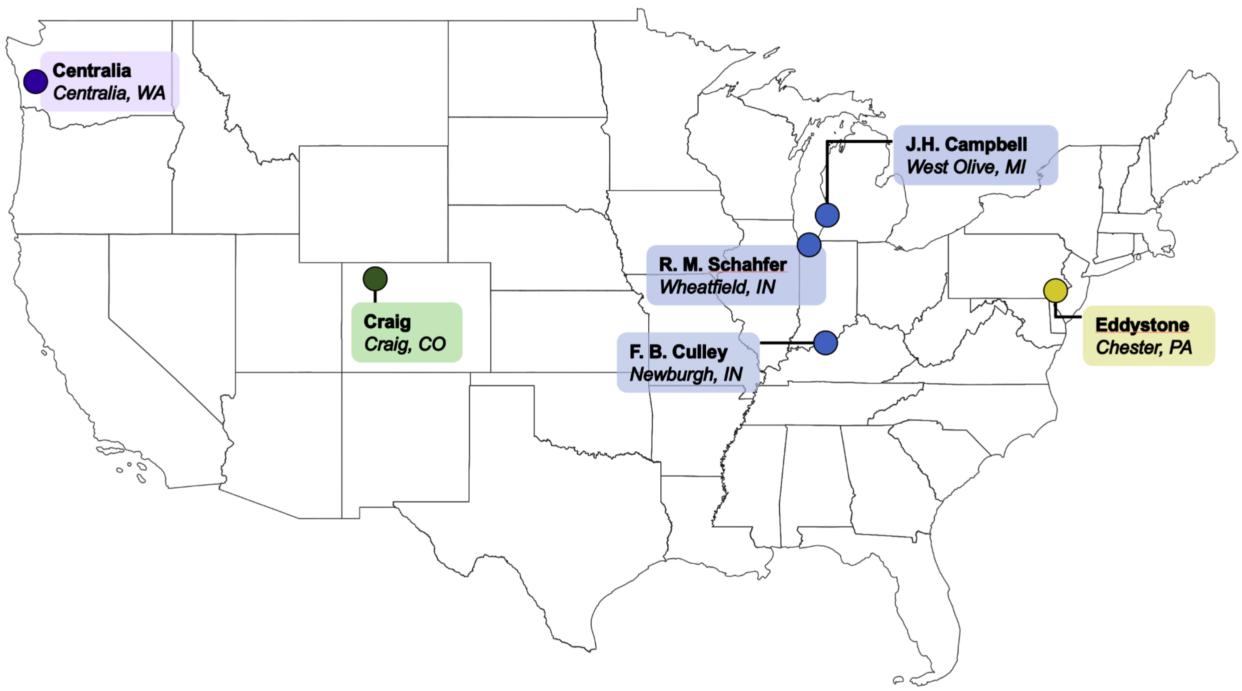
Unpacking the Cost of 202(c) Orders: Facility-Specific Cost Estimates and Methodological Approach

Prepared by Greg Wannier, Jonah Baskin, Jessi Eidbo, and Dan Prull

As of today, six facilities across the U.S. which had previously planned to retire have received 202(c) orders from the U.S. Department of Energy (DOE) forcing the facilities to stay online. Conservative estimates from the best available data sources put the cost of keeping these facilities online past their approved retirement dates in the hundreds of millions of dollars, with cost impacts increasing daily.[1] This document provides an in-depth explanation of the facility-level financial impacts caused by these 202(c) orders to date. **This document is a dynamic resource, and will be updated as new or updated information becomes available on facility-specific costs.**



[1] 202C Cost Estimate Calculator, https://www.sierraclub.org/burningmoney

Sierra Club National
2101 Webster St., Ste. 1300
Oakland, CA 94612
(415) 977-5500

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

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How do we evaluate estimated costs?

Untangling rate allocation is a difficult and opaque process. There are a number of layers and many actors between an energy generation facility and an individual customer's utility bill. The lack of publicly available data (including publication delays for unit operations and cost recovery filing for operational expenses) creates further challenges for updating cost estimates. This analysis therefore determines, using the best available data for each facility, the 202(c) order costs associated with each facility. We do this by 1) preparing an estimate for the **"gross" (total) daily cost** of continuing to operate targeted facilities, 2) estimating any revenues that targeted facilities were able to recuperate via energy and capacity sales, and 3) subtracting revenues from total cost to determine a **"net" daily cost,** for which we expect each targeted facility will seek cost recovery, usually from ratepayers.

What exactly does that mean? Put differently, the difference between gross cost and net cost accounts for any revenue that a utility can make on energy sales, offsetting the expenses to operate. The "gross" costs represent the total costs of running the 202(c) plant. However, some generators operating under a 202(c) order are able to sell their electric output into a regional market and thereby defray their costs of complying with the order. This sale of electricity displaces other generators from the market, but does not increase market costs to consumers. **To account for this defrayment of costs, our analysis provides the resulting "net" cost estimate, representing the marginal additional costs for which plant operators can be expected to seek reimbursement, most likely from ratepayers.** Thus, the "net" cost estimate can be understood as the extra costs that the 202(c) orders impose on ratepayers. So far, the owners of Campbell, Schahfer, and Culley have already sought permission to charge ratepayers in MISO for their net costs; and Eddystone's owner has done the same in PJM.

As a final note, where actual cost recovery requests have been filed, our estimate includes all costs that plant owners have incorporated into their reimbursement requests. For example, Consumers Energy has requested that MISO ratepayers reimburse it for the remaining undepreciated net book value of J.H. Campbell Units 1, 2, and 3.

Facility-Specific Cost Analysis:

- **Michigan: J.H. Campbell (West Olive, MI)**
- **Pennsylvania: Eddystone (Chester, PA)**
- **Washington: Centralia (Centralia, WA)**
- **Indiana: F.B. Culley (Newburgh, IN)**
- **Indiana: R.M. Schahfer (Wheatfield, IN)**
- **Colorado: Craig (Craig, CO)**

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(415) 977-5500

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50 F Street NW, Eighth Floor
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West Olive, Michigan - J.H. Campbell

DOE issued an initial 202(c) order to J.H. Campbell units 1, 2, and 3 on May 23, 2025 for 90 days. The plant has since received three additional orders, for a total of four orders, each lasting 90 days. The plant remains operational pursuant to a 202(c) order.

We derive an approximate daily cost to keep Campbell online using the values reported from two documents: First, Consumers Energy's (the majority owner of Campbell) filing at FERC requesting cost recovery (Cost Recovery Filing of Consumers Energy Company under ER26-1138),[2] which requests reimbursements the first 90 days that the Campbell facility operated under a 202(c) order.[3] And second, Consumers Energy's annual 10-K form prepared for shareholders and filed with the Securities and Exchange Commission (SEC), which discusses the costs it incurred in the 2025 calendar year associated with running the Campbell facility under the 202(c) orders (SEC 2025 financial statement filing).[4]

Together, these filings report a net cost from 202(c) orders of $135 million in the year 2025, starting when the plant was first targeted in May 2025 (here, net cost reflects $290 million in gross costs and $155 million of reported market revenues).[5] **This is equal to an estimated net cost of $605,381 per day to operate the facility's three units for the 223 days[6] in 2025 that the plant was forced to operate.** To then prepare an estimate for the total cost of the J.H. Campbell coal-burning units under 202(c), this daily average is extrapolated across the duration of the subsequent 202(c) order periods, including the year to date in 2026, to derive a reasonable estimate of impacts on customer electric bills. **This results in a calculated $213,699,493 in net costs to customers as of this document's latest update (May 11, 2026).**

Since the original order, Consumers Energy had sought, and has now received, approval from FERC to charge customers in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky for the costs of the Campbell plant. The area subject to cost recovery for the facility represents the northern region of the

[2] Cost Recovery Filing of Consumers Energy Company under ER26-1138, FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260123-5236&optimized=false&sid=2e6441f7-8422-4748-a4f6-002b4db2b283

[3] Consumers Energy has indicated that they might seek recovery for some limited costs associated with the first 202(c) orders in later filings. *See* Cost Recovery Filing of Consumers Energy Company Transmittal Letter at 13-14 ("[T]his cost recovery filing only includes Direct Legal and Consulting Costs incurred through the end of the May 2025 Order Duration Period. Any Direct Legal and Consulting Costs associated with the May 2025 DOE Order but incurred during the August 2025 DOE Order duration period will be presented in a separate cost recovery filing addressing that particular order.").

[4] Consumers Energy Filing to the Securities and Exchange Commission for the fiscal year ending December 31, 2025, filed February 10, 2026, https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115626000004/cms-20251231.htm

[5] Consumers Energy's cost request includes the remaining undepreciated net book value of Campbell, which it has included based on its determination that such recovery is authorized by Section 202(c); these costs were included because ratepayers across MISO are being asked to pay them.

[6] For the purposes of this analysis, the date at which the plant began operating pursuant to a 202(c) order was not the date the facility was planned to retire (May 31, 2025), but rather the date of the original order (May 23, 2025).

Sierra Club National
2101 Webster St., Ste. 1300
Oakland, CA 94612
(415) 977-5500

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

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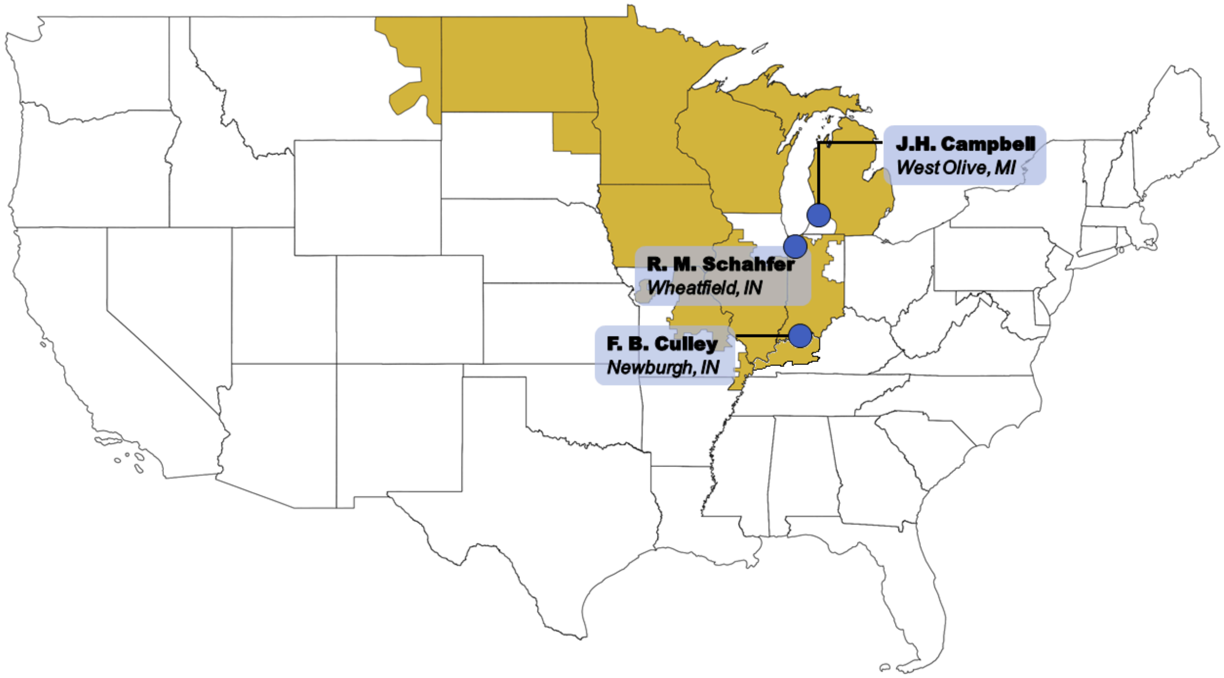
Midcontinent Independent System Operator (MISO) zones 1 through 7 (*the geographic extent of this region is approximated in gold on the map below*).[7]

FERC's approval of Consumers Energy's request foists costs on residents across this region who are also facing additional looming bill increases from 202(c) orders issued to the Cully and Schahfer facilities, both of which have requested to charge customers over the same territory.



[7] Order on Complaint re Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc. under EL25-90 et al., FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250815-3095&optimized=false&sid=28f0fe1a-d2c0-4d6d-8176-9e80386b67ac

Chester, Pennsylvania - Eddystone Generating Station

DOE issued an initial 202(c) order to Eddystone Generating Station units 3 and 4 on May 30, 2025 for 90 days. The plant has since received three additional orders, for a total of four orders, each lasting 90 days. The plant remains operational pursuant to a 202(c) order. **To date, Eddystone is the only non-coal facility to receive any maximum duration 202(c) orders; the facility burns a combination of oil and gas.**

As of May 4, 2026, PJM (the regional grid operator in which Eddystone is operating) has provided public documents detailing the extent of rate recovery under the PJM tariff revisions filed (and approved by FERC) in 2025.[8] Supporting analysis of PJM's filing by the Natural Resources Defense Council (NRDC) found that the filed costs for recovery totaled $8,641,409 over the period from June 1, 2025 through February 28, 2026 (a 272-day period), and equal to $10.2 million since the start of the multiple 202(c) orders through May 3, 2026 (a 336-day period).[9] **This is equal to an average of $30,357 per day in net cost over the duration of all 202(c) orders.**

As NRDC's analysis further reports, the rates provided in the PJM filing were calculated for each month and are therefore not cumulative. This means that the months with $0 Eddystone's energy and ancillary service (AS) revenues fully covered its costs. A number of additional assumptions are built into this analysis, and reflect updates to PJM filings on the cost Eddystone has accumulated over the period of compliance with the ongoing 202(c) orders. Chiefly, January 2026 was revised to zero, likely due to cold weather operations). November 2025 was bifurcated into two rate costs and nearly doubled for the first 25 days of the month. The PJM settlement file lists 'PI costs' in the notes for those days (which likely means Project Improvements). This meaningfully translates to an additional $1.68M in ratepayer charges for capex to keep Eddystone running due to the 202(c) **on top** of what was already being subsidized before the rate true-up.

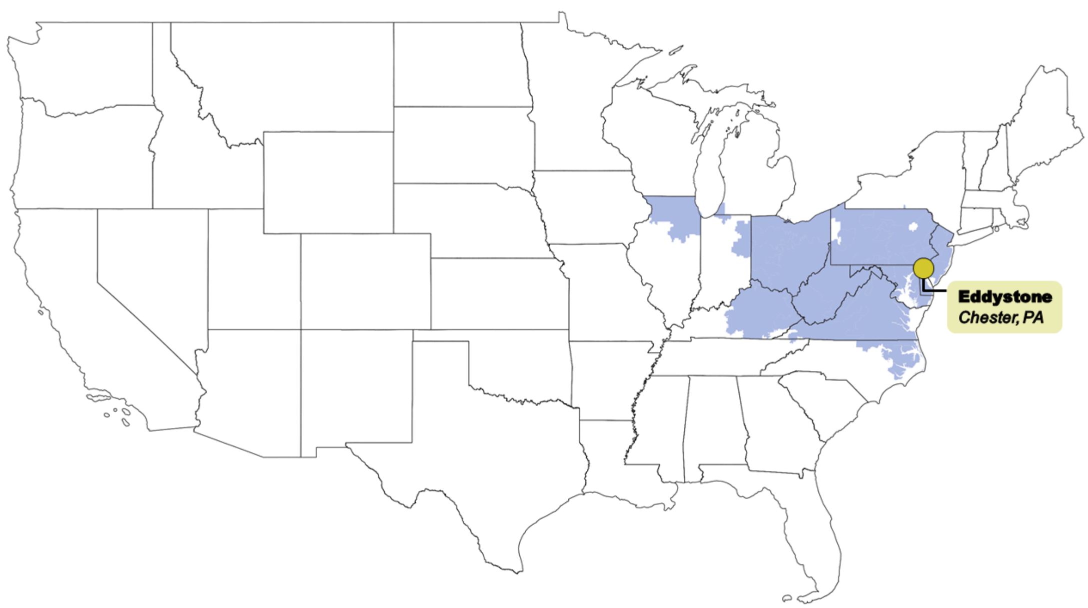
It's worthwhile to note that at present, the recovery filings that PJM has made public for Eddystone are largely in alignment with the historic operation costs for Eddystone based on 5-year past data made available by S&P. **Using that methodology, the estimated cost using average operating costs for the plant reported by S&P Global over a five year period (from 2020 through 2024, the most recent year with available data).** Over that period, the total annual cost of operating the two units ranged from $10.4 million to $16.1 million. Finally, it's important

[8] 202C Cost Allocation Rates Eddystone, PJM, last updated May 4, 2026, see 202(c) Cost Allocation Rates data file, from https://www.pjm.com/markets-and-operations/billing-settlements-and-credit (or directly at https://www.pjm.com/-/media/DotCom/markets-ops/settlements/eddystone-202c-cost-allocation-rates.xlsx)

[9] Supporting analysis from NRDC (Dana Ammann and Casey Roberts), May 4, 2026, utilizing publicly available data from PJM (see 1)

to consider that this is an extraordinarily conservative estimate; any number of things could increase costs incurred from Eddystone's requirement to comply with this order (whether it operates or not). Relatedly, energy prices have an outsized impact on what the continual costs filed for Eddystone's compliance costs for the 202(c) order; as energy prices continue to increase (which in PJM, is the current trend forecast), the cost of compliance is also likely to increase.

As noted, Constellation Energy has secured approval to recover those costs from across all of PJM. PJM is the electric grid operator for the region which spans all or parts of 13 states across the Mid-Atlantic region (IL, IN, OH, MI, KY, WV, PA, NJ, MD, DE, VA, NC, TN) and D.C. (*shown in blue on the map).* The Federal Energy Regulatory Commission (FERC) has granted recovery for at least the first 202(c) order.[10] PJM has since filed to revise their tariff so that subsequent 202(c) order costs are recoverable through the same mechanism, indicating a high likelihood that all PJM customers will foot the bill for all subsequent 202(c) orders.[11]



[10] Order Accepting Tariff Revisions re PJM Interconnection, L.L.C. et al. under ER25-2653 et al., FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250815-3094&optimized=false&sid=28f0fe1a-d2c0-4d6d-8176-9e80386b67ac

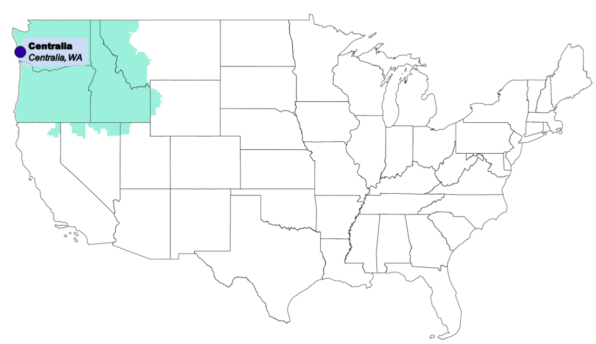
[11] PJM Critical Issue Fast Pass on FPA Section 202(c) Cost Allocation, Education on FPA Section 202(c) and DACC Cost Allocation, CIFP Day 1, Presentation given on June 10, 2025, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-doe-ca/2025/20250610/20250610-item-04-critical-issue-fast-path-doe-202c-cost-allocation-presentation.pdf

Centralia, Washington - Centralia Generating Station

DOE issued an initial 202(c) order to the Centralia Generating Station unit 2 on December 16, 2025 for 90 days. The plant remains operational pursuant to a second 202(c) order that was issued in March of 2026. Prior to these orders, the owner, TransAlta, had agreed in 2010 to retire the coal facility in 2025. TransAlta has been preparing for the retirement and replacement of Centralia for the last decade, alongside partners in state government, regional grid operators, labor unions, and environmental advocates.

We derive an approximate daily cost to keep Centralia online using the values reported from TransAlta's filing at FERC requesting cost recovery,[12] which requests reimbursement of $19.8623 million for the fixed cost of keeping the plant operational for the first 90 days that the Centralia facility remained operational under a 202(c) order. **This is equal to an estimated net cost of $220,692 per day just to maintain the facility's ability to operate if called upon.** The order also requests provisional startup and operational fees, but Sierra Club analysts do not believe the plant has actually operated so our estimate ignores these requests so far–this also means **that the plant's gross costs are likely equal to its net costs**. This daily average is extrapolated across the duration of subsequent 202(c) order periods to derive a reasonable estimate of impacts of the Centralia 202(c) orders on customer electric bills, which yields **$26,076,421 in net costs to customers as of this document's latest update (May 11, 2026).**

In its request for recovery, TransAlta has sought recovery from four grid operators: Bonneville Power Administration (BPA), Gridforce, CAISO, and Powerex. These territories cover areas serving customers in all or parts of Washington, Oregon, Idaho, California, Montana, Wyoming, Nevada, and the Canadian province of British Columbia.[13] Some subset of customers will be impacted. The map at right shows the largest area within Bonneville Power Administration (BPA). However, it is still not entirely clear which subset of customers will be asked to pay, partially because two of the responsible entities (Gridforce and Powerex) are market participants who administer grid services over disparate and unconnected geographic footprints.



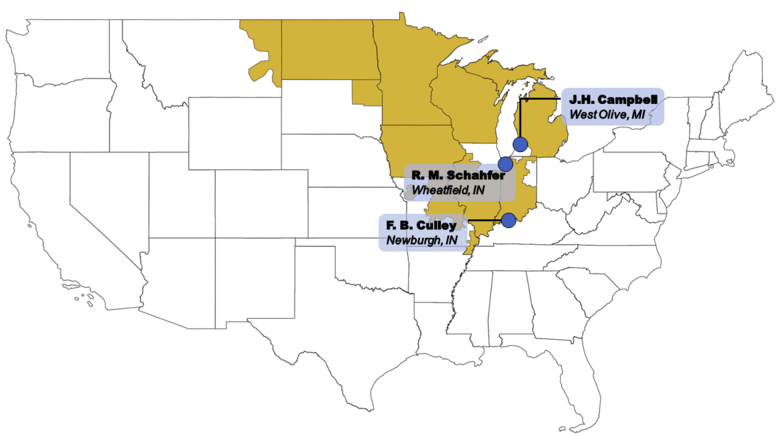
[12] Application for Cost Recovery of TransAlta Centralia Generation LLC under ER26-2422, FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260430-5425&optimized=false&sid=59be2029-c5ba-4774-bb80-3e88c8a93930.
[13] *Id.*

Newburgh, Indiana - F.B. Culley Generating Station

DOE issued an initial 202(c) order to the F.B. Culley Generating Station unit 2 on December 23, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order as of the date of last update, after receiving a second order in March 2026. The F. B. Culley facility is located in Indiana and owned by CenterPoint Energy. While CenterPoint Energy has not publicly posted information on operation costs for Culley Unit 2 while it has been operating pursuant to a 202(c) order, **a January 2026 analysis prepared by Synapse Energy Economics concluded that CenterPoint faces a net costs of approximately $21,000 per day to operate Culley Unit 2.** This amount was derived from an average gross cost of $47,000 per day.[14]

These estimates increase if CenterPoint runs Culley Unit 2 continuously as Consumers has done with Campbell: the facility would then have net costs of up to $24,000 per day, based on gross costs of up to $83,000 per day. These estimates do not include long-term maintenance and any capital costs needed to keep the plant running, which are estimated separately and would significantly increase the overall cost of compliance with ongoing 202(c) orders.

CenterPoint has requested permission from FERC to charge ratepayers across Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky (*see gold region approximated on map at right*) for the costs of Culley unit 2. This request would foist costs on residents who already are facing looming bill increases from the Campbell facility (in Michigan) and Schahfer (also in Indiana) subject to 202(c) orders, both of which have requested to charge customers over the same territory.



[14] Lucy Metz and Devi Glick, "Cost of Continued Operation of Culley Unit 2 and Schahfer Units 17–18 Under Federal Power Act Orders," prepared by Synapse Economics, (January 2026) https://www.sierraclub.org/sites/default/files/2026-01/burning-money-synapse-report-on-indiana-orders.pdf

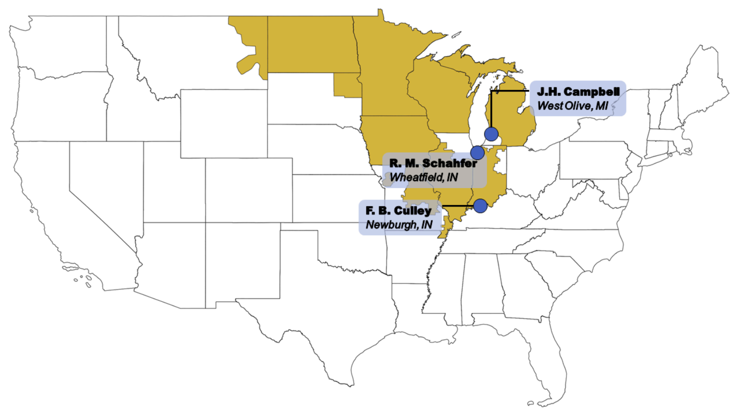
Wheatfield, Indiana - R.M. Schahfer Generating Station

DOE issued an initial 202(c) order to the R.M. Schahfer Generating Station units 17 and 18 on December 23, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order after receiving a second order in March 2026. The R. M. Schahfer facility is located in Indiana and owned by the Northern Indiana Public Service Company (NIPSCO).

While NISPCO has not publicly posted information on operation costs for Schahfer while it has been operating pursuant to a 202(c) order, the utility has indicated it will ask regulators to allow it to charge ratepayers the cost of keeping the plant online. **That would amount to a net cost of $173,944 per day, according to estimates from January 2026 prepared by Synapse Energy Economics**, derived from a gross cost of $317,900 per day.[15]

These estimates assume that Schahfer unit 18 incurs only fixed operations and maintenance costs while the turbine is repaired from a unit failure that destroyed one of the turbine blades, rendering it unable to operate, and it is assumed that unit 17 runs only when there are no cheaper generators that could supply energy to the grid.[16] However, if unit 17 runs continuously, costs will be even higher, with net costs of up to $187,900 per day derived from gross costs of up to $375,900 per day.

NIPSCO has requested permission from FERC to charge ratepayers across Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky (*see gold region approximated on map*) for the costs of Schahfer units 17 and 18. This request would foist costs on to residents who already are facing looming bill increases from the Campbell facility in Michigan, as well as the F.B. Culley facility in Indiana.



[15] Lucy Metz and Devi Glick, "Cost of Continued Operation of Culley Unit 2 and Schahfer Units 17–18 Under Federal Power Act Orders," prepared by Synapse Economics, (January 2026) https://www.sierraclub.org/sites/default/files/2026-01/burning-money-synapse-report-on-indiana-orders.pdf

[16] NIPSCO's president has estimated that the unit will take six months or longer to repair and "needs to be rebuilt." *See* comments at the IURC 2025 Winter Reliability Forum (Dec. 2, 2025) (video recording available at https://www.youtube.com/live/bCzALF4V45M?si=2pTcsnBZv98Ot2-T&t=3202.

Sierra Club National
2101 Webster St., Ste. 1300
Oakland, CA 94612
(415) 977-5500

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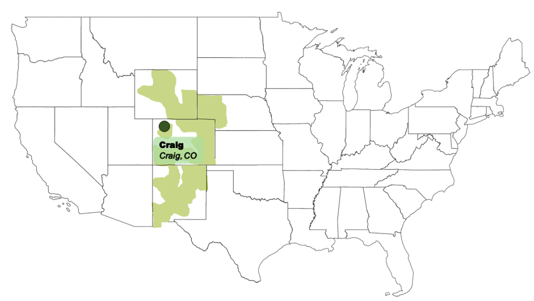
Craig, Colorado - Craig Generating Station

DOE issued an initial 202(c) order to Craig Generating Station unit 1 on December 30, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order after receiving a second order in March 2026. Prior to the order, the ownership group, led by Tri-State, announced in January of 2020 that it would transition to new wind and solar projects.[17] Tri-State's CEO at the time said the responses to its request for proposals showed that "*wind and solar energy now comes in prices lower than the cost of generating with any fossil fuel, coal or gas,*" allowing it to close coal plants early without negative rate impacts. Under the utility's "Responsible Energy Plan," Tri-State had expected to be 50% renewable by 2024, and achieve a "70% reduction in CO_2 emissions [for] Colorado wholesale electric sales" by 2030, from 2005 levels.[18] The forced delay to planned retirement has undermined the utility's stated objectives, prompting the utility to pursue legal action against the federal administration's order.[19]

Estimates of the cost to maintain functionality at Craig were sourced from an August 2025 analysis from Grid Strategies, which estimated an annual gross cost to keep the Craig facility operational of $79,740,475.[20] **This is equal to approximately $218,467 per day.** Unlike the case for other targeted plants, the 202(c) orders issued for Craig did not obligate the grid operator to allow the plant to run until April 1, 2026, which is also this document's latest update. This means that our analysis does not consider mechanisms requiring the grid operator to use the expensive energy produced by coal combustion at the Craig facility. As a result, we assume the plant has not operated, and that **the plant's gross costs are therefore equal to net costs.**

It remains to be seen if the plant owners will seek to recover costs to maintain plant functionality, despite contributing no power; no recovery requests have yet been filed. If filed, it is also not clear who will be asked to pay. Tri-State sells power to a number of electric utilities throughout the mountain west (an approximation of the Tri-state footprint shown in green on map below, stretching from Wyoming down through Arizona),[21] and recently joined SPP.



[17] "Tri-State will place coal plants with a gigawatt of new wind and solar," Clean Cooperative, February 9, 2020, https://www.cleancooperative.com/news/tri-state-will-replace-coal-plants-with-a-gigawatt-of-new-wind-and-solar

[18] Tri-State Generation and Transmission Association, Overview, Clean Cooperative analysis, 2020, https://www.cleancooperative.com/tristate.html

[19] Tri-State Generation and Transmission Association, Inc., & Platte River Power Authority, Petition for Rehearing, filed Jan. 29, 2026, https://tristate.coop/sites/default/files/PDF/Order%20No.%20202-24-14%20-%20Petition%20for%20Rehearing%20of%20Tri-State%20Generation%20and%20Platte%20River%20-%20FINAL%20COMBINED.pdf

[20] https://www.sierraclub.org/sites/default/files/2025-08/grid-strategies-report.pdf

[21] Tri-State Cooperative, Utility Service Territory, https://tristate.coop/

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Oakland, CA 94612
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