

House Energy & Environment

04/29/2021 01:30 PM

SB21-072 PUC Modernize Electric Transmission Infrastructure

Typed Text of Testimony Submitted

| Name, Position, Representing | Typed Text of Testimony |
|--|--|
| Gregory Glischinski Against AARP | <p>To: Energy and Environment Committee; Representatives Alex Valdez, Chair; Edi Hooton, Vice Chair; Tracey Bernett; Meg Froelich; Dominique Jackson; Andres Pico; Emily Sirota; Matt Soper; Brianna Titone; Tonya Van Beber; Mike Weissman; Perry Will; Dan Woog</p> <p>From: Greg Glischinski</p> <p>Subject: SB21-072 Public Utilities Commission Modernize Electric Transmission Infrastructure</p> <p>Chairman and Members of the Committee, my name is Greg Glischinski. I am a volunteer with AARP Colorado. AARP has 673,000 Colorado members age 50+. AARP can not support SB21-072 as written. AARP does support clean energy with a systematic means to achieve it. AARP does not believe the SB072 does this. It could do just the opposite by hastily placing us in an RTO.</p> <p>Here are some of my concerns:</p> <ul style="list-style-type: none"> • Why are we rushing this in place before the PUC has had hearings and published its findings of energy imbalance markets, RTO's, power pools and joint tariffs? • It seems we are starting off with a shotgun approach to meet future needs. • There doesn't seem to be a systemic approach for us to meeting our electrical needs in the future. Let's slow the process down and make a deliberate plan. • Four states are trying to get out of RTO's. • Is this the most economical approach for the consumer? Many of our members are on fixed incomes. • If we join a RTO, we lose our capability of local control by bypassing the PUC. • We already have energy balance through two existing markets. • Without a clear plan we could end up receiving dirty energy depending on an administration heading the federal government. • Do we want other states to tell us what we should do when it come to our energy needs? <p>Thank you for your consideration in this matter. Sincerely, Gregory A. Glischinski</p> |
| Ann Sutton For | <p>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</p> |

| | |
|---|--|
| <p>League of Women Voters of Colorado, Legislative Action Committee</p> | <p>contribution to our transition away from dependence on fossil fuels for electricity generation.</p> <p>The GHG Pollution Reduction Roadmap, 2021 targets reduction in GHG pollution 90% by 2050. Most GHG in Colorado is produced by electric power generation and by the transportation sector.</p> <p>The transition to clean renewable energy must be facilitated by more emphasis on electric grid modernization technologies and systems.</p> <p>Current “investment in innovation is inadequate for the scale of the challenge and what’s feasible.” ---2021 report by the National Academies of Science, Engineering and Medicine. The Future of Electric Power in the United States. Grid connections from sources of renewable energy such as wind farms and community solar gardens must be improved.</p> <p>A key priority in Colorado is to increase the number of electric vehicles, including trucks and buses, on our roads (GHG pollution roadmap). Also from the NAS report, future electricity demand will be shaped by the widespread adoption of a variety of potential electricity-intensive and/or demand-modulating technologies such as electric vehicles.</p> <p>“Widespread adoption of EVs may also depend, in part, to the availability of charging infrastructure across varying geographies and for all socioeconomic groups. Over 40 million Americans report interest in owning an EV for their next car. Large scale adoption of electric vehicles may necessitate the use of Level 2 charging [240V], which would increase loads at the charging point, as well as the system load profile. From a residential perspective, EV charging could rival the magnitude of electricity load from heating/ventilation/air-conditioning.”</p> <p>Expansion of transmission lines to provide higher system capacity to connect end-users to the electric grid is essential for moving our State forward in combating the effects of climate change.</p> <p>Respectfully submitted, Ann Sutton Volunteer Lobbyist LWVCO</p> |
| <p>Lois McLauchlan For Self</p> | <p>Let's help. our state prepare for the cleaner energy future by facilitating the market to work better for all.</p> |

April 27, 2021

To: Energy and Environmental Committee
Representative Alex Valdez, Chair
Representative Edie Hooton, Vice Chair
Representative Tracey Bennett; Representative Meg Froelich; Representative Dominique Jackson; Representative Andres Pico; Representative Emily Sirota; Representative Matt Soper; Representative Brianna Titone; Representative Tonya Van Beber; Representative Mike Weissman; Representative Perry Will; Representative Dan Woog

From: Dr. Irene Martinez Jordan, AARP Volunteer Advocate

Re: SB21-072 Public Utilities Commission Modernize Electric Transmission Infrastructure

Dear Chair and Members of the Committee:

My name is Irene Martinez Jordan I am an AARP Advocacy Volunteer, representing its 673,000 Colorado membership. We strongly oppose SB-072 as it is presently written.

AARP supports both affordable energy rates for older Americans and sustainable energy. We do not believe that this bill meets either of these requirements.

SB-072 is directing the PUC (Public Utilities Commission) to create a new Colorado Electric Transmission Authority (CETA) without evidence of its need. This bill would supersede the PUC and ignores the work that the PUC has been doing, the work that this legislature requested it to do under SB19-236 to "...investigate the potential costs and benefits to electric utilities, ...and customers... from participating in any energy imbalance markets, RTOs, power pools, or joint tariffs." The PUC is scheduled to release its report on or before December 1. Why are we going to create this RTO without proper study and community input?

The Greenhouse Gas Emissions Report that SB-072 sites has ambitious goals that we all want to achieve but how do we know that the creation of CETA is the answer? This idea is being thrown at a problem without a well thought out process, without a study of how it will work and what resources it has to make it work.

The American Public Power Association in its 2021 *Wholesale Electricity Markets and Regional Transmission Organizations Issue Brief* reports that

Public power utilities, state utility commissions, consumer- and low-income advocates, and industrial electric power customers have raised concerns about RTO-run wholesale electricity markets, ...around high and volatile prices...cost and effects of mandatory markets for capacity run by some RTOs...and lack of transparency in RTO dealings....

The PUC's study to see if RTOs would really benefit Colorado is critical. If you don't feel that your directive in SB19-236 is sufficient, modify it with some of the element of SB-072 to make an informed decision. But please don't throw a solution at the problem without truly studying the plus and minuses of your decision.

Again AARP understands the need for and supports the goal of sustainable energy but we want to be sure the means by which we get there is affordable and safe for older Americans and our underserved communities.

We ask you to remember that there is a tax payer funded study in the PUC that, as drafted, this bill would effectively pre-empt.

We are concerned with the possible increased costs to Colorado consumers and the loss of Public Utilities Commission oversight.

Please vote no on this bill or modify it to honor your own directive to the PUC and make your future decision based on a complete and impartial study.

Thank you for your time, consideration and your hard work for all the people of Colorado.

Irene Martinez Jordan
720-270-1688

Attached: APPA Brief

<https://www.publicpower.org/policy/wholesale-electricity-markets-and-regional-transmission-organizations>

American Public Power Association

<https://www.publicpower.org/policy/wholesale-electricity-markets-and-regional-transmission-organizations>

Wholesale Electricity Markets and Regional Transmission Organizations Issue Brief 2021

Summary

Some utilities generate the power they sell to customers, but a good portion of electricity sold to customers is first purchased at wholesale from a third party. In some regions, wholesale purchases can be made through centralized wholesale electricity markets operated by regional transmission organizations and independent system operators (RTOs and ISOs, respectively, but collectively referred to as RTOs). Public power utilities and many customers have extensive concerns about the high cost and negative effect of mandatory capacity markets operated in some RTOs. The American Public Power Association (APPA) has developed a policy proposal to address these concerns, including proposals to reduce impediments for utilities to self-supply capacity and energy. The association also encourages congressional oversight of Federal Energy Regulatory Commission (FERC or Commission) market policies including, but not limited to, the problems associated with capacity markets and lack of transparency in RTO dealings.

Wholesale Markets Overview

Some utilities generate the power they sell to customers, but most electricity is first purchased at wholesale from a third party. These wholesale purchases can be made bilaterally—although in some instances the third party is simply another company owned by the utility’s parent company. Wholesale purchases can also be made through centralized wholesale electricity markets operated by RTOs.

At the wholesale level, electric power generators are paid for providing:

- Energy — the actual electricity consumed by customers;
- Capacity — standing ready to provide a specified amount of electric energy;¹ and
- Ancillary Services — a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves. Ancillary services generally account for a very small portion of market revenue.

Within and outside of RTO regions, contracts for wholesale sales of these products can be arranged bilaterally through direct negotiation or through a broker. Energy sales may also be conducted through an electronic brokerage platform, such as the Intercontinental Exchange.

Within RTO footprints, wholesale purchases and sales may also be made through markets operated by RTOs.¹ They do not own power plants, but they exercise extraordinary control over power generation. RTOs decide which generators will run at what times and how much power they will generate;² manage the transmission system;³ and run the billing systems for payments for power, transmission, and other services.

Energy prices paid in these markets are also determined by the RTO. These prices are generally set through an auction in which the offers to sell power at a given time are stacked in increasing order until there is enough power bid at that price to meet the demand for power. All power is then sold at this highest “market clearing” price to generators that bid to provide power at or below this market clearing price.⁴ RTOs generally limit the maximum price of a bid, typically \$1,000 per MWh, but that cap can go as high as \$2,000 if the seller expects their costs of producing power to exceed \$1,000. Moreover, RTOs all have some form of shortage pricing where electricity prices can spike above these caps during times of system stress. Within RTO regions, customers can enter bilateral contracts with separate settlements at different prices. However, energy prices set by the RTO strongly influence the price of energy in bilateral contracts.

In some cases, congestion on power transmission lines may prevent generation from being delivered to customers in certain areas, resulting in the use of more expensive generation within these constrained zones to meet demand, producing a higher price for customers in that zone than outside the zone. Financial instruments may be used to hedge against such congestion costs, but some RTO market monitors have expressed concerns in recent years that these financial instruments are providing earnings for financial traders and not providing a sufficient a hedge for load-serving entities.

Capacity Markets Operate in Most RTOs

In addition to energy markets, four of the nation’s seven RTOs operate capacity markets.⁵ As discussed above, capacity represents a utility’s obligation to have enough generation to meet customer demand at all times. Demand can vary widely throughout the year, but the highest demand generally occurs during the hottest and coldest times of the year. For planning purposes, the amount of capacity a utility needs is its estimated peak demand plus a reserve margin. Utilities operating outside an RTO generally make this calculation on their own. Utilities operating inside an RTO generally must meet the capacity requirements calculated for the utility by the RTO. Because there is currently limited capability to store electric

energy, the need for capacity is primarily met by electric power plants standing ready to provide power. This means having a power plant in good working order, with staff and fuel on hand regardless of how much power the plant generates. Capacity payments are intended to help cover these costs. Large customers can also provide capacity by agreeing to curtail power usage if needed to help the utility avoid running out of power. This is called demand response.

Capacity can be purchased from days to years in advance, depending upon the nature of the RTO market. As with energy, capacity can be secured through ownership of a generating unit or through a bilateral contract with a third-party provider (collectively referred to as “self-supply”). Capacity can also be purchased through wholesale capacity markets operated by certain RTOs.

Three RTOs, the New York ISO (NYISO), PJM Interconnection (PJM), and ISO New England (ISO-NE), operate mandatory capacity markets. These markets are considered mandatory because all capacity used to meet required reserve margins must be purchased through a capacity market auction operated by the RTOs—even capacity that is self-supplied.⁶

Like RTO-run wholesale markets for energy, RTO capacity markets rely on an auction, which results in a single clearing price for capacity during the auctioned period determined by the intersection of the supply with a demand curve created by the RTO. Again, capacity bid at or below the clearing price is paid the clearing price. Capacity bid above the clearing price does not “clear” the auction and is not paid.⁷ Capacity auctions also allow prices to be set higher within transmission-constrained zones.

Buyer-Side Mitigation Rules

In contrast to energy markets, several RTO capacity markets (ISO-NE, PJM, and NYISO) also include mechanisms to prop up prices for generators, such as minimum offer price rules (MOPR) and other “buyer-side” market power mitigation rules. In general, these rules require electric generating resources to bid into the capacity market auctions at certain minimum prices, even if a generator would be willing to supply capacity at a price lower than the administratively determined minimum price. These rules have become progressively more restrictive as a result of generation owner backlash against states’ increasing attempts to take control of their energy resource futures, including through contracts with new renewable resources and payments to avoid the retirement of nuclear power plants.

The logical action for state-procured resources is to bid the capacity into the auction at a low or zero price to ensure that the bid price would be less than the clearing price set by the auction. There are two reasons for taking this approach. First, both parties to a bilateral contract for capacity would be indifferent to the final clearing price set by the market. While the purchaser would pay, and the seller would receive, the market clearing price, the seller and purchaser then would make a financial settlement to bring the actual price paid back in line with their bilaterally negotiated price, known as a “contract for differences.” If the unit is owned by a utility, then the owner is also indifferent to the price as it is buying and selling the same amount of capacity in the auction. Second, under the rules of a mandatory capacity construct, capacity that does not clear the auction is not counted toward the utilities’ reserve margin requirement. As a result, the utility’s customers would have to pay for capacity twice: once as part of the long-term contract or other payment to secure that capacity, and then a second time to purchase from the capacity market auction to meet the reserve margin obligation.

Incumbent generators, however, feared the displacement of existing units by state-procured generation and that lower-cost units would now set the market clearing capacity price, thus reducing their profits. In response to generator arguments, FERC has allowed, and even required, the expansion of buyer-side mitigation rules in each of the RTOs with mandatory capacity markets. These expanded buyer side mitigation measures can interfere with state and local resource decisions, because a state or public power entity seeking to secure new capacity would like that capacity to be bid at a price that will ensure that it clears the RTO’s auction, but the RTO is instead mandating a higher bid that puts that capacity at risk of not clearing the auction. This does nothing to help build new capacity, but instead simply serves to reward incumbent generators.

While many of these RTO MOPR changes have been proposed and approved by FERC in reaction to states’ efforts to assert control over power generation resource decisions, they affect all entities, including public power utilities and rural electric cooperatives seeking similar control. These expanded buyer-side mitigation measures create significant uncertainty for public power’s ability to self-supply in the future.

Additional RTO Energy Market Concerns

Participating in RTO-operated wholesale energy markets can achieve efficiencies by providing access to a variety of resources, thus reducing energy costs. However, there are still some potential problems, including the ability of some generators to strongly influence market prices (also known as the potential exercise of market power); highly complex rules; and problematic governance processes. These problems have arisen, and remain, because of a lack of sufficient FERC oversight. Although energy prices have declined with the drop in natural gas costs and increased levels of renewable energy, merchant generators operating in these markets still can extract excess revenues—either operating within the existing rules or obtaining FERC’s approval for changes to rules to generate excess revenues. In fact, retail electricity

prices are, on average, higher in RTO regions, and there is scant evidence that this price differential has produced greater levels of reliability or significant infrastructure development.

Congressional Action

In recent years, there has been limited activity in Congress on wholesale market issues. In the 116th Congress, lawmakers almost entirely constrained themselves to addressing wholesale electricity markets through oversight of FERC. For example, the House Energy & Commerce Committee in June 2019 held a hearing that examined how FERC's decisions impact the nation's energy and environmental future. Topics covered included transmission policy, energy storage in wholesale markets, and wholesale capacity markets.

APPA Position

APPA has long had concerns about RTO-operated markets, particularly related to the costs to electricity customers and potential market manipulation. In recent years, the association has focused intensely on the problematic mandatory capacity markets, but has also closely monitored efforts to change the energy market price formation rules to ensure such changes do not create price increases without benefits to consumers. APPA developed and recently reissued a proposal to replace these mandatory capacity markets with voluntary capacity markets that will create more opportunities for states and public power utilities to procure desired resources at a more reasonable cost. The association continues to urge congressional oversight of FERC market policies including, but not limited to, the problems associated with capacity markets, the lack of transparency for stakeholders in RTO dealings, and the implementation of new price formation rules to ensure fairness.

A Description of the RTOs

There are seven RTOs operating in the United States: ISO-NE; NYISO; PJM; MISO; CAISO; SPP; and the Electric Reliability Council of Texas (ERCOT). Of the seven, only ERCOT, which operates entirely within the state of Texas, is not subject to FERC jurisdiction. Below are descriptions of the remaining six:

California ISO (CAISO)

CAISO operates only in California, but it is under FERC's jurisdiction because the state's transmission grid is interconnected with the rest of the West. Some public power utilities in the state have chosen not to turn over operational control of their transmission facilities to CAISO, but all public power utilities are impacted by CAISO's energy market prices and provision of transmission service due to the web of business relationships among market participants in the state. In October 2014, the ISO began operating a voluntary energy imbalance market (EIM) with PacifiCorp, which has since been joined by many investor-owned and public power utilities. The EIM is generally viewed as providing many of the benefits from centralized energy dispatch over a large geographic area, but without the risks of a full RTO. CAISO has initiated a stakeholder process to examine whether to extend the day-ahead market to the EIM, which would result in a more RTO-like market structure.

CAISO does not operate a capacity market, and in 2018, FERC rejected a complaint requesting the creation of a capacity market in CAISO. APPA and multiple other parties supported FERC's rejection of the complaint.

ISO-New England (ISO-NE)

ISO-NE operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The region is facing numerous challenges from growing reliance on natural gas without a corresponding increase in natural gas pipeline capacity, retirements of nuclear and coal plants, and rising energy and capacity prices. The ISO recently implemented interim market rule changes to address concerns about the overreliance on natural gas during winter cold spells that would allow for additional payments to generators to have fuel in place during the winter. FERC is requiring ISO-NE to file permanent rule changes addressing fuel security this spring. ISO-NE operates a mandatory capacity market, called the forward capacity market, which procures capacity three years in advance.

Midcontinent ISO (MISO)

MISO operates in all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin, and Manitoba, Canada. MISO has seen both defections by transmission-owning utilities—First Energy and Duke left MISO to join PJM in 2011 and 2012 respectively—and a significant expansion of its territory at the end of 2013 to include what is known as MISO South. Many industry observers believe the former MISO utilities that joined PJM did so to receive lucrative capacity market payments not available from MISO, while MISO's revisions to its capacity market were an incentive for the southern expansion. In 2012, FERC approved a voluntary locational capacity market for MISO, but ruled against mandatory participation or a MOPR in that market.

New York ISO (NYISO)

NYISO operates only in New York, but is FERC-jurisdictional because the state's transmission grid is interconnected with the rest of the region. New York City is a very transmission-constrained area within NYISO, requiring substantial mitigation of the power sales into that area. The ISO operates a short-term capacity market than in PJM and ISO-NE, but it is only mandatory within the New York City and Lower Hudson Valley zones.

PJM Interconnection (PJM)

PJM operates in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM operates a three-year forward mandatory capacity market, called the reliability pricing model. In December 2019, FERC decided to dramatically expand PJM's capacity market's MOPR, greatly restricting public power's self-supply ability and state efforts to procure renewable resources or prevent nuclear plants from retiring.

Southwest Power Pool (SPP)

SPP operates in all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. SPP has approached RTO formation and market development on a slower and more conservative track than many other RTOs. SPP transitioned to a full RTO with both a day-ahead and real-time market in March 2014, but has not implemented a capacity market. In June 2019, SPP issued a proposal for a Western Energy Imbalance Services market (WEIS), which is similar to, and would operate alongside, the CAISO-operated western EIM. Thus far, five investor-owned, cooperative, and public power utilities have agreed to join the WEIS, which is expected to begin operating in 2021.

References

1. A more detailed description of all seven RTOs operating in the U.S. can be found at the end of this issue brief.
2. Generation owners also have the option to self-schedule a plant without it being dispatched by the RTO, but cannot set the price.
3. RTOs have functional control, but not ownership, of the transmission system in their footprint. They ensure non-discriminatory access to transmission lines to sellers and purchasers of electricity and eliminate rate "pancaking" (charging multiple transmission fees for one transaction). RTOs also coordinate regional planning for new transmission lines.
4. ISO-NE uses a reverse auction where the RTO starts at a high price and then sellers pull out in each round as the price is lowered. The price is then set when power from willing sellers equals the demand for power from purchasers.
5. The Southwest Power Pool, California Independent System Operator and Electric Reliability Council of Texas do not operate capacity markets.
6. Only some regions of the NYISO capacity market are mandatory.
7. As with energy, ISO-NE uses a reverse auction where the RTO starts at a high price and then sellers pull out in each round as the price is lowered. The price is then set when capacity from willing sellers equals the demand for capacity from purchasers.

Bill Levis, AARP Volunteer Advocate, SB21-072
Before Energy and Environmental Committee, April 29, 2021

Rep. Alex Valdez, Chair, Rep. Edie Hooton, Vice Chair; Rep. Tracey Bernett; Rep. Meg Froelich; Rep. Dominique Jackson; Rep. Andres Pico; Rep. Emily Sirota; Rep. Matt Soper; Rep. Brianna Titone; Rep. Tonya Van Beber; Rep. Mike Weissman; Rep. Perry Will; Rep. Dan Woog

On behalf of its nearly 700,000 members, AARP opposes SB21-072 as it passed in the Senate. The energy grid in Colorado is nothing like Texas and never has been. We need to slow down and not confuse the issue.

Colorado is part of the Western Interconnect with 10 other states. Both Xcel, providing electricity to 1.5 million customers in Denver and Grand Junction, and Black Hills with nearly 100,000 customers in Pueblo are each in 8 states. Tri-State that provides power to most of the rural electric associations in Colorado is in 4 states.

Unlike states in the western or eastern interconnect, Texas is an island that deregulated electricity 20 years ago. Its energy meltdown in February was its second in 10 years. It was warned to fix it in 2011 and failed to do so.

Colorado's Public Utilities Commission (PUC) regulates our two investor-owned utilities per article XXV of our state constitution. As a result and unlike in Texas, our wind turbines have heaters, our pipelines are buried sufficiently and our power plants are insulated against the bitter cold.

When Texas had blackouts in February, Colorado utilities continued to provide power. The same was true during our blizzard in March. However, regional transmission organizations (RTOs) suffered rolling blackouts in a number of states.

Two years ago, the Colorado General Assembly adopted Senate Bill 19-236, which then Rep. Hansen co-sponsored, calling on the PUC to study if it made for sense for our electric utilities to join an energy imbalance market or an RTO. The PUC will issue its findings by December after spending \$500,000 to do so.

But even before that report has been written, the legislature is considering SB 72 that would mandate RTO membership by 2030. Clearly, there is no need to rush. Let the PUC do its job and come up with its recommendation before the General Assembly supersedes its law of two years ago to require something it mandated the PUC study.

Colorado had the third lowest residential electricity bills in 2019 according to the U. S. Energy Information Administration. And bills were below average in 2020.

The question then is why Colorado legislators want to hand over regulatory authority to an RTO made up of more than ten states that will tell Colorado what to do?

Especially when CT, IL, MD and NJ are considering leaving RTOs because they don't see the benefits in paying for power in other states. Presently, the Colorado PUC, whose three members are appointed by the Governor with the approval of the state senate, determine the just and reasonable rates of Xcel and Black Hills.

Assuming Colorado joins an RTO, that responsibility would be turned over to the Federal Energy Regulatory Commission (FERC), which historically has allowed higher rates with less oversight. There also would be more costs for our PUC and its staff to attend the hundreds of meetings RTOs have every year. In section 3 on p. 8, SB 72 allows utilities to charge ratepayers for those costs. And then there would be the addition of unsightly transmission lines especially if the state were to join an RTO to the east.

With our PUC studying whether joining an RTO makes sense, the last thing we need is a rush to judgment. Especially when it would require joining by Jan. 1, 2030.

The only exception to utilities other than municipalities joining an RTO, defined as an organized wholesale market (OWM), are found in section 2 on p. 7 of the bill passed in the Senate. The bill states that "Upon application by a transmission utility, the commission may waive or delay the requirement...if: (a) the commission has determined that the transmission utility has made all reasonable efforts to comply with the requirement but there is no viable and available OWM that the transmission utility can join by January 1, 2030; **and** (b) the commission has determined, based on the study conducted in accordance with article 2.3 of this title 40, that requiring the transmission utility to join an OWM is not in the public interest."

The only problem is that SB19-236 repeals art. 2.3, title 40, effective Sept. 1, 2022. The current language also is contrary to the bill summary that says that the PUC may waive or delay the requirement if a utility is unable to find a viable RTO to join **OR** if the commission finds it would not be in the public interest.

AARP also is concerned that the bill would add another surcharge to consumer bills on top of at least 3 current clean air riders (Clean Air Clean Jobs, Energy Plan Adjustment and Renewable Energy Standard Adjustment) and 2 new ones for EV charging stations and the clean energy plan. Section 3 on p. 8 of the current bill would a transmission utility joining a RTO to recover fees and other RTO costs through rates or through a new or existing rider. This is another reason not to join an RTO.

Thank you.