ALLIANCE
FOR INDUSTRIAL EFFICIENCY

Standby Rates:

Barriers to CHP Deployment on a National Scale

What is a Standby Rate?

While combined heat and power (CHP) systems can operate independently of the grid, they need to interconnect for backup power during either scheduled or unscheduled outages. A utility implements a **Standby Rate** to recover its infrastructure costs related to providing this service—and assure CHP hosts that power is available when needed. However, in many cases, these rates are burdensome, inflexible, unpredictable, or lack transparency—making it less likely that a CHP project will be built in the first place. By making sure that standby rates better reflect the actual costs that a CHP system imposes on the grid, we can compensate utilities for those costs while still encouraging investments in CHP.

Standby rates include as many as two-dozen riders. Chief among them are:

- ***Reservation Fees***—A fixed per kW fee each month to reserve standby service;
- ***Demand Charges***—Charges to recover utility generation and transmission costs;
- ***Distribution Charges***—Charges to recover the utility's delivery infrastructure ("wires") costs; and
- ***Energy Charges***—Per kWh charges for grid energy use during an outage.

Apples-to-Apples Comparison

While CHP stakeholders have long complained about burdensome rates, there has never been a way to systematically compare monthly charges across utilities. In conjunction with the Midwest Cogeneration Association, 5 Lakes Energy developed an approach to compare rates across utilities, and across states, using a uniform set of assumptions about system size, needs, and outages. This "Apples-to-Apples" (A2A) approach shines a light on best—and worst—practices. To date, the A2A analysis has been completed for 17 utilities across five states (IN, MI, MN, OH, and PA) and is in process at three additional utilities in IA, MO and PA.

The A2A analysis estimates monthly standby tariffs for a "sample customer" that fits the following criteria:

- 2 MW in standby load for CHP system;
- And 3 MW in supplemental load.

The analysis then considers bills under a variety of standard outage scenarios, including:

- A "no outage" month (Fig. 1);
- A scheduled 16-hr off-peak outage;
- A scheduled 16-hr peak outage;
- A scheduled 8-hr peak/8-hr off-peak outage;
- A scheduled 32-hr off-peak outage;
- And an unscheduled 8-hr peak/8-hr off-peak outage (Fig. 2).

The A2A data is verified through conversations with the utilities and shared with Public Utility Commissions (PUCs).

Advocates like the Alliance for Industrial Efficiency, American Chemistry Council, Midwest Cogeneration Association, and Ohio Environmental Council use this information to engage with the PUCs and utilities to promote rate reform.

Figure 1: "No Outage" Scenario+

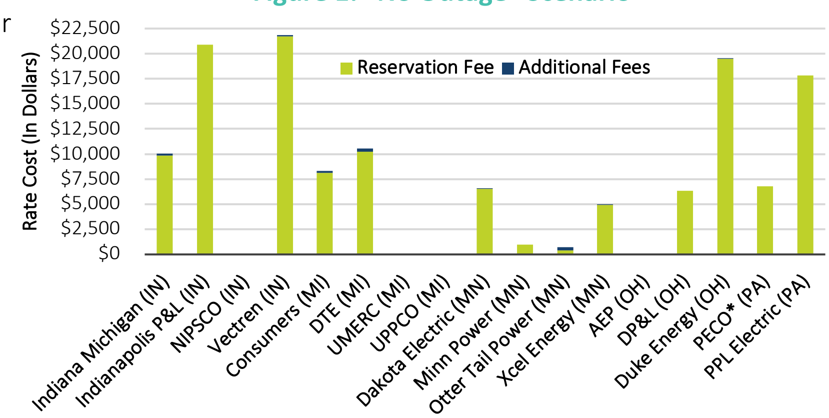
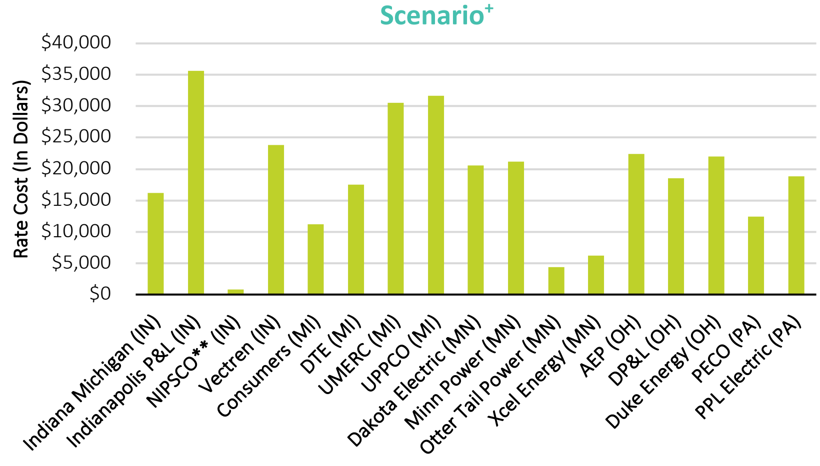


Figure 2: "Unscheduled Outage" (8-hr peak/8-hr off-peak) Scenario+



Disproportionate Standby Charges

The A2A analysis helps identify inequitable standby tariffs that don't reflect "cost of service."

Poorly designed standby tariffs are characterized by fixed reservation fees and demand charges that are billed on contracted standby capacity (kW) rather than actual use. These fixed charges fail to reflect the lower costs self-generation customers impose on utility infrastructure and the benefits they provide to the grid. In contrast, variable demand charges based on actual use and reservation fees based on forced outage rates (<5%) lead to equitable, lower fees and more reliable, energy-efficient CHP system operation.

Other issues with standby rates include:

- A lack of "cost of service" studies for standby customers;
- Many utilities fail to differentiate charges for peak and off-peak use of standby service and scheduled and unscheduled outages, creating little incentive for hosts to plan ahead;
- Some utilities impose burdensome penalty fees—or ratchets—for months following the outage;
- Some utilities deem standby service to be taken any time a CHP system operates below its contracted capacity, regardless of whether any power is taken from the grid during those times; and
- Utilities that charge large tariffs may simultaneously offer generous incentives to encourage deployment, sending conflicting signals to project hosts.

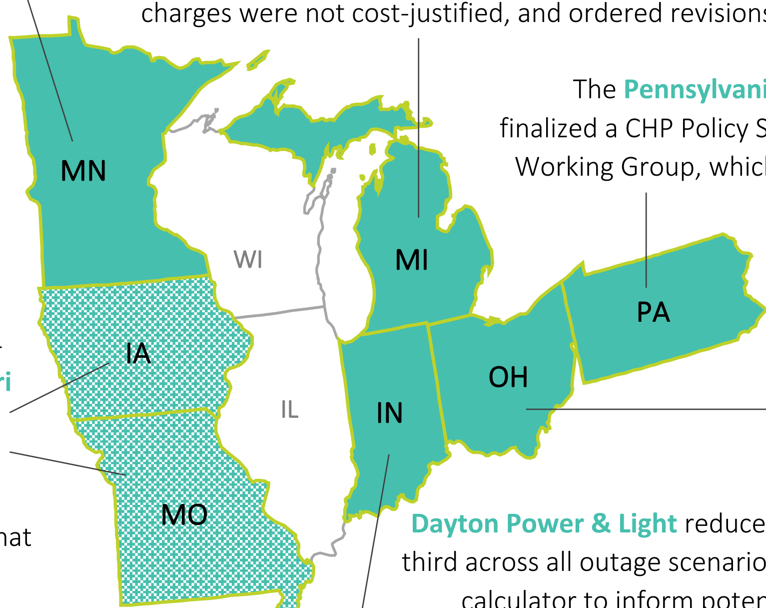
Utilities and Public Utility Commissions Take Action

"Best practices" recognition, now informed by the A2A analysis, is leading to changes on-the-ground:

In 2019, the **National Association of Regulatory Utility Commissioners** (NARUC) adopted a resolution that encourages regulators to consider whether the cost of standby rates discourages further deployment of CHP and WHP. The resolution received support from Commissioners, manufacturers, trade associations, and clean energy companies across the country.

In 2014, the **Minnesota Department of Commerce** held a series of stakeholder workshops on CHP, including best practices for standby rates. Thereafter, the **Minnesota Public Utilities Commission** opened a standby rate docket and in 2017 and 2018 ordered revisions to four utilities' standby tariffs.

In 2017, the **Michigan Public Service Commission** (PSC) convened a CHP standby rate working group and ordered **Consumers Energy** and **DTE Electric** to perform cost of service studies for the class of standby customers. In subsequent rate cases, the **Michigan PSC** rejected both utilities' proposed increases in standby rates, found their existing standby charges were not cost-justified, and ordered revisions to better reflect actual costs.



The **Pennsylvania Public Utilities Commission** finalized a CHP Policy Statement and launched a CHP Working Group, which provides a platform to share best rate-design practices.

The **Public Utilities Commission of Ohio** (PUCO) included standby rates in alternative ratemaking discussions as part of its grid modernization proceedings.

In rate cases in **Iowa** in 2014 (**MidAmerican**) and **Missouri** in 2015 (**Ameren Missouri**), CHP stakeholders and State Energy Offices negotiated revisions to standby tariffs that replaced fixed charges with variable charges.

Dayton Power & Light reduced its tariffs by more than one-third across all outage scenarios and developed an online bill calculator to inform potential hosts about project costs.

In 2017, the **Indiana** legislature ordered Indiana utilities to submit cost justification for standby tariffs. In 2018, the **Indiana Utility Regulatory Commission** opened a comment period and reported its findings to the legislature. The Alliance disagrees with the report's conclusion that utilities are providing fair costs of service. There has been no action by the legislature to date.

Refers to Fig. 1 and Fig. 2 (reverse)

+ Graph data reflects time at which A2A analysis was completed in each state: IN (May 2018), MI (Feb. 2017), MN (Aug. 2016), OH (Aug. 2017), PA (Apr. 2018). Some tariffs have improved as a result of this work.

*To avoid double-counting, PECO data excludes a 40% minimum billing demand for supplemental power, which is technically part of the standby tariff.

**NIPSCO's rates for an unscheduled outage also include an LMP (Locational Marginal Price), which differs by location within a utilities' region. Due to its variability, the LMP value is not reflected in Figure 2.