Colorado utilities to join any RTO without the benefit of the \$500,000 study that you required in 2019 is not in the public interest and will likely, in my opinion, damage the interests of Colorado. Utilities, before entering an RTO have the ability to negotiate numerous items. SB 72 takes away this leverage as the RTO will know the General Assembly has already made the decision the utilities must join.

One additional comment about hedge funds and their ability under SB 72 to control transmission building. I suggest you read the March 8, 2021 article in the New Yorker by Sheelah Kolkatkar— “What Happens when Investment Firms Acquire Trailer Parks.” In their never-ending quest for higher returns, hedge funds win and regular people suffer.

Hedge funds are unregulated. As a Commissioner, I could see and question and reduce the return on equity for utilities. No one has this power over hedge funds. Same with best value employment practices and safety practices.

I want to conclude by making some observations about the PUC staff and Public Service. My reputation at the Commission was one of cynicism with respect to the utilities and my focus was on protecting rate payers. Around the country and in Colorado, there are numerous utilities engaging in public “green washing” --assigning interests in dirty plants and buying renewable credits or planting trees. PSCO, however, is the real deal in decarbonizing. They have supported the Governor’s initiatives and are implementing House Bill 1261 and SB 236. They filed a \$1.7 billion transmission plan which will tie into their clean energy electric resource plan which will be filed in two weeks with a cost of about \$8 billion. Why slow down all of this progress with a requirement to join an TRO and setting up a Transmission Authority now? Let’s see what these plans look like, what stakeholders, who will have a full voice at the PUC say about the plans and let’s see how the Energy Imbalance Market works, before the General Assembly imposes new and costly requirements. If you enact SB 72, you will be telling utilities around the country that no good comes from supporting reduced emissions and the PSCO model of leadership in attaining a clean energy future is a failure.

I think the SB 72 will also be demoralizing to staff at the PUC. They have put hours into the study that you ordered and what you are saying to them, is that their work and dedication does not count and is not respected. Colorado is very lucky to have some incredible staff at the PUC, people (a lot of women) who could earn much more in the private sector, who day after day do the tough business of regulation because they care about good public policy and good results for rate payers. Show your respect for their hard work and table SB 72 this year.

In 2019, the General Assembly and the Governor put Colorado on a path to reduce emissions. The PUC, with limited and overworked staff, is thoughtfully and judiciously implementing those directives. To distract the Commission, PUC staff, the office of Consumer Counsel and the utilities with new initiatives and directives is not wise and in fact counter-productive.

I urge you to vote against allowing SB 72 out of your committee.
Thank you.



Group Organizational Chart

