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California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA
Via docket submission

Re: Docket No. 22-RENEW-01—Comments on Proposed Draft Demand Side Grid Support Program Guidelines, Fourth Edition

Dear Vice Chair Gunda and Energy Commission Staff,

Generac Power Systems (Generac) appreciates the opportunity to comment on the Proposed Demand Side Grid Support (DSGS) Program Guidelines, Fourth Edition. Generac has participated in this docket since its inception and has been consistent in our advocacy for the program to include a statewide smart thermostat virtual power plant (VPP) program. We commend the California Energy Commission (CEC) for their innovation with Option 4 as it presents a unique opportunity for existing and new smart thermostats to leverage runtime data (i.e. device-level data) and controls to provide market-aware demand flexibility. We appreciate the CEC's invitation for feedback on the design of Option 4.

Generac is a leading smart thermostat original equipment manufacturer (OEM) with grid services experience across the nation. We have ample smart thermostat capacity in California, equivalent to the output of a small power plant available for load flexibility. Our comments focus on the proposed Option 4, as well as overall DSGS requirements as they would apply to the new program under Option 4. Generac is excited for the opportunity to bring this VPP capacity to California. However, unless addressed, challenges related to the proposed penalty structure and the enrollment process may significantly hinder our ecobee thermostats from participating in Option 4. We have described these challenges and proposed program modifications and redlines in our comments below and respectfully urge the CEC to consider them. We respectfully submit these comments on the DSGS Guidelines as a follow-up to our participation in the recent public workshop.

I. Recommendations on Chapter 2 Reporting and Chapter 8 Compliance Requirements

Overall, Generac appreciates the proposed changes to the DSGS Guideline structure; however, we offer a few minor amendment requests to the Chapters dealing with program administration and compliance.

a. Generac recommends changing the performance reporting structure to provide thirty days for DSGS providers to report performance rather than five days.

Previously, claims under Incentive Option 3 had to be submitted annually and by the last business day of December of the same calendar year, and all other claims by the last business day of February of the following year. The new reporting requirements under Chapter 2.D.3 increase the frequency of reports to a monthly basis, and require filing within five business days of an event or test event for Option 4. Monthly reports may benefit Staff by improving visibility into the DSGS budget but will also lead to additional costs for aggregators.

The increased frequency and detailed nature of these reports, compared to the previous end-of-year submission deadlines, will add cumulative operational costs to aggregators. Additionally, five days may not be sufficient to gather all required data. We recommend that the final guidelines extend the reporting deadline from five business days to thirty days after an event (CH2.D.4). Five business days represents a significant turnaround time challenge given the potential volume of devices and manual data provision methods.

b. Generac recommends adjusting the "Flow Down" Requirements in Ch.8 Section S to clarify that these requirements apply only to appropriate participants, and not residential participants.

The current language in the "flow down" requirements require DSGS providers to pass down a broad range of terms and conditions to all participants, many of which would be relevant only to commercial participants and not appropriate for residential customers. Provisions such as Records Retention (Chapter 8, Section G) and "Drug-Free Workplace Certification" (Chapter 8, Section I) are clearly designed for commercial entities and are not applicable to individual residential participants. The current language would create undue obligations for residential customers and aggregators. Generac recommends the following redlines:

> DSGS providers shall flow down in their agreements with subcontractors and DSGS direct participants and shall ensure subcontractors flow down in their subcontracts, the requirements in the following terms… (Pg. 49)

The phrase "direct participant" is used in Option 1 to refer to commercial participants. By specifying "direct" participants in Chapter 8, the language would distinguish between commercial and residential customers, assuring aggregators that they are not obligated to flow down irrelevant provisions to residential customers. Additionally, we would recommend adding a sentence to section S that specifies: "these requirements do not apply to residential customers participating via a VPP aggregator in either Option 3 or Option 4."

II. Generac Echoes Recommendations of CALSSA on Option 3

California has shown itself to be a leader in advancing virtual power plants through the design and implementation of Option 3. Generac has participated in residential aggregations under Option 3 and plans to continue growing that participation. As a member of the California Solar and Storage Association (CALSSA), Generac echoes the suggestions and concerns expressed by CALSSA at the workshop and in their written comments submitted on the Fourth Edition Guidelines.

III. What additional program modifications should be considered for Option 4, and why?

Generac is supportive of the overall program design in Option 4 and recognizes it as a significant advancement in the DSGS program and in meeting the Legislature's clear intent to establish a statewide VPP program.[1] We are pleased with its innovative design and the opportunities it presents for leveraging residential demand flexibility to enhance grid reliability. Option 4 holds great potential for increasing VPP adoption and participation, and we are enthusiastic about contributing to its success.

a. <u>Generac recommends removing any penalty from the performance-adjusted payment schedule. Option 4 should have a pay-for-performance incentive structure, in line with other options in DSGS.</u>

Generac supports a strong pay-for-performance structure that awards performance and does not compensate non-performance. This would be a sufficiently high bar for a brand-new statewide program. Therefore, we respectfully urge the CEC to remove the penalty construct from the payment schedule delineated in Draft Guidelines and adhere to a strict pay-for-performance structure (CH6.C). The inclusion of such a severe penalty structure in Option 4 will discourage enrollment in this new program and goes against the DSGS program's goal of piloting options to increase VPP adoption and participation. Especially during emergency events, every kW of demonstrated capacity matters, and providing much needed capacity should not result in a penalty. Furthermore, since Option 4 is the only true "emergency" residential program, and aggregators could be required to dispatch day-of with less than an hour notification time, the high risk being placed on aggregators for a day-of residential dispatch seems disproportionate to the penalty proposed and the capacity payment offered.

The guidelines provide:

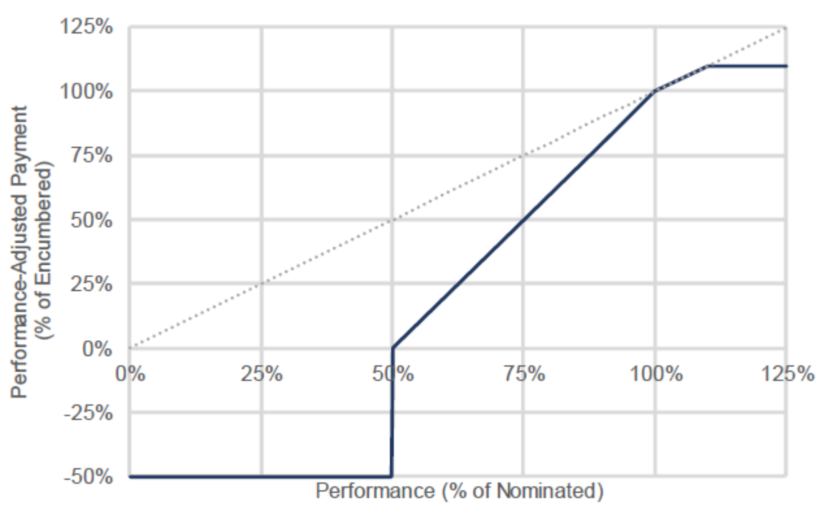
> "Compensation for performance below 100 percent of nominated capacity will be reduced by **two times** the percentage shortfall below 100 percent, until the performance-adjusted payment reaches zero as performance declines to 50

[1] Assembly Bill (AB) 205 (Ting, Statutes of 2022, Chapter 61).

percent of nominated capacity. If demonstrated capacity falls below 50 percent of nominated capacity, a penalty of 50 percent of the nominated capacity value shall be assessed on the DSGS provider." (Pg. 33 **emphasis added**)

No other DSGS Option has a penalty, and every other residential program would provide day-ahead notice based on either prices or known grid conditions. Option 3 (as run in 2024) required day-ahead prices to be >$200/MWh for consecutive hours, meaning that aggregators participating in Option 3 were essentially put "on notice" by market conditions in the day-ahead (noting that proposed changes to Option 3 would add an emergency component). Proposed changes to Option 3 would provide a *bonus* for emergency dispatch, whereas Option 4 is the only proposed emergency program under DSGS that would provide a *penalty* for missing capacity performance or for non-performance. While we understand the importance of committed capacity showing up, as a new program of fully residential aggregations, holding this program to a higher bar than others in DSGS is inappropriate. A bonus structure for meeting performance targets would put Option 4 on more even footing with Option 3.

Figure 4: Performance-Adjusted Payment Illustration



We urge the CEC to leverage a pure 0%-100% pay-for-performance structure (i.e. the dotted gray line in Figure 4 of CH6.C) for Option 4's inaugural season to foster participation and better understand the capabilities of aggregations participating under Option 4 for future years.

Alternatively, if the CEC is unwilling to implement a pure 0%-100% pay-for-performance structure, we recommend the CEC look to other states who have successful VPP programs for guidance, as these states have launched, and then adjusted program structures recently. The CEC could consider using the performance-adjusted payment structure previously implemented by New York utilities for the Commercial System Relief Program (CSRP) /

Distributed Load Relief Program (DLRP)[2] or the performance-adjusted payment structure currently used by ERCOT in ERS.[3]

b. Option 4 capacity incentive payments should be equivalent to the other Options in DSGS.

Generac thanks the CEC for inviting feedback on the DSGS Option 4 capacity incentive payments during the October 18th workshop. While removing the penalty from the performance-adjusted payment schedule is our main concern with respect to incentives, we are also concerned that the Option 4 capacity prices are not in line with those of other Options when looking at value provided to the grid. We suggest the CEC look at Option 3, which is both similar in operational design and inclusive of residential participants, and use maximum event hours as a capacity price barometer to adjust the Option 4 capacity prices upward. Specifically, it is our understanding that Option 4's maximum number of event hours is 60 and that Option 2's maximum number of event hours for a 2-hr resource is 70. Applying this ratio (60/70) to Option 2's incentive for a 2-hr resource ($62.10/kW) results in a season total Option 4 price of $53.23/kW.

Additionally, we see that the 30% bonus to capacity incentives for Option 2 and Option 3 have been maintained through 2026, but that this 30% bonus is not available to Option 4. Given both the precedence of offering the 30% bonus to new DSGS options and the similarities in program structure between Option 2, 3, and 4, we believe it is unreasonable to not offer a 30% bonus to Option 4. We respectfully urge the CEC to extend the 30% bonus to capacity incentives (through 2026) to Option 4.

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[2] The CSRP / DLRP structure shifted to a pure 0%-100% pay-for-performance structure. Originally the program linearly scaled payment to the demonstrated capacity to nominated capacity ratio until that ratio fell below 25%, after which payment was withheld in full. *See* ConEd's prior tariff change document, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0C4F4FB8-B008-4A37-AFC2-A8BDAB76FCA0%7D.

[3] The ERCOT ERS structure states that if 95% of a nomination is not met in the first full 15-min event interval, demonstrated is automatically derated by 25%. And if demonstrated capacity is ultimately lower than 75%, payments scale linearly with the ratio of demonstrated capacity to nominated capacity down to 0%. If consecutive test events (which can look back to prior years) are failed (i.e. test event performance is below 95% of a nomination), demonstrated capacity automatically gets paid on the average performance of said test events or 75% of nominated capacity, whichever is lower. *See* Section 8 of the ERCOT Protocols, available at https://www.ercot.com/mktrules/nprotocols/current.

c. The Guidelines language around day-of dispatch conditions and event determination should be both clarified and modified. Payment structures should reflect risks associated with day-of dispatch.

During the workshop Q&A, CEC Staff implied that day-of dispatch without any notice in the day-ahead would be possible under Option 4. This is unclear from the face of the guidelines. As currently written, the proposed Option 4 is confusing because the Guidelines are proposing a definition of event hours based on relative prices, not based on a "relative price trigger." Under Option 1, where resources are dispatched only based on the grid's EEA status, this is laid out more clearly.

Staff clarified in the workshop that Option 4 will only be triggered based on EEA status: EEA Watch, EEA 1 or EEA 2. As a second step, Staff clarified that the event hours during the 4-9 window will be determined based on the hours of highest price. Therefore, to avoid confusion, we propose a few significant edits. First, we propose removing the concept of "shoulder hours" from the event hour determination. This is confusing for a 4-hour program if you are determining based on the highest-priced hours. Instead, we propose that the day-ahead price alone be used to determine event hours, and that the guidelines clarify this is not a "trigger" but rather a determination of the event window. We propose the following redlines to Chapter 6.D:

> **~~Relative price trigger~~ Event Determination:** For all resources, price is defined as the California ISO day ahead locational marginal price (LMP) for the default load aggregation point (DLAP) of the host UDC, or the trading hub of the host UDC if a DLAP is not available.[8] The ~~relative price trigger~~ event shall take effect during hours with the highest consecutive ~~2~~ 4 hour mean LMP.
>
> ~~Shoulder Hours: The hours immediately preceding and following the two hours identified by the relative price trigger are considered shoulder hours. These hours shall be given half the weight of an hour meeting the relative price trigger for a given price.~~
>
> **Equal values:** If the highest mean consecutive hourly price applies to more than one set of hours (that is, if there is a tie), the event will be the first (that is, earliest) set of hours meeting these conditions.
>
> The test hours shall be consistent with the ~~relative price trigger~~ event determination... (Pg. 35)

Thermostats typically have the highest performance during the first hour of an event. Under the "shoulder hour" construct, the first hour's performance gets weighted at 50% in the demonstrated capacity formula, which would discount thermostat aggregation performance significantly. Other resources may have a "ramp up" period, but that is not necessarily the case for thermostat aggregations.

Aggregators should be incentivized to respond quickly to a dispatch signal that could come within only 15 minutes before the event (or 30 minutes as we propose below). The shoulder hour construct may disincentivize a quick and full dispatch in the first hour. The calculation for demonstrated performance should be the same across all event hours.

d. <u>15-minute response times without day-ahead dispatch notice or "warning" are unrealistic for a residential thermostat aggregation. 30 minutes is the minimum reasonable dispatch time.</u>

We propose increasing the minimum event notification from 15 minutes to 30 minutes to ensure ample time to prepare and enact load reduction. We intend to support the grid during true emergencies. However, a potential 15-minute dispatch window, as implied by Staff during the workshop, would be extremely difficult. We propose the following adjustment to section CH6.D.

> **EEA trigger**: If the host BA initiates an EEA or EEA Watch, the EEA triggered event shall take effect at the later of 4:00 p.m. and the first full hour beginning at least ~~15~~ <u>30</u> minutes from the announcement of the EEA or Watch, and last until 10:00 p.m. If no EEA or Watch is called by 8:45 p.m., no event shall be called. (Pg. 34 - 35)

Even Commercial Demand Response (BIP) is not required by CAISO to dispatch within 15 minutes. In a statewide VPP of residential customers, more time will be needed. In its first year, the Option 4 program should be treated as a pilot to demonstrate the maximum of what is possible and not dissuade participants from joining the program or aggregators from offering the maximum amount of capacity possible.

e. <u>Capacity commitments should be made monthly vs. annually to maximize capacity that can be delivered during peak summer periods when grid stress is most common.</u>

To maximize the capacity that can be delivered during the season, Generac recommends that capacity nominations should be made monthly, rather than annually. Nominating monthly allows us to account for seasonality of performance within the season and also allows us to bring in new customers during the season. These granularities and benefits are not available if capacity nominations are made on an annual basis. Generac and other providers could end up offering less capacity if required to nominate annually, which would not benefit the grid.

Monthly nominations could further allow us to hedge performance risk and customer fatigue. For instance, Generac could nominate only during a subset of summer months to avoid events where customer opt out may be higher than other times. As another example, we could create VPP subsets in each utility territory such that X% of our total utility portfolio is ever nominated and "participating" in any given month. The flexibility of monthly nominations would allow providers to be flexible and learn from participation to the benefit of CEC and the program overall.

f. As drafted, enrollment requirements would severely limit the potential of Option 4 to deliver significant capacity to California.

Generac requests that the Commission consider guideline modifications for enrollment specific to Option 4. As currently written, the guidelines would preclude Generac from bringing our ecobee thermostats to Option 4 at scale by severely hampering our ability to enroll customers. Generac has been engaged with the Commission for over two years because we believe in the ability of residential customers to support the grid during times of stress. We ask the Commission to consider the customer insights from companies like ecobee and Renew Home, who are directly engaged with customers and know what is feasible vs. infeasible.

With the aim of ensuring we can enroll as many customers as possible, we propose here specific redlines in CH6.A and CH6.B. These redlines make Option 4 more consistent with our existing grid services product and will allow Generac to enable Option 4 for our entire California thermostat footprint without intruding on our customers' experiences and increasing enrollment friction. Without these redlines, our participation in Option 4 would be significantly hampered if not completely foreclosed for the 2025 program year. We believe these concerns and suggestions are echoed by other large providers who cumulatively have millions of smart thermostats installed in California homes. We request that the Commission consider the following redlines to Option 4:

> To be eligible to serve as a load flexibility VPP aggregator of Incentive Option 4, the load flexibility VPP aggregator must:
>
> Receive authorization from participants allowing for the use of their device for ~~DSGS Program~~ demand response program participation.
>
> . . . Provide a pathway for device owners to enroll in supply-side (market integrated) DR by including an optional step to complete the data sharing agreement required for DR registration ~~in the enrollment process and in the DSGS information or settings page~~. (Pg. 31)

Program specific language can create confusion and hesitancy amongst customers, and DSGS is categorically a demand response (DR) program, which customers are more familiar with. Changing this language does not take away from the intent of the notification, rather, it reduces enrollment friction. Additionally, we propose striking "in the enrollment process and in the DSGS information or settings page" from the requirement to include an optional step for customers to complete the data sharing agreement needed for DR registration. This language is too restrictive. Removing this specificity allows us more flexibility to meet this requirement without intruding on customer experience and on such a short timeline.

In CH6.B, we propose the following redlines:

> "Acknowledgement and agreement from the ~~participant~~ load flexibility VPP aggregator that:
>
> The participant meets the eligibility requirements of the DSGS Guidelines and is not enrolled or participating in a conflicting program to the best of their knowledge.
>
> . . . Participant enrollment information may be reviewed by the CEC in an audit as in Chapter 8, Section D. To protect participant Personally Identifiable Information (PII), e.g. Name of the participant, PII will only be provided to CEC in an audit. (Pg. 32)

The first redline aims to acknowledge that since the load flexibility VPP aggregator is the residential participant's agent to access the program, it should be the load flexibility VPP aggregator's responsibility to attest to and own the sub-bullets under the acknowledgement and agreement construct in this section. The second redline is to explicitly recognize that Personally Identifiable Information (PII) - specifically the name of the participant - will only be provided to the CEC in an audit. Generac has concerns with providing PII, such as name, for residential participants. In other states' programs (such as ERCOT's Emergency Response Service [ERS] program), names are not required.[4]

Taken as a whole, the draft guidelines imply that not all of the listed enrollment information needs to be provided to enroll a participant, but rather that it all needs to be collected, maintained, and potentially provided in an audit. We ask that the Guidelines be explicit regarding PII.

g. Are there sufficient safeguards in place to help prevent dual enrollment issues under the proposed Option 4? If not, what other measures should the CEC consider?

CH6.A and CH6.B identify safeguards to address dual enrollment issues. To decrease the likelihood of dual enrollment, program administrators should be required to share enrollment data. It will be important for the CPUC to notify the CEC if it ever considers potentially moving any of its residential demand response programs to auto-enrollment. Similarly, it would be

[4] *See* ERCOT's ERS Submission Form Instructions, available at https://www.ercot.com/files/docs/2021/12/10/ERS_Submission_Form_Instructions.docx.

helpful to hear from publicly-owned utilities regarding whether they ever had or would consider auto-enrollment for residential demand response programs.

IV. Conclusion

Generac appreciates the opportunity to provide these comments and thanks the California Energy Commission for its commitment to advancing demand-side solutions that enhance grid reliability and promote clean energy. We are enthusiastic about the potential of Option 4 and believe that, with the suggested modifications, it can effectively leverage the flexibility of smart thermostats and deliver a novel, statewide VPP program for California.

We respectfully urge the CEC to consider our recommendations regarding reporting requirements and clarification of flow-down provisions in the overall DSGS requirements. For the new Option 4 we strongly recommend the following adjustments to the payment structure: a pay-for-performance incentive structure without unnecessary and unprecedented penalties and adjustments to the "shoulder hour" construct. The final guidelines should also provide clarification regarding day-of dispatch conditions and consider reasonable response times for residential aggregations. Additionally, Generac recommends that Option 4 allow for monthly capacity nominations, and the final guidelines modify enrollment requirements to maximize participation and therefore provide maximum capacity to the grid during emergencies.

By addressing Generac's concerns, we believe the DSGS program can better achieve its goals of increasing VPP adoption and participation, ensuring grid reliability during emergency events, and appropriately valuing the contributions of distributed resources. We look forward to continued collaboration with the CEC and stand ready to support the implementation of these improvements to create a more resilient and sustainable grid in California.

Sincerely,

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