THE COST OF COAL

A clean energy portfolio could provide the same energy and capacity requirements as the Alliant coal plants at a lower cost as early as 2026

SIERRA CLUB

MOVING WISCONSIN FROM COAL TO CLEAN ENERGY

A clean energy portfolio could provide the same energy and capacity requirements as the Alliant coal plants at a lower cost as early as 2026.

Coal is clearly no longer king in Wisconsin. To the contrary, coal is a regular loser in energy markets with a price that is consistently higher than any other energy source. In 2019, annual coal generation in Wisconsin fell by 26 percent from its 2018 level, but the state still gets 42 percent of its power from coal, far above the national average of 24 percent. The Sierra Club and its partners are fighting for a clean energy transition for Wisconsin to reduce costs to ratepayers and address the climate crisis. Seven utilities own varying shares in the more than 5,300 MWs of remaining coal capacity in Wisconsin. Alliant Energy, which operates in Wisconsin as the subsidiary Wisconsin Power & Light (WPL), owns 17 percent of that capacity.

This paper addresses Alliant's shares in Columbia, a two-unit, 1,023-MW coal plant built in 1975, and Edgewater 5, a 380-MW coal plant built in 1985. The utility has also announced plans to bring 1,000 MW of solar power online by 2023. It demonstrates that Alliant would save its ratepayers millions of dollars by retiring these coal plants and replacing them entirely with clean energy. The utility would only need a modest amount of additional clean energy beyond its current and planned renewable resources to satisfy its generation and reserve requirements. By doing so, Alliant would save customers money, contribute to the growing renewable energy job economy in Wisconsin, and help satisfy the governor's order to transition to a carbon-free energy sector by 2050.

Since 2010, Wisconsin utilities have retired over 2,800 MW of coal-fired generation and are proposing to take another 600 MW offline. Most recently, Dairyland Power Cooperative announced that it would retire its plant in Genoa by the end of 2021. Nonetheless, more than 5,300 MW of the state's coal capacity is still online today with no clear pathway for retirement and replacement by clean energy.

Figure 1: Remaining coal capacity in Wisconsin, 2010 to present

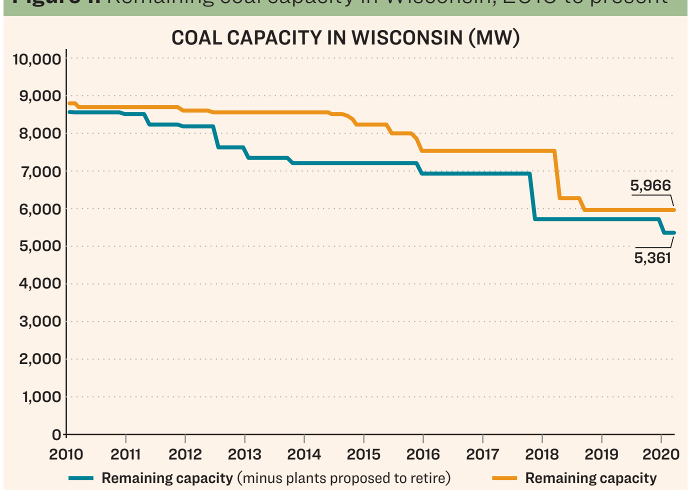
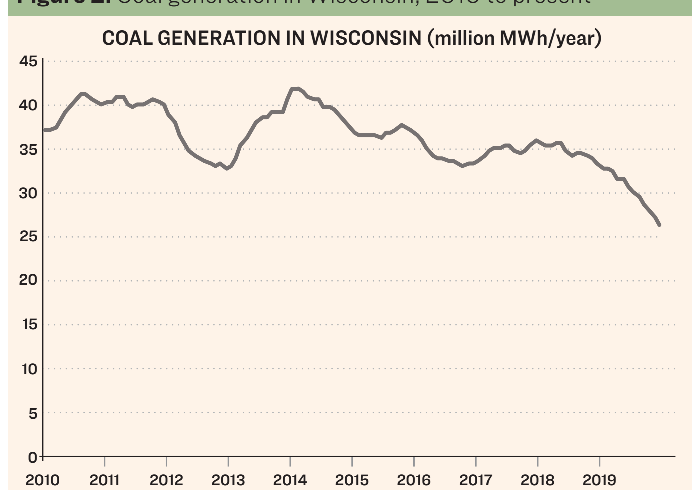


Figure 2: Coal generation in Wisconsin, 2010 to present



To limit the worst impacts of climate change and reduce the economic burdens of old coal plants, we need more rapid, ambitious action to replace all coal-fired power with clean energy by 2030. To this end, the Sierra Club has investigated Alliant's remaining coal fleet in Wisconsin from three standpoints: 1) its economic performance over the past five years, 2) its economic outlook through 2030, and 3) how coal plants can be cost-effectively replaced with clean energy. From this investigation, we find:

- The Columbia and Edgewater coal plants lost $16 million in 2019 relative to the cost of market-based energy and capacity.
- Operating these plants through 2030 would incur losses to Alliant's ratepayers of up to $461 million.
- Alliant could continue to satisfy its reliability requirements while retiring both Columbia and Edgewater prior to 2030 and replacing them with clean energy.

1. ALLIANT'S COAL PLANTS LOST UP TO $16 MILLION FOR ITS WISCONSIN RATEPAYERS IN 2019

Like other utilities in Wisconsin, Alliant purchases its power from and dispatches the power it generates into the regional energy market run by the Midcontinent Independent System Operator (MISO). The utility's ratepayers pay for the costs of operating the plants, offset by any revenues the utility collects by selling its power into MISO. When a utility owns power sources that are lower cost than the market, ratepayers can benefit from this arrangement by paying less in operational costs than the market revenues received. But when utilities own expensive power sources, ratepayers may pay more in order to keep those sources operating— in some cases much more. The most valuable sources of revenue for utilities that own power plants are payments for *energy* (the megawatt hours produced) and *capacity* (the availability of energy during peak hours). In MISO, most revenue flows through sales of energy. The timing of when energy is available to meet critical market demands also has value for a utility, and that is measured as capacity. Capacity is traded on a residual market. The clearing price of the annual auction for that market represents the cost to utilities that do not have sufficient capacity on their own to meet grid reliability standards. If utilities have excess capacity, then this market offers a small source of additional revenue.

During the past five years, as renewable energy has come online in bulk and as gas prices have decreased, the price of market-based energy has decreased, meaning that coal energy is increasingly the more expensive option, over both the short and long term. In 2019, the Sierra Club published a report, "Playing with Other People's Money," which reported that many coal plants in MISO and neighboring market regions had lost money on an operating basis— i.e., over the year they cost more to operate than they received in market revenues.

To help inform ratepayers and regulators, the Sierra Club modeled recent reported costs and revenues of Alliant's coal plants in Wisconsin. We compared the reported dispatch cost[1] of the Columbia and Edgewater coal units with the reported energy market price for each hour in which the coal units operated, and then accounted for other fixed costs of operation (e.g., labor and maintenance costs) as well as capacity revenue from MISO's annual Planning Resource Auction. We repeated this process for each year from 2015 to 2019. We found that from 2015 to 2018, both plants operated on the margin. The plants' MISO energy and capacity revenues were just enough to cover their costs of operation, though Edgewater's net margin was more consistent, while Columbia's margin fluctuated, producing net losses between 2015 and 2016, and producing net gains between 2017 and 2018. **In 2019, both plants had substantial operating losses: We found that Alliant lost $9 million from its shares in Columbia, and an additional $7 million from its ownership of Edgewater Unit 5.**

These losses are occurring in part because coal plants like Columbia and Edgewater can no longer economically serve their original purpose. Coal plants used to be called "baseload" because they were built to operate continuously. But in order to prevent a continuous loss of revenue, many coal plants have substantially reduced their generation, seeking to operate only during high market-priced hours. This is true of Alliant's plants as well, although our analysis finds that they too often still operated when market prices were low. For example, we calculated that the cost of operating the Columbia coal plant exceeded the market price of energy in three-quarters of all hours in 2019, and yet the plant ran at a capacity factor of 50 to 55 percent. In other words, the plant operated for many hours in which it lost revenue. It only earned net positive revenues from the energy markets

1. "Dispatch cost" in this case will refer to the short-run production cost of the coal unit, generally consisting of its fuel cost and other variable operating costs, such as the cost of water, chemicals, and maintenance that could be avoided if the unit operated less. We call it the "dispatch cost" because those short run costs reflect how much the plant should bid into the competitive energy market to operate, or dispatch. If the plant bids less than the dispatch cost, it will run during hours that are too low cost, and lose money relative to its costs. If the plant bids more than the dispatch cost, it will not operate during hours that it could have, and will be deprived of revenue.

in three of five years between 2015 and 2019. In fact, 2018 was the only year when those revenues could comfortably cover its fixed operational costs. Columbia lost substantial revenue through sustained low market prices extending through 2019 — simply by operating, Columbia lost $2 million on the energy market. Accounting for its fixed costs and capacity revenue, it lost $9 million for Alliant ratepayers. Over the full five-year period, the total losses were $15 million, a loss that Alliant ultimately passes onto ratepayers in the form of higher fuel charges and thus higher rates.

Table 1: Columbia Units 1 and 2 operation and economic summary, 2015-2019

	2015	2016	2017	2018	2019
UNIT 1					
Dispatch cost ($/MWh)	$27.6	$29.7	$27.7	$28.0	$28.0
Percent of hours where price > dispatch cost	33%	21%	45%	46%	25%
Capacity factor	50%	44%	49%	70%	51%
UNIT 2					
Dispatch cost ($/MWh)	$27.4	$27.7	$26.9	$28.0	$27.9
Percent of hours where price > dispatch cost	34%	26%	49%	46%	25%
Capacity factor	48%	51%	74%	61%	54%
Energy margin — WPL ($ millions)	**$0.5**	**$(3.5)**	**$6.0**	**$13.4**	**$(2.0)**
Long-run margin — WPL ($ millions)	**$(4.9)**	**$(6.9)**	**$0.1**	**$6.0**	**$(8.9)**

Edgewater Unit 5, built in 1985, is one of the newest coal units in the country. In theory, the plant should cost less to run than the older cohort of coal plants, yet it has similarly suffered under sustained low energy market prices.

While Edgewater 5 made a modest margin relative to market energy prices from 2015 to 2018, it cost far more to run than energy prices in 2019. In fact, average market prices were below its dispatch cost in all but two months. All told, we estimate that Edgewater 5 lost $7 million for Alliant ratepayers in 2019.

Table 2: Edgewater Unit 5 operation and economic summary, 2015-2019

	2015	2016	2017	2018	2019
UNIT 5					
Dispatch cost ($/MWh)	$25.1	$25.6	$26.3	$28.0	$28.4
Percent of hours where price > dispatch cost	49%	39%	49%	44%	25%
Capacity factor	70%	65%	62%	55%	39%
Energy margin — WPL ($ millions)	**$7.2**	**$5.1**	**$7.0**	**$8.5**	**$0.6**
Long-run margin — WPL ($ millions)	**$1.7**	**$2.2**	**$1.7**	**$0.6**	**$(7.0)**

What does this mean for Alliant and its ratepayers? Alliant has a responsibility to meet its ratepayers' requirements at the lowest reasonable cost. As a regulated monopoly utility, Alliant also has a responsibility to act similarly to a competitive enterprise. However, our analysis indicates that Alliant has done anything but act competitively with respect to its coal units. Competitive or "merchant" generators cannot sustain losses, and as such will only operate when they have confidence that revenues will exceed their costs. Our review of Alliant's operation of Columbia and Edgewater 5 suggests that the utility is leaning on Wisconsin ratepayers to pick up the tab, rather than ramping these units down to ensure that they don't operate during low-revenue periods. No-

Figure 3: Average market prices and estimated Columbia coal plant dispatch cost, 2015-2019

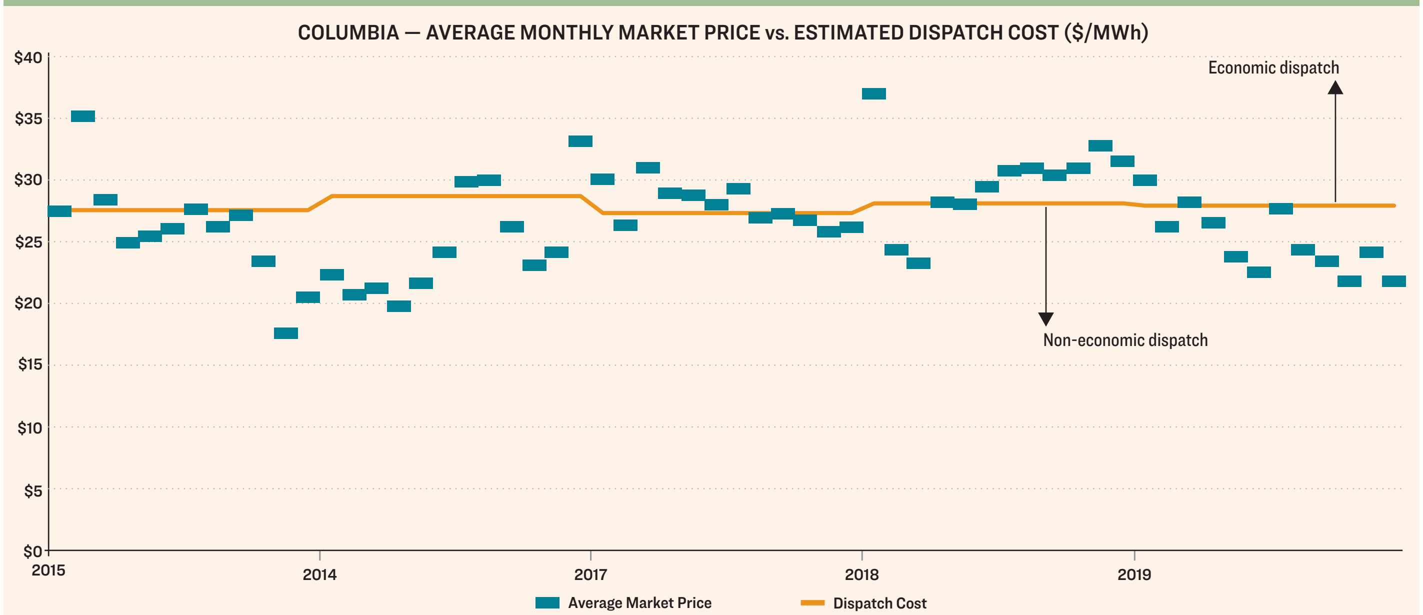
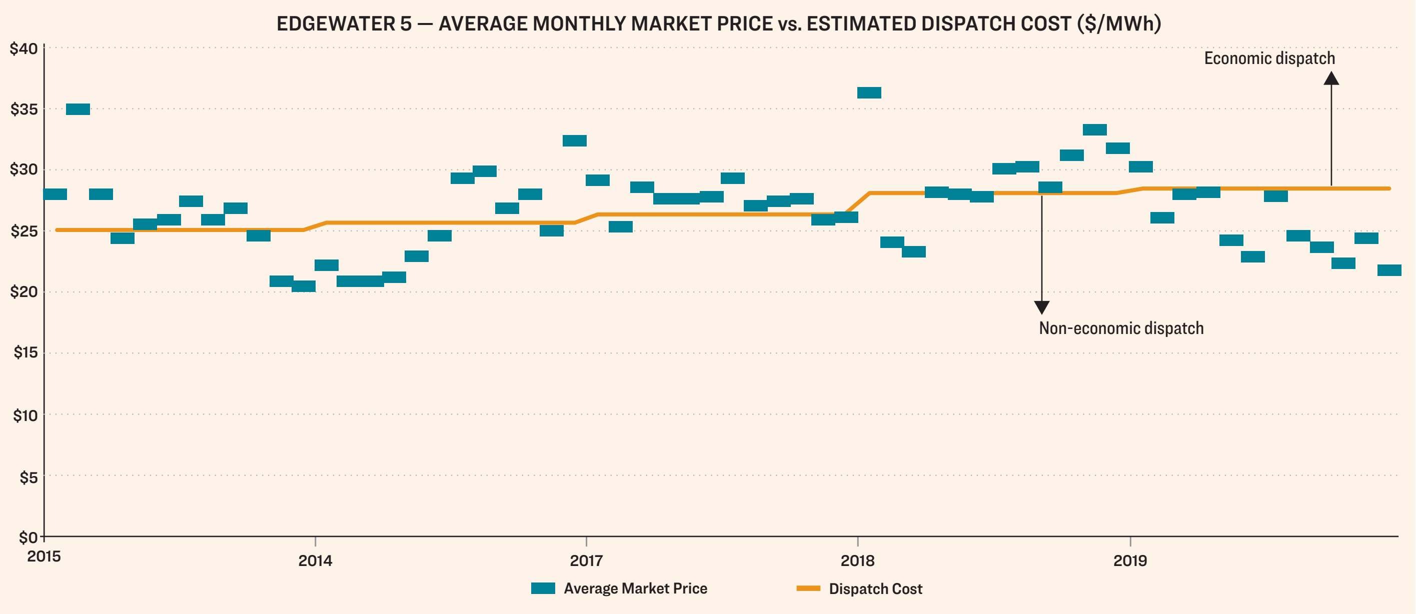


Figure 4: Average market prices and estimated Edgewater Unit 5 dispatch cost, 2015-2019



tably, some of Alliant's neighboring utilities have made different decisions, looking to optimize operations and reduce costs. For instance, in early 2020 Xcel Energy announced plans to operate some of its coal plants only during peak seasons, providing savings to ratepayers.

2. PLANTS COULD LOSE UP TO $461 MILLION OVER THE NEXT 10-YEAR PERIOD

Since 2019 was the worst year for these coal plants' economic performance, the Sierra Club performed a long-range analysis to find out how much higher these losses could go if Alliant continues to operate these plants out to 2030 or beyond. **We found that continuing to operate these plants could cost Alliant ratepayers up to $461 million over the next decade.**

A full explanation of our methodology and sources can be found in the appendix. We projected on-peak and off-peak monthly average prices and assumed the plants would run at a capacity factor in the range of 50-65 percent, which is within their historic average over the period between 2015 and 2019. In addition to the variable and fixed operations and maintenance costs used for the historic analysis in the prior section, we also assumed an average annual capital expenditure of $27/kilowatt--year. In the chart below, we compare those price projections to the total variable dispatch cost (i.e., the net cost to operate the plant) and the total plant cost, including fixed costs and capital expenditures, for Edgewater 5. In the latter five years, prices finally rose enough to justify on-peak operations, but even under those conditions the units are projected to lose money from continued operation.

We find that the net present value of Alliant's projected costs would be greater than the value of projected rev-

Figure 5: Estimated cumulative net present value for Columbia and Edgewater coal plants out to 2030

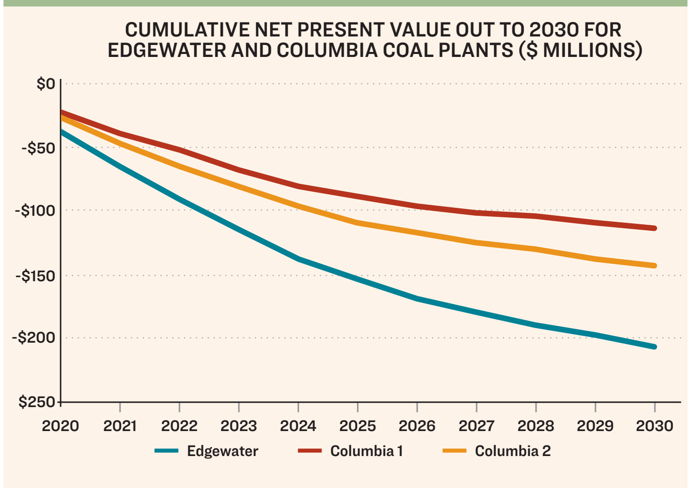
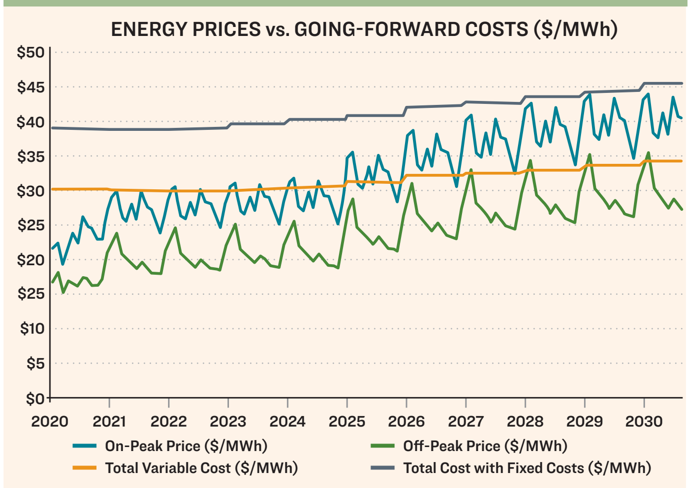


Figure 6: Estimated on and off-peak prices compared with Edgewater coal plant variable and total costs, 2020-2030



enues at Columbia Unit 1 by $114 million, at Columbia Unit 2 by $143 million, and at Edgewater Unit 5 by $206 million.[2] These results ignore the possibility of any future environmental regulations, including prices or caps on carbon emissions, that could make the plants even more uneconomic. In addition, the analysis assumes that the marginal cost of energy in MISO remains linked to the cost of gas, which may be an overly conservative assumption. The rapid increase in renewable energy deployment in the Midwest suggests that marginal energy costs may in fact continue to be depressed relative to the current market, where gas is predominantly the price setter. **If either of these events transpire (environmental regulations or a decoupling of market revenues and gas prices), the economic outcome for Alliant's coal units will be substantially worse than what is shown here, and our results already show that Alliant's coal plants will be financial losers over the next decade.**

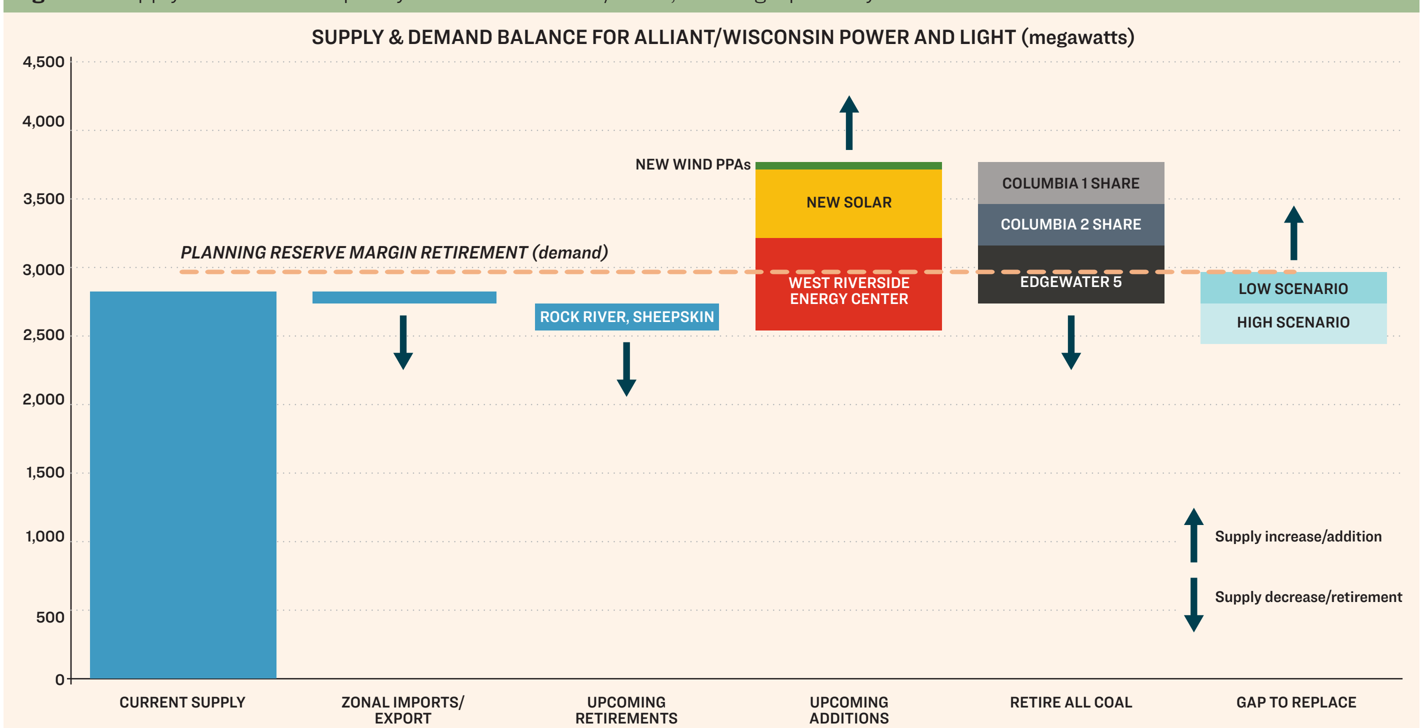
3. CLEAN ENERGY COULD REPLACE UNECONOMIC COAL PLANTS AND SAVE CUSTOMERS MILLIONS OF DOLLARS.

Given that these coal plants are projected to be such economic losers for Wisconsin ratepayers, Alliant should move swiftly to retire these plants and replace them with clean energy. Retirement of resources requires adequate planning to ensure that Alliant has enough supply to meet its planning reserve margin requirement, which is equal to the annual peak power demand from its ratepayers plus required reserve capacity. We have summarized the following information on Alliant's supply/demand balance pulled from a mixture of company-reported sources, including the Wisconsin Strategic Energy Assessment, company press releases, and Energy Information Administration (EIA) Form860 filings:

- **Demand:** Alliant currently has a planning reserve margin requirement of roughly 3,000 MW.
- **Upcoming retirements:** Alliant is planning to retire two gas peaker plants, Rock River and Sheepskin.
- **Upcoming additions:** Alliant has planned additions including West Riverside Energy Center, 1,000 MW of solar (which would account for 500 MW of peaking capacity based on MISO's current solar capacity credit), and some new wind farms for which Alliant has arranged power purchase agreements (PPAs).
- **Supply summary:** In summary, Alliant is planning to retire 197 MW of gas peakers while commissioning up to 1,227 MW of new resources: in total, 1,030 MW of net capacity additions. Their current ownership stakes in Columbia and Edgewater total 1,041 MW. So it seems that Alliant could swap out these old coal and gas peaker sources for its new planned resources with only a small gap remaining between its planning reserve margin requirement and its total supply.

2. Columbia would have higher losses at a plant level; these are the losses for Alliant's share in Columbia.

Figure 7: Supply and demand capacity balance for Alliant / WPL, showing a pathway to coal retirement



- **Replacement capacity:** Given all this, we find that if Alliant retired both units of Columbia and Edgewater Unit 5, it would only need to replace 225 to 500 MW of capacity, as opposed to the entirety of the more than 1,000 MW of coal that would retire. The discrepancy between the high and low scenario here relies on whether their demand increases and whether they sell a portion of West Riverside's capacity to another Wisconsin utility.

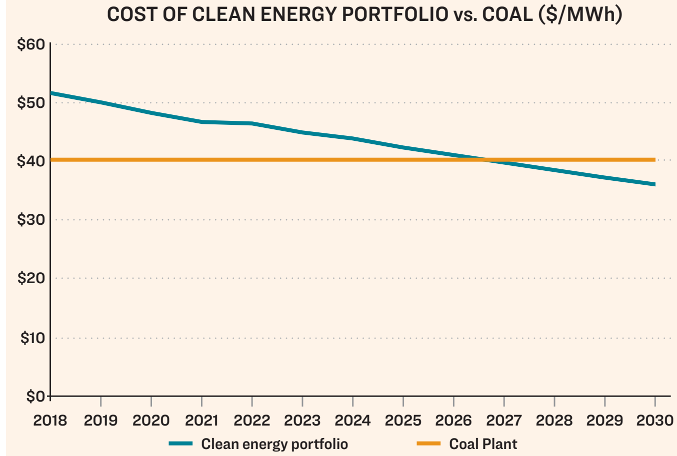
We find that a clean energy portfolio (CEP) consisting of wind, solar, storage, energy efficiency, and demand response technologies could provide the same energy and capacity requirements as the Alliant coal plants at a lower cost as early as 2026. In our methodology, the CEP is constructed to match the energy, peak capacity, and ramping characteristics of the Columbia coal plant, scaled at the capacity levels defined on the prior page (225-500 MW). Portfolios are optimized to satisfy these needs at the lowest cost possible. The result for a 225 MW coal plant replacement was 137 MW of solar, 303 MW of wind, 92 MW of battery storage, 107 MW of energy efficiency, and 70 MW of demand response. Currently, the cost of building this CEP is higher than the cost of operating the coal plant (largely because battery storage is still relatively expensive), but based on industry projections of the costs of storage and renewables, we have determined that it would be lower by the year 2026 . More details on our methodology and data sources can be found in the appendix.

Table 3: A breakdown of the clean energy portfolio breakdown by technology

Clean energy portfolio by technology (MW)					
Coal plant (MWs)	Solar PV	Wind	Battery Storage	Energy Efficiency	Demand Response
225	137	303	92	107	70

Importantly, a portion of the CEP is supplied by demand-side technologies that are cheaper than building new plants and thus save customers more money. Historically, the state of Wisconsin has ranked #25 out of 50 on the state scorecard from American Council for an Energy-Efficient Economy (ACEEE), while Wisconsin utilities received an energy efficiency scoring of just 7.5 out of 20. There is certainly room for improvement. Alliant should pursue higher levels of energy efficiency and demand response for its customers if it wants to find the most cost-effective energy and capacity replacements for its costly, aging coal plants.

Figure 8: Projected cost of operating coal plant vs. building and operating clean energy portfolio



ALLIANT BEYOND COAL

While Alliant Energy has pledged to reduce its greenhouse gas emissions by 80 percent and eliminate coal power from its portfolio by 2050, it appears the utility will meet this commitment through a "business as usual" approach. Under this plan, Alliant could run its coal units well into the 2040s and still meet its goal. Furthermore, a 2019 analysis by the Energy and Policy Institute found that— even though "electric utilities lie at the crux of the effort to decarbonize the U.S. economy"—Alliant was one of 11 major electricity providers that is planning to actually slow down its rate of decarbonization over the next decade. Alliant has publicly announced its intention to add 1,000 MW of solar generation by 2023, but it is not yet clear what this will mean for its fossil fuel fleet.

How quickly Columbia and Edgewater are retired has significant implications when it comes to the future of Alliant's energy mix, even as the utility is introducing plans to build new solar. As this paper shows, Alliant would save its ratepayers millions of dollars by retiring these coal plants and replacing them with clean energy. With time running out to avert the worst consequences of climate change, Wisconsin utilities must act to save customers money, contribute to the growing renewable energy job economy, and make plans that satisfy the Badger State's climate goals.

SOURCES AND METHODOLOGY

SOURCES

The data sources for this analysis are from public sources, including data reported by Alliant to the Energy Information Administration (EIA), Environmental Protection Agency (EPA), and Federal Energy Regulatory Commission (FERC).

- **State-level coal capacity:** Sierra Club analysis as verified from public sources including EIA-860M and company announcements
- **State-level monthly coal generation:** EIA's Electric Power Monthly, released Feb 26, 2020 https://www.eia.gov/electricity/monthly/
- **Hourly generation:** EPA Air Markets Program Database https://ampd.epa.gov/ampd/
- **Energy market prices:** MISO via S&P Global Market Intelligence
- **Coal prices and power plant deliveries:** EIA-923, costs through 2019 reported as of February 2020 https://www.eia.gov/electricity/data/eia923/
- **Coal and gas price forecasts:** EIA Annual Energy Outlook 2020 Reference case: https://www.eia.gov/outlooks/aeo/
- **Variable and fixed operations and maintenance:** FERC Form 1 filed by Alliant Energy, 2015-2018 https://www.ferc.gov/docs-filing/forms/form-1/data.asp
- **Capacity market revenue:** MISO Planning Resource Auction prices for Zone 2 https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf
- **Capital expenditures:** EIA Annual Energy Outlook https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf (p. 14)
- **Clean Energy Portfolio algorithm:** Rocky Mountain Institute, "The Growing Market for Clean Energy Portfolios," https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/
- **Alliant demand and supply balances:** Wisconsin Strategic Energy Assessment for the Years January 1, 2016, through December 31, 2022 http://apps.psc.wi.gov/vs2017/dockets/content/detail.aspx?id=5&case=ES&num=108
- **Efficiency:** ACEEE State Efficiency Scorecard https://database.aceee.org/state/wisconsin

HISTORIC PERFORMANCE

To evaluate historic performance from 2015 to 2019, we pulled hourly day-ahead energy market prices for the appropriate nodes (WPS.COLUMBIA1, WPS.COLUMBIA2, ALTE.EDGG5G5) and aligned them with hourly gross generation pulled from the EPA's Air Market Programs Database to produce energy market revenue. Fuel costs were pulled from fuel deliveries data reported on the EIA-923 and multiplied by the units' average heat rate for the year to get a fuel cost per MW hour of electricity produced. Variable and fixed operations and maintenance (O&M) data were pulled from FERC Form 1 filed by Alliant for the years 2015-2018. Since 2019's form has not yet been filed, 2018 numbers for O&M were used again for 2019. For variable O&M, the following categories of FERC reporting were included for Alliant's portions of the Edgewater and Columbia plants: Steam Expense, Electric Expense, Miscellaneous Power Expenses. For fixed O&M, the following categories were included: Operating Supervision and Engineering, Maintenance Supervision Expense, Maintenance of Structures, Maintenance of Boiler Plant, Maintenance of Electric Plant, Maintenance of Other Plant. Fuel costs and variable O&M were subtracted from energy market revenue to arrive at the energy margin. Fixed O&M was subtracted from and MISO

Planning Resource Auction capacity revenue was added to the energy margin to arrive at the long-run margin. Capacity revenue was arrived by multiplying the appropriate annual auction price by the Alliant-owned level of capacity in each unit.

FUTURE PERFORMANCE

In order to estimate the net present value of Columbia and Edgewater 5 for the period 2020 to 2030, we constructed a model to project future costs and revenues. All of the assumptions and projections are derived from publicly available information. As we note in several places below, many of these estimates are conservative, and the actual performance of Columbia and Edgewater may be less favorable to customers than our estimates. To build our model, we created starting assumptions or built projections for the following values:

- **Capacity factor:** The capacity factor stays fixed for the 10-year period at the following levels, which are representative of generation levels from the past five years—62 percent for Columbia Unit 1, 50 percent for Columbia Unit 2, and 60 percent for Edgewater Unit 5
- **On- and off-peak generation:** On-peak generation was assumed to account for 45 percent of operating hours, representative of 9 A.M.-5 P.M. weekdays. The remaining generation was assumed to be off-peak.
- **Fuel costs:** 2018 fuel costs as reported on EIA-923 for these plants were used as a starting point. From there, the costs were inflated in line with the EIA AEO 2020 reference coal price forecast for the East North Central region. The following heat rates were used: 10,541 British thermal units (btu)/kilowatt hour (kWh) for Edgewater 5, 10,475 btu/kWh for Columbia 1, and 10,371 btu/kWh for Columbia 2.
- **Variable O&M expenses:** 2018 variable O&M costs (see "Historic performance" methodology) were used as a starting point and inflated by two percent per year, in line with standard inflation.
- **Fixed O&M expenses:** 2018 fixed O&M costs were used as a starting point and inflated by two percent per year, in line with standard inflation.
- **Annual capital expenses:** Ongoing annual capital additions were calculated according to an equation found in EIA's Annual Energy Outlook methodology. EIA found a generalized equation (listed below) that describes how much coal plant owners spend on capital expenditures on average per year, as a function of coal plant age and whether or not the coal plant had flue gas desulphurization (FGD). For coal plants across the US, the range for ongoing capital expenditure (CapEx) is $19 to$30/kW-year. For Columbia and Edgewater, the average ongoing CapEx is on the higher end of the range at $26 to$28/kW-year (2017 dollars), which makes sense as all units have FGD installed and the ages of the units range from 35 to45 years. From here, we inflate this figure by two percent per year to account for normal inflation.

  $CAPEX = 16.53 + (0.126 * age) + (5.68 * FGD)$

  where FGD + 1 if a plant has an FGD, 0 if a plant does not have FGD
- **On- and off-peak prices:** In order to forecast on- and off-peak power prices between 2020 and 2030, we multiplied the EIA's forecast (from Annual Energy Outlook 2020) for gas delivered to West North Central (an EIA census region which includes Wisconsin) electric sector customers by the implied heat rate of each unit, since gas is commonly the marginal, price-setting resource in most markets today. The implied heat rate for each plant was calculated by looking at historic on- and off-peak prices (monthly average day ahead on- and off-peak strips) for the relevant market hub and dividing by the average monthly delivered gas price at the Chicago hub. Then, the average of those implied heat rates during the years 2016 to2019 was taken to represent the heat rate going forward. The resulting on-peak prices ranged from $19 to $44/MWh, while the resulting off-peak prices ranged from $15 to $35/MWh across the 10-year period.

We calculated the sum of energy revenues minus the costs (fuel, variable and fixed O&M, capital) for each year. The net present value of those annual sums was calculated using a discount rate of eight percent, which is a typical rate used by utilities across the US in integrated resource planning. The levelized cost of energy (LCOE) was calculated by taking an annualized payment of the net present value of all costs (also using a discount rate of eight percent) and dividing it by annual generation.

CLEAN ENERGY PORTFOLIO

Given that continuing to run these coal units would be a net cost to ratepayers compared with the energy market, the next step in the analysis is to investigate whether they can be cost-effectively replaced with clean energy and on what timeline. For this analysis, we used the Rocky Mountain Institute's Clean Energy Portfolio's algorithm from its 2019 report "The Growing Market for Clean Energy Portfolios" to identify a suite of clean energy technologies (wind, solar, storage, energy efficiency, and demand response) that could replace the services of the Alliant's coal plants.

A clean energy portfolio, or CEP, is a combination of renewable energy, storage, and demand-side management (DSM) projects that meet the needs of the grid and a utility's customers. We use the term DSM to collectively refer to energy efficiency projects (which lead to a reduction in load) and demand response projects (which lead to the shifting or temporary reduction of load). The use of CEPs differs from traditional resource planning, which typically focuses on a specific technology. Instead, a CEP looks at how a range of available clean energy resources could contribute in each hour of the year, and finds the combination that meets the unique needs of customers at the lowest feasible cost. In this study, the CEPs are constructed to match the energy, peak capacity, and ramping characteristics of the Columbia coal plant, scaled at the capacity levels defined in our analysis (225-500 MWs). Portfolios are optimized to satisfy these needs at the lowest cost possible.

The CEPs are conservatively designed to meet peak capacity needs in the top 50 hours of capacity need of the year in the Midcontinent Independent System Operator (MISO), the grid region where Alliant and its coal plants operate. Some of the 50 peak hours are in the summer, when solar output is high, and some of the hours are in the winter, when solar output is low. As such, the CEP must not rely on solar alone, but rather a complement of wind, solar, storage, and demand-side management technologies. The CEP also must meet the monthly energy requirement of the coal plant's total generation in each month of the year 2017. The CEP algorithm errs on the side of caution, in the sense that other grid resources (like existing gas plants or market purchases) play no role in the replacement, but those resources are typically included in system dispatch or capacity expansion models that utilities utilize in portfolio analysis. In other words, the CEP algorithm accounts for a complete energy and capacity replacement of the coal plant without the benefit of any other existing grid resources. We assume that energy efficiency and demand response could only account for up to 25 percent of the replacement energy and capacity of replacement portfolios, respectively.

We populated the Rocky Mountain Institute model framework with storage and renewable cost assumptions from Lazard's Levelized Cost of Energy, Version11, and Bloomberg New Energy Finance's 's New Energy Outlook 2018, both industry standard reports. In addition, the modeling includes the solar investment tax credit, excludes the wind production tax credit, and excludes an investment tax credit for storage (even though many storage projects qualify for that tax credit by pairing with solar). Any excess energy that renewables produced above and beyond the coal plant was valued at $27/MWh, which was the off-peak average price in MISO in 2018. The levelized costs of the CEPs were compared against the average LCOE calculated for the coal units in the future performance section — $40/MWh. The result for a 225-MW coal plant replacement was 137 MW of solar, 303 MW of wind, 92 MW of battery storage, 107 MW of energy efficiency, and 70 MW of demand response. The cost of this CEP would be lower than the cost of continuing to operate the coal plant by 2026.

Sierra Club National
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5500

Sierra Club Legislative
50 F Street, NW, Eighth Floor
Washington, DC 20001
(202) 547-1141

facebook.com/SierraClub
instagram.com/SierraClub
twitter.com/SierraClub

EXPLORE, ENJOY, AND PROTECT THE PLANET. **SIERRACLUB.ORG**

SIERRA CLUB