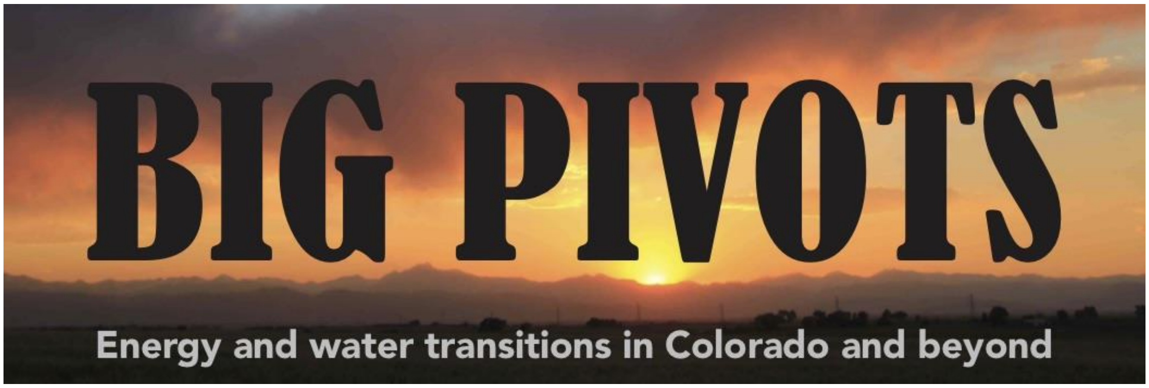

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So bold just a short time ago, 80% goal now commonplace

By Allen Best

It seems like many years ago since Ben Fowke, chief executive of Xcel Energy, standing on a podium at the Denver Museum of Nature and Science, announced that his company was confident it could decarbonize the electrical generation across its six-state operating area 80% by 2030 as compared to 2005 levels. This, he said, could be done using existing technology.

That declaration in December 2018 was national news. So was the company's disclosure in December 2017 of the bids for renewables to replace the two coal-fired units it intended to retire at Pueblo, Colo. They came in shockingly low.

A new report says that with necessary public policies, utilities can easily bypass need for new gas-fired generation—as Colorado Springs has chosen to do.

Now, 80% plans by 2030 are becoming almost commonplace. Consider the trajectory of Colorado Springs. The city council there, acting as a utility board, in June accepted the recommendation of city utility planners to shut down the city's two coal plants, the first in 2023 and the second in 2030.

That was the easy decision. But the Colorado Springs City Council, in a 7-2 vote, also accepted the recommendation to bypass new natural gas capacity. Xcel is adding natural gas capacity to its portfolio in Colorado, although the plant already exists.

Colorado Springs is now on track to get to 80% reduction by 2030.

As a municipal utility, Colorado Springs was not required by Colorado to reduce its emissions 80% by 2030. That applies to those utilities regulated by the state, and municipalities are exempt. It is subject to broader economy wide goals of 50% by 2030 and 90% by 2050.

A city utility planner says he believes the city can achieve 90% reduction by 2050.

"I do believe personally that in the next 10 years we will see some major advancements in the technology that will allow those technologies to go down and be more competitive," says Michael Avanzi, manager of energy planning and innovation at Colorado Springs Utilities.

A gas-fired power plant northeast of Denver. Photo/Allen Best

A report issued by the Center for Environmental Public Policy at the University of California, Berkeley, says it shouldn't take until 2050. Wind, solar, and battery storage can provide the bulk of the 90% clean electricity by 2035, according to the study, **2035 Report: Plummeting Solar, Wind, and Battery Costs Can Accelerate Our Clean Energy Future**.

This, the study notes, can be done even while electricity costs decline. This finding contrasts sharply with studies completed more than 5 years ago, which found deep penetration of renewables would elevate costs. These lower costs are being reported across the country, the study found, even in those areas considered resource-poor for renewable energy generation. Colorado is the converse: It has excellent renewables, among the best mix in the nation.

The study is important and rich with detail. Among the seven members of a technical review committee was Steve Beuning, of Glenwood Springs-based Holy Cross Energy.

The findings, though, are best understood in terms of the policy assumptions, which are found in a separate study conducted by Energy Innovation, a San Francisco-based consultancy. Colorado gets several mentions, and it's important to note that the chief executive is Hal Harvey, who grew up in Aspen. (Harvey has connections in high places; he inspired a column in late June by Thomas Friedman of the New York Times: "This Should Be Biden's Bumper Sticker.")

The conclusions describe an optimal set of policies to get the United States to 90% by 2035, including:

• federal clean energy standards and, especially in the absence of that, extension of federal tax credits for wind and solar.

• strengthening of federal authority to improve regional transmission planning by the Federal Energy Regulatory Authority.

• reform wholesale markets to reward flexibility.

Researchers in California did not specifically examine the case of Colorado Springs but more broadly found that U.S. electrical utilities can tap existing gas-fired plants infrequently along with

The Martin Drake plant near downtown Colorado Springs is to be closed by 2023 and 7 gas-fired generators moved in to generate power until 2030. Photo/Allen Best

storage, hydropower, and nuclear power to meet demands even during times of extraordinarily low renewable energy generation or exceptionally high electricity demand. All told, natural gas can contribute 10% of the electrical generation in 2035. That would be 70% less than the natural gas generation in 2019.

How did the California researchers decide how much natural gas would be needed to firm supplies? As the saying goes, the sun doesn't always shine, the wind doesn't always blow. And when would these times of low renewables intersect those of high demand? The researchers studied weather records for seven years, 60,000 hours altogether, and in 134 regional zones within the United States, from earlier in this century. That worst-case time, during the seven years examined, was on the evening of Aug. 1, 2007, a time when solar generation had declined to less than 10% of installed solar capacity, and wind generation was 18% below installed capacity

Based on this, they found a maximum need for 360 gigawatts of natural gas capacity. In other words, no new natural gas generation was needed. We have enough already.

Peak demand in Colorado Springs usually occurs late on hot summer afternoons. The all-time record demand of 965 megawatts occurred on July 19, 2019. As Colorado Springs grows during the next three decades, it will possibly become Colorado's largest city, with demand projected to push 1,200 megawatts (1.2 gigawatts) at mid-century.

For Avanzi and other utility planners charged with creating portfolios for consideration by elected officials, closing coal plants was an easy case to make. Coal has become expensive, severely undercut by renewables.

Also considered were 100% emission-free portfolios by 2030, 2040, and 2050. But they were seen as too risky and too costly, at least at this time.

Portfolio 17, the one ultimately adopted by the city council on June 25, calls for the Martin Drake plant to be closed in 2023 and the Ray Nixon plant in 2030.

Seven portable gas generators are to be installed at the Drake plant for use from 2023 to 2030, a need dictated by the existing transmission and not the inadequacy of renewables. Colorado Springs already has a gas plant, but the city council members accepted the recommendation of utility planners that no new plant will be needed. That vote was 7-2.

Writing in PV Magazine, Jean Haggerty pointed out that Colorado Springs was part of a trend among utilities to avoid building new natural gas bridges to renewable energy. Tucson Electric Power also plans to skip the gas bridge. And, on the East Coast, Florida Power & Light and Jacksonville's municipal utility reached agreement to rely on existing natural gas and new solar generation when they retire their jointly owned coal plant, the largest in the United States.

In creating the portfolios, Avanzi says he relied upon mostly publicly available reports, especially the National Renewable Energy Laboratory's annual technology baseline and U.S. Energy Information Administration documents. For battery storage, he relied upon a study by energy consultant Lazard.

Colorado Springs' plan calls for 400 megawatts of battery storage by 2030. Previously plans for a 25-megawatt battery of storage are expected to come on line in 2024.

All types of storage were examined. The single largest storage device in Colorado currently is near Georgetown, where water from two reservoirs can be released to generate up to 324 megawatts of electricity as needed to meet peak demands. The water than can be pumped uphill 2,500 feet to the reservoirs when electricity is readily available.

Colorado Springs studied that option. It has reservoirs in the mountains above the city. It found the regulatory landscape too risky.

The most proven, least risky, technology is lithium-ion batteries that have four-hour capacity and flow batteries with six hours capacity. They can meet the peak demand of those hot, windless summer evenings after the sun has started lessening in intensity.

New Mexico company gets bank deal to boost carbon capture hopes

AZTEC, N.M — Enchant Energy—the company that hopes to keep the San Juan Generation Station open by retrofitting the coal-fired power plant with carbon capture technology—has signed a deal with Bank of America for 45Q tax equity financing.

Peter Mandelstam, chief operating officer for Enchant, told the Farmington Daily News that the deal will help Enchant Energy attract investors and finance the carbon capture retrofit.

If San Juan Generating Station is successfully retrofitted, its investors can receive $35 in tax credits for every ton of carbon dioxide that is captured and sold for enhanced oil recovery. If the carbon dioxide is pumped into an underground saline aquifer for permanent storage, the investors can receive $50 per ton in tax credits.

A study now underway seeks to determine if the carbon dioxide can be placed in an aquifer near the current power plant site.

Mandelstam explained that the tax credit is similar to tax credits that helped develop the wind energy industry, which provides an additional sense of security for tax equity investors.

What the Economist says

The Economist this week suggests that Joe Biden may have the opportunity to effect transformative public policy if, as the polls now suggest, he is elected president. One of his goals is to adopt legislation that would bind America to reaching net-zero emissions by 2050.

See: Why Joe Biden's instinctive caution makes real change possible: How a retro can be a radical

Building electrification stands out in Denver's climate action report

by Allen Best

A task force convened in January has issued a report that urges Denver to hurry up and get more meaningful action done to reduce greenhouse gases.

Total emissions dropped 13% from 2005 to 2017, owing primarily to the greener electricity distributed by Xcel Energy. Direct emissions—primarily from natural gas in buildings and liquid fuels used for transportation—have not.

The report has proposals for ways to reduce emissions from the many sectors of the city's economy, but what stands out to me is the building sector. The way Denver slices the energy pie, as of 2018 buildings were responsible for 34% of carbon dioxide emissions and homes 15%.

The task force calls for a requirement that electrification of buildings occur when equipment has failed. And, by 2040, natural gas equipment should be replaced where possible.

The same section calls for net-zero (highly efficient, all-electric, renewable energy, grid-flexible) new homes required in the 2024 base building code and in new buildings in the 2027 base building code.

This fits in with a broad theme I am seeing. My own odyssey goes back almost a decade, when I was first introduced to the idea of beneficial electrification by the individual responsible for the buildings at Stanford University. He didn't call it that. But the idea that he articulated was that all buildings would be heated by electricity, and that electricity would, of course, come from renewable sources.

That has, in fact, now happened at Stanford, as Denver's report notes.

And it's beginning to happen in Colorado. The most prominent example is at all-electric Basalt Vista. Now I hear from Chris Bilby, one of the energy architects from Holy Cross who made that project happen, that a bunch of housing under construction or soon to break ground in Pitkin County will be all-electric.

(And elsewhere in Colorado I hear of conversations starting about the end of natural gas infrastructure).

What strikes me as interesting about Denver's report is that this is something the city government has the power to implement. A scrape-and-replace in Highlands? This should be easy.

The provision calling for replacement of existing natural gas infrastructure, as it breaks down, could be powerful, although I admit I don't know what all would be involved.

(I replaced a natural gas furnace at my house several years ago, but with another natural gas stove. I had a hard time persuading the appliance guys that I wanted a 96% efficiency stove and not just an 84% efficiency off-the-shelf stove that is the stock in trade at Home Depot.)

Denver's task force very much reveals the broad currents of recent times. It makes note of Denver's diversity but also the outsized impacts of pollution on racial and other minorities. It wants to seize the momentum evident in the Black Lives Matter movement of recent months to move forward on climate action, too.

Another provision calls for expanding the tree canopy to under-resourced neighborhoods.

The report estimates that an all-ion approach would require $198 million annually in funding. It proposes to raise that revenue in various ways, including a sales tax at 0.25%, which would yield $36 million, along with other sources

Read the plan yourself here.

Xcel Energy's Cheyenne Ridge wind farm in eastern Colorado has now arisen, preparing the way for lowering of the Comanche 1 and 2 (striped smokestacks) at Pueblo after operations end in 2022 and 2025. Mortenson, the contractor (see construction trailer, Sunday evening), set the first of the 229 turbines In June 2019 and the last one in May. [Xcel projects the beginning of operations in September.] This is in the area between Cheyenne Wells and Burlington, about 180 miles east of Denver. ***Photos/Allen Best***

Why large renewable projects can achieve deep decarbonization more cost effectively

Or so goes one of arguments in mother-of-all-rulemaking cases

by Allen Best

Not all paths will take Colorado toward its rapid economy-wide decarbonization goals with the same efficiency. That's the primary message of Michael Milligan, a consultant who recently retired as principal researcher at the National Renewable Energy Laboratory.

Milligan in November published a paper, which is posted on the website of [Renewables for Colorado](). He is identified as a senior advisor for grid integration with the organization.

Michael Milligan

Joshua Epel, former chairman of the Colorado Public Utilities Commission, is identified as a senior advisor for policy. Also on the team is Jim Carpenter, a long-time political operative in Colorado associated with Democratic politicians. The director is Mary Hanley, who has held communication posts with The Wilderness Society and in the Clinton administration.

The stated purpose on the group's website is to provide "energy expertise to policy leaders and the public on implementing state carbon reduction mandates and making the transition to 100% clean energy."

Funding for the group has not been identified.

Milligan's paper makes the case that procurement of new renewable energy must be based on a competitive bidding process regardless of the size of the facility.

"Every 100 megawatts of grid generation—whether it is a single development of 100 MW or dispersed across 20 or more sites—should be held to the same interconnection requirements, reliability standards, performance expectations and cost requirements," he writes. "To do otherwise subjects ratepayers to a lower level of reliability at higher cost."

Renewable energy acquired non-competitively, he says, will increase consumer rates needlessly and crowd out more efficient solutions.

Colorado has a goal of reducing carbon emission from its economy 90% by mid-century. The assumed logic for achieving this is through rapid decarbonization of its electrical supply. Most coal plants will come down during the next decade.

But the natural gas fleet is on the line, too. New facilities are unlikely, as was demonstrated by Colorado Springs. It is retiring its two coal plants in 2023 and 2030 without building additional gas generation (except temporary units at the Drake unit).

"Replacing Colorado's remaining coal and natural gas-fired facilities will likely require expanding the electricity transmissions system to integrate and balance multiple new sources of energy," says Milligan.

"The clear solution is to require all renewable providers to competitively bid for the purchase of their power," he writes in the paper.

The elephant in Milligan's paper is the effort by sPower, a Salt Lake City-based company that in 2018 submitted to the Colorado PUC a proposal to build 18 small solar power facilities across Colorado.

Xcel Energy gets power from several large solar farms in the San Luis Valley. Photo/Allen Best

Individually, they would produce about 80 megawatts. Combined, they would have had the capacity to generate 1,400 megawatts of power.

The state's two investor-owned utilities, Xcel Energy and Black Hills, would have been forced to buy the power at "qualified facility" rates under terms of a 1978 law called Public Utilities Regulatory Policy Act, or PURPA. The goal of the 1978 law was to provide access to small renewable energy providers, known also as qualified facilities, or QFs, to compete with fossil fuel-generated electricity.

Utility Dive, in a 2018 story (States, greens face off over PURPA implementation at FERC), further explained that Congress in 2005 amended PURPA as part of the Energy Policy Act to account for the growth of wholesale power markets.

This is already a messy storyline, and it gets worse. There's also court action (unresolved) and an appeal to the Federal Energy Regulatory Commission.

Meanwhile, there's a PUC decision in 2018 that speaks of the "complex and interrelated provisions" in rules governing procurement of electric generating resources. In that decision, 18R-0492E, the PUC struck "clearly contradictory language" in its Rule 3902(c) that relates to qualifying facilities. But the written decision also made clear that the PUC intended to return to the matter in a forthcoming comprehensive rulemaking.

That time has come. Meanwhile, we have Epel, who was chairman of the PUC from 2011 to 2017, talking up reform. In an essay published by Utility Dive in November 2019, the same time as Milligan's paper was published, Epel wrote that "PURPA contains a number of outdated concepts that are contrary and indeed impeding the effort to decarbonize the electric utility sector. Unlike 40 years ago, QFs are not replacing fossil fuels; they are blocking the growth of renewable energy projects necessary to replace fossil fuels.

Epel went on to write that "the "most abusive manipulation of PURPA is the use by QFs (funded in many instances by hedge funds) to force utilities into lengthy 'must-take' contracts, including provisions that compel payment for renewable energy above fair market prices and lock that above-market rate in for years or decades to come."

He cited Colorado as a state that has largely avoided utilities being forced to pay too much for solar and wind power. Not so Idaho Power or PaciCorp. "The solution to the problem is adopting a Colorado-type planning and competitive bidding process, not forced use of QFs."

This takes us to the current rulemaking, as the PUC commissioners had contemplated in their 2018 decision. The PUC is hearing arguments in this case, [19R-0096E,] on many aspects of what rules it should use when evaluating proposals by the regulated utilities. Some have called it the mother-of-all-rulemaking.

For example, a 2019 law ruled that the PUC must integrated the social cost of carbon, currently $47 per ton of emissions, into its reviews. Should that include transmission, too. (Xcel Energy says no, Western Resource Advocates says no.).

This stuff gets wonky beyond belief but is ultimately an integral part of the story of how does Colorado achieve its deep decarbonization goals during the next three decades.

sPower Development Co.—don't you wish companies would avoid getting cutesy with their spellings?—filed comments with the PUC in late April that insists once again that federal rules apply here, not the predilection of the PUC—and the proposed rule 3903 (a) violates the federal law:

"*The FERC's regulations also give the QF – not the utility, and not the Commission – the right to determine whether it will sell its energy and capacity on an "as available" basis or "pursuant to a legally enforceable obligation." A QF cannot exercise this right, which arises from federal law, if it must first compete in a bidding process. As the Commission is aware, Public Service and Black Hills have refused to purchase any energy and capacity from QFs, such as sPower's QFs, unless such QFs have participated in or won a competitive bidding process. Such refusal is directly at odds with PURPA's must-buy obligation and FERC's implementing regulations, and the Commission should avoid taking a similarly unlawful approach."*

Ready for a breather? Let's review Milligan's more-than-25-years of experience in power systems and wind and solar power integration. In a telephone interview during March, he affirmed his views in the paper that Colorado has been a national leader in the energy transition.

In the early 1990s, when he began working in the field, little wind generation existed in Colorado, or for that matter, much of anywhere other than California. California had something like 2,000 megawatts of wind generation in the late 1990s. Solar was mostly confined to solar thermal generation.

But in all cases there were concerns about capacity value. In other words, each megawatt of wind or solar needed a megawatt of fossil generation, as backup.

Colorado's first wind farm of note was Colorado Green, located south of Lamar, in the state's southeastern corner. It was proposed in the late 1990s and developed with a 162-megawatt capacity by Iberdola, the Spanish company. Production began in 2003. Xcel Energy was the purchaser. Milligan was there for the dedication in May 2004.

It's a different world now in terms of renewable generation and penetration. Wind capacity reached 100 gigawatts in 2019 in the United States. That's roughly 50 times the capacity since Milligan began working in the field in the early 1990s. The American Wind Energy Association reports wind provides 17% of total U.S. electrical production.

Wind was already responsible for 17% of power generation in Colorado by 2016, according to the Colorado Energy Office. It's greater now since the giant, 600-megawatt Rush Creek wind farm began production in October 2018. More yet is coming.

Solar lags, but has been rapidly gaining. The Solar Energy Industries Association reports that 3.24% of Colorado's electricity came from solar as of 2019. But with prices having fallen 385% over the last 5 years, Colorado could add 3,049 megawatts during the next 5 years.

Xcel Energy, says Milligan, was one of the first utilities to realize advanced controls at wind turbines. The key time was at night, when wind production revved up, but Xcel did not want to shut down its coal-burning units completely, as it takes 18 hours to ramp them up. Xcel, and others, figured out how to decrease wind production enough to avoid completely ramping down the plants. With that greater ability, the utility has been able to ramp up renewables to close to 80% of total production at times.

"The learning curve has yielded some pretty interesting things. Twenty years ago, we weren't thinking out about trying to control wind turbine output, but now we can do it and do it pretty well," he says.

Looking forward, Milligan says he's not sure just what the energy mix will end up being. What will be important in determining those resources will be their flexibility.

"I think utilities and wholesale power markets are sort of grappling with about how to have this flexibility. If something provides value, how should it be paid for," he points out. One component of flexibility is demand management.

Another question going forward will be the placement of energy storage. It's not necessarily best to tie the storage device directly to the wind and solar dispatches, because a system operator, whether Xcel or some other utility, may have a bigger view of how to use that battery. Then there is the additional complication of juggling both big and small solar. On the other hand, investors may want to see renewables and storage packed into one venture.

On the matter of smaller solar, though, Milligan warns of problems. "Preferential pricing creates incentives to 'game' the system," he says.

He points to a proposal from sPower to add 1,400 megawatts of new solar power via 18 separate facilities producing less than 80 megawatts of power each. Each of them, he says will be located just far enough apart to qualify for above-market pricing.

"If small-scale renewable power is more costly than large facilities, then the price of electricity will increase as reliability declines," he writes.

"Special carve-outs for small-scale providers will make it more difficult for the state to reach its clean energy goals. In addition to needlessly raising costs for consumers, new infrastructure may be required to integrate these small, disparate facilities reliably and cost-effectively if they are not located where the need is greatest; multiple small facilities could determine grid economics. Small facilities are not subject to the rigorous reliability rules that must be followed by large projects. And because they are not visible or controllable from a system operator, many small-scale facilities may well undermine grid reliability."

Using data from Xcel and sPower to calculate the extra cost for one year of 500 megawatts of small-scale solar, Milligan came up with $54 million and more than $1 billion over the life of the facilities for 500 megawatts of small-scale capacity."

Using the same mathematics, he comes up with $3 billion over 20 years for extra costs for 1,400-megawatt of small-scale capacity.

Read Milligan's study here.

Delta-Montrose Electric splits the sheets with Tri-State G&T. Will others soon follow?

by Allen Best

At the stroke of midnight on July 1, Colorado's Delta-Montrose Electric Association officially became independent of Tri-State Generation and Transmission.

The electrical cooperative in west-central Colorado is at least $26 million poorer. That was the cost of getting out of its all-requirements for wholesale supplies from Tri-State 20 years early. But Delta-Montrose expects to be richer in coming years as local resources, particularly photovoltaic solar, get developed with the assistance of the new wholesale provider Guzman Energy.

The separation was amicable, the parting announced in a joint press release. But the relationship had grown acrimonious after Delta-Montrose asked Tri-State for an exit fee in early 2017.

Tri-State had asked for $322 million, according to Virginia Harmon, chief operating officer for Delta-Montrose. This figure had not been divulged previously.

The two sides reached a settlement in July 2019 and in April 2020 revealed the terms: Guzman will pay Tri-State $72 million for the right to take over the contract, and Delta-Montrose itself will pay $26 million to Tri-State for transmission assets. In addition, Delta-Montrose forewent $48 million in capital credits.

Under its contract with Guzman, Delta-Montrose has the ability to generate or buy 20% of its own electricity separate from Guzman. In addition, the contract specifies that Guzman will help Delta-Montrose develop 10 megawatts of generation. While much of that can be expected to be photovoltaic, Harmon says all forms of local generation remain on the table: additional small hydro, geothermal, and coal-mine methane. One active coal mine in the co-operative's service territory near Paonia continues operation.

The North Fork Valley, part of the service territory of Delta-Montrose Electric, has been known for its organic fruits and vegetables — including corn. Photo/Allen Best

The dispute began in 2005 when Tri-State asked member cooperatives to extend their contracts from 2040 to 2050 in order for Tri-State to build a coal plant in Kansas. Delta-Montrose refused.

Friction continued as Delta-Montrose set out to develop hydropower on the South Canal, an idea that had been on the table since 1909, when President William Howard Taft arrived to help dedicate the project. Delta-Montrose succeeded but then bumped up against the 5% cap on self-generation that was part of the contract.

This is the second cooperative to leave Tri-State in recent years, but two more are banging on the door to get out. First out was Kit Carson Electrical Cooperative of Taos, N.M. It left in 2016 after Guzman paid the $37 million exit fee. There is general agreement that the Kit Carson exit and that of Delta-Montrose cannot be compared directly, Gala to Gala, or even Honeycrisp to Granny Smith.

Yet direct comparisons were part of the nearly week-long session before a Colorado Public Utilities Commission administrative law judge in May. Two Colorado cooperatives have asked Tri-State what it will cost to break their contracts, which continue until 2050. Brighton-based United Power, with 93,000 customers, is the largest single member of Tri-State and Durango-based La Plata the third largest. Together, the two dissident cooperatives are responsible for 20% of Tri-State's total sales.

The co-operatives say they expect a recommendation from the administrative law judge who heard the case at the PUC. The PUC commissioners will then take up the recommendation.

In April, Tri-State members approved a new methodology for determining member exit fees. But United Power said the methodology would make it financially impossible to leave and, if applied to all remaining members, would produce a windfall of several billion dollars for Tri-State. In a lawsuit filed in Adams County District Court, United claims Tri-State crossed the legal line to "imprison" it in a contract to 2050.

Also see: **Why Tri-State's new policies don't work for these two dissident members**

Tri-State also applied to the Federal Energy Regulatory Commission in a bid to have that body in Washington D.C. determine exit fees. FERC recently accepted the contract termination payment filing—rejecting arguments that it did not have jurisdiction. Jessica Matlock, general manager of La Plata Electric, said the way FERC accepted the filing does not preclude the case in Colorado from going forward.

Fitch, a credit-rating company, cited the ongoing dispute with two of Tri-State's largest members among many other factors in downgrading the company to A-. It previously was A. Fitch also downgraded Tri-State's $500 million commercial paper program, of which $140 million is currently outstanding, to F1 from F1+.

"The rating downgrades reflect challenging transitions in Tri-State's operating profile and the related impact on its financial profile," Fitch said in its report on Friday. It described Tri-State as "stable."

For broader background see: The Delta-Montrose story is a microcosm of the upside down 21st century energy world

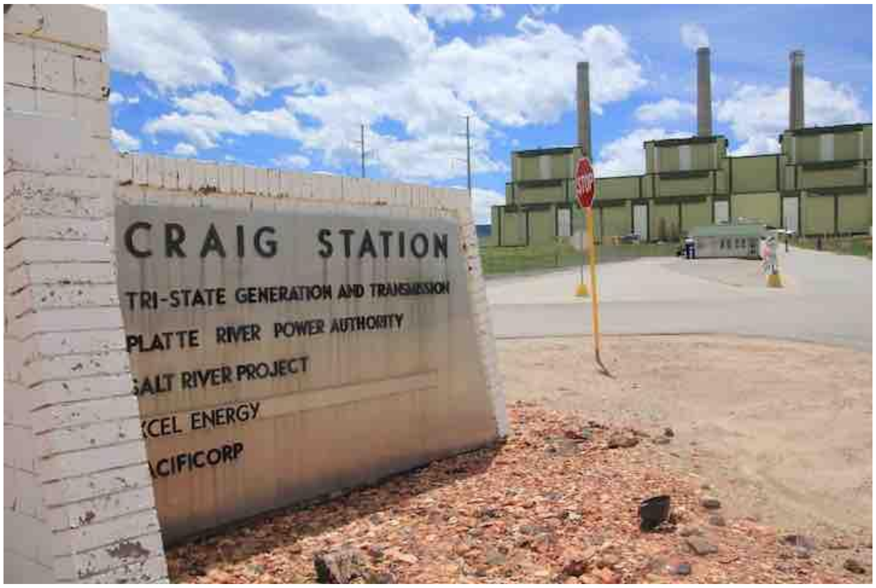
Black Hills proposes 200-megawatt solar farm

PUEBLO, Colo. – Black Hills Energy proposes a 200-megawatt solar project near Pueblo. The utility deemed the solar farm as the best fit from among 54 different projects for wind, solar, and solar-plus-battery storage.

The project would be completed by 2023, according to the timeline identified by Black Hills, and allow Black Hills to achieve 51% renewable energy in its resource portfolio.

The Pueblo Chieftain reports that Black Hills also wants the Colorado Public Utilities Commission to approve two backup bids, to ensure the projects move forward in time before federal tax incentives expire. One is for a duo of solar projects with a total capacity of 170 megawatts, and the other is for 150 megawatts of solar.

Julie Rodriguez, a spokesperson for Black Hills, said the preferred project will result in $66 million in customer cost savings over 15 years. Another benefit would be 250 construction jobs.



Craig unit to be retired in 2028

The second unit of the Craig Generation station will be retired on Sept. 30, 2028.

Tri-State Generation and Transmission, the operator and majority owner of the units, announced today that after months of analysis and discussion, the five owners of the unit unanimously agreed on the retirement date for the 410-megawatt generating unit.

Craig Station is a 1,285-megawatt, three-unit generating facility located along the Yampa River in northwestern Colorado. Unit 1 will retire at the end of 2025, as had been previously announced, and Unit 3—the only unit owned entirely by Tri-State— will retire by 2030, as was announced in January.

Craig Station Units 1 and 2 make up the Yampa Project, owned by PacifiCorp, Platte River Power Authority, Salt River Project, Tri-State Generation and Transmission Association and Xcel Energy – Colorado.

The Yampa Project owners previously announced the retirement of the 427-megawatt Unit 1 by the end of 2025. The 448-megawatt Craig Station Unit 3, which is owned by Tri-State, will retire by 2030.

As the operator of Craig Station, Tri-State will work with local officials and the State of Colorado to develop a transition plan for those impacted by the retirement of the power plant, which currently employs 240.

“Even though the Unit 2 retirement date is only one year earlier than the full retirement date for Craig Station, the decision weighed heavily on us,” said Duane Highley, chief executive of Tri-State. “As we implement our Responsible Energy Plan, we remain focused on working with our partners in the plant, as well as local and state leaders, to support our employees and the community through this transition.”

In a release from Tri-State, both Jason Frisbie, chief executive of Platte River, and Alice Jackson, president of Xcel Energy - Colorado, complimented Tri-State’s leadership.

“Each of the five partners in the Yampa Project face different challenges associated with this resource and we greatly appreciate Tri- State’s leadership in the process to find the most optimal date for Unit 2’s retirement,” said Frisbie.

Climate change lawsuit to stay in Colorado courts

Three Colorado jurisdictions that filed a lawsuit against Suncor Refinery and ExxonMobil have gained a victory in court.

The Tenth Circuit Court of Appeals ruled that the case belongs in state court. Suncor and Exxon had wanted a federal court to hear the case.

Boulder and San Miguel and Boulder counties filed the lawsuit. It's one of among near 20 similar lawsuits filed across the country against the oil and gas industry since 2019 that claim climate change damages.

The federal Tenth Circuit Court of Appeals ruled unanimously that the Colorado lawsuit can proceed in state court. This is an echo of two other cases, in California and Baltimore, where the same legal strategy was made.

The Suncor refinery in Denver. Photo/Allen Best

Richard Wiles, executive director of the Center for Climate Integrity, had this to say:

"This ruling is the latest in a growing list of losses for Exxon and other Big Oil companies. The industry has fought tooth and nail to prevent communities seeking just compensation for climate damages from having their rightful day in court.

"Three appeals court panels in a row have now issued unanimous rulings that climate damages cases against fossil fuel companies belong in state court. Big Oil's days of escaping accountability for causing and lying about climate change are numbered."

Read for yourself:

https://payupclimatepolluters.org/uploads/media/Boulder-v-Suncor-10th-Circuit-remand.pdf

And before you go…

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