SIERRA CLUB

February 1, 2021

Via Electronic mail

Indiana Utility Regulatory Commission
Attn: Research, Policy, and Planning Division
101 W. Washington Street, Suite 1500 E.
Indianapolis, IN 46204-3407
bborum@urc.in.gov

Re: Sierra Club Comments on Indiana Municipal Power Agency 2020 Integrated Resource Plan

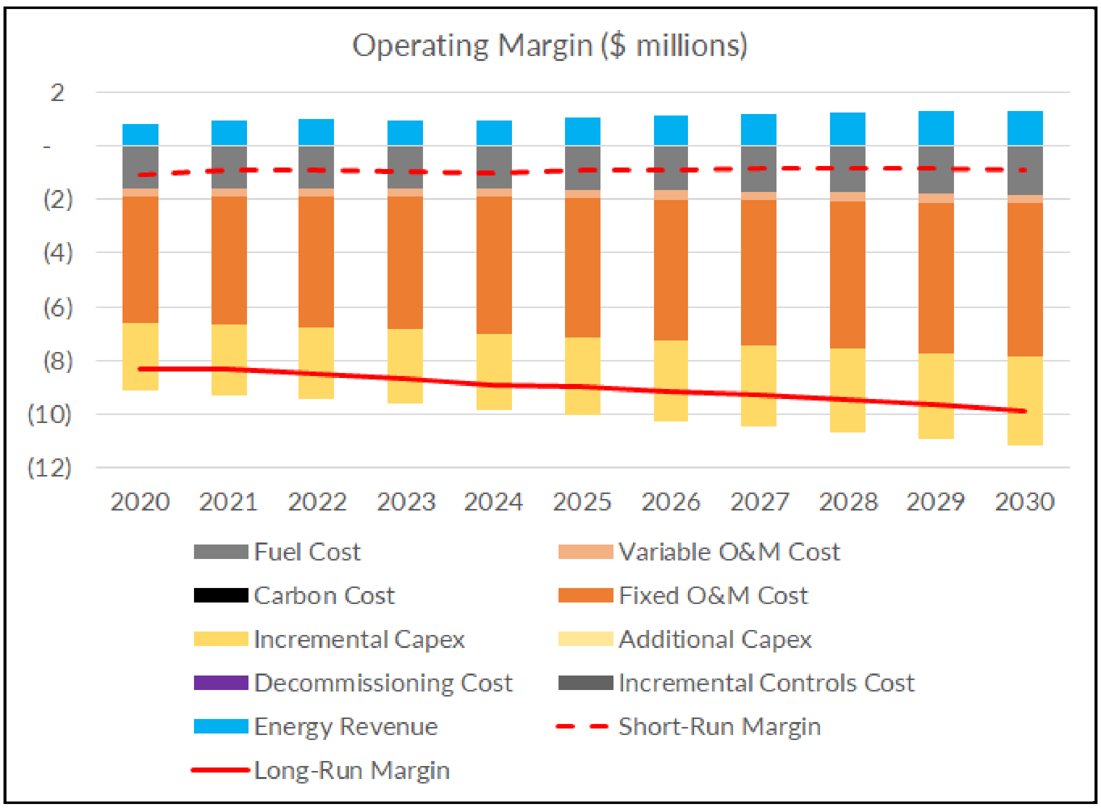
Dear Dr. Borum:

On behalf of Sierra Club and its more than 11,000 Indiana members, we submit these comments regarding Indiana Municipal Power Agency's 2020 Integrated Resource Plan ("IMPA's IRP"). We make three recommendations to improve IMPA's resource planning.

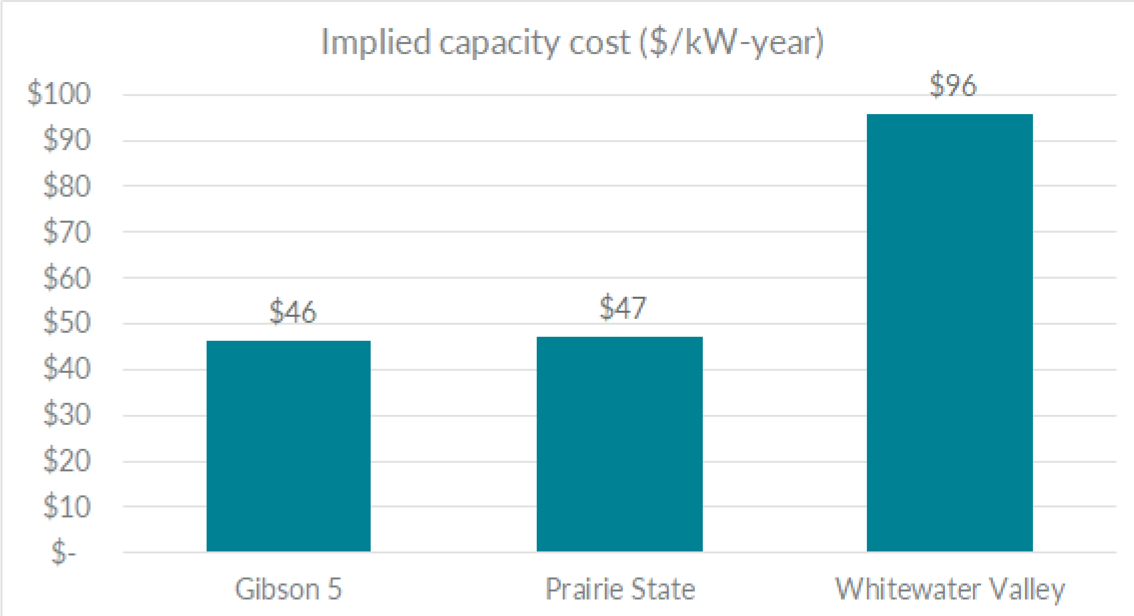
First, IMPA has failed to study the economics of its most-expensive coal unit, Whitewater Valley, which is approximately double the cost of Gibson unit 5, a unit that is on track to retire within the next half decade. IMPA should produce an addendum to the IRP to properly evaluate the economics of maintaining Whitewater Valley versus retiring it. Second, IMPA should consider a clean energy portfolio that would provide the same services as its existing units for lower cost and less pollution. Third, IMPA should update its resource planning to consider energy storage as a resource option.

I. IMPA Did Not Properly Assess The Economics Of Maintaining Operation of Whitewater Valley, Its Most-Expensive Coal Plant.

Indiana Municipal Power Agency failed to consider an earlier retirement for its most costly power plant, Whitewater Valley. The plant's two units are 65 and 47-years-old and have heat rates of 14,438 btu/kWh and 13,479 btu/kWh. According to the EIA-923, the plant had delivered fuel costs of $3.93/mmbtu or $54/MWh when considering the very high heat rates. The plant is used as a peaking unit, with a capacity factor of 3% in 2019. When considering the small amount of energy revenue the plant makes with its little operation against the high fuel, operations and maintenance, and incremental capital expenditures, the plant has a negative long run margin of $8-10 million per year (see Appendix for our methods of valuation). If you were to value the capacity of the plant based on this negative margin, the cost would be about $96/kW-year, which is very expensive for a capacity resource.



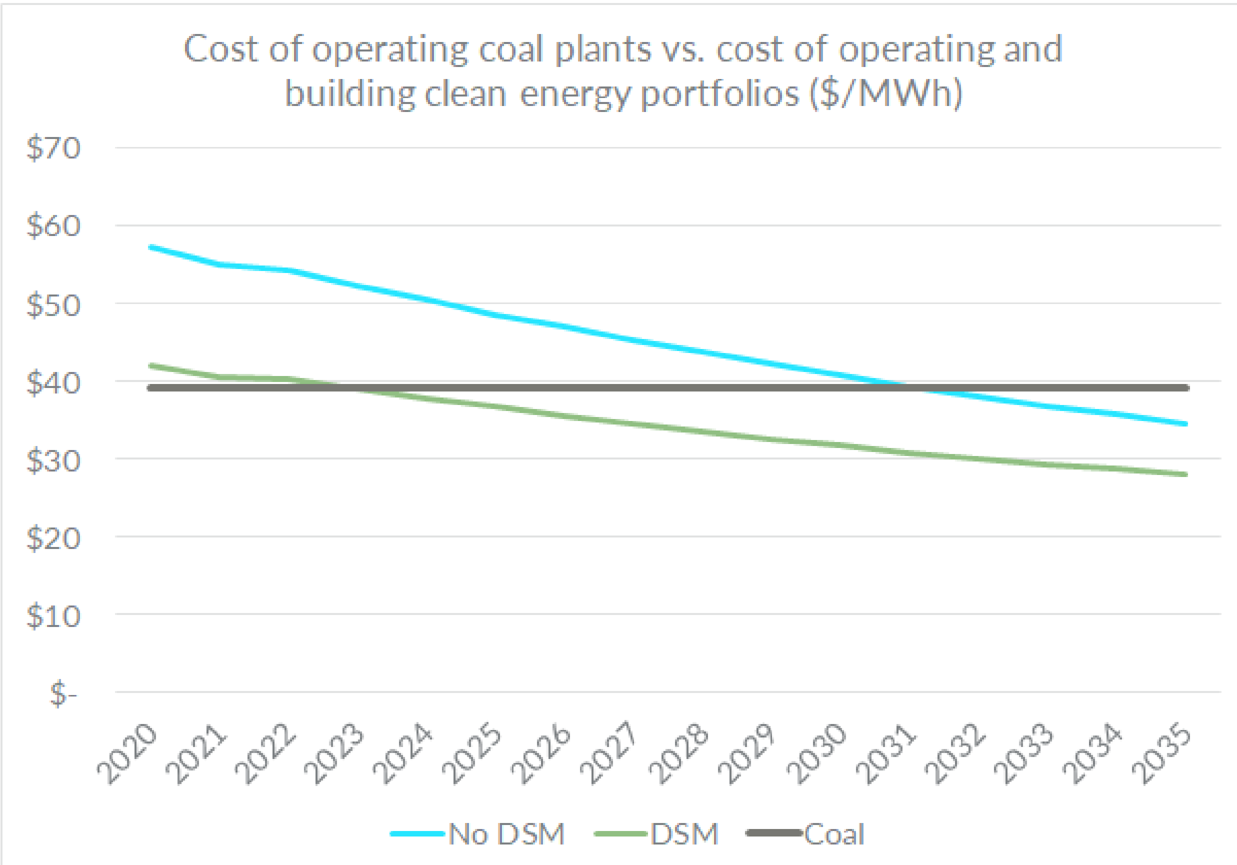
IMPA notes in their IRP that Gibson 5 is retiring. Gibson's implied capacity cost according to the same methodology is only $46/kW-year. Whitewater Valley's implied capacity cost is therefore double that of the retiring unit Gibson 5. Notably, Prairie State -- another coal asset which IMPA owns a portion of -- also has an implied capacity similar to Gibson's and may also be ripe for retirement modeling and consideration.



II. A Clean Energy Portfolio Replacement Provides a Reasonable Future Alternative that IMPA Should Consider.

IMPA's total capacity across its ownership in high cost coal units Gibson 5, Prairie State, and Whitewater Valley is 456 MW based on 2019 data. Given the high costs of these coal units and failure of IMPA to model storage, we looked at a clean energy portfolio replacement to find when it could cost-effectively replace the energy, capacity, and ramping services of IMPA's share in those coal plants. More detailed methodology can be found in the Appendix. We constructed two portfolios: 1) "No DSM" which consists of solar PV, wind, and battery storage and 2) "DSM" which consists of solar PV, wind, storage as well as demand side management technologies including various forms of customer energy efficiency and demand response. Once the clean energy portfolio was constructed, we modeled the cost against the average levelized cost of energy that the coal plants provide, which we calculated at $39/MWh. Though the clean energy portfolio is initially more expensive due to high storage costs, if it is constructed later then eventually the cost to build and operate the clean energy portfolio falls below the operating cost of building the coal plant. When the total cost of a new solution falls below the marginal cost of an existing solution, it will save customers money to go with the new solution immediately regardless of any sunk costs. We found that a No DSM portfolio is cost effective in 2031, while a DSM portfolio is cost effective as early as 2023. These dates are both well before IMPA's modeled retirement of Whitewater Valley in 2035. It did not model any retirement of Prairie State.

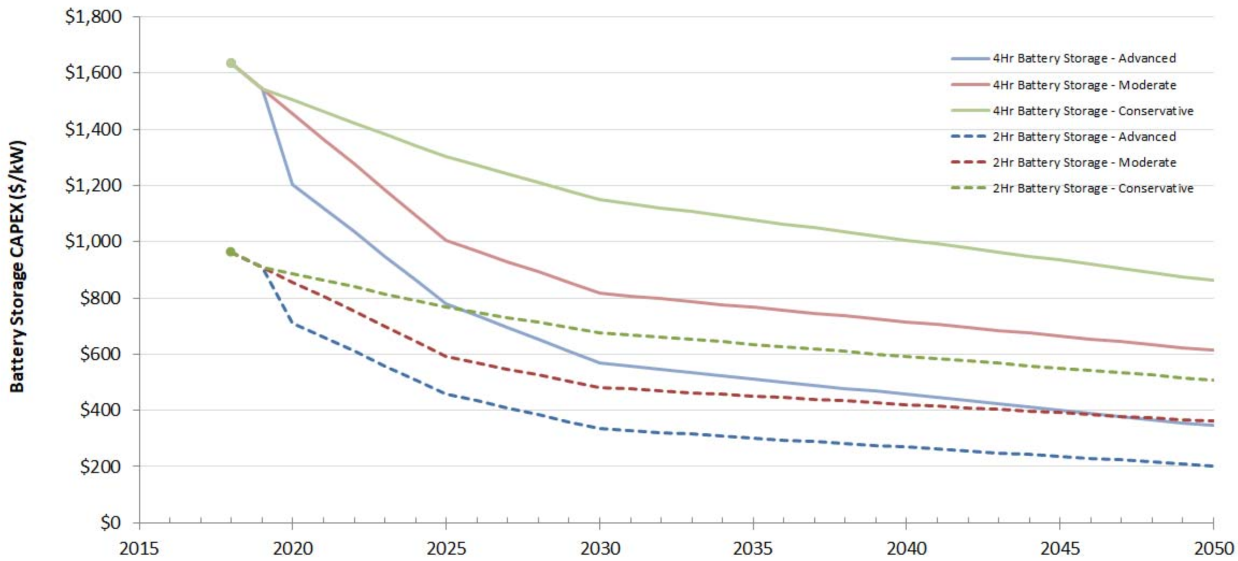
	Solar PV	Wind	Battery storage	Energy efficiency	Demand response	Cost effective year
No DSM	418	826	267	0	0	2031
DSM	321	667	138	257	149	2023



III. IMPA Failed to Consider Storage.

IMPA did not consider storage for reasons of purported cost and feasibility. EIA is tracking at least 4,300 megawatts of new storage in 2021, in places as diverse as California, Arizona, New York, Florida, Texas, and Montana. Fellow Indiana utility Northern Indiana Public Service Company is preparing to deploy 135 MW of storage by 2023. Kentucky utility LG&E / KU is currently soliciting bids for 100 MW of storage.

In terms of cost, we recommend IMPA can consider using costs from NREL's 2020 ATB study, rather than the 2011 study it benchmarked (granted they did apply cost reductions). For example, ATB's capital costs for 2-hour storage and 4-hour storage range are $900/kW and $1500/kW respectively in 2020 in the moderate scenario. IMPA's assumed cost for a 3-hour storage system was $3000/kW, which is way above NREL's current benchmark, let alone the further cost declines NREL is predicting in their moderate or advanced scenario.



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Sierra Club appreciates the opportunity to comment on this IMPA IRP and we would be pleased to discuss these comments further with the Director.

Respectfully submitted,

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Appendix

1. Future Performance of Whitewater Valley

In order to estimate the long run margin of Whitewater Valley, 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 the unit 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 its 2019 value of 3%.
- 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: 2019 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. We assumed a heat rate of 13,780 British thermal units (btu)/kilowatt hour (kWh) for the plant.
- Variable and fixed O&M expenses: S&P Global Market Intelligence uses a regression model to estimate variable and fixed O&M based on capacity, age, and generation. For Whitewater Valley they estimate VOM at $10/MWh and FOM at $45/kW-year.
- 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 Whitewater Valley, the average ongoing CapEx is on the higher end of the range at $27/kW-year (2017 dollars), as one unit has FGD and is 48 years old and the other does not have FGD but is 66 years old. 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 2040, we multiplied the EIA's forecast (from Annual Energy Outlook 2020) for gas delivered to East North Central (an EIA census region which includes Indiana) 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 to 2019 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 $36/MWh across the first 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. The implied capacity cost was calculated as the negative value of the long run margin divided by the operating capacity.

2. Clean Energy Portfolio

Given that continuing to run these coal units would be a net cost to customers 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 three of the coal plants IMPA receives energy and capacity from: Gibson 5, Prairie State, and Whitewater Valley.

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 JH Campbell coal plant unit 3. 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 some of IMPA’s plants (including Gibson) 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, Version 11, 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—$39/MWh.