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# Opportunities for installed combined heat and power (CHP) to increase grid flexibility in the U.S.

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A B S T R A C T

Increasing use of renewable energy requires sufficient grid flexibility to address uncertainty and variability in electricity generation. Previous studies suggest that combined heat and power (CHP) systems may support grid flexibility but they do not consider operating hours. In this paper, we used CHP operating data and determined annual and monthly availability of the installed CHP capacity from various sectors (e.g., utility, independent power producer, commercial, and industrial) in all seven U.S. independent system operators (ISOs) and regional transmission organizations (RTOs). Also, we estimated hourly CHP availability installed in five facility types (i.e., hospitals, universities, hotels, offices, and manufacturing) in the state of New York. The results show that regardless of ISO/RTO, sector, or season, more than 40% of the installed CHP capacity (0.7–8.7 GW) was not fully utilized in 2019; the results are similar for 2018. This available CHP capacity accounted for up to 9% of the ISO/RTO's peak electric demand, which may yield cost savings up to $16 billion by avoiding installation costs of new natural gas combustion or combined-cycle turbines. To exploit the available CHP capacity to enhance grid flexibility, we recommend different policy implications including flexible contract lengths between CHP owners and grid operators, improved market designs, and simplified interconnection standards.

## 1. Introduction

In the U.S, renewable energy such as solar and wind generation accounts for up to 23% of the total electricity generation (Sun et al., 2020). Although solar and wind generation provide low-carbon electricity, their variability and uncertainty—due to the inability to predict electricity production at specific times—can lead to critical problems in balancing of demand and supply, and negative market prices (Cochran et al., 2014, 2015; Denholm et al., 2016). Also, old grid infrastructures can cause transmission congestion, leading to significant curtailments of renewable energy. For example, up to 17% of wind generation was curtailed in the Electric Reliability Council of Texas in 2009 (Bird et al., 2014). Moreover, electrical output from renewable sources can change rapidly depending on the availability of solar or wind energy. Thus, high renewable penetration requires sufficient grid flexibility (Ahn et al., 2019a; Kondziella and Bruckner, 2016). According to a U.S. Department of Energy (DOE) report, grid flexibility is defined as the ability to address variability and uncertainty in demand and generation resources (U.S. DOE, 2016). In California, where the grid has high solar penetration, solar energy production falls rapidly in the late afternoon while electric demand rises,[1] requiring high ramp rates from non-solar power resources (California Independent System Operator, 2016). A previous study shows that the required ramping capacity could increase further due to increasing electrification across different sectors (e.g., residential, commercial, industrial, and transportation) (Ebrahimi et al., 2018). Therefore, grids with high levels of renewables are likely to require more grid flexibility to meet rapidly varying or peak demand. Although the need for greater flexibility could be met with new conventional peaking plants, this approach may bring its own challenges and offset the benefits of renewable generation. First, if new peaking plants are used as fast-ramping resources, their payback periods would be long (9–17 years) due to limited operating hours, increasing the levelized cost of electricity (Carvalho, 2018). Second, peaking plants may need up to 12 hours from cold start to full load, delaying the response time to intermittency of renewable generation (Comstock, 2020). Third, frequent cold-start cycles and part-load operations of peaking plants may increase criteria pollutants (e.g., $NO_x$ and PM) and greenhouse gas (e.g., $CO_2$) emissions (U.S. DOE, 2016; Denholm and

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[1] For more than a decade, California's annual peak has occurred in the summer between 3:30 p.m. and 6 p.m. when solar production has fallen substantially (California Independent System Operator, 2020).

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Hand, 2011; Thind et al., 2017).

As an alternative to peaking plants, previous studies have demonstrated that combined heat and power (CHP) systems[2] are capable of supporting grid flexibility. For example, a CHP system successfully modulated its electric output to mitigate significant frequency fluctuations during power outages in Great Britain while marginally impacting energy supply to its host site (Bian et al., 2017; Xu et al., 2019). At Princeton University, a CHP system supports frequency regulation in the Pennsylvania, New Jersey, and Maryland Interconnection region while maximizing its economic benefits by selling electricity when a real-time price is high (Jones and Kelly, 2017).

Regarding CHP's capability to support grid flexibility, one study projected that about 40% of the newly installed CHP capacity at manufacturing sites in California (up to 1280 MW) could be used to support the grid (Bhandari et al., 2018). This study also showed that newly installed CHP systems can reduce grid operating costs, avoid the installation cost for new centralized power plants, and alleviate grid stress when the net load changes rapidly. Another study evaluated grid flexibility in the U.S. using the total rated capacity of five different power resources: interconnection, combined-cycle gas turbine, CHP, hydro, and pumped hydro (Yasuda et al., 2013). They found that installed CHP systems in the U.S. could meet about 20% of the peak electric load.

Because these studies focus only on facility-level case studies, they do not fully represent CHP's potential at a grid-level scale. Also, the total rated capacity is not an accurate measure of the capacity available to support grid flexibility as it does not capture operating schedules of CHP systems. Therefore, it is still unknown how much installed CHP capacity could realistically be available to support grid flexibility. Specifically, there is lack of information about seasonal- and hourly-availability of the installed CHP capacity. Providing such information can help estimate avoidable costs that otherwise could be incurred by additional technologies to mitigate variability and uncertainty of renewable generation and associated societal benefits.

The purpose of this study is to quantify the installed CHP capacity which feasibly could be available to support grid flexibility across the seven U.S. independent system operators (ISOs) and regional transmission organizations (RTOs). We determined availability of the installed CHP capacity using capacity factors[3] at three different time scales (i.e., annual, monthly, and hourly). Using CHP operating data from the U.S. Energy Information Administration (EIA) (U.S. EIA, 2020a; U.S. EIA, 2020b), we calculated annual and monthly capacity factors for the installed CHP systems in four sectors (i.e., utility, independent power producer, commercial, and industrial) across the seven U.S. ISO/RTOs. However, hourly CHP capacity factors were calculated only in the state of New York for five facility types (i.e., hospitals, universities, hotels, offices, and manufacturing).[4] To fully utilize the estimated CHP capacity available and enhance grid flexibility,[5] we recommend different policies that support flexible contract lengths between grid operators and CHP owners, improve markets for CHP systems, and simplify interconnection standards.

## 2. Methods

We determined opportunities for installed CHP systems to enhance grid flexibility using the following steps. First, we identified the peak and median electric demands in the seven U.S. ISO/RTOs as a baseline to be compared with available CHP capacity in the corresponding regions. Then, we estimated the installed CHP capacity in various sectors across the seven U.S. ISO/RTOs. Using CHP operating data from the EIA, we determined annual availability of the installed CHP capacity. To examine how the available CHP capacity varies seasonally, we also investigated monthly availability of the CHP systems. Last, we determined hourly availability of CHP systems in different facility types in New York to investigate if CHP systems may be able to support grids when renewable generation decreases during the day.

### 2.1. Estimation of regional electric demands in ISOs and RTOs in the U.S

In the U.S., an ISO or RTO manages a region's electrical grid to balance demand and supply of electricity. ISO/RTOs also administer energy and ancillary services markets that foster competitive bidding of offerings among electricity buyers and sellers (Federal Energy Regulatory Commission, 2021). Fig. 1 shows the seven U.S. ISO/RTOs: California ISO (CAISO); Southwest Power Pool (SPP); Electric Reliability Council of Texas (ERCOT); Midcontinent ISO (MISO); Pennsylvania, New Jersey, and Maryland (PJM) Interconnection; New York ISO (NYISO); and ISO New England (ISO-NE).

Some ISO/RTOs comprise several smaller balancing authorities while others consist of a single balancing authority. Balancing authorities are entities that maintain the balance between supply and demand of electricity (Hoff, 2016). For 66 balancing authorities in the U.S., hourly operating data are available from EIA (U.S. EIA, n.d.). Table 1 provides lists of balancing authorities, for which hourly operating data are available, for the seven U.S. ISO/RTOs. Some balancing authorities such as PacifiCorp West and Nevada Power Company are included in CAISO although they are not within its geographical boundary.

Based on the list of the balancing authorities, hourly electric loads in 2019 were estimated for the seven U.S. ISO/RTOs and they are provided in Fig. 2. In the box-whisker plot, the maximum, upper quartile (Q3), median (Q2), lower quartile (Q1), and minimum of hourly electric loads are provided. Outliers indicate data points that are more than 1.5 times the inter-quartile range (Q3 − Q1) above the upper quartile or below the lower quartile. The peak electric load is greatest in PJM (155 GW), followed by MISO (120 GW), CAISO (80 GW), ERCOT (75 GW), SPP (55 GW), NYISO (30 GW), and ISO-NE (24 GW). The peak electric load in each ISO/RTO is about 1.5–2 times greater than the median. The electric loads are relatively smaller in NYISO and ISO-NE mainly due to their small serving regions.

### 2.2. Estimation of the installed CHP capacity in the seven U.S. ISO/RTOs

To determine available CHP capacity at various time scales, we used two datasets: EIA-860 (U.S. EIA, 2020a) and EIA-923 (U.S. EIA, 2020b). Specifically, EIA-860 provides generator-level information such as an identification code, prime mover, nameplate capacity, operating status, and primary energy source of a generator with capacity of 1 MW or greater (U.S. EIA, 2020a). It also provides the name, address, and balancing authority of a plant at which a generator is located, a sector to which a generator is applied, and whether a generator is associated with CHP. The most recent EIA-860 was released in September 2020 and it contains data on more than 22,000 generators as of 2019. From this dataset, we collected generators that are associated with CHP and in service. Based on a balancing authority in which CHP systems are located (see Table 1), the collected CHP data were grouped into the

[2] CHP systems generate electrical and thermal energy from a single primary energy source, yielding greater energy, environmental, and economic benefits compared to thermal- or electricity-only generation (Ahn et al., 2018, 2019b; Smith et al., 2013; Kerr, 2008; Wu and Wang, 2006).

[3] Capacity factor is defined as the ratio of the actual electric output to the maximum available electric output, thus accounting for CHP operating hours.

[4] To the authors' knowledge, only the New York State Energy Research & Development Authority provides publicly available dataset containing hourly CHP operating data (NYSERDA, n.d.). Accordingly, the analysis based on this dataset may be applicable only to New York. However, this study provides a methodology useable when hourly data are available for other regions, and the conclusion may be applicable to other U.S. ISO/RTOs.

[5] As the U.S. DOE report's definition of grid flexibility does not include local resiliency (U.S. DOE, 2016), our analysis did not account for potential benefits of CHP systems on local resiliency. However, CHP systems can enhance local resiliency, providing societal benefits (Martínez Ceseña et al., 2016).

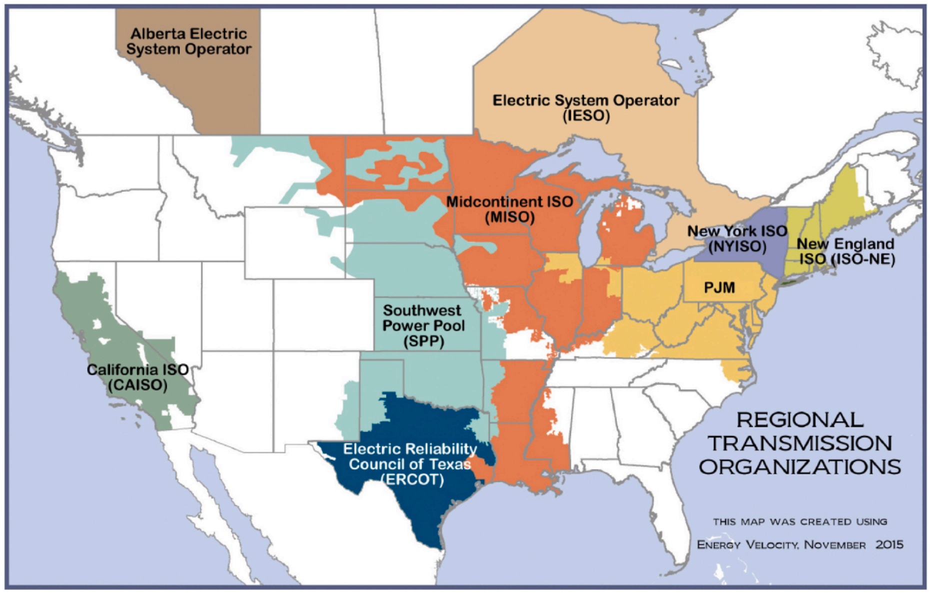


**Fig. 1.** Nine independent system operators (ISOs)/regional transmission organizations (RTOs) in North America (Federal Energy Regulatory Commission, 2021). This study focuses on the seven U.S. ISO/RTOs: CAISO, SPP, ERCOT, MISO, PJM, NYISO, and ISO-NE.

**Table 1**
Balancing authorities in the seven U.S. ISO/RTOs (U.S. EIA, n.d.).

| ISO/ RTOs | Balancing authorities[a] |
|---|---|
| CAISO | Balancing Authority of Northern California (BANC) |
| | CAISO |
| | Imperial Irrigation District (IID) |
| | Los Angeles Department of Water and Power (LDWP) |
| | Nevada Power Company (NEVP) |
| | PacifiCorp West (PACW) |
| | Turlock Irrigation District (TIDC) |
| | Western Area Power Administration - Desert Southwest Region (WALC) |
| SPP | Associated Electric Cooperative, Inc. (AECI) |
| | Southwestern Power Administration (SPA) |
| | SPP |
| ERCOT | ERCOT |
| MISO | MISO |
| PJM | PJM |
| NYISO | NYISO |
| ISO-NE | ISO-NE |

[a] Only balancing authorities that provide hourly operating data are listed; thus, some may be missing in the table.

seven U.S. ISO/RTOs.

EIA-923 provides annual and monthly electricity generation and fuel consumption, fossil fuel stocks, disposition of electricity, and pollutants emissions in 2019 (U.S. EIA, 2020b). To create a comprehensive dataset of CHP systems, we combined generator-level information from EIA-860 with monthly electricity generation from EIA-923, using an identification code of a CHP system and a name of a facility in which the CHP system is installed. In the combined dataset, data that lacked complete monthly generation information were removed. Fig. 3 illustrates the combining process of the two datasets. Table 2 summarizes the number and installed capacity of CHP systems over 1 MW in the seven U.S. ISO/RTOs. It should be noted that the majority of the collected CHP systems (744 of 759) are for self-use while the rest are in standby, meaning that systems are available for service but not normally used. The number of CHP systems in each of EIA-860 and EIA-923 is provided in Table S1 of Supplemental Information. The collected CHP systems have nameplate capacities ranging from 1 MW to 285 MW (see Figure S1 in Supplemental Information).

### 2.3. Estimation of annual- and monthly-averaged capacity factors of installed CHP systems

To determine annual and monthly availability of installed CHP

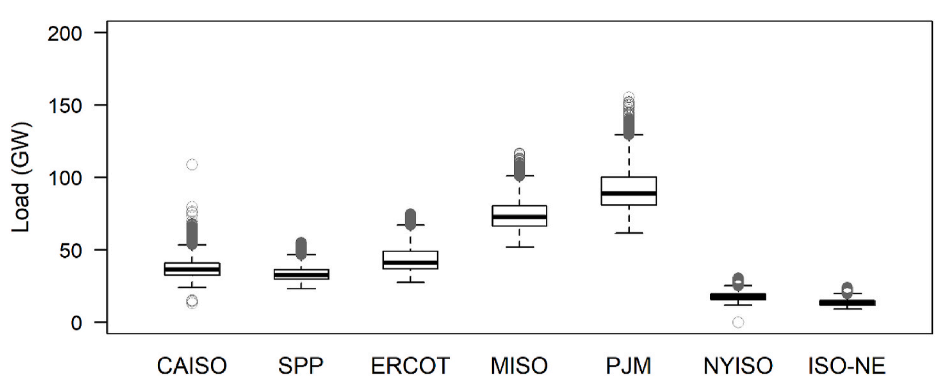


**Fig. 2.** Hourly electric loads for the seven U.S. ISO/RTOs in 2019. The lower, middle, and upper lines of a box indicate the first, second, and third quartiles of hourly electric loads, respectively, and the bottom and top whiskers indicate the minimum and maximum. Outliers are presented as hollow circles below the bottom whisker or above the top whisker. Data are taken from EIA (U.S. EIA, n.d.).

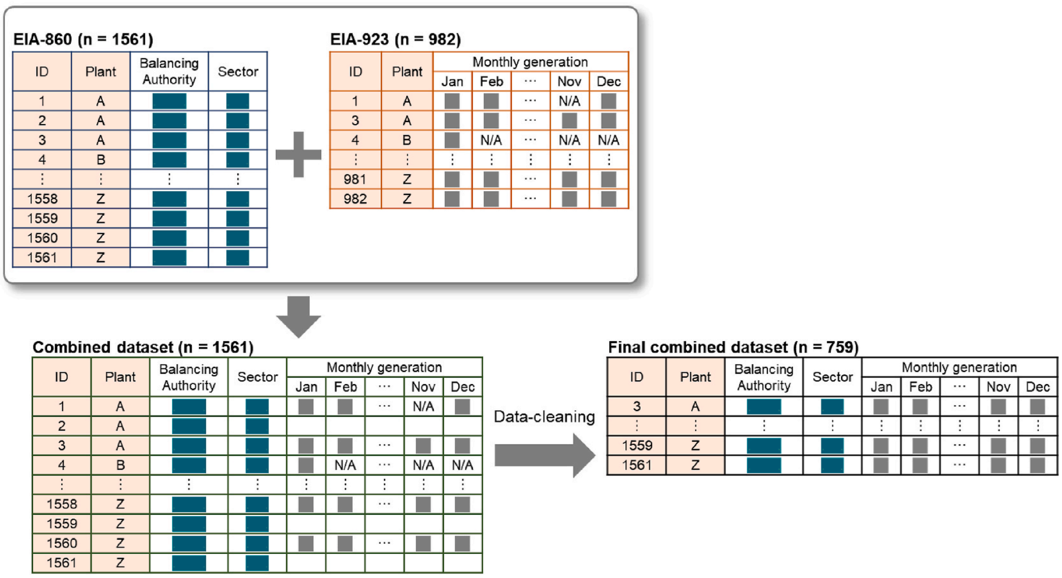


**Fig. 3.** Illustration of combining EIA-860 and EIA-923.

**Table 2**
The number and installed capacity of CHP systems over 1 MW in the seven U.S. ISO/RTOs in 2019. Data are taken from EIA-860 (U.S. EIA, 2020a) and EIA-923 (U.S. EIA, 2020b).

| ISO/RTO | Number of CHP systems over 1 MW | Installed capacity (GW) |
|---|---|---|
| CAISO | 105 | 4.9 |
| SPP | 25 | 1.0 |
| ERCOT | 102 | 11.1 |
| MISO | 266 | 19.0 |
| PJM | 145 | 6.7 |
| NYISO | 61 | 4.6 |
| ISO-NE | 55 | 1.3 |
| **Total** | **759** | **48.6** |

capacity, we estimated annual- and monthly-averaged capacity factors of CHP systems in the seven U.S. ISO/RTOs in 2019. A capacity factor is defined as the ratio of the actual electric output over a given time period to the maximum available electric output. To ensure consistency in results across different years, we also estimated CHP capacity factors with the 2018 data from EIA (see Section S4 in Supplemental Information).

For each of the seven U.S. ISO/RTOs, an annual-averaged capacity factor ($CF_{annual}$) of CHP systems was calculated as

$$CF_{annual} = \frac{\sum_{n=1}^{n=N}\sum_{i=1}^{i=12} ME_{n,i}}{\sum_{n=1}^{n=N} P_{max,n} \times 8760} \tag{1}$$

where $ME_{n,i}$ indicates the $i$-th month's monthly electricity generation (MWh/month) for the $n$-th CHP system; $P_{max,\,n}$ indicates the nameplate capacity (MW) of the $n$-th CHP system; $N$ represents the total number of the installed CHP systems in each ISO/RTO; and 8760 indicates the number of hours in one year.

Similar to Eq (1) estimation, for each ISO/RTO the $i$-th month's monthly-averaged capacity factor ($CF_{monthly,n,i}$) for the $n$-th CHP system was calculated as

$$CF_{monthly,n,i} = \frac{ME_{n,i}}{P_{max,n,i} \times T_i} \tag{2}$$

where $T_i$ indicates the number of hours in the $i$-th month. Because nameplate capacity of combustion turbines or engines can vary with ambient conditions (Derrow et al., 2015), the summer nameplate capacity was used for June, July, and August (i.e., $i = 6, 7, 8$) whereas the winter nameplate capacity was used for January, February, and December (i.e., $i = 1, 2, 12$). For the other months, the default nameplate capacity was used. While the annual-averaged capacity factor was estimated for each ISO/RTO, the monthly-averaged capacity factor was estimated for each generator, providing a distribution function.

### 2.4. Estimation of hourly-averaged capacity factors of CHP systems installed in New York

To understand how CHP systems may also mitigate hourly-varying penetration of solar and wind generation, we leveraged data from the New York State Energy Research & Development Authority (NYSERDA) (NYSERDA, n.d.). This dataset is the only publicly available dataset that provides hourly electricity generation, heat generation, fuel consumption, and capacity factor for active distributed energy resources including CHP systems. From the NYSERDA data, we used CHP operating data collected after 2012 to investigate relatively recent trends for CHP utilization. To understand how hourly CHP availability varies with facility types, we focused on CHP systems implemented in five facility types: hospitals, universities, hotels, offices, and manufacturing facilities. As a result, a total of 24 CHP systems in NY were selected. The detailed information about the selected CHP systems (e.g., a prime mover type, total electric capacity, year of operating data) is provided in Table S3 of Supplemental Information.

It should be noted that the size of CHP systems in the NYSERDA data ranges from 65 kW to 15 MW per unit, while that in the EIA data is greater than 1 MW per unit (see Figure S1 in Supplemental Information). However, operating schedules for the selected facility types may not be region-specific; thus, the hourly analysis with the NYSERDA data might help illuminate annual and monthly CHP availability in other ISO/RTOs estimated with the EIA data.

## 3. Results and discussion

### 3.1. Regional and sectoral availability of installed CHP capacity to improve grid flexibility

Available CHP capacity was determined using annual-averaged capacity factors across four sectors (i.e., utility, independent power producer, industrial, and commercial) in the seven U.S. ISO/RTOs in 2019. As shown in Fig. 4, only 39–57% of the installed CHP capacity is utilized across all ISO/RTOs; thus, a large amount of the installed CHP capacity (0.7–8.7 GW depending on the ISO/RTO) could be available to improve

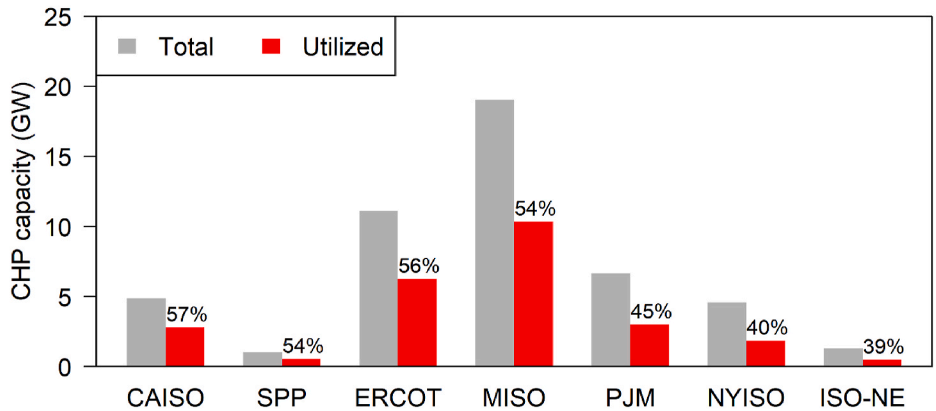


**Fig. 4.** The total and utilized capacity of the installed CHP systems in the seven U.S. ISO/RTOs in 2019. The percentage above each red bar indicates the annual-averaged capacity factor of the installed CHP in each ISO/RTO. Data are retrieved from EIA-860 (U.S. EIA, 2020a) and EIA-923 (U.S. EIA, 2020b). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

grid flexibility. The available CHP capacity represents 1–9% of the peak electric load or 1–16% of the median load in corresponding regions (see Fig. 2). This available capacity is smaller than a previous work's estimation—about 20% of the peak electric load could be met by installed CHP systems in the U.S. (Yasuda et al., 2013)—because calculations in that work were based only on the total rated capacity, which did not account for CHP operating hours and may overestimate the available CHP capacity for grid support.

Natural gas combustion or combined-cycle turbines are traditionally used to help grids meet the peak net load during times of high stress and rapid ramping (Bhandari et al., 2018). Given that most (96–99%) of installed CHP systems use a turbine as a prime mover (see Figure S2a in Supplemental Information), these installed CHP systems could displace some of natural gas combustion or combined-cycle turbines. Because the installation cost of natural gas combustion or combined-cycle turbines ranges from \$690/kW to \$1900/kW (Newsom, 2019), the cost savings could reach up to \$16.4 billion if the estimated available CHP capacity can be fully used to displace new natural gas combustion or combined-cycle turbines. If CHP systems need grid connection, the avoided installation cost can decrease by \$50–400/kW per unit as the above installation cost does not include the cost for grid connection. A detailed estimation of the avoided installation cost is provided in Section S3 in Supplemental Information. In addition to the avoided installation costs, utilizing installed CHP capacity may reduce financial risk of grid operators (Regnier, 2007; Henning et al., 2003). This is because new generators commonly need long-term contracts with grid operators to amortize the installation costs; however, installed CHP systems may have surpassed their payback periods, allowing grid operators to renew or modify contracts depending on volatility of fuel prices. Moreover, installed CHP systems may be used as a non-wires alternative[6] that can defer or avoid an upgrade of transmission or distribution systems when combined with various energy efficiency or demand response measures (Ahn et al., 2021; Chew et al., 2018; Eckman et al., 2020). This may lower levelized-cost of electricity for the surrounding community.

Consistent with the results for the regional CHP availability, Fig. 5 shows that a large portion of installed CHP capacity (42–63%) could be available to support grid flexibility from all sectors. Independent power producers have the greatest CHP capacity (26–91%) and could support up to 12.6 GW for grid flexibility. The industrial sector has the second greatest CHP capacity (5–53%), which could provide up to 6.4 GW.

The results shown in Figs. 4 and 5 reveal that regardless of ISO/RTO or sector, a large amount of installed CHP capacity may be under-utilized and could be used to support grid flexibility. The low CHP utilization may stem from three factors. First, CHP systems could have been designed based on thermal loads (Hedman et al., 2013) but actual thermal loads may be lower than originally designed because some thermal processes may no longer be needed. Second, facilities may have purposely oversized CHP systems to maximize incentives. For example, a previous study investigated installed CHP systems in the state of NY and revealed that about 40% of the CHP systems were oversized (Athawale et al., 2016). The study concluded that the oversizing tendency was mainly due to a fixed, one-time incentive that was calculated using only the installed CHP capacity (kW).[7] This tendency may be prevented by performance-based incentive programs that provide incentives when performance requirements are satisfied in addition to upfront incentives for CHP's capital costs, which is similar to Self Generation Incentive Program of California Public Utilities Commission (California Public Utilities Commission, 2020). A third factor that may explain the under-utilization of installed CHP systems is an economic dispatch strategy. Some facilities may only operate their CHP systems when electricity price is high to maximize their economic benefits, as found in the case of Princeton University (Jones and Kelly, 2017; Princeton University, 2019).

Although it would not be the driving factor for the low CHP utilization, it should be noted that the ratio of power to thermal output for most CHP systems ranges from 0.5 to 1.2 (Derrow et al., 2015; Darrow et al., 2015); however, that of electric to thermal load is from 9 to 61 for some manufacturing facilities such as food, leather and allied product, nonmetallic mineral, and primary metal manufacturing (Hampson et al., 2016). Thus, if CHP systems operate following the thermal load of these manufacturing facilities, they can meet only a small fraction of electric load (less than 10%) while a grid needs to provide the remainder (Schwartz et al., 2017).

It should be noted that the results for 2018 are consistent with those for 2019. A summary of the 2018 results can be found in Section S4 in Supplemental Information.

[6] Non-wires alternatives are defined as "electricity grid investments or projects that use non-traditional transmission and distribution (T&D) technologies such as distributed generation, energy storage, energy efficiency, and demand response to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level" (Chew et al., 2018; Cohn, 2019).

[7] Further research would be required to determine if "oversizing" occurred only where non-utility CHP facilities have been encouraged by regulation as CHP facilities meeting certain requirements have been encouraged by some states since the implementation of the Public Utility Regulatory Policies Act (PURPA) of 1978.

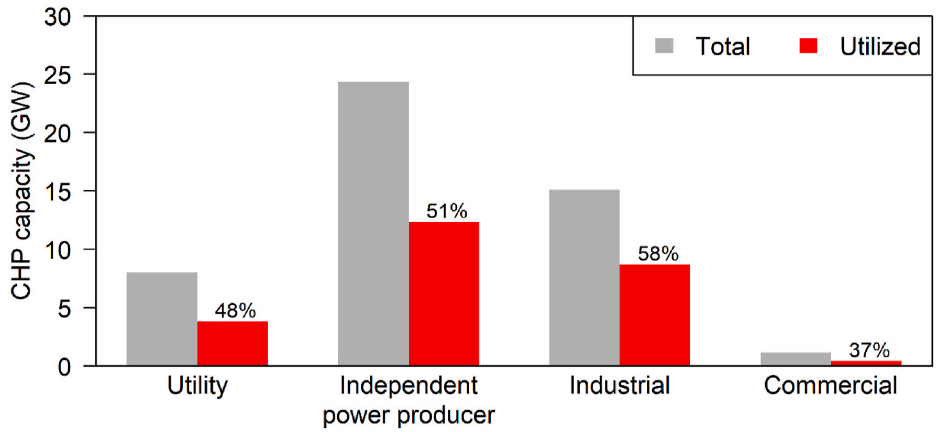


**Fig. 5.** The total and utilized capacity of the installed CHP systems in utility, independent power producer, industrial, and commercial sectors in the U.S. in 2019. The percentage above each red bar indicates the capacity factor of the installed CHP in each sector. Data are retrieved from EIA-860 (U.S. EIA, 2020a) and EIA-923 (U.S. EIA, 2020b). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

### 3.2. *Seasonal availability of installed CHP capacity to improve grid flexibility*

Seasonal variability on available CHP capacity was determined using monthly-averaged capacity factors. Fig. 6 shows monthly-averaged capacity factors of the installed CHP systems in the seven U.S. ISO/RTOs in 2019 with a 95% confidence level. Due to a low sample number in SPP, NYISO, and ISO-NE, the 95% confidence interval is relatively wider (<0.4) compared to those in the other ISO/RTOs (<0.2). The result shows that monthly-averaged capacity factors are consistently lower than 0.6 across all ISO/RTOs during most of the year except a few months (e.g., June, July, and August) in ERCOT. Also, variations between months are within a marginal range (<0.3). This result indicates that regional and sectoral availability of the installed CHP systems, discussed in Section 3.1, is marginally influenced by seasons. Therefore, more than 40% of the installed CHP capacity (0.7–8.7 GW) may be available during most of the year to enhance grid flexibility. These patterns are consistent also in 2018 (see Section S4 in Supplemental Information).

The low capacity factors with a small seasonal variation can indicate that the installed CHP systems mostly operate at part-load conditions. Part-load operations of CHP systems can reduce their overall efficiency and increase primary energy consumption and carbon emission rates (i.e., carbon emission per MWh produced). For example, a carbon emission rate of a gas turbine at a 50% load is 18% greater than that at a full load (Lew et al., 2013). Therefore, if the installed CHP systems can be utilized to support grid flexibility and their capacity factors increase, their carbon emission rates can be reduced.

### 3.3. *Hourly availability of installed CHP capacity in New York*

Using hourly CHP operating data from NYSERDA for the state of NY, we calculated hourly-averaged CHP capacity factors to understand how CHP systems could mitigate hourly-varying generation of renewable energy (NYSERDA, n.d.). Fig. 7 shows hourly-averaged capacity factors for five facility types (i.e., hospitals, universities, hotels, offices, and manufacturing) in NY. For all facility types, a 95% confidence interval is within ±0.03 of the estimated mean. For each facility type, we named CHP systems using a combination of letters and prime mover types. For example, letters (e.g., A, B, and C) represent different systems within the same facility type, while “Turbine” and “Engine” indicate turbine-driven and internal combustion (IC) engine-driven CHP systems, respectively.

As shown in Fig. 7, hourly-averaged capacity factors depend on facility types and prime movers. In hospitals, universities, and hotels, the hourly-averaged capacity factors range from 0.44 to 0.97 whereas the capacity factors are lower than 0.56 in manufacturing facilities. Some manufacturing facilities—such as facility A, facility C, and facility E—consistently exhibit even lower hourly-averaged capacity factors (<0.34). These results imply that CHP systems in manufacturing facilities may provide a large amount of flexible capacity to grids without hourly time restrictions. Some manufacturing facilities may shift their operating schedules to off-peak periods (e.g., 6 p.m.–6 a.m.) and provide greater flexibility to a grid. Additionally, manufacturing facilities may integrate thermal energy storage with CHP systems and reduce primary energy consumption and carbon emission (Smith et al., 2013). With thermal energy storage, CHP systems can flexibly provide electricity to the grid even when thermal loads are low and reduce operating costs through economic arbitrage (Princeton University, 2019). Cost savings can be maximized with time-of-use rates where energy and demand charges are 2–3 times greater during peak hours than off-peak hours, which may offset the installed cost of thermal energy storage.

Regarding prime movers, IC engine-driven CHP systems tend to yield a wider variation in hourly-averaged capacity factors than turbine-driven CHP systems. This pattern occurs because IC engines can quickly start, stop, and ramp up or down with a relatively small degradation in part-load efficiency (Power Engineering International, 2015; Badami et al., 2008). Fig. 7d shows that IC engine-driven CHP systems in Office B, Office C, and Office D are likely to follow an hourly occupancy schedule during the day, whereas a turbine-driven CHP system in Office A operates continuously at a constant load. In Office A and Office E, the hourly-averaged capacity factors are almost constant during the day regardless of prime mover because they are mixed-use offices that integrate commercial and residential uses (see Table S3 in Supplemental Information).

For most office buildings that are not mixed-use, the hourly-averaged capacity factors decrease by more than 0.4 (80%) outside normal working hours (i.e., 6 p.m.–6 a.m.). This time period is when grids are often highly stressed to meet fast ramp, especially with high solar penetration, which corresponds to the “neck” in the “Duck Curve” in CAISO (California Independent System Operator, 2016). Therefore, if IC engine-driven CHP systems can respond quickly to grid operators and provide grid services during this time period, grid flexibility can be significantly enhanced. A previous study also demonstrated that IC engine-driven CHP systems are capable of regulating frequency fluctuation within the tolerance range of a power grid in Great Britain (Xu et al., 2019). Also, due to fast ramping capability, IC engine-driven CHP systems may be able to provide various ancillary services such as regulation and spinning reserves (Power Engineering International, 2015; Gemmer, 2018; GE Energy Consulting, 2012).

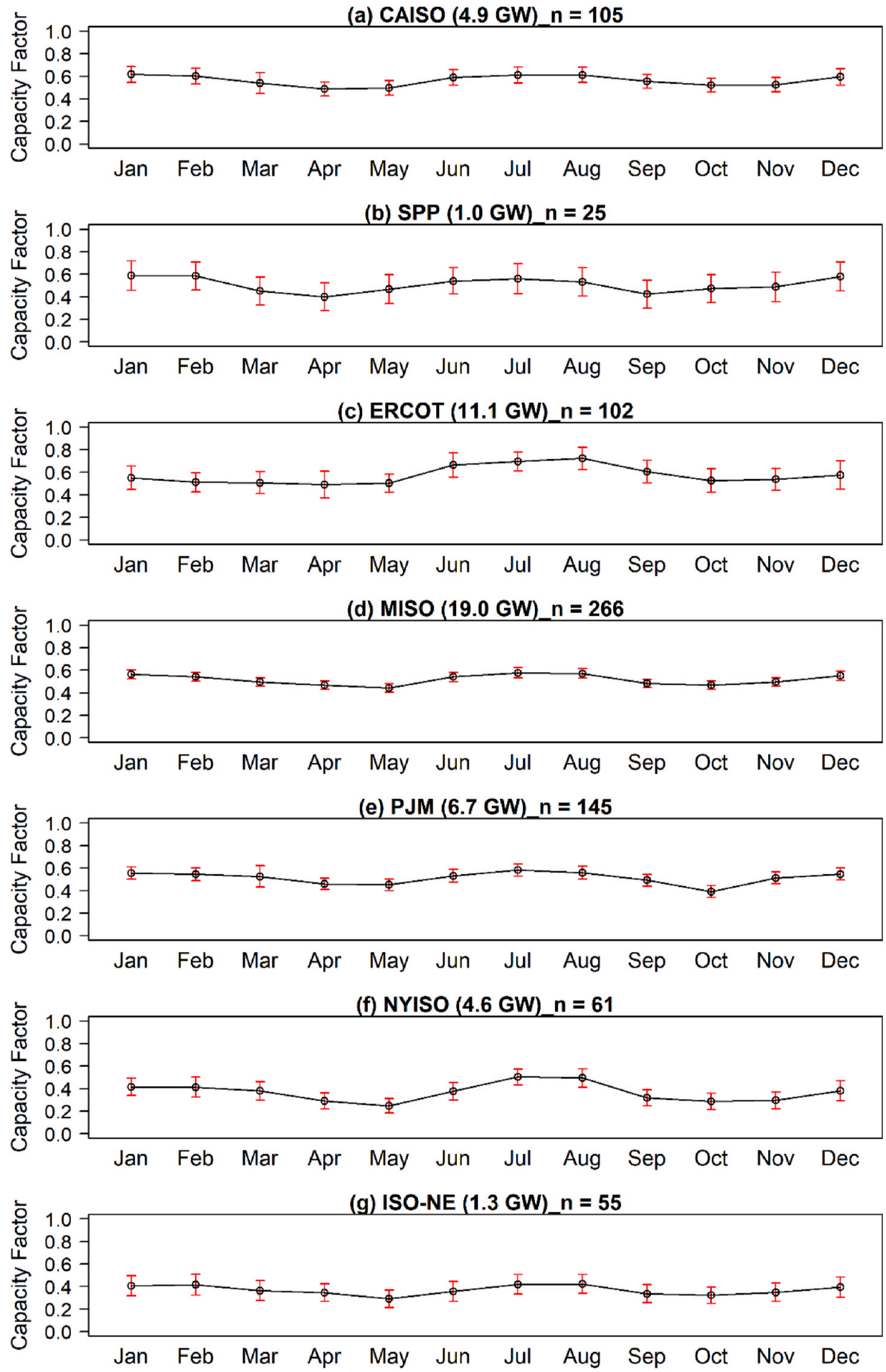


**Fig. 6.** Monthly-averaged capacity factors of the installed CHP systems in the seven U.S. ISO/RTOs in 2019. The error bar indicates a 95% confidence interval of the estimated mean. In the parentheses, the total installed CHP capacity and the number of data samples are provided for each ISO/RTO. Data are retrieved from EIA-860 (U.S. EIA, 2020a) and EIA-923 (U.S. EIA, 2020b).

## 4. Conclusion and policy implications

This study explored the potential for installed CHP systems to support grid flexibility for each of the seven U.S. ISO/RTOs, using their operating data at the three time scales (i.e., annual, monthly, and hourly). The results revealed that regardless of ISO/RTO, sector, or season, more than 40% of the installed CHP capacity was not fully utilized and may be available to enhance grid flexibility. The available CHP capacity ranged from 0.7 to 8.7 GW and accounted for 1–9% of the peak electric demand in the corresponding ISO/RTOs. Using this available CHP capacity could avoid up to $16.4 billion in installation costs of new peaking plants to meet the peak demand, ramping capacity, or other needs brought on by rising levels of renewable generation. Due to the reduced cold-start cycles and part-load operations, installed CHP systems could reduce criteria pollutants and greenhouse gas emissions than those new peaking plants. While this study focused on the seven U.S. ISO/RTOs, this approach could be applied to more local situations. For example, this approach could be used to estimate available CHP capacity

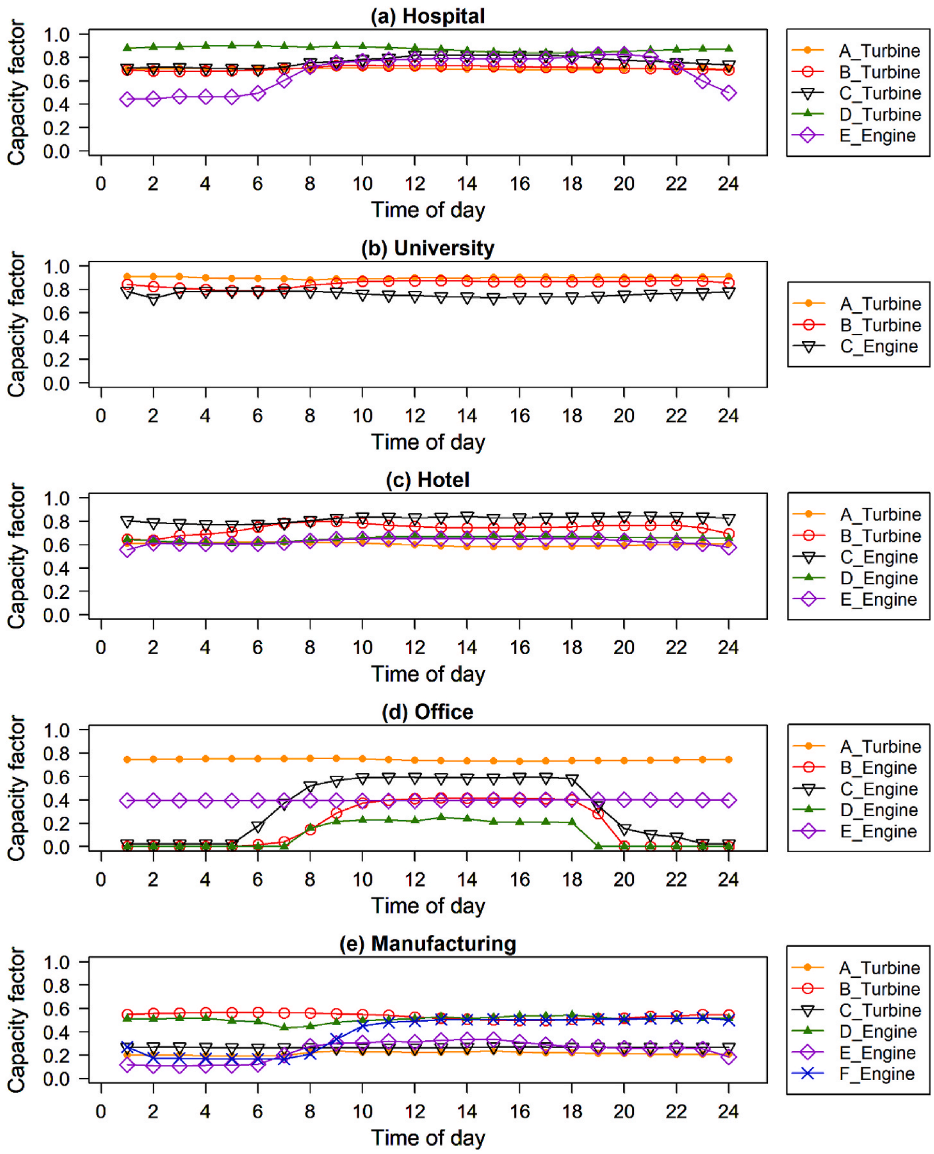


**Fig. 7.** Hourly-averaged capacity factors of the installed CHP systems in five facility types: (a) hospitals, (b) universities, (c) hotels, (d) offices, and (e) manufacturing facilities in NY. A 95% confidence interval is within ±0.03 of the estimated mean. In each facility type, the number of examined CHP systems and the combination of prime movers vary depending on available data from NYSERDA (NYSERDA, n.d.). In the legend, letters represent different systems within the same facility type while "Turbine" and "Engine" indicate turbine-driven and internal combustion engine-driven CHP systems, respectively.

to support grid reliability of a local distribution company with high levels of renewables.

Policies that support the following three categories could help realize CHP's potential for improving grid flexibility: 1) flexible contract lengths between CHP owners and grid operators, 2) improved market designs for CHP systems as a fast ramping product, and 3) simplified interconnection standards. Because regulation of the electrical industry in the U.S. is complex and varies significantly between ISO/RTOs, implementing these policies may require specific adaptation to a particular regulatory situation.

New policies that support flexible contract lengths between the CHP owners and grid operators could benefit both parties. The grid operator could reduce the cost of acquiring new ramping resources. By adjusting the price of the electricity provided by CHP systems, risk from fuel price volatility could be minimized. CHP owners could increase CHP capacity factors and overall efficiency by adjusting the amount of contracted capacity they will provide to the grid. The contracted capacity could be determined based on the historic uses of the CHP system to ensure that the CHP system can meet the energy demand of its primary facility. The contracts could also provide time frames of available capacity (e.g., time of the day or seasons) that align with the grid operator's anticipated needs. Furthermore, contract lengths could be shorter than 7 years, which is, for example, the shortest length of existing feed-in-tariff contracts in California (California Public Utilities Commission, n.d.).

Improving market designs for CHP systems as a fast ramping product may further enable the CHP systems to support grid flexibility. For example, Federal Energy Regulatory Commission (FERC) Order 2222[8] allows aggregations of distributed energy resources to participate in an ISO/RTO's wholesale market (Federal Energy Regulatory Commission, 2020). The Public Utilities Commission of Ohio also launched the PowerForward initiative, which allows gathering distributed energy resources and providing services to customers (Public Utilities Commission of Ohio, 2018). In this model, distribution utilities are paid for providing their distribution infrastructure. Initiatives like PowerForward and FERC Order 2222 could enable installed CHP systems to be aggregated and provide their under-utilized capacity to the grid. However, in traditional capacity-based markets, CHP systems cannot participate in real-time energy markets when they participate in

[8] On September 17, 2020, the U.S. Federal Electrical Regulatory Commission adopted its Order-2222 directing the ISO/RTOs under its jurisdiction to revise their tariffs for wholesale markets to accommodate distributed energy resources including CHP systems (Federal Energy Regulatory Commission, 2020).

ancillary services (e.g., regulation and load-following services) markets (Gottstein and Skillings, 2012; Navid and Rosenwald, 2013). An improved market could allow CHP systems to meet demand changes occurring between real-time dispatch intervals while participating in energy markets within each interval (Xu and Tretheway, 2014). Also, shorter real-time dispatch intervals can further help incentivize CHP systems for following dispatch instructions and improving grid flexibility (Potomac Economics, 2017).

Simplifying interconnection standards could also enable installed CHP systems to connect to the grid and use their potential to support grid flexibility. Currently, various interconnection standards across and within states create barriers for CHP deployment (Chernyakhovskiy et al., 2016). For example, protection requirements ensuring the grid's safety and reliability may not be commensurate with the CHP's size (U. S. Department of Energy Advanced Manufacturing Office, 2020). As a result, CHP systems are often operated independently from the grid (i.e., in "island-mode") or in some cases, developers will decide not to pursue new CHP projects (Chittum and Kaufman, 2011). Simplifying and standardizing the interconnection process could also reduce hidden costs such as overhead costs and costs associated with seeking information and writing documents (Thollander et al., 2010), leading to lower levelized cost of energy.

In addition to the three policy implications described above, routinely acquiring detailed operating and system data at a national scale for installed CHP systems would further streamline grid interconnection and operation. These data could include CHP system location, capacity, ramping capability, generation profiles, and performance histories. To minimize congestion in the distribution system, CHP electrical connectivity into the power system network should also be provided (MDPT Working Group, 2015). Currently, the U.S. DOE's CHP Installation Database provides locations, capacities, prime movers, fuel types, and applications for about 4700 installed CHP systems (U.S. DOE, n.d.). Only 16% of the CHP systems, however, provide monthly and annual generation profiles, which are recorded in the EIA database (U.S. EIA, 2020a; U.S. EIA, 2020b). Additional granular generation profile data, such as NYSERDA's hourly CHP operating data, could also help grid operators identify available CHP capacity at smaller time scales and dispatch it in real-time, as needed. Furthermore, ramping capabilities of the CHP systems could be categorized into different time frames (e.g., ramping kW or MW within a minute, 5–10 min, and multi-hour) similar to an approach used by the International Energy Agency (International Energy Agency, 2011). With this information, a grid operator could request support from CHP systems with prenegotiated grid-supply capacities. The capacity from the CHP systems could be added sequentially to the grid's resources to meet significant portions of the total ramping capacity.

## CRediT authorship contribution statement

**Hyeunguk Ahn:** Conceptualization, Methodology, Investigation, Data curation, Writing – original draft, Writing – review & editing, Visualization. **William Miller:** Term, Validation, Writing – review & editing. **Paul Sheaffer:** Writing – review & editing, Project administration, Funding acquisition. **Vestal Tutterow:** Writing – review & editing. **Vi Rapp:** Conceptualization, Methodology, Writing – review & editing, Supervision, Funding acquisition.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2021.112485.

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