BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Proposed Amendments	)	
to 4 CSR 240-20.060, Filing Requirements	)	File No. EX-2020-0006
for Electric Utility Cogeneration	)	

RENEW MISSOURI'S COMMENTS

COMES NOW Renew Missouri Advocates d/b/a Renew Missouri ("Renew Missouri"), offers these comments and asks the Commission to amend its cogeneration rules at 20 CSR 4240-20.060.[1]

I. Introduction

1. Renew Missouri appreciates the Commission's willingness to consider changes to its cogeneration rules in a variety of recent working dockets and cases. The rule changes under consideration in this docket make some incremental improvements but would be improved by addressing the additional language discussed in these comments.

2. These amendments would grant Independent Power Producers ("IPPs") non-discriminatory access to the market, create transparency to avoided cost data, and create the ability to enter into fixed-term contracts with utilities, as Federal law requires. Further delay is unwarranted and prevents Missouri from realizing significant energy and economic benefits.

II. Need for Rule Change

3. Congress passed the Public Utility Regulatory Policies Act ("PURPA") in 1978, with the aim of diversifying the country's power supply by facilitating market access for small renewable energy generators and cogeneration facilities. PURPA requires utilities to purchase power

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[1] The Case caption refers to the rules at 4 CSR 240 of the State regulations, however these provisions are now located at 20 CSR 4240.

generated from Qualifying Facilities ("QFs") at the price that it would have cost the utility to generate or purchase the power, commonly referred to as the utility's "Avoided Cost."

4. In particular, 16 USC Section 824a-3(a) states that the Federal Energy Regulatory Commission ("FERC") must issue rules "to encourage cogeneration and small power production encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity" which require electric utilities to offer to "purchase electric energy from such facilities." In requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase:

> (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.[2]

Today, few PURPA-eligible QFs are operating in Missouri because our own rules do not facilitate non-discriminatory market access or otherwise encourage cogeneration and small power production development as envisioned under PURPA.

5. On July 24, the Commission asked its Staff to file a recommendation on whether this rulemaking should proceed given that FERC's Order 872 was issued to include updates to Federal PURPA regulations. Staff filed its response that the rulemaking should proceed. Renew Missouri agrees. For context, in his dissent to Order 872 FERC Commissioner Richard Glick described that order as "gutting our longstanding regulations."[3] While the new rules submitted to the Federal Register are restrictive, Missouri's regulations still fall short of the "gutted" version to be filed with the Federal Register. Because the Missouri Commission's cogeneration rules have been

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[2] 16 USC 824a-3(b).
[3] https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-part-regarding-qualifying-facility-rates-and

ineffective at implementing PURPA and opening market access to diverse and least-cost, renewable generation in Missouri they should be revised and can be revised even with changes occurring at the federal level. In short, the changes Renew Missouri proposes still fall in line with the new federal rules that have received criticism as regressive.

III. PURPA requires non-discriminatory access and to encourage cogeneration and small power production

6. Generally, utilities have an obligation to purchase power from QFs. However, FERC regulations provide that an electric utility's obligation to purchase can be terminated if the QF is determined to have nondiscriminatory access to certain markets. At the time of this filing, regulations provide a rebuttable presumption that QFs with a net capacity at or below 20 MW do not have nondiscriminatory access to those markets. However, this presumption is addressed in the FERC's recent Order No. 872. Within Order No. 872, the final rules (to be effective 120 days after publication in the Federal Register) update the threshold for the rebuttable presumption for small power production facilities (but not cogeneration facilities[4]). The draft final rule changes the rebuttable presumption from 20 MW to 5 MW. This dramatic reduction was compared to a 1 MW limit on the presumption in the initial proposed rule. The FERC explained its decision:

> …we find it reasonable to update the presumption under these regulations as to what constitutes a small entity that has non-discriminatory access to RTO/ISO markets and markets of comparable competitive quality below 20 MW, and that 5 MW represents a reasonable new threshold that accounts for the change of circumstances indicating that 20 MW no longer is appropriate but also accommodates commenters' concerns that a 1 MW threshold would be too low. We acknowledge that "there is no unique and distinct megawatt size that uniquely determines if a generator is small." **We find that a 5 MW threshold accords with PURPA's mandate to encourage small power production facilities**, recognizes the progress made in wholesale markets as discussed above, and balances the competing claims of those seeking a lower threshold and those seeking a higher threshold. (emphasis added).[5]

[4] The rebuttal presumption for cogeneration facilities remains at 20 MW.
[5] FERC Order 872, pp. 351-53.

7. Renew Missouri does not highlight this reduction from 20 MW to 5 MW for the presumptions related to market access as a good thing – to be clear, it is not a good thing. Further, it is our analysis that this order can be successfully challenged on appeal. But this reduction illustrates the inadequacy of the Missouri regulations. FERC saw the *reduction* from 20 MW to 1 MW (the level in the NOPR) to be too drastic. Yet, the *improved* regulations for Missouri will only require Standard Offer Contracts to *increase* to 1 MW. Renew Missouri's modifications to the rule address this discrepancy.

IV. Standard Offer Contracts

8. PURPA regulations require electric utilities to provide standard rates for purchases from QFs with a capacity of 100 kilowatts or less and explicitly permit standard rates for larger facilities: "[t]here may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts."[6] The availability of standard rates brings advantages by reducing transaction costs (less lawyers, for example) and reduces the need for every QF (and the utility) to negotiate for systems that would bring benefits to the grid, customers, and the environment. By increasing the sizes of standard offer contracts in its regulations, the Commission would significantly encourage the development of cogeneration and small power producers.

9. The Commission's proposed rule increases the standard offer contract size to include two categories 1) QFs under 100kW and 2) QFs over 100kW up to 1,000kW. These categories are an improvement, but the Commission should include increased ranges for standard offer rates, at a minimum, to include the levels of 2.5 MW and 5 MW it ordered

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[6] 18 CFR Section 292.304(c).

the utilities to study previously in its *Order Directing Utilities to Evaluate Impacts of Standard Offer Contracts* in EW-2018-0078. These rates would fit within the directives of the newer Order 872 capacity limit for small power production facilities. There is no reason to delay a rule requiring SOCs up to and including that limit. Furthermore, the pending Order 872 continues the preferential treatment for cogeneration systems up to 20 MW. Because of that, the SOCs included in the Missouri rule should include contracts up to 20 MW. To accomplish these changes the following modifications should be included under the proposed "Section (4) Standard Rates for Purchase and Standard Contracts" (new language in **bold** or ~~strikethough~~):

(4) Standard Rates for Purchase and Standard Contracts.

(A) Each electric utility shall put into effect commission-approved standard rates for purchases from qualifying facilities with a design capacity:

1. Of one hundred (100) kilowatts or less; ~~or~~
2. Over one hundred (100) kilowatts to one thousand (1,000) kilowatts~~.~~**;**
3. **Over one thousand (1,000) kilowatts to two thousand five hundred (2,500) kilowatts;**
4. **Over two thousand five hundred (2,500) kilowatts to five thousand (5,000) kilowatts; and**
5. **Over five thousand (5,000) kilowatts to twenty-thousand (20,000) kilowatts.**

10. In addition to the modifications above to SOC sizes, the reporting requirements in the proposed rules at 11(C) should be updated for the larger system sizes to reflect the additional QF levels:

(C) Each regulated electric utility shall verify it maintains and aggregates the following information:

1. For systems less than one hundred kilowatts (100 kW)—
   A. Characterization of the distribution circuits where the systems are connected;
   B. Aggregate capacity of the systems for each feeder or load; and
   C. Relevant interconnection standard requirement that specify the performance of the system; and
2. For systems over one hundred kilowatts (100 kW) and under one thousand kilowatts (1000 kW)—
   A. Type of generating resource;
   B. Distribution bus nominal voltage where the system is connected;
   C. Feeder characteristics for connecting the system to distribution bus, if applicable;
   D. Capacity of each resource;
   E. Relevant interconnection standard requirements; and

F. Actual plant control modes in operation.
3. For systems over one thousand (1,000) kilowatts and under two thousand five hundred (2,500) kilowatts —
A. Type of generating resource;
B. Distribution bus nominal voltage where the system is connected;
C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation; and
4. For systems over two thousand five hundred (2,500) kilowatts and under five thousand (5,000) kilowatts —
A. Type of generating resource;
B. Distribution bus nominal voltage where the system is connected;
C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation; and
5. For systems over five thousand (5,000) kilowatts and under twenty thousand (20,000) kilowatts —
A. Type of generating resource;
B. Distribution bus nominal voltage where the system is connected;
C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation.

11. When tasked to evaluate system impacts from standard offer contracts of 1 MW, 2.5 MW, and 5 MW, each electric utility raised certain concerns about modeling those figures. Ameren Missouri responded by pointing out its view that different SOCs might not encourage QF development because: "1) distribution system pacts would be facility-specific, and 2) QF participation rates are not a function of only the capacity of the SOC, but are very dependent upon the price and term of the SOC."[7] Renew Missouri agrees in part, but disagrees with the way to address Ameren Missouri's concerns about larger SOC and the price and terms. Additional language should be inserted on contract length for the standard offer contracts by modifying 4(C) in the proposed rules to say:

> C) The commission shall approve standard contract templates for purchases from qualifying facilities with the design capacities described in (4)(A). **Such standard rates shall include both as-available and time-of-obligation options for avoided costs.** The approved standard contract templates will be the basis of the standard contracts utilized by each utility through its respective tariffs and shall include provisions for Renewable Energy Certificate (REC) ownership. The terms and conditions of the standard contract templates will be established in accordance with Section 210 of PURPA and the provisions of this

[7] Response Regarding Standard Offer Contracts, Doc. No. 37, Case No. EW-2018-0078.

> rule. **Such standard terms must include a contract tenure of at least 15 years.** Standard contract templates will be made available through the commission website.

12. Empire District Electric Company (now Liberty-Empire) noted that "the safety of the public and the reliability of the system continue to be important considerations as utilities design the distribution system of the future."[8] Thus, "all scenarios and distributed generation installations of the sizes requested by the Commission must be analyzed and accommodated uniquely until the distribution system, through upgrades, becomes robust enough to safely and reliably support distribution generation additions at any location."[9] No additional change would be necessary to the proposed rule to address this response by Liberty-Empire.

13. Renew Missouri agrees that safety and reliability are important but should not be a reason to avoid implementing SOCs that will determine price and contract term. The proposed rule already includes provision 4(D) that provides "[e]ach electric utility will develop technical and performance standards and interconnection test specifications specific to its distribution system to be included in its standard contract templated. Technical and performance standards will include provisions related to metering, protection equipment, and disconnect switches." It is reasonable to require QFs to adhere to safety and performance standards, and the best way to accomplish meeting those standards while still encouraging QF development is to include those requirements in the SOC templates.

14. Kansas City Power & Light (now Evergy) offered that it would be able to accommodate SOCs of various sizes and pointed out that its concern was allocating risk of cost causation to other customers as QF systems got larger. On system impact, Evergy noted:

> …from an engineering perspective, KCP&L/GMO can accommodate varying sizes of a customer system, including 1 MW, 2.5 MW, and 5 MW systems, that is part

[8] Empire's Response to Commission Order, Doc. No. 36, Case No. EW-2018-0078.
[9] Id.

> of an SOC through a site-specific analysis and any resulting upgrades needed for the distribution system.[10]

If the Commission accepts Renew Missouri's modifications to the SOC size offerings, Evergy will be able to incorporate changes to the rules, at least from an engineering perspective. While Evergy did not discuss systems of a 20 MW size in its response, the reasons it could accommodate the smaller QFs would also apply to a larger 20 MW system:

> It is important to point out that KCP&L/GMO will accommodate the needs for customer systems of different sizes, and any associated system improvement and interconnection costs identified in a site-specific analysis is paid by the customer prior to contract approval and completion of the customer owned installation. These same provisions are also included in the proposed cogeneration rule 7(A): The customer shall be required to reimburse the utility for the interconnection costs of any equipment or facilities which result from connecting the customer's generating system with the utility's system.[11]

15. Evergy also stated its belief that long-term contracts with fixed pricing are not appropriate because "[f]orcing utilities into long-term contracts at prices that are potentially substantially above market <u>may</u> provide a producer a favorable economic position" and "<u>could</u> have a negative impact on utility customers"(emphasis added).[12] Evergy's negative assumptions should not dissuade the Commission from requiring SOCs at levels of 1 MW, 2.5 MW, 5 MW, or 20 MW for electric utilities. First, Evergy made clear in its response to a prior Commission order that it would be able to incorporate QFs of varying size into its system. Renew Missouri expects that Ameren Missouri and Liberty-Empire can do the same.

16. Second, to the extent that Evergy (or the other utilities) are concerned about entering contracts at fixed prices, the complaint appears to actually be about one of the tenets of FERC's PURPA regulations, which says that a QF has the option either:

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[10] Kansas City Power & Light Company's and KCP&L Greater Missouri Operations Company's Response to Order Directing Utilities to Evaluate Impacts of Standard Offer Contracts, Doc. No. 38, Case No. EW-2018-0078.
[11] Id.
[12] Id.

> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.[13]

17. These FERC regulations are, again, subject to modification by Order 872 that grants states more flexibility "to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered."[14] "Under this change, if a state exercises this flexibility, a QF no longer would have the ability to elect to have its energy rate be fixed, but would continue to be entitled to a fixed capacity rate for the term of the contract or LEO."[15] To reiterate, variable energy contracts are not permitted by the current regulations and are not required by the proposed Federal regulations in Order 872. Current FERC rules do not prevent the Commission from requiring SOCs for larger QFs and the proposed FERC rules changes "could lead to *longer* contract terms" (emphasis added).[16] Ultimately, establishing SOCs and the appropriate rates for energy and capacity remain subject to the Commission's authority and proposed rules in this docket maintain that authority. Incorporating Renew Missouri's recommended SOC ranges will encourage the development of cogeneration and small power producers.

18. Third, Evergy's assumption that long-term contracts at Commission-determined prices will be "potentially substantially above market" price is unfounded. Allowing longer-term SOCs for larger QFs, as Renew Missouri proposes, will enable IPPs and developers enough certainty of cost

[13] 18 CFR §292.304 (d)(1-2).
[14] FERC Order 872, p. 42.
[15] Id.
[16] Id. at 32.

recovery and provide the ability to build systems that may wind up saving customers money as compared to the utility constructing and operating its own investments. Indeed, no large-scale utility investments get made by any party without certainty regarding project revenues, which necessarily subjects ratepayers to price risk in exchange for certainty of generation supply. In the case of investor-owned utilities, the ratepayer also carries the risk of construction cost overruns, operation and maintenance expenses, and, with non-renewable resources, fuel price volatility. Whereas an IPP, and its financiers, bear all the risk of developing a QF. Furthermore, the proposed rules provide that SOC rates will be approved by the Commission under the terms included at Sections (4) and (11), thereby allowing the Commission to exercise its obligation to ensure Missourians are paying just and reasonable rates for electric service.

19. In the event that the Commission does not require SOCs for systems over 5 MW and up to 20 MW as Renew Missouri proposes, FERC's current PURPA regulations require that utilities also purchase the output of QFs above the standard offer pursuant to long-term, fixed price long-term contracts, unless the QF has non-discriminatory access to wholesale markets. Therefore, Missouri's Cogeneration rule should also require that utilities purchase the output of QF up to 20,000 KW in size pursuant to long-term fixed price contracts.

V. <u>Transparent Avoided-cost Data</u>

20. In prior dockets, Renew Missouri argued that transparent avoided cost data is a key aspect of fully implementing PURPA. This includes a standard process for Commission review of utility costs and subsequent review and approval of utility avoided cost forecasts. Avoided cost forecasts have served as the basis for standard contract pricing and for PPAs under PURPA. The Commission's proposed rule makes certain improvements related to the transparency of avoided cost data and how those figures are determined by including a new section (11) "Filing

Requirements" as well as requiring the bi-annual filing of the SOCs and additional information.

21. This section should be expanded upon by providing the Staff, stakeholders, and the Commission adequate time to review avoided costs and the resulting standard offer tariffs before approval. Other states that have successfully implemented PURPA with a non-negligible number of QFs have multi-month biennial review periods of avoided cost methodology and inputs, including a review of key avoided cost model inputs to keep rates fresh. Renew Missouri suggest that the Commission adopt a procedural timeline for review of avoided costs consistent with other states that have seen significant QF development. This can be accomplished by adding a new subsection to the Section (11) filing requirements:

> **(E) Within thirty (30) days of the January 15 avoided cost filings required by subdivision (A) of section (11) of this rule, the commission shall open a file allowing the staff for the commission, the office of public counsel, and other interested parties to participate fully in the proceeding, including through the presentation of testimony and other evidence and the cross-examination of utility witnesses. Based on the record in such proceeding, the commission shall issue an order directing each regulated electric utility to adopt such avoided cost methodology, standard offer contracts, inputs and rates that the commission determined to be just and reasonable.**

VI. <u>Legally Enforceable Obligations</u>

22. A key provision of PURPA that is referenced in Staff's draft rule changes but not defined is the legally enforceable obligation ("LEO"). The LEO is important for many reasons, but in particular, two stand out. First, the LEO establishes the commitment from the QF to sell its energy and capacity to the utility and the obligation on the electric utilities to purchase energy and capacity from a QF. Second, the date a LEO is established determines the avoided cost rates paid to a QF for time-of-obligation rates.

23. In considering how to define the LEO, it is imperative that the Commission's rules provide clear guidance on when and how an LEO is established. Specifically, it is important that it be through the action of a QF that an LEO is established. The objective of the proposed language is

to create a mechanism that provides, when a "QF PPA" is executed and delivered to the utility, it has "unequivocally committed itself" to sell energy and capacity to the utility. In turn, the utility is obligated to purchase such energy and capacity. Renew Missouri proposes amending the rule to address this point in Section (13) under the heading "Legally Enforceable Obligations.":

(13) Legally Enforceable Obligations. A qualifying facility may establish a legally enforceable obligation by one of the following methods:

1. A qualifying facility may tender an executed copy of a commission-approved standard offer contract or form power purchase agreement pursuant to a commission-approved standard rate for purchase, after which the electric utility shall countersign within 30 days to establish a legally enforceable obligation.

2. A qualifying facility may tender a modified form power purchase agreement pursuant to a commission-approved standard rate for purchase, after which the electric utility shall respond to the qualifying facility within 30 days. If after 60 days the parties have failed to execute a power purchase agreement, the qualifying facility may submit a claim to the commission for resolution.

VII. Additional definitions

24. Renew Missouri proposes two modifications and additions to the "Definitions" section of the proposed rule for "Time of delivery Rates" and "Time of Obligation Rates." These terms appear at various points within the proposed rule and the definitions for each would clarify of the rules. Renew Missouri proposes in include:

(D) "Time of delivery rates" means rates based on the Avoided Costs for energy and capacity of the Electric Utility that are determined at the time the Qualifying Facility delivers electricity to the Electric Utility.

(E) "Time of obligation rates" means rates based on the avoided costs for energy and capacity of the Electric Utility that are determined: (1) for a Qualifying Facility that is already constructed, at the time a Qualifying Facility commits to selling its output to the Electric Utility; or (2) for a Qualifying Facility not already constructed, at the time a Qualifying Facility establishes a Legally Enforceable Obligation.

VIII. Fully implementing PURPA through Renew Missouri's proposed revisions can make Missouri competitive for corporate investment

25. In addition to allowing customers to benefit from economic and renewable generation, implementing the foregoing changes suggested by Renew Missouri will create other benefits to Missouri. In several recent CCN cases for utility-proposed renewable generation, Renew Missouri has offered testimony that a growing number of customers want more access to renewable energy resources to meet their own sustainability metrics.[17] This is evidenced by the dozens of major companies that have signed on to support the Corporate Renewable Energy Buyers' Principles.[18] Governmental bodies – such as the Cities of St. Louis and Kansas City – are also establishing their own clean energy goals. With this pressure from leading large utility customers, Missouri utilities must look at additional renewable generation to meet customers' need and preferences for affordable renewable energy that can be advanced and encouraged under PURPA.

26. The Corporate Clean Energy Procurement Index 2020 (attached as **Schedule B**), was created to guide commercial and industrial ("C&I") renewable electricity usage across the United States. The Index ranks all 50 U.S. states based upon the ease with which companies can procure renewable energy based on indicators tracking both policy mechanisms and deployment levels. One metric states are judged on is "net metering requirements for onsite photovoltaic (PV) generation and policies or regulations that ease the interconnection of distributed generation (DG) systems to the grid."[19] Missouri ranks 29th on on-site/direct deployment of renewables rankings, in the bottom half. This category has two deployment indicators and two policy indicators that affect the rankings. The deployment indicators consider how much generating capacity in each state is comprised of: (1) C&I onsite deployment of distributed wind and solar generation, and (2) large offsite projects directly owned by a company. For the policy indicators, states are awarded

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[17] See Owen Rebuttal, Case No. EA-2019-0181.
[18] https://buyersprinciples.org/about-us/
[19] Schedule B, p. 4.

for the quality of their procedures for connecting a distributed generation system to the grid. They also earn a score for the quality of their net metering policies that allow a retail electric utility customer to receive credit for the electricity generated by a distributed generation system serving that customer. Improving the Commission's cogeneration rules to better align with PURPA will make Missouri more competitive for corporate energy procurement and increasingly site location.

27. Many of the companies pursuing on-site development of renewable of renewable energy are in the retail industry with a substantial presence in Missouri, including: Target, Walmart, Prologis, Apple, Amazon, Brookfield Properties Retail Inc., IKEA, Macy's, Kohl's, and Costco.[20] The ability to attract companies extends beyond retail businesses. In Missouri, a recent case where contracting for additional renewable energy helped secure the location of a steel mill in Sedalia, Missouri when the Commission allowed Evergy to obtain the power needed to serve Nucor by entering into a power purchase agreement for the delivery of wind power.[21] The Commission found that "[u]pon completion, the Nucor project will encompass more than $250 million of private investment and will create 250 new employment opportunities. The new employment positions include highly technical, skilled, well compensated positions, with an estimated average annual salary of $65,000, nearly double the current average wage in the Sedalia area."[22] Increasing renewable access results in real investments in jobs and economic opportunity. This is always important for Missouri but increasingly more so during this economic downturn.

28. Improving these cogeneration rules provides another opportunity for the Commission to elevate Missouri as an ally to corporations seeking to increase their clean energy procurement and can attract commercial and industrial companies to Missouri. Increasing the size of the SOCs will

[20] Schedule B, p. 27.
[21] See Report and Order, p. 7, Case No. EO-2019-0244.
[22] Id. at 6.

also help businesses currently located within Missouri who want realize financial benefits of adding on-site generation, such as warehouse distribution centers or poultry farms, in a streamlined and efficient manner.

IX. Fully implementing PURPA's mandate to encourage small power Production and cogeneration will lead to economic benefits

29. Failing to effectively implement PURPA has caused Missouri to lag behind other states in developing renewable energy and realizing the attendant economic benefits. Renew Missouri has previously filed comments in workshops and its own rulemaking petition discussing the example of North Carolina. As a result of PURPA, that state catapulted to 2nd in the nation in installed utility-scale solar owned by IPPs, which are collectively responsible for billions of dollars in private sector energy investment. While North Carolina has a comparable solar resource and population profile to Missouri, the state had approximately 25 times the amount of installed solar.[23] Private companies in North Carolina have invested more than $7.75 billion in solar and employ over 6,500 people, compared to Missouri's investment of about $548.97 million and 2,819 employees.[24] One of the primary reasons for these differences is North Carolina's approach to implementing PURPA with standard offers above the proposed 1,000 KW. For example, North Carolina's 5,000 KW standard offer program facilitated billions of dollars of solar development in the state.[25] As Missouri suffers from shrinking economic prospects due to COVID-19, these rules changes are a tangible and significant way the Commission can jumpstart our recovery.

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[23] According to SEIA's website, Missouri has a total of 202.32 MW installed, while North Carolina has roughly 5,260 MW. See: https://www.seia.org/state-solar-policy/north-carolina-solar, https://www.seia.org/state-solar-policy/missouri-solar

[24] *Id*.

[25] The North Carolina General Assembly recently reduced the standard offer program to 1 MW given that almost 3 GW of solar had come on line in the state.

30. In its comments above, Renew Missouri proposes several changes to the Commission's rules that will help Missouri get on the right track for encouraging the types of valuable market investment that will make Missouri's grid more decentralized, efficient, diverse, and resilient. Plus, these changes will result in a more favorable economic market to attract business to our state.

X. Conclusion

31. The full text of the proposed cogeneration rules, with Renew Missouri's amendments highlighted in yellow, is attached as **Schedule A**.

32. PURPA was created to remove market barriers to competition in electric generation because it is widely accepted economic theory that increased competition leads to decreased prices. Missouri's current cogeneration rules have failed to implement the goals and requirements of the law. Through this rulemaking, Missouri can increase market access for small, non-utility generators. In turn, this will put downward pressure on prices, particularly with respect to solar generators. For these reasons, Renew Missouri asks the Commission to commence this formal rulemaking so that Missouri can reap the all of the benefits of increased renewable generation.

WHEREFORE, Renew Missouri requests the Commission adopt the amendments described herein to the Commission's cogeneration rules at 20 CSR 4240-20.060.

Respectfully,

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Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 20—Electric Utilities

PROPOSED AMENDMENT

20 CSR 4240-20.060 Cogeneration *and Small Power Production*. The commission is amending section (1), section (2), section (5), section (6), section (7), section (8), section (9), and section (10) and adding new section (4), section (11), and section (12).

PURPOSE: This amendment expands the use of standard contracts and rates for purchase from qualifying facilities and removes unnecessary language.

(1) Definitions. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this rule as they have under PURPA, unless further defined in this rule.

[(B) Back-up power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(C) Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent those costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(D) Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(E) Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

(F) Purchase means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(G) Qualifying facility means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of Part 292 of the Federal Energy Regulatory Commission's (FERC) regulations.

(H) Rate means any price, rate, charge or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity or any rule or practice respecting any such rate, charge or classification and any contract pertaining to the sale or purchase of electric energy or capacity.

(I) Sale means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(J) Supplementary power means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(K) System emergency means a condition on a utility's system which is likely to result in imminent significant disruption of service to consumers or is imminently likely to endanger life or property.]

(B) Fuel costs, or energy costs, means the variable costs associated with the production of electric energy and represent the cost of fuel and operating and maintenance expenses.

(C) Capacity costs means the costs associated with providing the capability to deliver energy.

(D) "Time of delivery rates" means rates based on the Avoided Costs for energy and capacity of the Electric Utility that are determined at the time the Qualifying Facility delivers electricity to the Electric Utility.

(E) "Time of obligation rates" means rates based on the avoided costs for energy and capacity of the Electric Utility that are determined: (1) for a Qualifying Facility that is already constructed, at the time a Qualifying Facility commits to selling its output to the Electric Utility; or (2) for a Qualifying Facility not already constructed, at the time a Qualifying Facility establishes a Legally Enforceable Obligation.

(2) Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of *[the Public Utility Regulatory Policies Act of 1978]* **PURPA**.

(C) Every regulated utility which provides retail electric service in this state shall enter into a contract for parallel generation service with any customer which is a qualifying facility, upon that customer's request, where that customer may connect a device to the utility's delivery and metering service to transmit electrical power produced by that customer's energy generating system into the utility's system.

[1. The utility shall supply, install, own and maintain all necessary meters and associated equipment used for billing. The costs of any such meters and associated equipment which are beyond those required for service to a customer which is not a qualifying facility shall be borne by the customer. The utility may install and maintain, at its expense, load research metering for monitoring the customer's energy generation and usage.

2. The customer shall supply, install, operate and maintain, in good repair and without cost to the utility, the relays, locks and seals, breakers, automatic synchronizer, a disconnecting device and other control and protective devices required by the utility to operate the customer's generating system parallel to the utility's

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system. The customer also shall supply, without cost to the utility, a suitable location for meters and associated equipment used for billing, load research and disconnection.

3. The customer shall be required to reimburse the utility for the cost of any equipment or facilities required as a result of connecting the customer's generating system with the utility's system.

4. The customer shall notify the utility prior to the initial testing of the customer's generating system and the utility shall have the right to have a representative present during the testing.

5. Meters and associated equipment used for billing, load research and connection and disconnection shall be accessible at all times to utility personnel.

6. A manual disconnect switch for the qualifying facility must be provided by the customer which will be under the exclusive control of the utility dispatcher. This manual switch must have the capability to be locked out of service by the utility-authorized switchmen as a part of the utility's workman's protection assurance procedures. The customer must also provide an isolating device which the customer has access to and which will serve as a means of isolation for the customer's equipment during any qualifying facility maintenance activities, routine outages or emergencies. The utility shall give notice to the customer before a manual switch is locked or an isolating device used, if possible; and otherwise shall give notice as soon as practicable after locking or use.

(D) No customer's generating system or connecting device shall damage the utility's system or equipment or present an undue hazard to utility personnel.

(E) If harmonics, voltage fluctuations or other disruptive problems on the utility's system are directly attributable to the operation of the customer, these problems will be corrected at the customer's expense.]

*[(F)]***(D)** Every contract shall provide fair compensation for the electrical power supplied to the utility by the customer. **For qualifying facilities whose systems fall out of the standard contract ranges described in Section (4)**, *[I]***i**f the utility and the customer cannot agree to the terms and conditions of the contract, the *[Public Service Commission (PSC)]* **commission** shall establish the terms and conditions upon the request of the utility or the customer. Those terms and conditions will be established in accordance with Section 210 of *[the Public Utility Regulatory Policies Act of 1978]* **PURPA** and the provisions of this rule. **Any Federal Energy Regulatory Commission (FERC) granted exemption granted from qualifying facility purchases also applies to qualifying facility purchases within the state of Missouri.**

(3) Electric Utility Obligations Under This Rule.

(A) Obligation to Purchase From Qualifying Facilities. Each electric utility shall purchase, in accordance with section *[(4)]***(5)**, any energy and capacity which is made available from a qualifying facility—

1. Directly to the electric utility; or

2. Indirectly to the electric utility in accordance with subsection (3)(D) of this rule.

(B) Obligation to Sell to Qualifying Facilities. Each electric utility shall sell to any qualifying facility, in accordance with section *[(5)]* **(6)** of this rule, any energy and capacity requested by the qualifying facility.

(C) Obligation to Interconnect.

1. Subject to paragraph (3)(C)2. of this rule, any electric utility shall make interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this rule. The obligation to pay for any interconnection costs shall be determined in accordance with section *[(6)]***(7)** of this rule.

2. No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(D) Transmission to Other Electric Utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from a qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which energy or capacity is transmitted shall purchase energy or capacity under this subsection (3)(D) as if the qualifying facility were supplying energy or capacity directly to the electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to paragraph *[(4)(E)4.]* **(5)(D)4.** of this rule and shall not include any charges for transmission.

(E) Parallel Operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with section *[(8)]***(9)** of this rule.

(4) Standard Rates for Purchase and Standard Contracts.

(A) Each electric utility shall put into effect commission-approved standard rates for purchases from qualifying facilities with a design capacity:

1. Of one hundred (100) kilowatts or less; ~~or~~

2. Over one hundred (100) kilowatts to one thousand (1,000) kilowatts~~.~~;

3. Over one thousand (1,000) kilowatts to two thousand five hundred (2,500) kilowatts;

4. Over two thousand five hundred (2,500) kilowatts to five thousand (5,000) kilowatts; and

5. Over five thousand (5,000) kilowatts to twenty-thousand (20,000) kilowatts.

(B) There may be put into effect commission-approved standard rates for purchases from qualifying facilities with a design capacity of more than one thousand (1,000) kilowatts.

(C) The commission shall approve standard contract templates for purchases from qualifying facilities with the design capacities described in (4)(A). Such standard rates shall include both as-available and time-of-obligation options for avoided costs. The approved standard contract templates will be the basis of the standard contracts utilized by each utility through its respective tariffs and shall include provisions for Renewable Energy Certificate (REC) ownership. The terms and

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conditions of the standard contract templates will be established in accordance with Section 210 of PURPA and the provisions of this rule. Such standard terms must include a contract tenure of at least 15 years. Standard contract templates will be made available through the commission website.

1. For systems which qualify for net-metering under 20 CSR 4240-20.065 and section 386.890 RSMo, the standard contract shall be substantially the same as the interconnection application located on the commission's website and incorporated by reference.

2. RECs associated with qualifying facilities shall be owned by the customer; however, as a condition of receiving solar rebates for systems operational on or after January 1, 2019, customers transfer to the electric utility all rights, title, and interest in and to the RECs associated with the new or expanded solar electric system that qualified the customer for the solar rebate for a period of ten (10) years from the date the electric utility confirmed the solar electric system was installed and operational.

3. If the electric utility purchases S-RECs under a Standard Offer Contract in 20 CSR 4240-20.100(4)(H), the electric utility shall also offer purchase from qualifying facilities under the same rates and terms. S-RECs from qualifying facilities may be used for compliance with the Renewable Energy Standard (RES) requirements of section 393.1030, RSMo subject to the same conditions as all RECs and S-RECs.

(D) Each electric utility will develop technical and performance standards and interconnection test specifications specific to its distribution system to be included in its standard contract template. Technical and performance standards will include provisions related to metering, protection equipment, and disconnect switches.

(E) The standard rates for purchases under this subsection shall be consistent with subsections (5)(A) and (E) of this rule, and may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

*[(4)]***(5)** Rates for Purchases.

(A) Rates for purchases shall be just and reasonable to the electric consumer of the electric utility and in the public interest and shall not discriminate against qualifying cogeneration and small power production facilities. Nothing in this rule requires any electric utility to pay more than the avoided costs for purchases.

(B) Relationship to Avoided Costs.

1. For purposes of this section, new capacity means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

2. Subject to paragraph *[(4)]***(5)**(B)3. of this rule, a rate for purchases satisfies the requirements of subsection *[(4)]***(5)**(A) of this rule if the rate equals the avoided costs determined after consideration of the factors set forth in subsection *[(4)(E)]* **(5)(D)** of this rule.

3. A rate for purchases (other than from new capacity) may be less than the avoided cost if the *[PSC]* **commission** determines that a lower rate is consistent with subsection *[(4)]***(5)**(A) of this rule and is sufficient to encourage cogeneration and small power production.

4. Rates for purchases from new capacity shall be in accordance with paragraph *[(4)]***(5)**(B)2. of this rule, regardless of whether the electric utility making the purchases is simultaneously making sales to the qualifying facility.

5. In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for the purchases do not violate this paragraph if the rates for the purchases differ from avoided costs at the time of delivery.

[(C) Standard Rates for Purchases.

1. There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of one hundred (100) kilowatts or less.

2. There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than one hundred (100) kilowatts.

3. The standard rates for purchases under this subsection shall be consistent with subsections (4)(A) and (E) of this rule, and may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.]

*[(D)]***(C)** Purchases as Available or Pursuant to a Legally Enforceable Obligation. Each qualifying facility shall have the option either—

1. To provide energy as the qualifying facility determines this energy to be available for the purchases, in which case the rates for the purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

2. To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for the purchases, at the option of the qualifying facility exercised prior to the beginning of the specified term, shall be based on either the avoided costs calculated at the time of delivery or the avoided costs calculated at the time the obligation is incurred.

*[(E)]***(D)** Factors Affecting Rates for Purchases.
In determining avoided costs, the following factors, to the extent practicable, shall be taken into account:

1. The data provided pursuant to *[4 CSR 240-3.155]* **section (10) of this rule**, including *[PSC]* **commission** review of any such data;

2. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

A. The ability of the utility to dispatch the qualifying facility;

B. The expected or demonstrated reliability of the qualifying facility;

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C. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance;

D. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

E. The usefulness of energy and the capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

F. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

G. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

3. The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph *[(4)(E)2.]* **(5)(D)2.** of this rule, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of *[oil]* **fossil fuel** use; *[and]*

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity*[.]***; and**

5. The stochastic effect achieved by the aggregate output of dispersed small systems, that is, statistically a dispersed array of facilities may produce a level of reliability not available by any one (1) of the units taken separately. When that aggregate capacity value which allows the utility to avoid a capacity cost occurs and can be reasonably estimated, a corresponding credit must be included in the standard rates. The tariffs should take into account patterns of availability of particular energy sources such as the benefits to a summer peaking utility from photovoltaic systems or to a winter peaking utility for wind facilities. For the purposes of this rule, rate means any price, rate, charge or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity or any rule or practice respecting any such rate, charge, or classification and any contract pertaining to the sale or purchase of electric energy or capacity.

*[(F)]***(E)** Periods During Which Purchases not Required.

1. Any electric utility which gives notice pursuant to paragraph *[(4)(F)2.]* **(5)(E)2.** of this rule will not be required to purchase electric energy or capacity during any period which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make the purchases, but instead generated an equivalent amount of energy itself.

2. Any electric utility seeking to invoke paragraph *[(4)(F)1.]* **(5)(E)1.** of this rule must notify, in accordance with applicable state law or rule, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

3. Any electric utility which fails to comply with the provisions of paragraph *[(4)(F)2.]* **(5)(E)2.** of this rule will be required to pay the same rate for the purchase of energy or capacity as would be required had the period described in paragraph *[(4)(F)1.]* **(5)(E)1.** of this rule not occurred.

4. A claim by an electric utility that this period has occurred or will occur is subject to verification by the *[PSC]* **commission** as the *[PSC]* **commission** determines necessary or appropriate, either before or after the occurrence.

*[(5)]***(6)** Rates for Sales.

(A) Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that those rates apply to the utility's other customers with similar load or other cost-related characteristics.

(B) Additional Services to be Provided to Qualifying Facilities.

1. Upon request of a qualifying facility, each electric utility shall provide supplementary power, back- up power, maintenance power and interruptible power.

2. The *[PSC]* **commission** may waive any requirement of paragraph *[(5)]***(6)**(B)1. of this rule if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the *[PSC]* **commission** finds that compliance with that requirement will impair the electric utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

(C) Rates for Sale of Back-Up and Maintenance Power. The rate for sales of back-up power or maintenance power—

1. Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak or both; and

2. Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

*[(6)]***(7)** Interconnection Costs.

(A) The customer shall be required to reimburse the utility for the interconnection costs of any equipment or facilities which result from connecting the customer's generating system with the utility's system according to the provisions contained in the utility's tariffs for connections at distribution or the governing Regional Transmission Organization (RTO) provisions if connecting to transmission.

*[(A)]***(B)** If the utility and the qualifying facility cannot reach agreement as to the amount or the manner of payment of the interconnection costs to be paid by the qualifying facility, the *[PSC]* **commission**, after hearing **under the procedure of 20 CSR 4240-2.070**, shall assess against the qualifying facility those interconnection costs to be paid to the utility, on a nondiscriminatory basis with respect to other customers with similar load characteristics or shall determine the manner of payments of the interconnection costs, which may include reimbursement over a reasonable period of time, or both. In determining the terms of any

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reimbursement over a period of time, the commission shall provide for adequate carrying charges associated with the utility's investment and security to insure total reimbursement of the utility's incurred costs, if it deems necessary.

*[(7)]***(8)** System Emergencies.

(A) Qualifying Facility Obligation to Provide Power During System Emergencies. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent provided by agreement between the qualifying facility and electric utility or ordered under section 202(c) of the Federal Power Act.

(B) Discontinuance of Purchases and Sales During System Emergencies. During any system emergency, an electric utility may discontinue purchases from a qualifying facility if those purchases would contribute to the emergency *[and]***. During any system emergency, an electric utility may discontinue** sales to a qualifying facility, provided that discontinuance is on a nondiscriminatory basis.

*[(8)]***(9)** Standards for Operating Reliability. The *[PSC]* **commission** may establish reasonable standards to ensure system safety and reliability of interconnected operations. Those standards may be recommended by any electric utility, any qualifying facility or any other person. If the *[PSC]* **commission** establishes standards, it shall specify the need for the standards on the basis of system safety and reliability.

*[(9)]***(10)** Exemption to Qualifying Facilities From the Public Utility Holding Company Act and Certain State Law and Rules.

(A) Applicability. *[This section applies to qualifying cogeneration facilities and qualifying small power production facilities which have a power production capacity which does not exceed thirty (30) megawatts and to any qualifying small power production facility with a power production capacity over thirty (30) megawatts if that facility produces electric energy solely by the use of biomass as a primary energy source.]* **As defined in PURPA section 292.601 (a) & (b) and section 292.602 (a) & (b).**

(B) A qualifying facility described *[in subsection (1)(A)]* **in PURPA** shall not be considered to be an electric utility company as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(C) Any qualifying facility shall be exempted (except as otherwise provided) from Missouri *[PSC]* **commission** law or rule respecting the rates of electric utilities and the financial and organizational regulation of electric utilities. A qualifying facility may not be exempted from Missouri *[PSC]* **commission** law and rule implementing subpart C of PURPA.

(11) Filing Requirements.

(A) On or before January 15 of every odd-numbered year, unless otherwise ordered by the commission, all regulated electric utilities shall file, in accordance with 20 CSR 4240-2.065(4), tariffs which contain the standard contracts as described in section (4) of this rule and the standardized rates for sales and purchase described in section (5) and section (6) of this rule. The biennial filings will consider the factors affecting rates for purchases as described in subsection (5)(D) and be accompanied by the data described in subsection (11)(B) and the verification described in subsection (11)(C) of this rule.

(B) Each regulated electric utility shall maintain for public inspection the following data:

1. The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. These levels of purchases shall be stated in blocks of not more than one hundred (100) megawatts for systems with peak demand of one thousand (1,000) megawatts or more, and in blocks equivalent to not more than ten percent (10%) of the system peak demand for systems of less than one thousand (1,000) megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next five (5) years;

2. The electric utility's plans for the addition of capacity by amount and type, for purchases of firm energy and capacity and for capacity retirements for each year during the succeeding ten (10) years; and

3. The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(C) Each regulated electric utility shall verify it maintains and aggregates the following information:

1. For systems less than one hundred kilowatts (100 kW)—

A. Characterization of the distribution circuits where the systems are connected;

B. Aggregate capacity of the systems for each feeder or load; and

C. Relevant interconnection standard requirement that specify the performance of the system; and

2. For systems over one hundred kilowatts (100 kW) and under one thousand kilowatts (1000 kW)—

A. Type of generating resource;

B. Distribution bus nominal voltage where the system is connected;

C. Feeder characteristics for connecting the system to distribution bus, if applicable;

D. Capacity of each resource;

E. Relevant interconnection standard requirements; and

F. Actual plant control modes in operation.

3. For systems over one thousand (1,000) kilowatts and under two thousand five hundred (2,500) kilowatts —

A. Type of generating resource;

B. Distribution bus nominal voltage where the system is connected;

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C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation; and

4. For systems over two thousand five hundred (2,500) kilowatts and under five thousand (5,000) kilowatts —
A. Type of generating resource;
B. Distribution bus nominal voltage where the system is connected;
C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation; and

5. For systems over five thousand (5,000) kilowatts and under twenty thousand (20,000) kilowatts —
A. Type of generating resource;
B. Distribution bus nominal voltage where the system is connected;
C. Feeder characteristics for connecting the system to distribution bus, if applicable;
D. Capacity of each resource;
E. Relevant interconnection standard requirements; and
F. Actual plant control modes in operation.

(D) In establishing the avoided cost on the electric utility's system in accordance with paragraph (10)(C)1., the following methodologies may be utilized:

1. Proxy Unit. This methodology assumes that the electric utility avoids building a proxy generating unit by utilizing the qualifying facilities power. The fixed costs of the hypothetical proxy unit set the avoided capacity cost and variable costs set the energy payment;

2. Integrated Resource Plan (IRP) Based avoided cost. This methodology relies on the electric system resource planning to predict future needs and costs that may be avoided by qualifying facilities;

3. Market Based Pricing. Qualifying facilities with access to competitive markets receive energy and capacity payments at market rates; and

4. The electric utility may propose any other method that can be demonstrated to reflect avoided costs.

(E) Within thirty (30) days of the January 15 avoided cost filings required by subdivision (A) of section (11) of this rule, the commission shall open a file allowing the staff for the commission, the office of public counsel, and other interested parties to participate fully in the proceeding, including through the presentation of testimony and other evidence and the cross-examination of utility witnesses. Based on the record in such proceeding, the commission shall issue an order directing each regulated electric utility to adopt such avoided cost methodology, standard offer contracts, inputs and rates that the commission determined to be just and reasonable.

(12) Implementation of Certain Reporting Requirements. Any electric utility which fails to comply with the requirements of subsection (11)(B) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Federal Energy Regulatory Commission's (FERC's) regulations issued under Section 133 of PURPA.

(13) Legally Enforceable Obligations. A qualifying facility may establish a legally enforceable obligation by one of the following methods:

1. A qualifying facility may tender an executed copy of a commission-approved standard offer contract or form power purchase agreement pursuant to a commission-approved standard rate for purchase, after which the electric utility shall countersign within 30 days to establish a legally enforceable obligation.

2. A qualifying facility may tender a modified form power purchase agreement pursuant to a commission-approved standard rate for purchase, after which the electric utility shall respond to the qualifying facility within 30 days. If after 60 days the parties have failed to execute a power purchase agreement, the qualifying facility may submit a claim to the commission for resolution.

AUTHORITY: sections 386.250 and 393.140, RSMo ***[2000]* 2016***. This rule originally filed as 4 CSR 240-20.060. Original rule filed Oct. 14, 1980, effective May 15, 1981. Amended: Filed Aug. 16, 2002, effective April 30, 2003. Moved to 20 CSR 4240-20.060, effective Aug. 28, 2019. Amended: Filed May 29, 2020.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment is expected to incur the aggregate cost of a one- (1-) time cost of seventeen thousand five hundred dollars ($17,500) and an annual cost of seven thousand dollars ($7,000).

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than July 31, 2020, and should include a reference to Commission Case No. EX-2020-0006. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., August 11, 2020, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

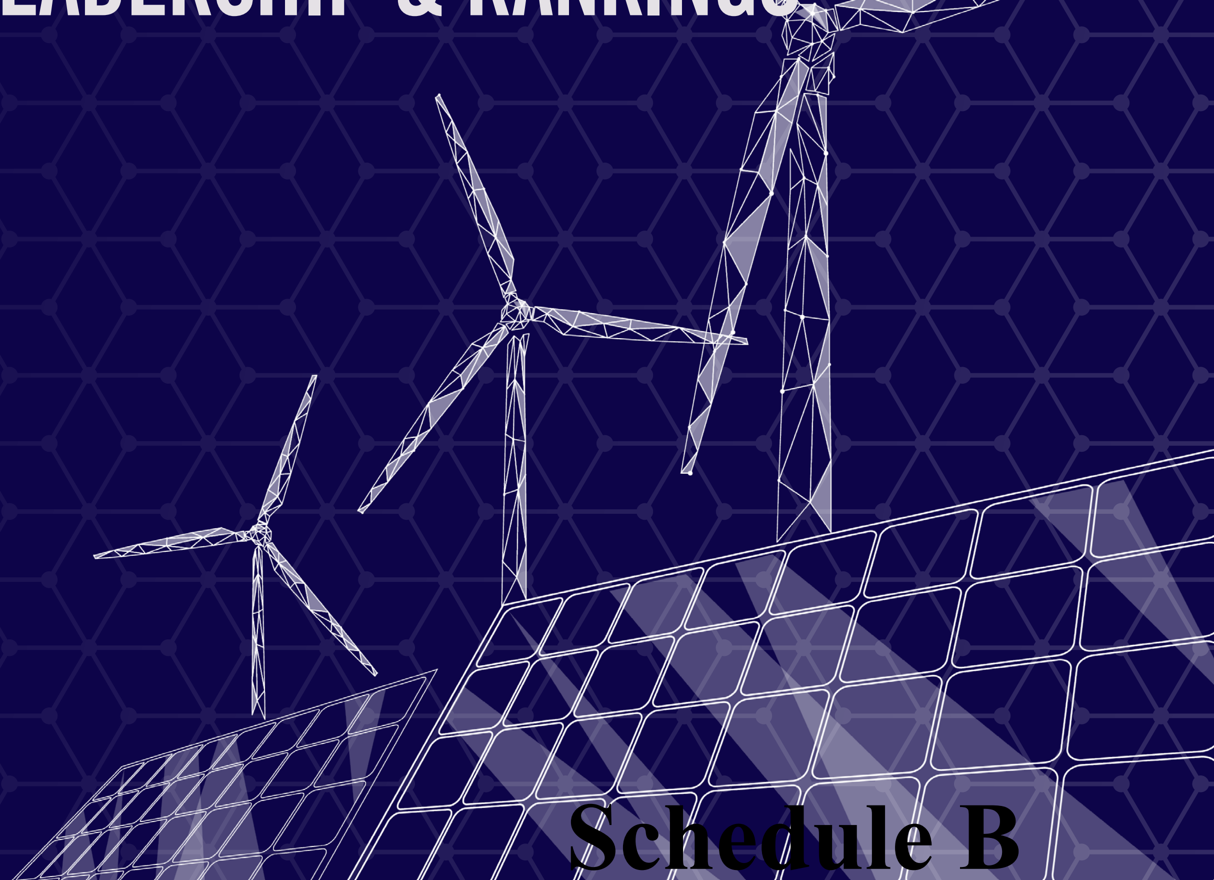
Schedule A

RETAIL INDUSTRY LEADERS ASSOCIATION

CORPORATE CLEAN ELECTRICITY PROCUREMENT INDEX 2020:

STATE LEADERSHIP & RANKINGS

MARCH 2020



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EXECUTIVE SUMMARY

The first *Corporate Clean Energy Procurement Index: State Leadership & Rankings* (Index) was published in 2017 and created to help guide companies in their efforts to boost commercial and industrial (C&I) renewable electricity (RE) usage across their operations in the United States. In the three years since the Index's initial analysis and publication, state-level RE markets have undergone dramatic changes on multiple fronts, including: commercial development, utility engagement, RE technology and development, economics, state-level policy frameworks, substantial growth in voluntary C&I RE purchases, and an evolution in buyer experience, sophistication, and expectations. These market changes create an opportunity to refine and update the Index for 2020 and provide companies with the granular insights that they need to make effective RE sourcing decisions across their U.S. operations.

While developed by the Retail Industry Leaders Association (RILA), this Index is broadly applicable to many stakeholders, including other business sectors, the military, higher education institutions, and state and local governments. While the Index has many potential uses, one key purpose is to assist RE buyers in selecting states with favorable RE policy conditions. Additionally, the Index seeks to assist policymakers and RE buyers in advancing policies that help, rather than hinder, RE development.

Since the last Index was released in 2017, many states have dramatically increased their C&I renewable energy deployment and enacted policies that are more favorable to RE buyers seeking additional procurement. Continued growth and expansion of state policies and regulations that enable procurement is critical to increasing the number of C&I buyers seeking out RE to meet their companies' objectives.

The Index ranks all 50 U.S. states based upon the ease with which companies can procure RE, considering a given set of indicators tracking both policy mechanisms and deployment levels. Those 13 indicators are broken into three categories: Utility Purchasing Options & Market Structure, Third-Party Purchasing Options, and Onsite/Direct Deployment Options. The data for the indicators was collected from industry sources between August and October of 2019 and may not reflect policy or deployment changes after that time. States may also have additional policies that allow for RE purchases within the state or even across state lines.

OVERALL INDEX RESULTS

Illinois leads the Index rankings with an overall score of 73.6 (out of a possible 100), nearly four points ahead of the next highest state, New Mexico, which leapt ahead 22 spots to the second position. Illinois moved up one spot from 2017, while previously top-ranked Iowa dropped to #14. Massachusetts moved up three spots to third place, while Nevada moved ahead 13 spots to #4 and New Jersey dropped two spots to round out the top five.

CORPORATE CLEAN ENERGY PROCUREMENT INDEX: TOP 20 STATES

1 Illinois	6 California	11 Texas	16 Maryland
2 New Mexico	7 Oregon	12 Ohio	17 Delaware
3 Massachusetts	8 Virginia	13 Rhode Island	18 Maine
4 Nevada	9 Utah	14 Iowa	19 North Carolina
5 New Jersey	10 New York	15 Connecticut	20 Vermont

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The updated Index highlights that states in the Northeast as well as many Western states (the Pacific and lower half of Mountain West states) generally score very well overall, while states in the Midwest and Texas score very well for large, offsite purchases via third-party providers.

All nine Northeast states are within the top half in the rankings, driven by supportive policies and comparatively high energy prices, making RE options more attractive.

The Western region as a whole improved from the 2017 Index with New Mexico and Nevada now in the top five and Utah moving inside the top ten to #9. California fell two spots in the rankings to #6, but Oregon jumped up nine spots to #7 and Washington moved up three spots to #24, pushing the region into a more favorable position.

While many Midwestern states saw considerable increases in the deployment of large, offsite third-party purchases, the region somewhat stagnated in the overall rankings as other regions surged ahead.

The South continues to trail the rest of the U.S. Despite improved overall rankings for Georgia, North Carolina, Tennessee, and Virginia, more work is needed. Of course, Texas remains in a category of its own, with well over 7 gigawatts (GW)—or nearly six percent—of the state's entire electric generating capacity derived from C&I utility-scale power purchase agreements (PPAs) via third-party providers.

Texas' success is driven by the availability of retail choice, which is a critical factor for a state's attractiveness to corporate and other large institutional buyers of RE. Notably, 12 of the top 15 states receive full or partial credit for C&I retail choice, while the remaining three (New Mexico, Nevada, and Iowa) have robust utility purchasing options.

In addition to market structures and utility or third-party purchasing options, other specific onsite policies also have a significant impact on a state's ranking. Those include strong net metering requirements for onsite photovoltaic (PV) generation and policies or regulations that ease the interconnection of distributed generation (DG) systems to the grid. For example, the top 10 states in the Onsite/Direct Deployment category are also in the top 20 of the overall Index.

The overall deployment and market growth of C&I RE over the past three years is exponential. Since 2017, utility purchasing has increased nearly four times to 4.3 GW, offsite PPAs have increased from 4.8 GW to 16.6 GW, and onsite deployment has increased from 0.8 GW to 5.5 GW. However, some significant policy barriers still remain for C&I customers.

KEYS FOR DRIVING ADDITIONAL RENEWABLE DEPLOYMENT

In general, policymakers should broadly focus on removing policy barriers to enable:

1. The deployment of *onsite renewable energy* for C&I energy buyers.
2. The deployment of *offsite renewable energy* for C&I energy buyers.
3. *Utility purchasing options* which create utility-delivered renewable energy product options that meet customer economic and environmental requirements.

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INTRODUCTION

The ability of businesses to purchase or produce renewable electricity (RE)—by purchasing through their electric utility, purchasing through a third-party, or building their own generation facilities—continues to expand. It is now possible for corporations to set and reach ambitious RE goals by utilizing a diversity of options, and the trend towards action is rapidly accelerating. Nearly half of Fortune 500 companies have made public renewable energy, greenhouse gas (GHG), or energy efficiency commitments, according to the *Power Forward 3.0* report.[1] Among Fortune 100 companies, 63% have adopted a public RE commitment. Additionally, *RE100*—a global corporate leadership initiative bringing together influential businesses committed to 100% RE—now includes over 200 companies, with 2028 as the average target date for companies to achieve their goals. One in three *RE100* companies have already achieved at least 75% RE.[2]

More than 22 GW of corporate renewable energy deals have been announced in the U.S. since 2008, with over 13.5 GW of purchases announced in 2018 and 2019 alone, according to the Renewable Energy Buyers Alliance (REBA).[3] In 2019, more than half of the unique buyers were first-time buyers of RE. This increase is consistent with national RE trends. The Energy Information Administration (EIA) reports that U.S. RE generation nearly doubled between 2008 and 2018 to reach about 17% of electricity generation nationwide, with nearly 90% of that increase coming from wind and solar.[4]

According to Wood Mackenzie, C&I buyers represented about 20% of the total U.S. wind market in 2018 and about 20% of total of U.S. solar capacity from 2016-2018. Looking forward, they estimate up to 85 GW of RE demand through 2030 within the Fortune 1000.[5]

In the United States, the development of state policies and regulations that help enable corporations to procure RE—or remove barriers to doing so—is a key driver of the expansion and acceleration of corporate RE procurement. Other important factors include: the falling costs of solar and wind generation, expanding and more aggressive corporate sustainability goals, the desire to participate in efforts to prevent climate change, and the growing ability for corporations to hedge their energy costs against fossil fuel price volatility.

But states are not equal when it comes to the policy landscape. According to Smart Energy Decisions' *2019 State of Corporate Renewable Energy Sourcing,* which surveyed 110 companies from across various sectors, potential energy cost savings and GHG reductions were the key reasons for companies looking to pursue RE procurement, with price risk and unfavorable economics being the top barriers.[6] Each of these factors are directly influenced by a state's policy and market structure. Therefore, states that remove policy barriers and provide more options for companies can increase their economic attractiveness for corporations looking to invest in RE projects. In many cases, policy frameworks influence decisions regarding which states companies with RE targets may decide to expand their operational footprint.

The *Corporate Clean Electricity Procurement Index 2020: State Leadership & Rankings* was created to guide members of the Retail Industry Leaders Association (RILA) and others in their efforts to boost RE usage across their operations in the United States. While created on behalf of RILA, the Index is broadly applicable to many other stakeholders, including other business sectors, the military, higher education, healthcare, and state and local governments. It is intended to assist policymakers and large RE buyers in advancing policies that help, rather than hinder, RE development. The Index can also help large RE buyers to select states in which they may make RE investments. These investments, in turn, drive broader societal benefits such as job growth, increased tax revenue, and lower emissions of air pollutants.

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INDEX STRUCTURE

The Index ranks all 50 U.S. states based upon the availability by which companies can procure RE for their operations located within each state. The Index consists of 13 indicators, broken into three categories:

- **UTILITY PURCHASING OPTIONS & MARKET STRUCTURE,** which ranks states based upon the opportunities available to procure RE through electric utilities in the state, as well as overall state electric market factors.
- **THIRD-PARTY PURCHASING OPTIONS,** where states are ranked by how readily companies can procure RE through third-party (i.e. non-utility) developers and other organizations.
- **ONSITE/DIRECT DEPLOYMENT OPTIONS,** which analyzes states based upon how effectively companies can deploy RE onsite (such as rooftop solar systems) or through other direct purchasing options.

The scoring of the Index is calculated with each of the three categories weighing equally toward the overall score. Within each of the three categories the quantitative deployment factor(s) are weighed equally with the qualitative policy/market related items.

The indicators in this Index are a subset of many factors that influence RE deployment. They are included as the factors that more directly impact the ability of large customers, such as RILA members, to acquire RE. The Index excludes some items due to a lack of available or reliable data.

The following sections detail the overall results of the Index and then delve into how states rank in each of the three categories, while also discussing some of the policies and tools that have been important to corporate and other institutional RE procurement. Sections consider policy changes since the 2017 Index was published, as well as market trends, and discuss how those are accounted for in the new Index.

INDEX CATEGORIES AND COMPONENTS

UTILITY PURCHASING OPTIONS & MARKET STRUCTURE

- Green Tariff/Direct Utility Purchase Deployment
- Green Power Purchase Option
- Retail Choice (including the existence of C&I retail choice and allowance of green tariff offerings)
- Market Structure (including the presence of a Renewable Portfolio Standard and RTO/ISO participation)

THIRD-PARTY PURCHASING OPTIONS

- Third-Party Utility-Scale Offsite (Wind/Solar PPA) Deployment
- Third-Party Onsite PPAs for Distributed Generation
- Third-Party Onsite Leases for Distributed Generation
- Community Renewables
- Community Choice Aggregation

ONSITE/DIRECT DEPLOYMENT OPTIONS

- Onsite Wind and Solar Deployment
- Direct Investment Procurement Deployment
- Interconnection
- Net Metering

WHAT'S NEW?

In the Utility Purchasing Options & Market Structure category, this Index combined the Existence of a Green Tariff and C&I Retail Choice as sub-indicators to comprise the Retail Choice Indicator. In the same category, renewable portfolio standards (RPSs) were added as a sub-indicator combined with presence of an ISO/RTO to form the Market Structure Indicator. In the Onsite/Direct Deployment Options category the indicator for fixed charges was not included in the 2020 edition. See page 31 for more information about details of the components in the Index.

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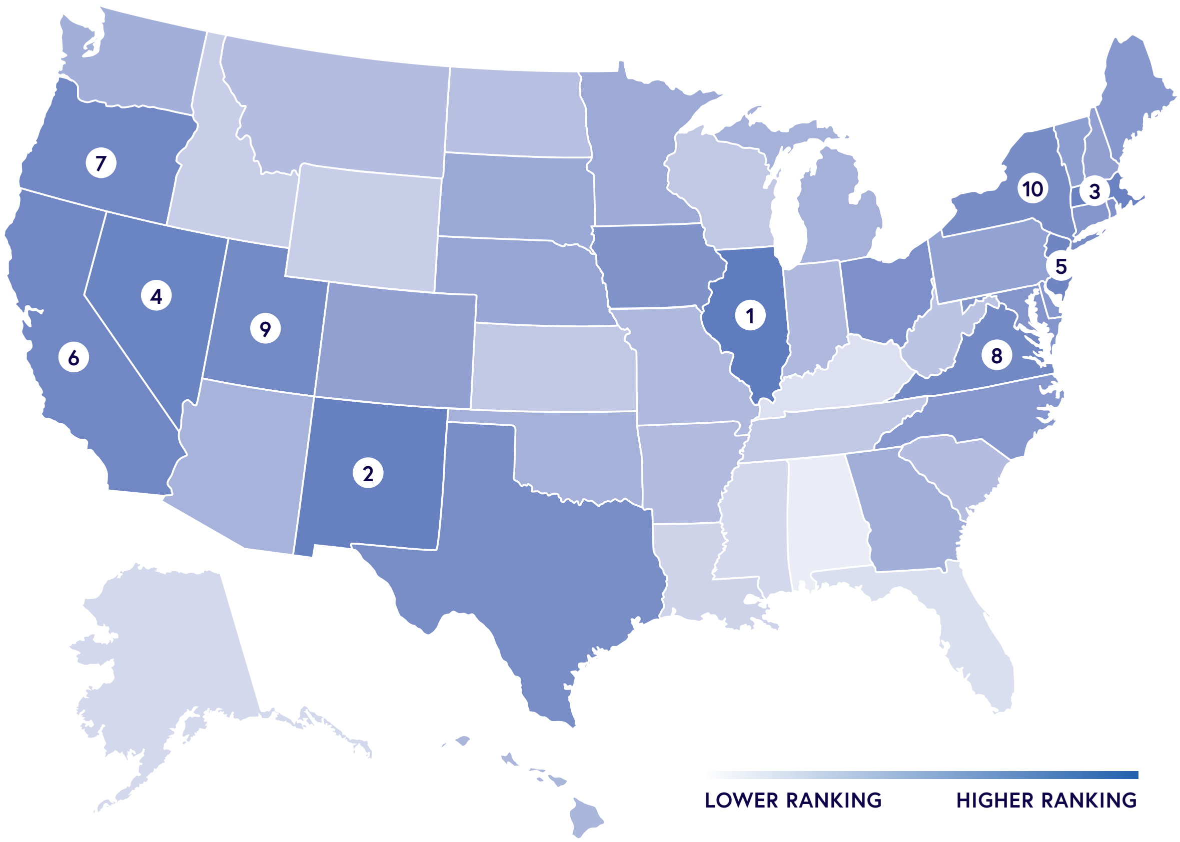
CORPORATE CLEAN ELECTRICITY PROCUREMENT INDEX:

OVERALL RESULTS



Five states are new to the top 10, each adding over 300 MW of corporate deals since the last Index.

RANK	STATE	INDEX SCORE
1	Illinois	73.67
2	New Mexico	69.68
3	Massachusetts	69.43
4	Nevada	67.94
5	New Jersey	66.04
6	California	64.92
7	Oregon	64.58
8	Virginia	64.39
9	Utah	62.89
10	New York	61.05
11	Texas	59.85
12	Ohio	58.48
13	Rhode Island	57.15
14	Iowa	55.85
15	Connecticut	55.28
16	Maryland	55.11
17	Delaware	53.64
18	Maine	53.42
19	North Carolina	53.34
20	Vermont	49.50
21	New Hampshire	48.28
22	Colorado	48.02
23	Pennsylvania	46.70
24	Washington	45.80
25	Nebraska	44.84

RANK	STATE	INDEX SCORE
26	South Dakota	43.02
27	Minnesota	41.77
28	Georgia	39.75
29	Oklahoma	38.06
30	Indiana	37.98
31	Michigan	37.71
32	Arizona	37.19
33	Hawaii	35.05
34	Missouri	32.91
35	Arkansas	31.85
36	South Carolina	31.30
37	Montana	30.79
38	North Dakota	28.80
39	West Virginia	27.23
40	Kansas	25.41
41	Wisconsin	25.02
42	Tennessee	24.78
43	Wyoming	22.44
44	Idaho	21.69
45	Louisiana	19.02
46	Mississippi	17.22
47	Alaska	17.08
48	Florida	13.65
49	Kentucky	13.21
50	Alabama	8.07

RETAIL INDUSTRY LEADERS ASSOCIATION

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OVERVIEW

In April 2019, U.S. monthly electricity generation from renewable sources exceeded coal-fired generation for the first time, according to the Energy Information Administration (EIA).[7] During that month, renewable sources provided 23% of total electricity generation, compared to coal's 20%.

In this game-changing transition from conventional sources to clean electricity, corporations and other large organizations that seek to meet their RE goals by purchasing and deploying renewables have unprecedented options. But the transition is—at times—a bumpy one, with an ever-changing landscape of policy, finance, and technology factors at the state level. On the policy side, state energy and utility regulations and the availability of customer choice are increasingly key considerations for companies in determining the best locations for buying or building significant amounts of RE generation or even where to site their operations.

The *Corporate Clean Electricity Procurement Index 2020: State Leadership & Rankings* finds a wide range of progress among states on policies related to corporate acquisition of renewables. Some policies, like allowing third-party power purchase agreements (PPAs) and permitting C&I customers to choose their electric generation supplier, are fairly widespread, while others are more limited. Based on the commitments from companies alone, it's reasonable to expect that the momentum of corporate investment in RE will continue to increase in coming years. However, the speed and progress of C&I RE procurement will ultimately depend on policymakers clearly understanding the economic and environmental benefits achieved by those states that have implemented strong RE and customer choice policies.

RESULTS

HIGHEST SCORING STATES

Illinois, the overall Index leader, ranked the highest in the onsite solar deployment indicator and in the top five for both the Third-Party Purchasing and Onsite/Direct Deployment categories. New Mexico leapt ahead 22 spots to the second position overall, largely due to policy changes and nearly 400 megawatts (MW) of total green tariff or direct utility purchase deals, while Massachusetts moved up three spots to #3, buoyed by more than 28 times the amount of onsite/distributed direct deployment than it had at the time of the previous Index—21 MW in 2017 compared with 600 MW for 2020. Nevada came in at #4, moving ahead 13 spots as a result of 250 MW of green tariff or direct utility deals. New Jersey dropped two spots to round out the top five, though the state is still in the top 20 in each category (including third in Onsite/Direct Deployment), and has nearly four times as much onsite deployment as it had in 2017 with almost 1 GW installed.

REGIONAL PROGRESS

Some regions of the country have demonstrated leadership across categories by developing policies that encourage additional deployment. Certain states are leaders on a national or regional level and can provide an example to their neighbors for how to develop and implement policies that encourage more RE generation.

The Northeast continues to lead as a region, with all nine of its states ranking in the top half of the Index. States throughout the region continue to be policy leaders in each of the three categories, and these states tend to have C&I retail choice as well as strong net metering and interconnection policies, which are important considerations for onsite deployment. However, and perhaps expectedly, deployment levels for large, offsite projects are smaller for this region compared to the Midwest, West, and Texas.

The Mountain West moved ahead with two states, New Mexico and Nevada, now in the top five, and Utah moving inside the top ten to #9. In addition to the policies in Nevada and New Mexico, Utah's 337 MW in green tariff or direct utility purchasing and 122 MW of offsite PPA deals aided the region's rise. Though Arizona moved up seven spots to #32, it is still a laggard in the region, with only a modest amount of deployment in each of the quantitative indicators measured in this Index. Additionally, Arizona's net metering score decreased from the 2017 Index to this version, creating a potential barrier to onsite deployment. However, the state now allows third-party PPAs, providing an opportunity for additional growth in offsite procurement moving forward.

On the Pacific Coast, California fell two spots in the rankings to #6, Oregon jumped ahead nine spots to #7, and Washington moved up three spots to #24, pushing the region into a more favorable position overall.

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REGIONS MAP

WEST

Mountain West: Moved ahead with two states, New Mexico and Nevada, now in the top 5, and Utah moving inside the top ten to #9

Pacific Coast: California fell two spots in the rankings to #6, Oregon jumped ahead to #7

MIDWEST

East North Central: Illinois took the overall top position for 2020

West North Central: In the Great Plains, South Dakota and Nebraska jumped from #39 in 2017 to #1 to #8 respectively, and Oklahoma remained inside the top 3 in the Third-party Purchasing Category

SOUTH

Southeast: Continues to trail the rest of the U.S., despite improved rankings from Georgia, North Carolina, and Tennessee

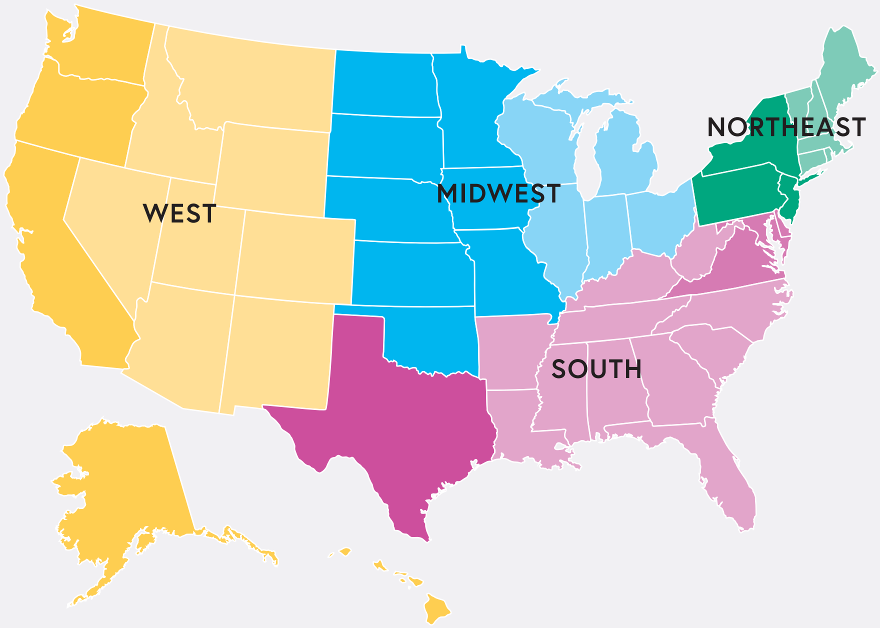
Mid-Atlantic South: Virginia, Maryland, and Delaware all scored in the top 20 in each of the three categories of the index

Texas: Still has by far the most PPA procurement with 7.2 GW as well as almost five times as much total offsite deployment as it had in 2017

NORTHEAST

Mid-Atlantic North: New Jersey and New York remained in the top ten overall

New England: All states, except New Hampshire (#21), were in the top 20 overall



California has far and away the most onsite/distributed deployment overall with 2.67 GW, though the state only ranks fourth in the indicator due to normalizing the data as a percentage of its total electric generating capacity. Oregon's RPS and 356 MW of green tariff and direct utility purchase deals pushed it into the top ten.

The Mid-Atlantic continues to be a favorable region overall for corporate customers to purchase RE as the states here generally score well in various categories. In the Mid-Atlantic South, Virginia, Maryland, and Delaware all scored in the top 20 in each of the three categories of this Index.

While Illinois captured the top spot in this Index and many Midwest states also saw increased deployment in at least one category, the region stagnated in the overall rankings as other regions surged ahead. However, several Midwest states saw success in the category rankings, as Iowa and Michigan claimed the fifth and sixth spots in the utility category, and Illinois and Ohio took the second and sixth ranks in the onsite category and also scored well in the third-party category.

Though Texas fell six spots to rank at #11 this year, the state remains a strong regional leader across categories and a national leader in the third-party category. Texas still has by far the most PPA procurement with 7.2 GW as well as almost five times as much total onsite deployment as it had in 2017.

The Midwest led in the third-party category in this Index, with South Dakota and Oklahoma claiming the top two spots in the category and Nebraska coming in eighth.

The Southeast as a region continues to trail the rest of the U.S., Georgia and Tennessee improved overall from 2017 and North Carolina climbed 11 spots to reach #19, yet more work is needed to make the region competitive with states in other regions.

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POLICY CHECKLIST

State	Overall Index Rank	Existence of Green Tariff	Green Power Purchase Option	C&I Retail Choice	Presence of an ISO/RTO	Third-Party PPAs for DG	Third-Party Leases for DG	Community Renewables	Community Choice Aggregation	RPS in Effect	Interconnection Law/Policy	Net Metering Law/Policy
IL	1		●	●	●	●	●	●	●	●	4	3
NM	2	●	●			●	●			●	4	3
MA	3		●	●	●	●	●	●	●	●	4	4
NV	4	●	●			●	●			●	3	4
NJ	5		●	●	●	●	●		●	●	3	4
CA	6		●	●	●	●	●	●	●	●	4	4
OR	7	●	●	●		●	●	●		●	4	4
VA	8	●	●	●	●	●	●	●	●		4	3
UT	9	●	●			●	●				4	3
NY	10		●	●	●	●	●	●	●	●	3	4
TX	11		●	●	●	●	●			●	1	2
OH	12		●	●	●	●	●		●	●	4	4
RI	13		●	●	●	●	●	●	●	●	3	4
IA	14		●		●	●	●			●	3	3
CT	15		●	●	●	●	●	●		●	3	4
MD	16		●	●	●	●	●	●		●	3	4
DE	17		●	●	●	●	●	●		●	3	4
ME	18		●	●	●	●	●	●		●	3	3
NC	19	●	●				●	●		●	3	3
VT	20		●		●	●	●	●		●	3	4
NH	21		●	●	●	●	●	●		●	1	4
CO	22	●	●			●	●			●	3	4
PA	23		●	●	●	●	●			●	3	3
WA	24	●	●			●	●	●		●	3	3
NE	25	●	●		●	●	●				0	3
SD	26		●		●	●					2	0
MN	27	●	●		●	●	●	●		●	2	4
GA	28	●	●	●		●	●				1	3
OK	29		●		●	●	●				0	0
IN	30		●		●	●	●				3	3
MI	31	●	●	●	●	●	●			●	2	0
AZ	32		●			●	●			●	0	2
HI	33					●	●	●		●	3	1
MO	34	●	●		●	●	●			●	2	3
AR	35		●		●	●	●				0	4
SC	36	●	●				●	●			0	3
MT	37		●			●	●			●	2	3
ND	38				●	●	●				3	1
WV	39		●		●						3	4
KS	40	●	●		●						0	1
WI	41	●	●		●	●	●			●	1	1
TN	42		●			●	●				0	2
WY	43		●			●	●				0	3
ID	44		●			●	●				0	3
LA	45		●		●	●	●				0	1
MS	46		●			●	●				0	1
AK	47					●	●				0	2
FL	48		●								1	3
KY	48	●	●								0	3
AL	50		●								0	0

Source: REBA, CNEE, AEE, DSIRE, EIA, FERC, EQ Research, Solar Power Rocks, NREL, Shared Renewables HQ, Lean Energy US, IREC, Vote Solar.

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FACTORS DRIVING THE RESULTS

UTILITY MARKET STRUCTURE AND PROCUREMENT POLICIES

A state's electric utility market structure and availability of retail electricity choice is a key determinant of attractiveness for corporate RE procurement, and an important factor toward performance in this Index.

States with fully or partially deregulated electricity markets—those that allow C&I customers to choose their electric generation supplier—have a big advantage. The 14 states that receive full credit for having C&I retail choice are positioned in the top 23 of the overall Index. In some states with fully regulated markets—where electric utilities provide generation as well as transmission and distribution services—certain customers may still be able to purchase RE generation services. Some utilities in states that have fully regulated markets offer green tariff programs or direct utility procurement deals, allowing at least some customers to purchase RE through the utility. States where customers have taken advantage of these offerings also rank well in the Index: the five states where green tariffs or direct utility procurement deals make up more than 2% of total generating capacity are ranked #2 (New Mexico), #4 (Nevada), #7 (Oregon), #9 (Utah), and #14 (Iowa) in the overall Index.

A state's participation in an independent system operator (ISO) or regional transmission organization (RTO) is also a key attractiveness factor: regional electricity markets offer companies more options in their quest to procure RE. Of the top 20 states overall, only five do not have at least 87% of their electric utility customers served by a utility that participates in such a regional grid.

Further, this Index gives states credit for both having an RPS and additional credit for the amount of its target. States with an RPS generally scored better in the rankings: all of the top seven states have 25% or higher RPS (the top five with targets over 50%), whereas only three of the top 25 states don't have one in place. Only two states in the bottom 16 have an RPS.

THIRD-PARTY PURCHASING POLICIES

On policies that allow or incentivize third-party purchasing, the top overall states perform consistently well. Of the top 23 states, only #19 North Carolina does not allow third-party PPAs. For third-party leases, all of the top 38 states except for #26 South Dakota have this policy. The community energy-related policy indicators are a bit more sporadic, though some states have added to their policies in this area since the last Index. Six of the top ten and 13 of the top 20 states require utilities to offer community renewables, while all eight states that allow community choice aggregation are in the top 13.

ONSITE/DIRECT DEPLOYMENT POLICIES

Policy indicators in the Onsite/Direct Deployment category also help propel most of the top overall states to their high Index scores. The interconnection and net metering policy indicators offer grades from 0 to 4, rather than a simple either yes or no score, and here too, the top overall states show strength. For policies or regulations that ease the interconnection of DG systems to the grid, all but one (#11 Texas) of the top 20 states received a 3 or 4 for their score. Among the ten states with the lowest overall scores, none scored higher than a 1.

The policy of net metering—requiring a state's utilities to provide customers retail credit for excess electricity generated by onsite DG systems—is a critical state policy issue for solar customers of any kind. In this Index, the net metering indicator is indeed a big determinant of strong performance. Each of the states in the overall top ten scored a 3 or 4 in this indicator, as did all of the top 25 states except for Texas, though that state did improve its net metering score from a 0 in the 2017 Index to a 2 in this edition. A few states that ranked low overall show strong net metering policies, including Arkansas (#35) and West Virginia (#39). Compared to nine states in the 2017 Index, there are only four states with a zero grade for net metering this time: South Dakota (#26), Oklahoma (#29), Michigan (#31), and Alabama (#50).

ONSITE AND OFFSITE PROCUREMENT

New Jersey, Massachusetts, and California (each among the top 5 in the category overall) were the leaders in onsite corporate clean energy deployment where generating capacity from onsite procurements comprises between 3.49% and 5.80% of the state's total generating capacity. Illinois—the overall Index leader, Texas (#11), and Arizona (#32) had the most

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direct investment with 98 MW, 232 MW, and 50 MW of procurement deals, respectively. The growth in this arena since the last Index is significant: the number of states with offsite PPAs more than doubled, while the GW of those deals more than tripled.

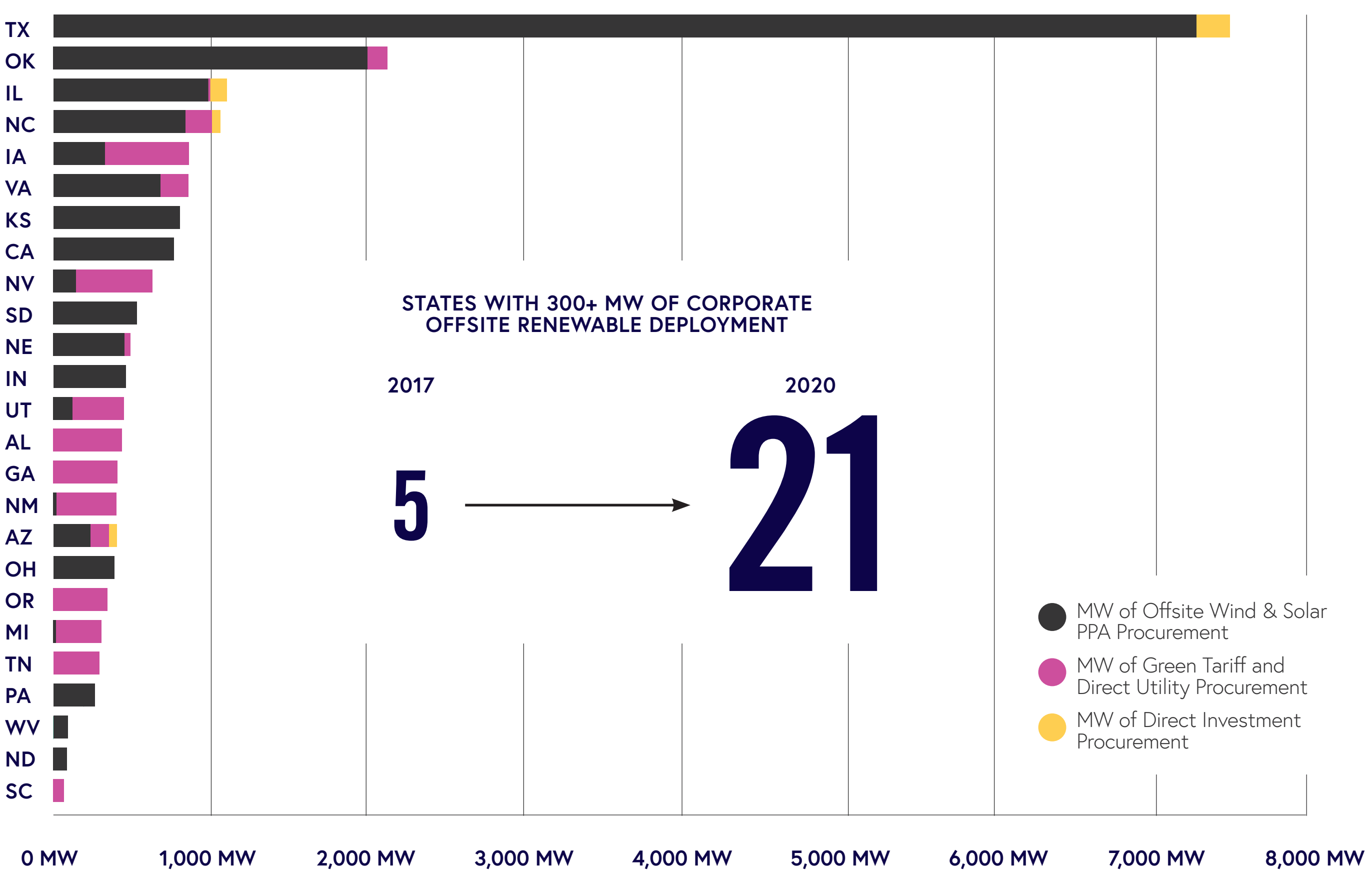
TAKEAWAYS

The availability of retail choice is a critical factor for a state's attractiveness to corporate and other large institutional buyers of RE. States that wish to gain the job creation and economic development benefits of corporate RE-powered facilities should encourage their policymakers and regulators to enable customer choice. Nonetheless, companies in some fully regulated states, such as New Mexico and Nevada, have successfully worked with utilities to create notable corporate RE deployments.

Beyond market structure and customer choice, other specific policies have a significant impact on corporate buyers' RE procurement (and increasingly, facility siting) decisions. Among these are the allowance of offsite third-party PPAs and leases, strong net metering requirements for onsite PV generation, and policies or regulations that ease the interconnection of DG systems to the grid.

According to the National Renewable Energy Laboratory's resource assessments from 2019, among the states that were in the bottom ten in the Index, several have above-average potential to harness renewable energy resources: Kansas, Wyoming, and Idaho for wind, and Florida for solar.[8] Policymakers and regulators in these states could capitalize on corporate RE procurement by enacting policies that are more conducive to additional deployment.

CORPORATE OFFSITE RENEWABLE DEPLOYMENT, TOP 25 STATES (IN MW)



Source: REBA, SEIA, AWEA, EIA 2019

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MARKET UPDATE

The status of the market for corporate renewables has changed since the first Index was released in 2017. Policy changes at the state level, national trends for corporate buyers, and overall deployment growth shape what the market looks like in 2020 and beyond.

POLICY CHANGES SINCE THE PREVIOUS INDEX

Numerous policies shape the RE market, several of which are measured in this Index. Since its first publication in 2017, some states adopted new policies, providing additional opportunities for companies that purchase electricity in those states to procure RE. For example, 17 states approved or proposed green tariffs, up from five states in the last Index. Five more states also made third-party PPAs clearly legal. Several states adopted community renewables policies, bringing the total to 19 states that offer such an option, while one state added a community choice aggregation policy, though the total number of states with such a policy remains small, at eight.

NATIONAL TRENDS FOR CORPORATE BUYERS

In order to meet aggressive targets, corporate electricity buyers continue to seek out opportunities for RE deals, which are rapidly increasing in number nationwide. From 2014 to 2016, less than six GW of corporate renewable deals were announced in the U.S. The volume of these deals has surged from 2017 through the third quarter of 2019, 16.3 GW of corporate renewable deals were announced, according to REBA.[9, 11]

OVERALL DEPLOYMENT GROWTH SINCE 2017

According to the EIA, RE comprised nearly 18% of total U.S. electricity generation in 2018.[10, 12] While 22 states counted wind, solar, or geothermal energy as one of their top three sources of electricity generation in 2015, that number increased to 25 states in 2018. Wind or solar power was the #2 electricity source in eight states and the #3 source in another 17, while geothermal was the #3 source in one state. Increases in deployment can be seen across all four of the deployment indicators in the three categories in this Index.

Utility Green Tariff or Direct Deployment

This deployment indicator measures the percentage of a state's total generating capacity installed through green tariffs or direct utility purchases. The number of states with this type of deployment more than doubled since 2017 from 8 to 17 states, and the amount of deployment increased nearly four times to 4.3 GW.

Offsite PPA Deployment

Deployment is measured by looking at the amount of wind and solar power that corporations procured through large offsite PPAs as a percentage of a state's total generating capacity. In this indicator, the number of states with third-party purchasing deployment increased from 14 states in 2017 to 29 states, while the amount of deployment increased from 4.8 GW to 16.6 GW.

Onsite RE Deployment

This category has two deployment indicators which consider how much generating capacity in each state is comprised of C&I onsite deployment of wind and solar and large offsite projects directly owned by a company. Here, too, there are increases: the number of states with companies that have onsite solar or wind grew from 37 in 2017 to 46, with total deployment increasing from 0.8 GW to 5.5 GW.

While direct investment contracts have only been signed in four states, up from three in the previous Index, there was still increased deployment from 283 MW in the 2017 Index to 420 MW now.

THE FUTURE OF THE MARKET

The national trend towards the deployment of more RE generation is evident in policy changes at the state level. Additionally, large corporations are making new and revised commitments to utilize additional renewable resources. Further deployment of renewable generation by utilities who are working with companies is also on the rise. As more companies demand additional renewable resources, procured directly or through utility programs, the market will continue to expand.

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BUYER BEWARE: VA, OH, NC

One of the most significant challenges for corporate energy buyers is that the U.S. RE market is far from a single, uniformly organized entity. It is a complex combination of markets with different structures and policies. This creates significant confusion for companies considering RE, especially for larger buyers evaluating options across multiple markets and for smaller entities with limited internal expertise. It's worth highlighting some of the specific market barriers C&I buyers may want to consider:

VIRGINIA

Virginia (#8) has made progress since the previous edition of the Index when it was ranked #20. Much of that progress has been driven by companies that have engaged successfully to demand more access to RE options.

There is strong additional RE momentum in Virginia. Under a September 2019 executive order from the governor, Virginia targets having 2.5 GW of offshore wind in operation by 2026 and 100% carbon-free energy by 2050.[13] Additionally, Virginia does offer retail choice for residential customers, however the path is not as clear for C&I customers. The RE utility products that do exist primarily serve large, new load C&I customers and so leave large existing loads unserved by effective RE options. C&I customers continue to call on the government and utilities in the state to provide more RE options.

Policymakers have been presented with multiple options that would increase competition and customer access to supply options, yet incumbent utility interests opposed to those expansions have prevailed to date.

OHIO

In Ohio (#12), while many of the indicators in the data sets used to generate the rankings remain solid, policy developments unique to the state (and thus outside the scope of this Index) provide a very significant warning to companies interested in effective RE procurement. HB6, signed by Governor Mike DeWine in the summer of 2019, reduces the Ohio RPS target for 2026 and then eliminates the target after 2026.[14] The law also provides costly bailouts for two nuclear plants and two aging coal plants owned by a utility collective. Further, the law also reduces the state's energy efficiency target.

Moreover, in 2014, Ohio passed another unique policy (again outside the scope of this Index) which implemented a set of highly challenging requirements for wind projects, according to wind developers. These requirements reduce the number of turbines a given project can host, diminishing power generation potential and increasing development costs.

Many advocates expect a chilling slowdown in new RE development in Ohio. Companies should actively consider these pullbacks from policy commitments and restrictive siting requirements when looking for procurement options in the state.

NORTH CAROLINA

North Carolina (#19) has seen growth in onsite solar deployments, but—like Virginia—customer choices are very limited for offsite projects due to pro-incumbent utility policies. North Carolina does allow for the offering of green tariff programs by incumbent utilities, however they have not found high rates of market acceptance, largely due to pricing considerations. Only three corporations participated in the initial pilot green tariff program and the City of Charlotte is the only customer to publicly announce its intention to participate in the current program. Other jurisdictions that have offered a more favorable green tariff have experienced a larger rate of participation. A shift in this dynamic could open North Carolina up to a notable acceleration in offsite RE procurements and deployments.

TEXAS

Conversely, Texas is notable for its continued success with C&I utility-scale power purchase agreements (PPAs) via third-party providers. Texas has more than 7 GW of RE capacity—nearly six percent of the state's entire electric generation portfolio. Texas' combination of competitive market access and favorable development policies continues to enable high degrees of C&I-driven RE activity. Despite dropping a few spots in this year's Index, Texas remains a very attractive market for specific projects.

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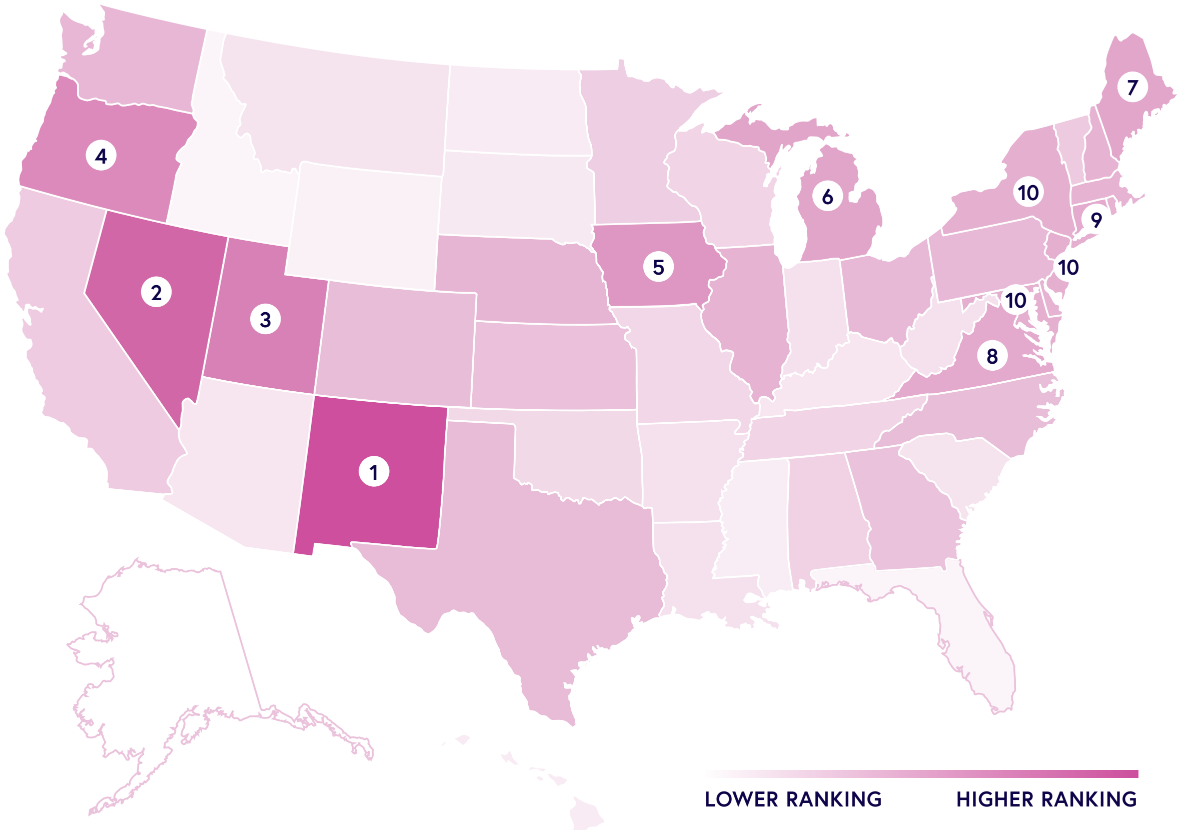
CORPORATE CLEAN ELECTRICITY PROCUREMENT INDEX:

UTILITY PURCHASING OPTIONS & MARKET STRUCTURE



Of the top 25 states in this category, only four of them do not have an RPS in place and 14 of the top 20 states in the category have most or all of their customers in an ISO/RTO

RANK	STATE	INDEX SCORE	RANK	STATE	INDEX SCORE
1	New Mexico	100.00	26	Kansas	34.35
2	Nevada	88.18	27	South Carolina	33.23
3	Utah	71.60	28	Vermont	29.45
4	Oregon	66.26	29	California	28.17
5	Iowa	58.39	30	Minnesota	26.17
6	Michigan	50.17	31	Alabama	24.20
7	Maine	48.78	32	Wisconsin	22.90
8	Virginia	47.23	33	Tennessee	22.72
9	Connecticut	45.81	34	Missouri	20.61
10	New York	44.17	35	Oklahoma	19.67
10	New Jersey	44.17	36	Indiana	14.72
10	Maryland	44.17	36	Arkansas	14.72
13	Illinois	41.15	36	Louisiana	14.72
14	Rhode Island	40.90	36	West Virginia	14.72
14	Massachusetts	40.90	40	Montana	14.29
14	New Hampshire	40.90	41	Arizona	13.38
14	Delaware	40.90	42	Kentucky	12.67
18	Nebraska	39.97	43	South Dakota	11.16
19	Washington	39.26	44	Hawaii	9.82
20	Georgia	38.88	45	North Dakota	9.82
21	Ohio	37.63	46	Mississippi	9.37
21	Pennsylvania	37.63	47	Wyoming	6.91
23	Texas	37.37	48	Idaho	4.91
24	Colorado	35.99	48	Florida	4.91
25	North Carolina	35.76	50	Alaska	0.00

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OVERVIEW

The Utility Purchasing Options category measures two key aspects of corporate RE procurement: a company's ability to purchase RE through its electric utility, and the basic structure of the state's electric utility market. The category's sole deployment indicator measures the percentage of a state's total generating capacity installed through green tariffs (special tariffs available to large customers that help finance new RE development), green power purchasing options, or direct utility purchases (special deals negotiated between a utility and a corporate customer to procure RE through the utility).

The policy subcategory consists of three indicators. The first rewards states that either mandate that their utilities offer green power programs, where customers generally pay extra for a "block" of a few hundred kilowatt-hours of RE, or where some utilities offer these programs voluntarily. The second policy indicator, the Retail Choice Indicator, is comprised of two sub-indicators. The first credits states for being home to a utility that offers a green tariff or rider, while the second awards credit to states that have restructured to allow electric retail choice.

The final policy indicator in this category, the Market Structure Indicator, also has two sub-indicators. One sub-indicator rewards states for being part of an ISO or RTO, such as the PJM Interconnection, while the other provides credit to those that have an RPS. States with the strongest RPS (50% or greater) get full credit for this sub-indicator. A state that has either of these two measures in place, or provides expansive C&I customer choice, offers companies more options in their quest to procure RE.

RESULTS

New Mexico leads this category and jumped 20 spots compared to the 2017 Index. The state now has nearly 400 MW of green tariff or direct utility purchase deals and has a strong RPS. Nevada maintained its #2 position in this category, with almost 500 MW of total green tariff or direct utility purchase deals to go along with its RPS. Another Mountain West state, Utah, moved ahead to #3 in this category. Though Utah does not have an RPS and is not part of an ISO/RTO market, the state does have more than 330 MW of green tariff or direct utility purchase deals, bringing its percentage of total state electric generating capacity from green tariff or direct utility purchase deals to 3.74%.

Oregon was previously tied for #21, but rose to the #4 spot with more than 350 MW of total green tariff or direct utility purchase deals. Former front-runner Iowa rounds out the top five in this year's Index, with nearly 550 MW of total green tariff or direct utility purchase deals.

Filling in the top ten were Michigan (#6), Maine (#7), Virginia (#8), Connecticut (#9), and New Jersey, New York, and Maryland (#10). Of the top half of all states in this category, only four have no RPS, while of the bottom 16 states, just two have an RPS. All nine Northeastern states have an RPS, and all but two (#21 Pennsylvania and #28 Vermont) landed in the top 20 in this category. The Mid-Atlantic states also did well in this category: in addition to Virginia (#8), which has some deployment and relatively strong policies, Maryland (#10) and Delaware (#14) ranked well due to the strength of their policies.

DEPLOYMENT COMPARISON: GREEN TARIFF OR DIRECT UTILITY DEALS

INDEX YEAR	NUMBER OF STATES	TOTAL DEPLOYMENT (GW)
2017	8	1.1
2020	17	4.3

Source: WRI, 2016. REBA, 2019.

Each of the top six states have at least 300 MW of deployment, while Iowa (#5), Michigan (#6), and Virginia (#8) all scored well with a mix of deployment and policy, in particular ISO/RTO market participation.

POLICY DISCUSSION

While nearly all states offer some green power purchase option, the choice of electric generation supplier—at least for C&I customers—is only offered in 18 states. Many, though not all, of these states also have deregulated electricity markets.

However, states with deregulated electric markets are no longer the only ones that offer at least some of their customers the ability to purchase RE. The proliferation of states that offer green tariffs—now at 17 states with new-build green tariffs approved or proposed, up from five states in the last Index—means that more customers now have the option to purchase RE through their utility. States scored well in this category where

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customers have taken advantage of this offering. This flexibility was evident in the first Index but has increased rapidly in the last three years.

While customer choice is an important first step, including the ability to provide cost savings or price stability over the long term is even more critical. Green tariffs and direct utility deals, while providing consumers options, may only be available at a premium cost: green tariffs are often priced separately in riders that are in addition to a customer's typical electric rate. Price premiums could be offset by long-term price predictability, but deals that offer neither savings nor stability may not be attractive to customers.

Customers in deregulated states can procure RE directly from an electric generation supplier and may realize cost savings, especially as the economics of developing and maintaining solar and wind generation facilities continue to decease. These customers may also be able to negotiate long-term deals, locking in continued savings. Work must proceed in regulated states to encourage additional RE purchasing options, while also providing opportunities for customers to benefit from the declining costs of RE generation.

This year, the Index considered whether any electric customers in a state are in an electric service territory that participates in an ISO or RTO, as well as if states implemented an RPS as part of their renewable energy

GROWTH IN GREEN TARIFFS

Green tariffs are special, commission-approved utility rate structures that allow C&I or other customers to obtain RE (and the associated renewable energy credits (RECs)) directly through the customer's utility. Green tariffs can be structured as tariffs or as riders placed on top of the customer's existing tariff. Generally, where green tariffs are offered, they are broadly available to large C&I customers and build upon a company's existing relationship with its utility, offering predictability and replicability to customers. But sometimes, green tariffs come at a price premium and do not guarantee additionality.

As of November 2019, 17 states have approved or proposed green tariffs through their state public utility commission. This is a dramatic increase since the first Index was completed, when only five states had approved green tariffs. Of the 17 states where green tariffs are currently offered, deals have been executed in 15 of them.

The following chart lists all states where a green tariff program has been approved for at least one utility in the state, though deals utilizing the tariff have not been executed in all states. The year listed is when the earliest tariff in the state was approved, as some states have had more than one program over time. The status indicates whether a state has a current approved program, as at least one state had a tariff that concluded, though it later started a new program. In all, 31 tariffs have been approved or are pending approval in 18 states since 2013.

STATES WITH GREEN TARIFF PROGRAMS

STATE	YEAR EARLIEST PROGRAM APPROVED	STATUS	UTILIZED
Nevada	2013	Approved	Yes
North Carolina	2013	Approved	Yes
Utah	2015	Approved	Yes
Colorado	2016	Approved	Yes
New Mexico	2016	Approved	Yes
Virginia	2016	Approved	Yes
Washington	2016	Approved	Yes
Georgia	2017	Approved	Yes
Nebraska	2017	Approved	Yes
Wisconsin	2017	Approved	Yes
Kansas	2018	Approved	Yes
Kentucky	2018	Approved	No
Michigan	2018	Approved	Yes
Missouri	2018	Approved	No
South Carolina	2018	Proposed	N/A
Minnesota	2019	Approved	No
Oregon	2019	Approved	Yes

Source: REBA U.S. Electricity Markets: Utility Green Tariff Update—a 2019 report by the World Resources Institute staff on utility green tariff offerings throughout the US. https://wriorg.s3.amazonaws.com/s3fs-public/emerging-green-tariffs_0.pdf

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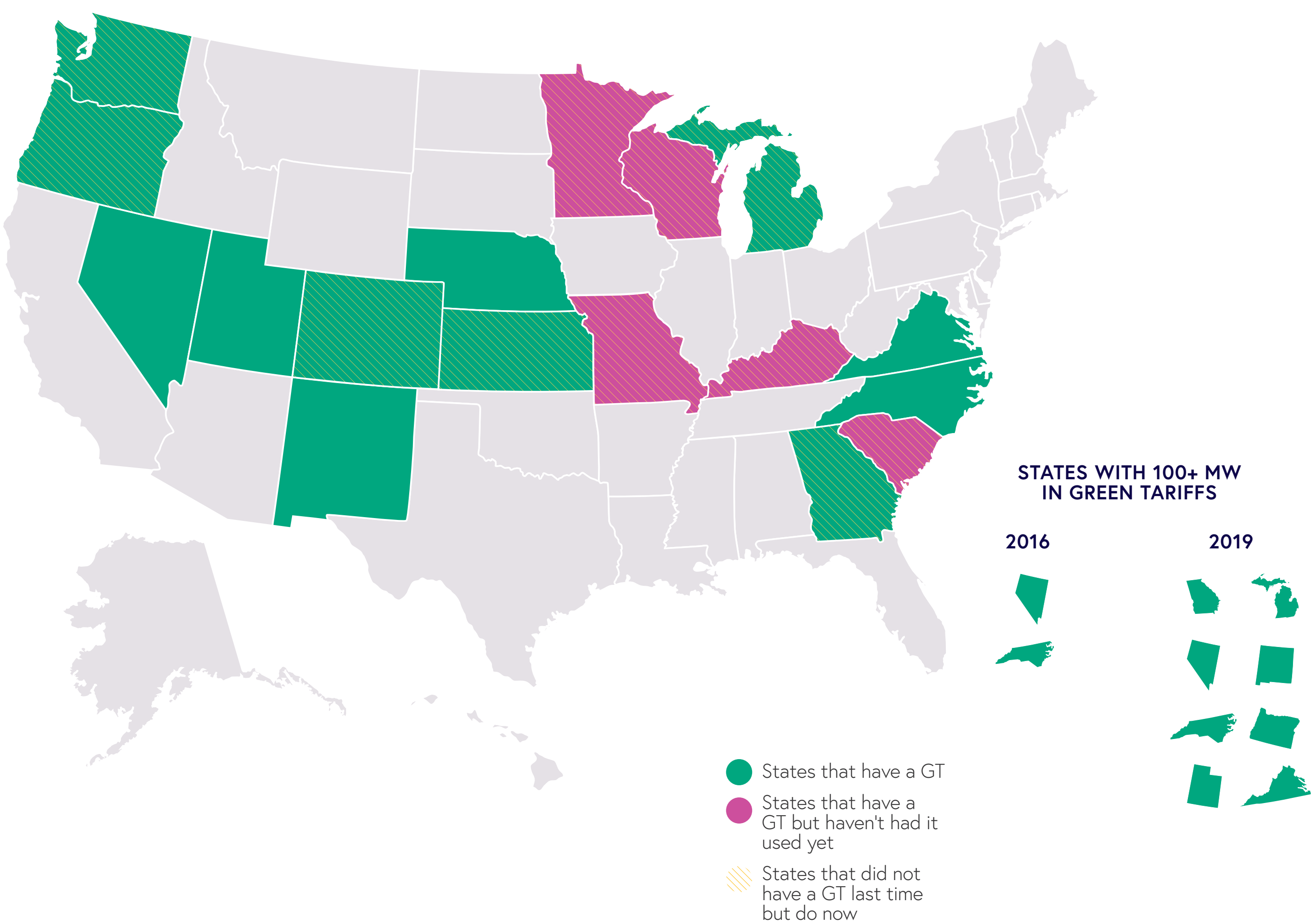
policy. Twenty-nine states have an RPS in effect. Thirty-one states have a majority of their electric utility customers served by a utility that is part of an ISO or RTO, and an additional eight states have at least some customers served by such a utility. Of the top 20 states in the overall Index, 18 have an RPS, and in 15 of the top 20 states at least 87% of each state's electric customers are located in utility territories that are part of an ISO or RTO. Of the bottom 10 states, only one has an RPS, and 12 of the bottom 20 states have less than half of each state's electric customers located in utility territories within an ISO or RTO.

State policies that include an RPS provide customers with a starting point for RE, while participation in an ISO or RTO provides access to a larger marketplace for customers and utilities alike to obtain RE, as state laws permit. Of those states where at least some electric customers are in a service territory that participates in an ISO or RTO, 64% also have an RPS.

GREEN TARIFF MAP



Source: REBA, SEIA, AWEA, EIA 2019

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ADDITION OF AN RPS INDICATOR

Since the previous edition of the Index, renewable portfolio standards (RPSs) and utility purchasing options have both evolved significantly across the U.S. market. These changes have impacted the state rankings and may be important considerations for companies evaluating their RE sourcing options.

As of November 2019, 13 U.S. states, the District of Columbia, and Puerto Rico have a 100% clean energy or renewable energy target, goal, or portfolio standard. Those states include: Washington, California, Nevada, New Mexico, Colorado, Hawaii, Minnesota, Wisconsin, New York, Maine, Connecticut, New Jersey, and Virginia.

This is a remarkable shift in the market and reflects continued and growing confidence by policymakers in the technical, economic, and environmental value of RE. For companies, the possibility of high levels of RE via utility-delivered default power products can be very attractive.

Companies seeking to source significant amounts of RE have traditionally been forced to undertake procurement initiatives on their own. The collective results of these efforts have been significant, of course, but the difficulty and expense of those initiatives has also been significant.

Thinking specifically about power purchase agreements (PPAs), companies have routinely cited risk and complexity as barriers to entering the market or as constraints on their ability to move more quickly. Corporate RE procurements—even in the case of companies working with expert third-party advisors—can often run one to three years from launch to deal execution. Multiple internal stakeholders have to be engaged and educated on the complex dynamics between commodity power procurement and a PPA that will likely occur in a different state or energy market.

High-percentage RPSs should enable more companies to access RE with reduced complexity, risk, and effort than would otherwise be possible. These benefits are key to continuing to accelerate RE deployments that convey economic and environmental benefits to all stakeholders.

Similarly, states with utility RE products that align well with corporate buyers' needs have seen strong utilization of these products and have moved up in the rankings. Notable examples include New Mexico, Nevada, and Utah.

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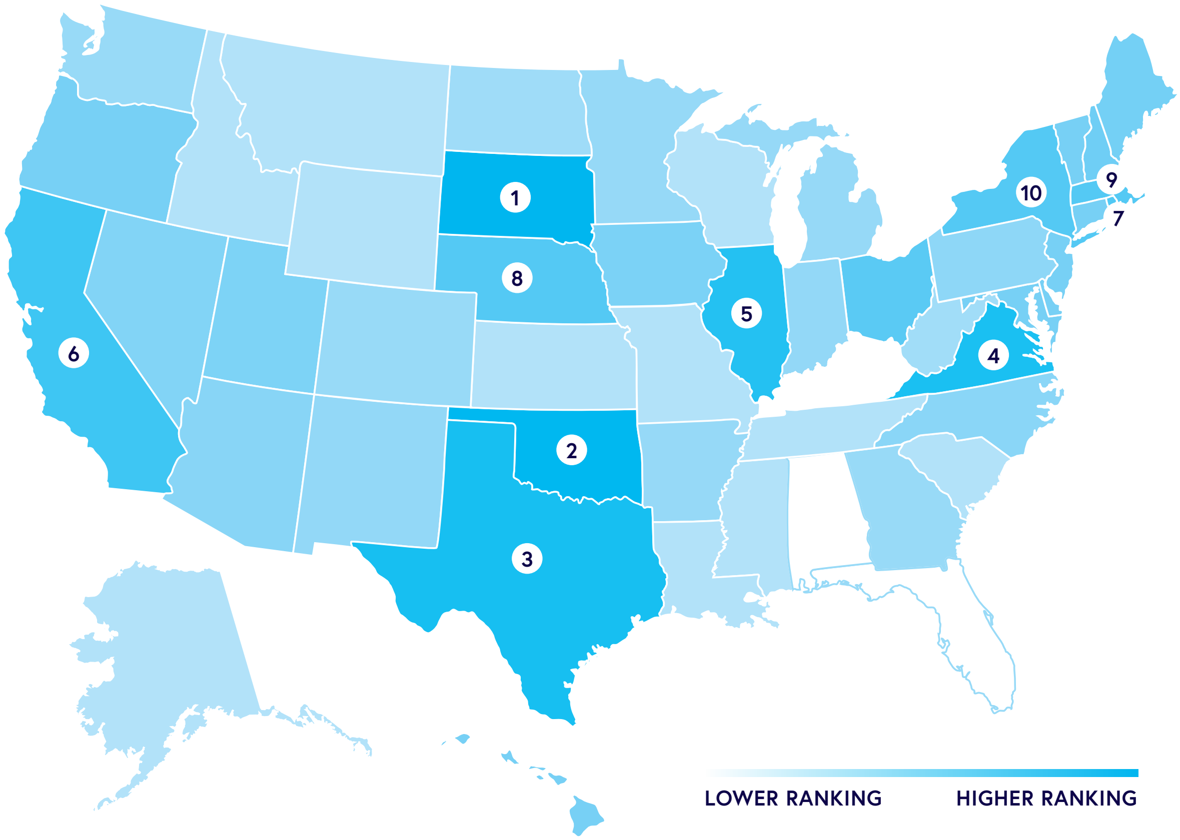
CORPORATE CLEAN ELECTRICITY PROCUREMENT INDEX:

THIRD-PARTY PURCHASING OPTIONS



Each of the top six states in this category has over 500 MW of offsite PPA procurements.

RANK	STATE	INDEX SCORE
1	South Dakota	100.00
2	Oklahoma	94.51
3	Texas	83.88
4	Virginia	83.19
5	Illinois	81.30
6	California	73.49
7	Rhode Island	67.69
8	Nebraska	67.46
9	Massachusetts	67.41
10	New York	67.00
11	Ohio	65.16
12	New Hampshire	58.84
13	Maine	57.36
14	Hawaii	56.35
15	Delaware	56.06
16	New Jersey	55.56
16	Oregon	55.56
16	Connecticut	55.56
16	Maryland	55.56
16	Vermont	55.56
21	Iowa	55.44
22	Utah	53.64
23	Nevada	51.80
24	Arizona	50.18
25	North Carolina	49.47
26	Pennsylvania	48.34
27	New Mexico	46.05
28	Indiana	45.50
29	Minnesota	45.06
30	Arkansas	45.00
31	Michigan	44.86
32	Colorado	44.44
32	Washington	44.44
32	Georgia	44.44
35	North Dakota	40.62
36	Missouri	33.33
36	Montana	33.33
36	Tennessee	33.33
36	South Carolina	33.33
36	Wisconsin	33.33
36	Wyoming	33.33
36	Idaho	33.33
36	Louisiana	33.33
36	Mississippi	33.33
36	Alaska	33.33
46	Kansas	32.65
47	West Virginia	4.35
50	Florida	0.00
50	Kentucky	0.00
50	Alabama	0.00

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OVERVIEW

The five indicators in the Third-Party Purchasing category are influential ones for large purchasers. Access to RE and choice in the market are key factors for many companies with 100% RE targets in their site selection process as they consider where to expand or move their operations.

This category's quantitative deployment indicator measures the amount of wind and solar power that corporations have procured—through large offsite PPAs, REC contracts, equity investments, and community solar projects—expressed as a percentage of total in-state installed capacity. (It is important to note that third-party offsite PPAs are generally only available in states with organized competitive electric markets.)

The first two policy measures reward states for allowing onsite third-party PPAs and leases. The Index only gives states credit for these indicators if they also allow participants to engage in net metering or a similar program. Additionally, there are two indicators that reward states for allowing customers to pool their resources. One credits states for requiring utilities to offer community renewable energy programs, and the other indicator credits states that offer community choice aggregation (CCA).

RESULTS

The middle of the country scored well in this category with South Dakota, Oklahoma, and Texas taking the top spots. For each of these states, the offsite procurement generating capacity is more than five percent of the state's entire electric generating capacity. Texas and Oklahoma led this category in 2017, while South Dakota was previously ranked #39 This year, though South Dakota did get credit for permitting third-party PPAs for DG systems, its success in this category was predominantly due to deployment which comprised more than 13% of its total electric generating capacity. Both Oklahoma and Texas did well due to a mix of favorable policies and strong deployment (they are the only two states with more than 1 GW of deployment), while Virginia (#4) and Illinois (#5) rounded out the top five with improved policies and deployment numbers.

CATEGORY OVERALL TOP 5

Deployment Comparison: Offsite Third-Party Procurement (% of Total State Electric Generating Capacity)

STATE	2017 INDEX MW	2017 % OF CAPACITY	2020 INDEX MW	2020 % OF CAPACITY
South Dakota	0	0	546	13.1%
Oklahoma	799	3.22%	2,022	7.38%
Texas	2,237	1.91%	7,213	5.81%
Virginia	80	0.30%	680	2.44%
Illinois	175	0.39%	988	2.16%

Source: REBA, SEIA, AWEA and U.S. EIA 2019. And note that other leaders not in the top 5 of the Index category, were leading for deployment of offside procurement as a % of total capacity including Nebraska at 5.03%, Kansas at 4.81%, and North Carolina at 2.38%

The coastal states of California, New York, and Massachusetts made up the rest of the top five in 2017, but each fell somewhat this year to #6, #10, and #9, respectively, as other states added respectable amounts to their offsite procurement portfolios. There are now 16 states with more than 100 MW of deployment via third-party PPA deals, and 29 states have some level of deployment.

DEPLOYMENT COMPARISON: THIRD-PARTY PURCHASING OPTIONS

INDEX YEAR	NUMBER OF STATES	TOTAL DEPLOYMENT (GW)
2017	14	4.8
2020	29	16.6

Source: AWEA, RMI, WRI 2016. AWEA, REBA, SEIA 2019.

Nebraska (#8) leapt ahead 31 spots from the 2017 Index due to its deployment and increased policy score on third-party leasing. The state had a high level of deployment as a percentage of its total generating capacity at 5.03%, as did Kansas (#46) at 4.81% and North Carolina (#25) at 2.38%, though the latter two states did not score as well overall due to low policy scores.

POLICY DISCUSSION

States across the country use a variety of policies to increase third-party purchasing of RE. The policy indicators used in this category—PPAs, leases, community renewables, and community choice aggregation—demonstrate the diverse deployment strategies that allow states to be successful.

South Dakota's success in this category demonstrates that a state can do well by deploying a proportionately

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large amount of offsite renewable generation. However, the experiences of Kansas and North Carolina show that strong deployment does not guarantee success in the Index—particularly if it is not accompanied by robust, supportive policies that provide buyers a diversity of procurement options.

Since the last Index was published, five more states have clarified the legality of third-party PPAs: Arizona, Arkansas, Oklahoma, Utah, and Virginia. Each of these states also saw gains in offsite deployment, with Oklahoma and Virginia making it into the top five in the category, as discussed above in the Results subsection. This brings the total number of states where the legality of PPAs has been clarified under state policy to 28. While the legal status of PPAs remains ambiguous in several states, seven states continue to specifically prohibit third-party PPAs. As demonstrated by Oklahoma and Virginia, permitting PPAs can help unlock the potential for procurement of offsite wind and solar electric generation resources.

The Index illustrates how C&I electricity customers are utilizing the option to procure offsite RE, particularly in places that do not have a strong RPS, as measured by this Index. Of the 15 states where at least 1% of total generation is from offsite wind and solar PPA procurement, eight have no RPS and four more receive less than full credit for their RPS being less than 25%. In contrast, of the 11 states that receive full credit for their RPS (being over 50%), five have no generation from offsite wind and solar PPA procurement, while the remaining six have somewhat lower offsite procurement ranging from 0.05% to 1.08% of their total generating capacity.

Since the 2017 Index was published, five additional states have adopted community renewable energy policies, bringing the total to 19. One state has also added a community choice aggregation policy, though the total number of states with such a policy remains small, at eight.

STATE TO WATCH: SOUTH CAROLINA

In May 2019, South Carolina lawmakers unanimously passed the Energy Freedom Act to open the state's energy market. As a result, renewable energy developers are now able to enter a competitive market and work directly with businesses to meet clean energy demand. The law ensures that the state's solar industry will continue expanding, as long as it remains truly competitive. The law, as signed by Governor McMaster, will also:

- Require the Public Service Commission to initiate a new proceeding to review and approve rates and terms provided to large-scale solar facilities, ensuring contract terms are reasonable for such projects;
- Eliminate net metering caps and extend the existing residential solar rates for two years until the Public Service Commission determines a successor program;
- Provide for more transparency and competition in long-term utility generation planning; and
- Give the Public Service Commission the authority to establish a new neighborhood community solar program with the opportunity to expand solar access to low-income customers.

In March 2019, 32 businesses, including retailers such as Home Depot, Target, and Walmart, sent a **letter**[1] to the Senate Judiciary Committee publicly supporting the legislation. The unification of the supplier and buyer community in favor of this law provided enough political support for policy makers to engage in an effective negotiation with the incumbent utility over aspects of the law. Other state's leaders would benefit from looking to South Carolina as a model for how to do renewable energy policy right.

At the time of writing this report, many of these policy changes had not gone into effect as the bill requires future action at the state public service commission. Therefore, the state's overall ranking did not change significantly from 2017. However, given the projected RE deployment as a result of the pending policy changes, South Carolina is likely to improve considerably in future iterations and is our state to watch for this edition of the Index.

1 https://www.employersforrenewableenergy.com/wp-content/uploads/2019/05/SC-h.-3695-Support-Letter-3-11-19.pdf

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PPAS

2017 DEALS IN 14 STATES;

2020 DEALS DOUBLE TO 29 STATES

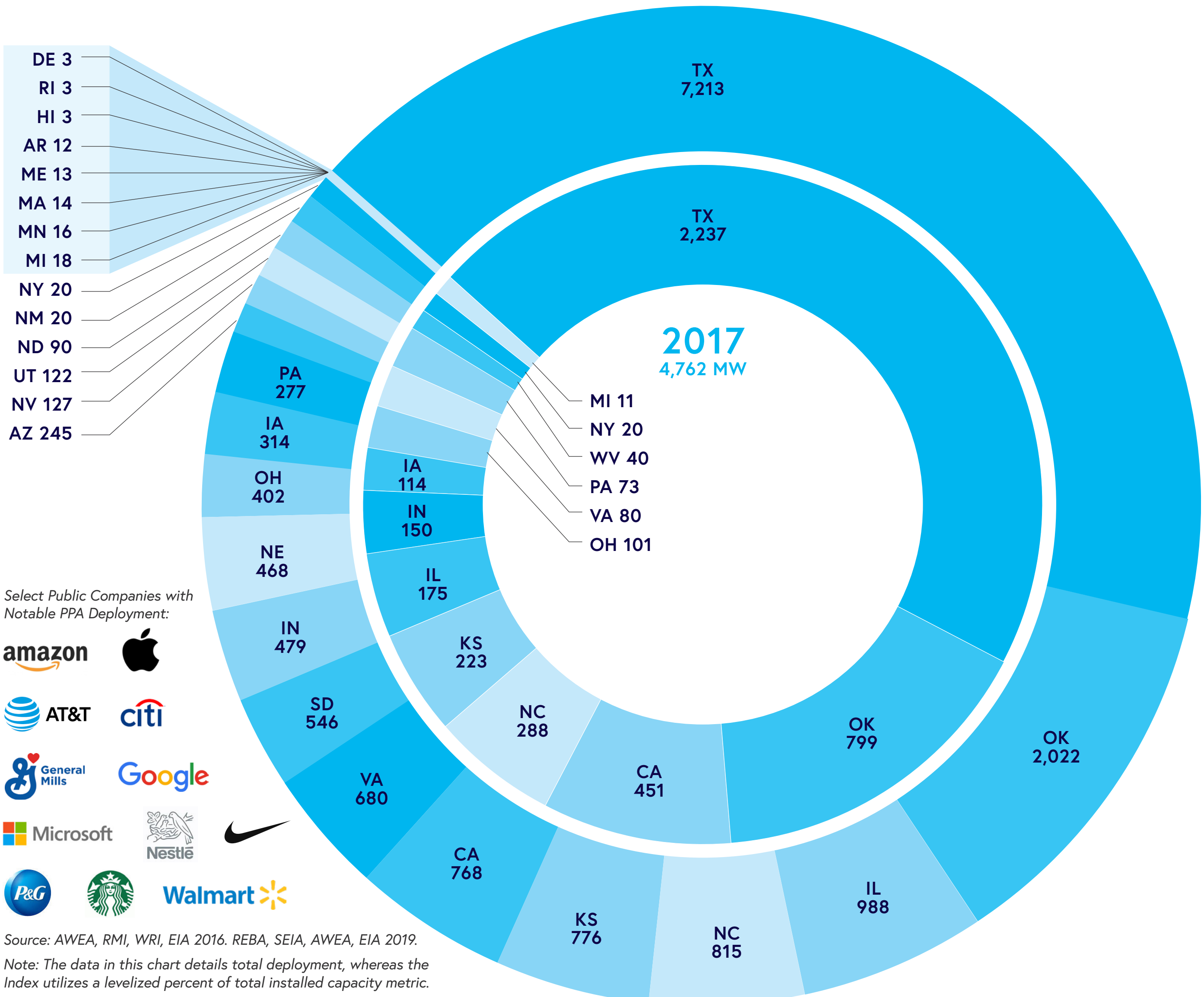
43%

OF ALL PPAS ARE IN TX, MORE THAN THE BOTTOM 47 STATES COMBINED

9 STATES WITH OVER 100 MW IN 2017

NOW 16 STATES OVER 100 MW

CORPORATE OFFSITE THIRD-PARTY WIND & SOLAR PPA DEPLOYMENT (MW) BY STATE



Select Public Companies with Notable PPA Deployment:

amazon, Apple, AT&T, citi, General Mills, Google, Microsoft, Nestlé, Nike, P&G, Starbucks, Walmart

Source: AWEA, RMI, WRI, EIA 2016. REBA, SEIA, AWEA, EIA 2019.

Note: The data in this chart details total deployment, whereas the Index utilizes a levelized percent of total installed capacity metric.

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THIRD-PARTY PURCHASING

ARKANSAS CASE STUDY

To date, most renewable capacity deployed via third-party purchasing options has been through large, offsite projects. However, as the price of solar becomes more cost-effective (and the cost of battery storage continues to decline), companies are increasingly looking to onsite options to meet their renewable objectives and/or to directly power their facilities with RE.

Additionally, onsite projects are great options for companies with numerous commercial-scale facilities such as warehouses, hospitals, office facilities, and brick-and-mortar stores. Furthermore, as smaller businesses look toward RE options, policies that enable cost-effective onsite procurement options will grow in importance.

Until this past year, the lack of onsite procurement options, in addition to the existence of policy barriers to third-party financing—both solar leases and onsite PPA's—were obstacles for many businesses with renewable targets in Arkansas.

In the 2017 Index, Arkansas was tied for last place in third-party purchasing with a score of zero. For 2020, Arkansas has jumped to #30 in the category and moved up 8 spots overall—from #42 in 2017 to #34 in 2020. This jump was catalyzed by a simple 2019 bill that received overwhelming bipartisan support. Let's take a moment here to examine how a small policy change can drive market development.

The Solar Access Act (SB 145), introduced by Senator Dave Wallace (R-Leachville) and Representative Aaron Pilkington (R-Clarksville) in early 2019, began as a mere two-page bill with only two objectives:

1. To allow onsite third-party purchasing options by residential and C&I customers directly with clean energy companies, and
2. To increase the RE facility size limit of net-metered installations from 300 kilowatts (kW) to 1 megawatt (MW) for C&I customers (and retain the current net metering cap for residential customers).

The bill was publicly supported[1] by several leading companies with facilities located in Arkansas who have ambitious RE objectives, including Mars, Target, Unilever, and Walmart—which is famously headquartered in the state. The political driver for the bill was the compelling business case around its potential to generate jobs and provide economic growth.

Ultimately, the bill expanded to ten pages during the legislative process as stakeholders negotiated several compromises. However, once an agreement was reached, the bill received overwhelming bipartisan support, passing the Senate 28-2 and the House 83-5.

Arkansas is now well positioned to dramatically increase its deployment of onsite C&I solar as a result of this legislation. It will continue to improve in this category as projects are brought online. The Solar Access Act provides a great example of how a small policy change can make a big difference for companies working to achieve RE objectives and a great template for other states in the Southeast looking to expand their untapped solar potential.

1 https://www.dgardiner.com/wp-content/uploads/2019/02/SB145-Corp-Sign-on-letter-2-18-19.pdf

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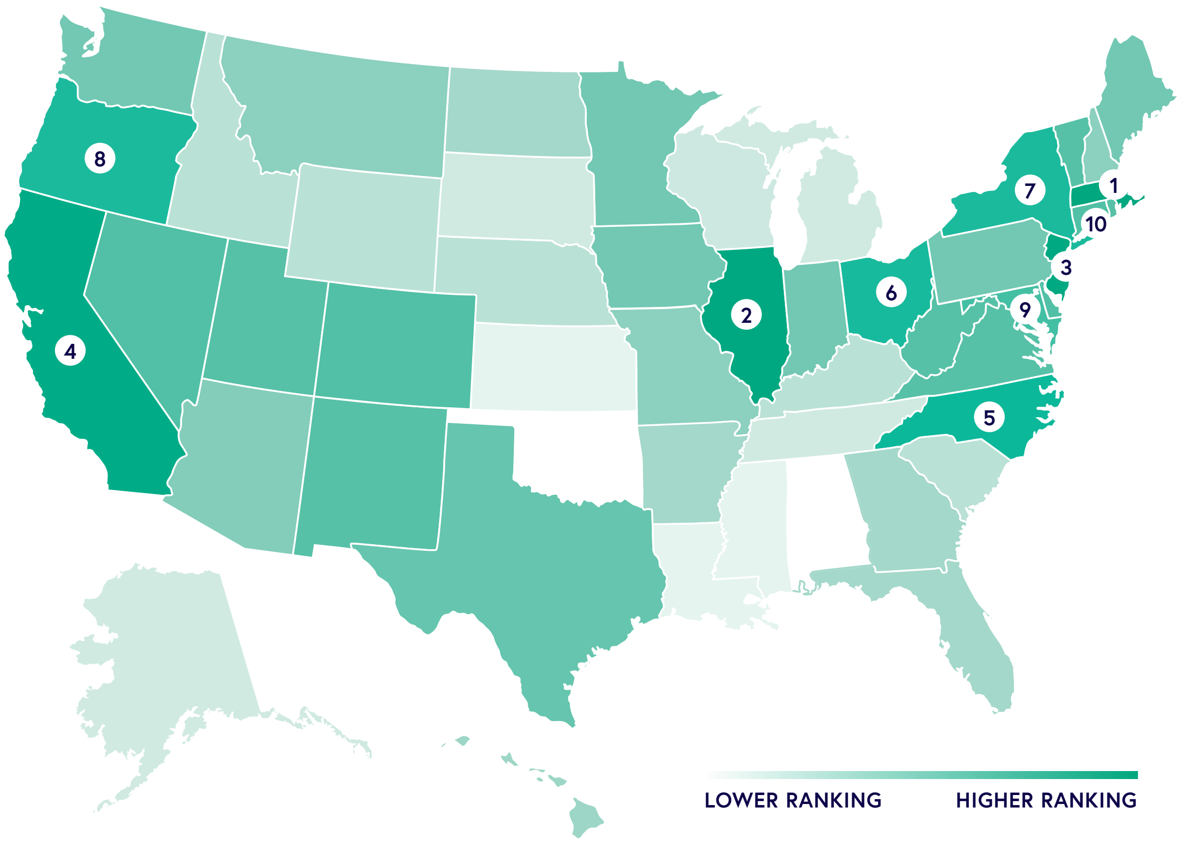
CORPORATE CLEAN ELECTRICITY PROCUREMENT INDEX:

ONSITE/DIRECT DEPLOYMENT OPTIONS



All of the top 10 overall are in the top 18 of this category.

RANK	STATE	INDEX SCORE
1	Massachusetts	100.00
2	Illinois	98.57
3	New Jersey	98.41
4	California	93.11
5	North Carolina	74.80
6	Ohio	72.65
7	New York	71.98
8	Oregon	71.91
9	Maryland	65.59
10	Connecticut	64.49
11	Delaware	63.95
12	Nevada	63.84
13	Colorado	63.62
14	Vermont	63.49
15	Utah	63.42
16	New Mexico	62.99
17	Rhode Island	62.86
18	Virginia	62.74
19	West Virginia	62.62
20	Texas	58.29
21	Pennsylvania	54.15
22	Maine	54.13
23	Minnesota	54.08
24	Iowa	53.74
25	Indiana	53.72

RANK	STATE	INDEX SCORE
26	Washington	53.70
27	Arizona	48.01
28	New Hampshire	45.11
29	Missouri	44.77
30	Montana	44.75
31	Hawaii	38.97
32	Florida	36.05
33	North Dakota	35.98
34	Georgia	35.92
35	Arkansas	35.83
36	South Carolina	27.34
37	Nebraska	27.09
38	Wyoming	27.07
39	Kentucky	26.96
40	Idaho	26.84
41	Wisconsin	18.82
42	Tennessee	18.27
43	Michigan	18.09
44	Alaska	17.91
45	South Dakota	17.89
46	Kansas	9.21
47	Louisiana	9.01
48	Mississippi	8.96
50	Oklahoma	0.00
50	Alabama	0.00

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OVERVIEW

The number of corporate customers that are deploying renewables, usually solar PV on facility rooftops or on corporate campuses, continues to grow as these companies strive to achieve increasingly aggressive RE targets. The Onsite/Direct Deployment category measures this trend, along with the most significant state policies and regulations that help such deployment. Where feasible, onsite solar arrays or wind turbines provide clear RE additionality as well as visibility of a company's RE commitments.

Of the three categories in the Index, Onsite/Direct Deployment has the most overlap with the overall rankings. Of the top 20 states in this category, all but two—Colorado and West Virginia—are also in the top 20 in the overall Index.

This category has two deployment indicators and two policy indicators. The deployment indicators consider how much generating capacity in each state is comprised of: (1) C&I onsite deployment of distributed wind and solar generation, and (2) large offsite projects that are directly owned by a company. Indicator scores are higher where more of a state's total electric generating capacity comes from these sources.

For the policy indicators, states are awarded for the quality of their procedures for connecting a distributed generation system to the grid. They also earn a score for the quality of their net metering policies that allow a retail electric utility customer to receive credit for the electricity generated by a distributed generation system serving that customer. These policy indicators are rated for the Index on a scale of 1 to 4, and a higher score equates to a higher quality policy.

RESULTS

The top four states in this category remained the same, though in a new order: Massachusetts took the top spot, with Illinois, New Jersey, and California following. North Carolina jumped ahead 22 spots to complete the top five, while Ohio (#6), New York (#7), Oregon (#8), Maryland (#9), and Connecticut (#10) all remained in the top ten.

Overall, the Northeastern states performed well here. In addition to four states in the top ten, Vermont (#14), Rhode Island (#17), Pennsylvania (#21), and Maine (#22) made the top half of all states, and New Hampshire (#28) just missed out. These states generally scored well on their interconnection or net metering policies and also have a good amount of distributed solar and wind as a percentage of their overall generating capacity. The Mid-Atlantic South states also did well, with all three states in the top half due to strong policies. Three Northeastern states—New Jersey, Massachusetts, and New York—along with California, have far and away the most distributed solar and wind as a percentage of their total electric generation capacity, ranging from 1.52% in New York to 5.80% in New Jersey.

While the previous Index only considered onsite solar, this Index considers both onsite solar and wind, though wind continues to make up only a small fraction of all onsite deployment. The leading states each increased their capacity from the 2017 Index, contributing significantly to the overall deployment across the country. Notably, all but four states have at least some onsite installation of wind or solar.

CATEGORY OVERALL TOP 5

Deployment Comparison: Onsite Wind & Solar Procurement (% of Total State Electric Generating Capacity)

STATE	2017 INDEX MW (ROUNDED)	2017 % OF CAPACITY	2020 INDEX MW (ROUNDED)	2020 % OF CAPACITY
New Jersey	226	1.21%	995	5.80%
Massachusetts	21	0.16%	591	4.61%
Illinois	2	0%	13	0.03%
California	285	0.38%	2670	3.49%
New York	23	0.06%	626	1.52%

Source: SEIA, AWEA, and U.S. EIA., 2019.

DEPLOYMENT COMPARISON: ONSITE WIND & SOLAR PROCUREMENT

INDEX YEAR	NUMBER OF STATES	TOTAL DEPLOYMENT (GW)
2017	37	0.8
2020	46	5.5

Source: SEIA 2015 "Solar Means Business" report. SEIA, AWEA 2019.

Direct investment in offsite deployment continues to make up a small portion of the total, though there was an increase in both the number of states with direct investment as well as the total amount deployed.

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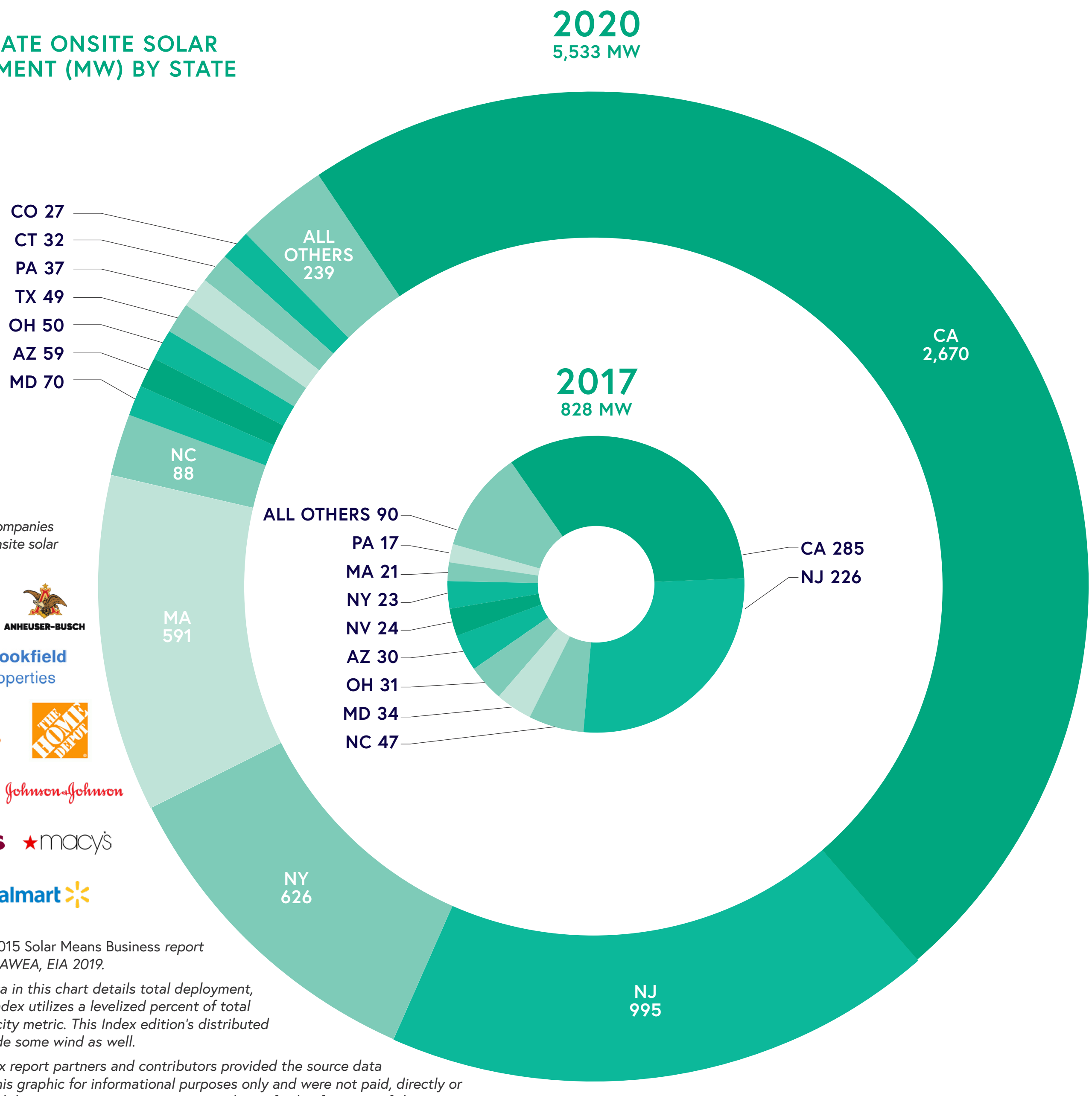
RETAIL IS LEADING ONSITE DEPLOYMENT

The retail industry has been a long-standing leader in onsite solar deployments in the U.S. According to the *2019 Solar Means Business Report* from the Solar Energy Industries Association (SEIA), eight of the top ten leaders in onsite solar deployments are retailers: Target (1), Walmart (2), Prologis (3), Apple (4), Amazon (5), Brookfield Properties Retail Inc. (6), IKEA (7), Macy's (8), Kohl's (9), and Costco Wholesale (10).[15]

Five more retailers—ALDI, Bed Bath and Beyond, The Home Depot, Staples, Walgreens—are in the top 25 leaders nationwide. And Apple, Amazon, Target, and Walmart are the four largest corporate solar users in the U.S., including on- and offsite deployments.

The emergence of solar & storage solutions may open additional opportunities for effective onsite deployment within retail. The retail industry has been particularly effective at taking lessons learned in early onsite RE efforts and using those to drive scale as technologies, economics, and policy environments improve.

CORPORATE ONSITE SOLAR DEPLOYMENT (MW) BY STATE



Select public companies with notable onsite solar deployment:

Source: SEIA 2015 Solar Means Business *report and EIA. SEIA, AWEA, EIA 2019.*

NOTE: The data in this chart details total deployment, whereas the Index utilizes a levelized percent of total installed capacity metric. This Index edition's distributed numbers include some wind as well.

RILA, and Index report partners and contributors provided the source data contained in this graphic for informational purposes only and were not paid, directly or indirectly, nor did any receive remuneration or anything of value from any of the companies identified in this report. Logo placements were merely for illustrative purposes only and are not intended to be an endorsement of any particular company or their products or services offered.

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POLICY DISCUSSION

Eight states received the highest possible score (4 out of 4) in the interconnection indicator, and notably, none of these states ranked below #12 in the overall Index. These states are geographically diverse with the Northeast, Mid-Atlantic South, Midwest, Pacific and Mountain West all represented. Seventeen states received the highest score in the net metering indicator, though these states had more varied overall results, ranging from Massachusetts (#3) to West Virginia (#39). All of the Northeastern states except for Maine and Pennsylvania (both with a score of 3 out of 4) had the highest score for net metering, as did two of the Pacific states, California and Oregon.

Perhaps unsurprisingly, the four states with the most onsite deployment of wind and solar as a percentage of the state's total electric generating capacity—New Jersey, Massachusetts, California, and New York—all received the highest score for their net metering policies and either the highest or second highest score for their interconnection policies. While these policies do not guarantee deep penetration of onsite deployment, they likely facilitated higher deployment levels in these states by making investment economically attractive with net metering and easing the navigation of the process with clear interconnection standards.

States interested in increasing this type of deployment would do well to develop clear interconnection standards that are consistent with nearby states. This would allow companies to replicate successful models across jurisdictions, potentially speeding up additional deployment. Clear and predictable net metering policies will also help make the economic case for expenditures for additional deployment, while allowing the grid to be served by more RE.

CONCLUSION

The *Corporate Clean Energy Procurement Index 2020* shows that the demand for clean energy resources is alive and strong in America. In only three years, the level of offsite renewable procurement grew 3.5 times while onsite renewable deployment grew more than five times. Combined offsite and onsite corporate renewables grew from 7 GW in 2016 to nearly 27 GW in 2019, and the interest is not waning. Commitments by corporations large and small, in industries of all types, continue to build. Market-competitive offerings are becoming increasingly available, and states across the country are doing their part to see how they can ensure that companies are getting the clean energy resources they are interested in.

Between a growing number of major state and city commitments, one in three Americans lives in a jurisdiction that has committed to being powered by 100% clean electricity. In those states, as well as in many others, policymakers are ensuring that critical pieces of the puzzle are in place so companies can get the clean resources they want. Those options include ensuring that green tariffs can be put in place via utilities, allowing for customer choice, the ability to execute offsite PPA contracts, and easy-to-use onsite interconnection and net metering requirements.

As the corporate clean energy landscape matures, the role that states play to ensure continued success has never been more important. The U.S. electricity industry is huge and complex, making change an equally huge and complex endeavor. It is clear, however, that lessons can be shared across borders. Working together, we can ensure that the reliable and affordable energy that has powered the country — and the industries that drive it ahead — can increasingly come from renewable sources. The positive benefits of this movement will be felt for generations to come.

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INDEX PARTNERS

RETAIL INDUSTRY LEADERS ASSOCIATION

The Retail Industry Leaders Association (RILA) is the U.S. trade association for retailers that have earned leadership status by virtue of their sales volume, innovation or aspiration. We convene decision-makers to collaborate and gain from each other's experience. We advance the industry through public policy advocacy and education. And through research and thought leadership, we propel developments that foster both economic growth and sustainability. Our aim is bold but simple: To elevate a dynamic industry by transforming the environment in which retailers operate.

D|G/A
David Gardiner and Associates

David Gardiner and Associates (DGA) is a strategic advisory firm focused on climate change, renewable energy, energy efficiency, electric vehicles, and an expanded and modernized electric grid. We work with businesses, associations, institutions, and others to accelerate climate and clean energy solutions and policy. Our approach is built on a foundation of in-depth analysis and sharp strategic planning, based on our team's decades of experience.

Thanks to these organizations for providing data and expertise as we pulled the Index together.

AWEA AMERICAN WIND ENERGY ASSOCIATION

REBA Renewable Energy Buyers Alliance

SEIA Solar Energy Industries Association®

ACKNOWLEDGEMENTS:

Thanks to the Energy Foundation for funding to make the Index possible.

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APPENDIX A: METHODOLOGY

The Index measures each state on a 100-point scale and is based on calculations made at the indicator, subcategory, and category levels. The Index scores each state on a 0-100 scale for each indicator. The best-performing state in each indicator gets a score of 100, the lowest ranked state gets a score of zero, and the Index scores other states based upon how closely they measure up to the top state.

The Index breaks each category in the Index into two subcategories, one for deployment measures and the other consisting of policy indicators. Each category weights the subcategories equally, so that deployment and policy each count for 50% of the category score. Scores for indicators in each subcategory are averaged, after which each state is assigned a category score in the same way that indicator scores get awarded. Finally, the category scores are equally averaged (1/3 to each of the three categories) to give each state an overall Index score.

The quantitative deployment indicators (tracking corporate RE installations by type) are all adjusted by dividing the megawatts (MW) of deployed renewable capacity by the state's total installed capacity. The result is expressed as a percentage. This puts states on a level playing field and does not punish less populous states for their size. Some policy indicators are binary yes/no measures, while others grade states on the degree and/or quality of their policies.

The researchers collected data for the *Corporate Clean Energy Procurement Index: State Leadership & Rankings* in the fall of 2019, with most datasets current to shortly before then. (See Appendix B for definitions and data source details for each indicator.) Data sources include:

- **Advanced Energy Economy (AEE)**
- **American Wind Energy Association (AWEA)**
- **Database of State Incentives for Renewables and Efficiency (DSIRE)**
- **EQ Research LLC**
- **Federal Energy Regulatory Commission (FERC)**
- **Interstate Renewable Energy Council (IREC)**
- **LEAN Energy U.S.**
- **National Renewable Energy Laboratory (NREL)**
- **Rocky Mountain Institute (RMI)**
- **Renewable Energy Buyers Alliance (REBA)**
- **Solar Energy Industries Association (SEIA)**
- **State Policy Opportunity Tracker (SPOT) for Clean Energy**
- **Solar Power Rocks**
- **U.S. Energy Information Administration (EIA)**
- **Vote Solar**

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APPENDIX B: INDICATOR DEFINITIONS

Most data for this Index was gathered in the fall of 2019 updated during 2019 unless otherwise noted below.

UTILITY & MARKET PURCHASING OPTIONS CATEGORY

UTILITY GREEN POWER PROCUREMENT This indicator captures the share of generating capacity in each state represented by three sources: utility green tariff offerings, special renewable PPAs signed by utilities on behalf of specific customers, and PPAs signed directly by companies through the competitive market (called direct access purchases). This measure adds up the total megawatts from green tariff deals, utility corporate PPA purchases, and direct access purchases in each state and divides this number by the state's total installed generating capacity as of June 2019. Data used for this indicator comes from the Renewable Energy Buyers Alliance (REBA), the Solar Energy Industries Association (SEIA), the American Wind Energy Association (AWEA), and the U.S. Energy Information Administration (EIA).

Size-Adjustment Metric: Total Installed Generating Capacity in MW.

Indicator Calculation: The summation of MW of Green Tariff, Utility Corporate Purchase Agreements, plus Direct Access Purchase Agreements divided by Total Installed Capacity.

EXISTENCE OF A GREEN TARIFF A green tariff is a special rate structure offered by utilities to large customers, allowing for the construction of new renewables on the local electric grid. States where at least one utility has issued a green tariff receive half credit for this indicator, while states where that green tariff has been used by at least one buyer receive full credit. Data used for this indicator comes from the Renewable Energy Buyers Alliance (REBA).

RETAIL CHOICE This indicator measures whether a state allows large C&I customers to choose where they get their electricity. It is comprised of two equally weighted sub-indicators, both of which were included in the previous iteration of the Index, but which have been combined here for the first time:

Green Power Purchasing Option: Green power purchasing programs—which support the development of clean energy by charging premium rates to cover any above-market costs of clean energy installations—are offered by many, but not all, utilities across the U.S. They allow customers to purchase RECs in incremental "blocks" of kWh, usually for a premium of a few dollars per block of a few hundred kWh. To advance the green power pricing market, some states have made it mandatory for utilities to offer consumers a way to participate in the purchase of green power. This indicator is weighted so that it counts for only half as much credit as a fully weighted indicator. States that have one or more utilities that offer green power purchasing programs voluntarily receive half credit for this indicator (essentially one-quarter of a full-credit indicator), while states that require utilities to provide such programs receive full credit (half a full-credit indicator). The source for this indicator is the Center for the New Energy Economy (CNEE), in partnership with the Nature Conservancy.

Retail Choice: Retail choice allows an electric C&I customer to choose an electricity provider other than the customer's electric distribution company. To receive credit for this indicator, a state must allow at least some C&I customers to choose an electricity provider. States that have capped retail choice at a specific level or that only allow retail choice for customers above a specific size are still counted here as having retail choice (although with reduced credit in some cases). For this measure, states with full retail choice for C&I customers receive full credit. States that have significant limitations (e.g., percent of sales or kW demand eligibility thresholds) receive partial credit. This indicator closely aligns with the green tariff indicator (above) and is combined with that under one retail choice indicator. Data for this indicator comes from Advanced Energy Economy (AEE), and was last updated in 2017.

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MARKET STRUCTURE This indicator measures whether each state has policies in place that encourage high penetrations of overall deployment of renewable energy. This is a new indicator for this iteration of the Index. It is comprised of two equally weighted sub-indicators:

Renewable Portfolio Standards: Renewable portfolio standards (RPSs) require utilities in a state to procure a certain percentage of their electricity from renewable sources by a specified target year. States differ widely in both the percentage of energy they require their utilities to obtain, as well as the year by which they must procure that energy. States get 1/3 credit for this sub-indicator just for having a mandatory RPS. States requiring a higher percentage of renewable energy (at least 25%, regardless of the target year) receive an additional 1/3 credit. States with the best RPS' (at least 50%, regardless of the target year) receive full credit for the sub-indicator. This is a new indicator for this iteration of the Index. Data for this indicator comes from the Database of State Incentives for Renewables & Efficiency (DSIRE), administered by the North Carolina Clean Energy Technology Center (NCCETC).

Presence of an ISO/RTO: Companies with operations in states that participate in an ISO or RTO have additional renewable energy procurement opportunities available to them. Most notable among these is the ability to sign third-party offsite renewable PPAs. Most ISOs/RTOs serve multiple states, though not all of a state's territory may fall within an ISO/RTO. For this sub-indicator, states are ranked based on the percentage of their electric customers that are serviced by a utility that participates in an ISO/RTO; states where an ISO/RTO covers the full state receive full credit, while states with no customers in an ISO/RTO receive no credit. While this indicator was included in the previous version of the Index, it has now been combined with the RPS sub-indicator to comprise the Market Structure indicator. Data for this indicator comes from EIA, FERC, and previous analysis performed by EQ Research.

THIRD-PARTY PURCHASING CATEGORY

OFFSITE PPA PROCUREMENT This indicator captures the share of generating capacity in each state represented by four sources: PPAs, REC contracts, tax equity financing, and community solar contracts. This measure adds up the total megawatts from PPAs, REC contracts, tax equity financing contracts, and community solar contracts in each state and divides this number by the state's total installed generating capacity as of June 2019. Data used for this indicator comes from the Renewable Energy Buyers Alliance (REBA), the Solar Energy Industries Association (SEIA), the American Wind Energy Association (AWEA), and the U.S. Energy Information Administration (EIA).

Size-Adjustment Metric: Total Installed Generating Capacity in MW.

Indicator Calculation: MW of PPAs, REC Contracts, Tax Equity Financing, plus Community Solar Contracts divided by Total Installed Capacity.

THIRD-PARTY PPAs FOR DG SYSTEMS This refers to an arrangement where a non-utility owner of a DG system sited on the premises of a retail electric customer sells the electricity generated by the system to the retail electric customer. To receive credit for this indicator, a state's statutes and/or regulations must allow for PPA arrangements without subjecting the third-party owner to significant regulatory barriers, and must allow participants in such arrangements to engage in net metering or a similar program. States in which the legal status of third-party PPAs is unclear receive half credit for this indicator, while states where third-party PPAs are illegal receive no credit. Data for this indicator comes from the Database of State Incentives for Renewables & Efficiency (DSIRE), administered by the North Carolina Clean Energy Technology Center (NCCETC).

THIRD-PARTY LEASES FOR DG SYSTEMS This refers to an arrangement where a non-utility owner of a DG system sited on the premises of a retail electric customer leases the system to the retail electric customer. To receive credit for this indicator, a state's statutes and/or regulations must allow for lease arrangements without subjecting the third-party owner to significant regulatory barriers, and must allow participants in such arrangements to engage in net metering or a similar program. Data for this indicator comes from the Database of State Incentives for Renewables & Efficiency (DSIRE), administered by the North Carolina Clean Energy Technology Center

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(NCCETC); the Center for the New Energy Economy (CNEE), in partnership with the Nature Conservancy; and the Solar Power Rocks website.

COMMUNITY RENEWABLES This arrangement allows multiple retail electric customers at different locations to subscribe to the electrical output of a DG system located at a different site, and/or to receive net metering credits from a DG system located at a different site. To receive credit for this indicator, a state must have established a policy requiring major electric utilities to allow such billing arrangements. This indicator is weighted so that it counts for only half as much credit as a fully weighted indicator. Data for this indicator comes from the National Renewable Energy Laboratory (NREL) and the Shared Renewables HQ website.

COMMUNITY CHOICE AGGREGATION Community choice aggregation (CCA) legislation allows local governments to pool the electricity (and sometimes natural gas) demand within their jurisdictions in order to purchase or develop power for their residents and businesses from an entity other than their local utility. This indicator gives credit to states that have enabled such programs through legislation, according to LEAN Energy US. This indicator is weighted so that it counts for only half as much credit as a fully weighted indicator.

ONSITE/DIRECT PURCHASING CATEGORY

DISTRIBUTED WIND AND SOLAR PROCUREMENT

This indicator measures the share of generating capacity in each state represented by C&I distributed wind and solar projects within each state. This measure adds up the total megawatts from distributed wind and solar projects in each state and divides this number by the state's total installed generating capacity as of June 2019. Data used for this indicator comes from the Solar Energy Industries Association (SEIA), the American Wind Energy Association (AWEA), and the U.S. Energy Information Administration (EIA).

Size-Adjustment Metric: Total Installed Generating Capacity in MW.

Indicator Calculation: MW of Distributed Wind & Solar Projects divided by Total Installed Capacity.

DIRECT INVESTMENT PROCUREMENT This indicator measures the share of generating capacity in each state represented by large offsite projects that are directly owned (as opposed to leased or for which a PPA has been signed) by a business. This measure adds up the total megawatts from directly-owned projects in each state and divides this number by the state's total installed generating capacity as of June 2019. Data used for this indicator comes from the Renewable Energy Buyers Alliance (REBA), the Solar Energy Industries Association (SEIA), the American Wind Energy Association (AWEA), and the U.S. Energy Information Administration (EIA).

Size-Adjustment Metric: Total Installed Generating Capacity in MW.

Indicator Calculation: MW of Directly-Owned Projects divided by Total Installed Capacity.

INTERCONNECTION PROCEDURES Interconnection governs the technical and procedural rules for connecting a DG system to the distribution grid. To receive credit for this indicator, a state must have adopted interconnection procedures that apply to major electric utilities. The level of credit awarded reflects the overall quality of the state's policy, based on numerous policy nuances. Data for this indicator comes from the Freeing the Grid report, last produced by IREC and Vote Solar in 2016, and the Solar Power Rocks website. Both sources issue A through F grades, which have been converted to a 0-4 scale in order to score this Index, where A=4, B=3, C=2, D=1, and F=0.

NET METERING This billing arrangement generally allows a retail electric customer to receive retail credit for the electricity generated by a DG system serving that customer. To receive any credit for this indicator, a state must have an active policy requiring major electric utilities to allow net metering. The level of credit awarded reflects the overall quality of the state's policy, based on numerous policy nuances. Data for this indicator comes from the Freeing the Grid report, last produced by IREC and Vote Solar in 2016, and the Solar Power Rocks website. Both sources issue A through F grades, which have been converted to a 0-4 scale in order to score this Index, where A=4, B=3, C=2, D=1, and F=0.

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APPENDIX C: ORGANIZATIONS AND PUBLICATIONS

Below are some useful resources, including organizations that are helping businesses procure more RE, and publications outlining some of these efforts.

ORGANIZATIONS

ADVANCED ENERGY BUYERS GROUP is a coalition of leading advanced energy purchasers, engaging on policies to unlock opportunities for customers to access affordable, reliable, clean, and innovative energy options.

THE CERES BICEP NETWORK (BUSINESS FOR INNOVATIVE CLIMATE AND ENERGY POLICY) members support three principles: increased adoption of renewable energy and energy efficiency, increased investment in a clean energy economy, and increased support for climate change resilience.

CDP is a not-for-profit that runs the global disclosure system for investors, companies, cities, states and regions to manage their environmental impacts.

DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY (DSIRE) is the most comprehensive source of information on incentives and policies that support renewable energy and energy efficiency in the United States.

EMPLOYERS FOR RENEWABLE ENERGY (ERE) is a coalition that represents job creators nationwide who support state policies that enable greater customer choice of renewable energy and strong competition among producers.

ENVIRONMENTAL PROTECTION AGENCY GREEN POWER PARTNERSHIP is a voluntary program that encourages organizations to use green power as a way to reduce the environmental impacts.

RE100 is a global initiative of influential businesses committing to 100% RE. It is a joint effort of CDP and The Climate Group.

RENEWABLE ENERGY BUYERS ALLIANCE (REBA) is a membership association for large-scale energy buyers seeking to procure renewable energy across the U.S. Taking on RMI, WRI, WWF RE efforts in 2019 including Buyers Principles, deal tracking and more, the organization holds a number of RE procurement initiatives and resources. The organization's goal is to catalyze 60 gigawatts (GW) of new renewable energy projects by 2025 and to unlock the energy market for all large-scale energy buyers by creating viable pathways to procurement.

SCIENCE BASED TARGETS INITIATIVE champions science-based target setting as a powerful way of boosting companies' competitive advantage in the transition to the low-carbon economy. It is a collaboration between CDP, the United Nations Global Compact (UNGC), World Resources Institute (WRI), and the World Wide Fund for Nature (WWF) and a We Mean Business Coalition commitment.

UN GLOBAL COMPACT is the world's largest corporate sustainability initiative. It's a call to companies to align strategies and operations with universal principles on human rights, labour, environment and anti-corruption, and take actions that advance societal goals, including the Caring for Climate commitment.

WE ARE STILL IN is a coalition of cities, states, tribes, businesses, universities and other groups who strongly oppose the U.S. withdrawal from the Paris accords and who take seriously the global response to the climate crisis.

WE MEAN BUSINESS is a global nonprofit coalition working with the world's most influential businesses to take action on climate change. Together we catalyze business leadership to drive policy ambition and accelerate the transition to a zero-carbon economy.

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