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PUC PROJECT NO. 54335

WHOLESALE ELECTRIC	**§**	**PUBLIC UTILITY COMMISSION**
MARKET REFORM	**§**	**OF TEXAS**
ASSESSMENT BY E3	**§**	

COMMENTS OF WÄRTSILÄ NORTH AMERICA, INC. REGARDING PCM FEASIBILITY AND IMPLMENTATION

COMES NOW Wärtsilä North America, Inc. ("Wärtsilä") and files these comments as a response to the Public Utility Commission of Texas ("Commission") to highlight and discuss concerns with the PCM product that was proposed in E3's market report dated November 10, 2022.

I. INTRODUCTION

Wärtsilä is a global energy and marine technology company based in Helsinki Finland, with its North American headquarters in Houston, Texas. Wärtsilä's mission is to enable a transition towards a reliable, flexible, and affordable clean energy future. Wärtsilä's offerings comprise of utility-grade reciprocating internal combustion engine power plants (RICE), hybrid solar power plants, and battery energy storage systems (BESS). Wärtsilä has 76 GW of installed power plant capacity in 177 countries around the world, and over 1 GW in Texas, including 850 MW of engine power plants and 200 MW of battery energy storage systems.

Wärtsilä is well-known for its RICE technology, which is significantly more efficient compared to similarly sized gas open cycle units with regards to both fuel and water consumption. In addition, RICE tolerate frequent starts and stops, as well as ramping power up or down. In addition to natural gas or diesel, RICE are also capable of using a variety of alternative fuels, such as hydrogen blends, biodiesel, synthetic methane, and green ammonia. RICE can be dual-fuel and can switch fuel without stopping. These advantages enable Wärtsilä to be more flexible and precise in meeting Texas's dispatchability and reliability needs while providing emissions reductions using best available control technologies.

Wärtsilä's technology solutions provide grid operators with cost-effective, reliable, and precise tools to support modern renewable heavy power systems, providing a critical piece of the renewable energy integration puzzle.

II. OVERVIEW

The current ERCOT electricity market construct is being stressed by increased load growth, a rapid deployment of variable renewable energy resources (VREs), and extreme weather events. At the same time, ERCOT lacks sufficient modern flexibly dispatchable generation to balance and backstop growing system variability and manage uncertainty. Wärtsilä is supportive of market reforms that promote resource adequacy, operational reliability, flexibility, and affordability through investment in new generation equipment, improvements to existing equipment, and retirement of older uneconomic inflexible generators.

Not all megawatts (MWs) of capacity are created equal. Much of Texas's generation fleet have aged beyond their useful life but are unable to retire due to system reliability needs. Around 24,000 MW[1] the of 62,000 MW (39%) of installed Coal, Combined Cycle, Gas Turbines, and Gas Steam Turbines are older than 40 years in age. Furthermore, these resources were built to serve a very different power system than today's ERCOT grid, let alone what is needed to maintain reliability and minimize costs for customers in the future.

There is a clear need for not only new dispatchable capacity, but in particular *flexible* dispatchable resources as shown by ERCOT's increased procurement of RUC and Non-Spin reserve service to ensure system stability. Texas is home to one of the nation's largest and fastest growing renewable fleets, with 36,000 MW of wind and 11,500 MW of solar capacity today[2]. The intermittent nature of VREs coupled with the need to keep supply and demand balanced at all times, indicates a need for resources that can compensate in real-time for the volatility of renewable generation output. Modern resources for efficient renewable integration exhibit five elements of flexible dispatchability, which include minimizing start-up time, minimum run time,

[1] SARA Summer 2022 report
[2] ERCOT Fact Sheet November 2022

minimum down time, and minimum operating level while maximizing ramp speed and operating duration. The dynamics of a highly variable system with older, less flexible assets creates many operational challenges and can result in significant unnecessary costs to Texas ratepayers.

III. Before committing to the performance credit mechanism (PCM), the PUCT's focus should be on incremental reforms, such as developing an uncertainty product.

Additional assessment/development of uncertainty products should be the first and primary focus of the PUCT and ERCOT before determining that a capacity payment construct is needed. ERCOT has had a long successful history maintaining low-cost electricity rates without the use of a capacity market. The Independent Market Monitor (IMM) has emphasized the need to focus on products that fit within the "energy only" market construct. The PUCT has not yet adequately assessed proposals of uncertainty products as proposed by the IMM. In short, the PUCT has not demonstrated that the energy-only approach has fundamentally failed and that a capacity compensation mechanism is required to maintain resource adequacy.

An Ancillary Service Uncertainty Product (ASUP) could also serve as an alternative to the PCM, acting as a more immediate solution to ERCOT. The ASUP is a 2 to 4 hour reserve product procured in the day ahead ancillary market and provided by certified equipment that targets the most uncertain hours of operation as opposed to 30 hours addressed by the PCM. Continued focus on PCM as for the immediate needs will further delay the development and implementation of a truly needed and beneficial uncertainty product. The more time that passes without a product that values flexible dispatchable resources, the more ERCOT will need to continue to buy additional capacity in the day-ahead markets through the non-spin and reliability unit commitment products, increasing uplift costs to customers. If simpler, faster alternatives prove insufficient, then concepts like the PCM can be revisited.

The ASUP will serve a more targeted population of generators through its qualification process. Wärtsilä recommends focusing on the elements of dispatchability listed below in Section IV as requirements. The ASUP can be quickly implemented without real time optimization as the ancillary service infrastructure is already in place. If real time co-optimization is needed, a bridge product for new resources, as discussed below, may be needed due to implementation time.

The ASUP does not yet have a clearly defined nonperformance penalty other than utilizing the existing construct for ancillary services. However, generators could benefit from the ASUP if it is priced at a level that is sufficient to incentivize new generation to participate, e.g., the Value of Lost Load (VOLL). It is worth noting that several questions must still be answered on the ASUP. What is the correct duration of the product? How much notice to provide the product is needed? Would ASUP nonperformance be penalized at VOLL or a cost-of-new-entry (CONE)? What specific thresholds would cause a unit to be disqualified from providing the service? Clearly defining these penalties is necessary to send the correct signals for retirement and entry into the ERCOT market.

Although additional details regarding eligibility for participating in an uncertainty product must still be settled, it is likely that this can be resolved much more quickly than PCM. The ASUP proposed by the IMM[3] as a 2–4-hour product could be implemented without any major modifications as it would be an additional ancillary service. However, as Real-Time Co-Optimization is not complete there is still a timetable of at least 2024[4] to receive the maximum benefit from this product.

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[3] 2021- State of The Market Report For the ERCOT Electricity Markets pg 8
[4] Real Time Co-Optimization Report

IV. Any new market design should provide specific value for the attributes needed to ensure reliability, not simply installed capacity

As proposed, the PCM treats all generators as equal and does not explicitly target specific attributes from generators needed to balance the system. More specifically, the Commission should develop market products that focus on:

(1) Start-up time,

(2) Minimum Run Time,

(3) Minimum Down Time,

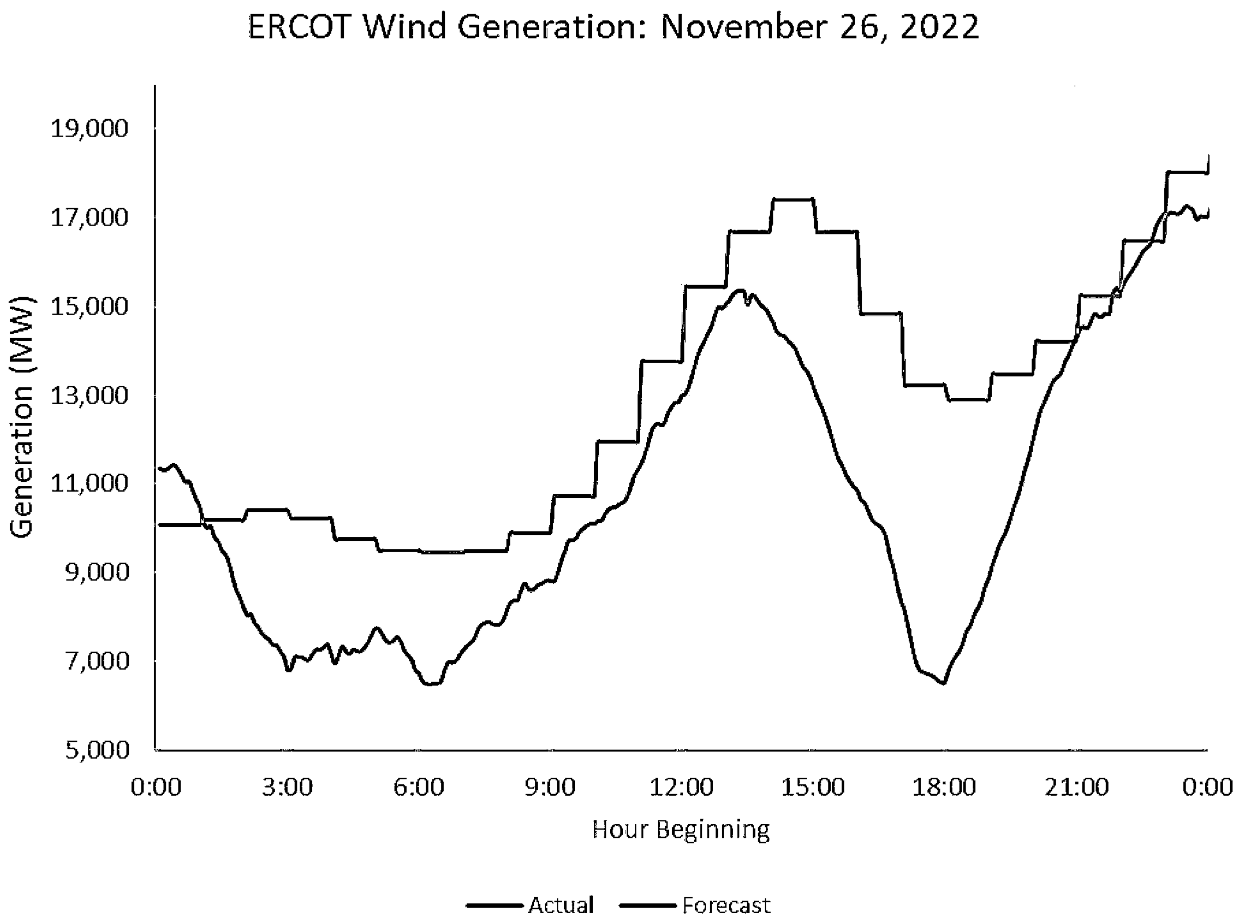
(4) Minimum Operating Level,

(5) Ramp Speed, and

(6) Resource duration

In order to provide these market products, resources would need to qualify by demonstrating they can operate within acceptable limits of the elements described above and be able to quantify the amount of the product they are able to provide over any given time horizon. Units that can minimize elements 1 through 4 and maximize elements 5 and 6 should be highly desired as they will mitigate volatility in the market, stabilizing prices for consumers and offer better reliability to ERCOT through flexible dispatch.

The ASUP is intended to operate within a 2–4-hour window and resolve issues around tight system conditions. The IMM proposed this product to address renewable intermittent generation that can cause large ramps in real time operation as well as address the conservative posture the PUCT has taken towards grid operations. It is not clear, as proposed, what attributes would qualify a generating asset to be sufficiently flexible. Even a 2-hour notification for startup or shutdown could be too long of an allowance to provide flexibility in the market. During the weekend after Thanksgiving, the system lost 8,000 MW[5] of wind from hour beginning 15:00 to 19:00 to then gain 8,000 MW of wind back from 19:00 to 23:00 that the evening, as shown below:



These large ramps will continue to grow as more wind and solar continue to be developed. As a result, generation that can quickly cycle and respond is needed. Failure to address the flexibility needs in conjunction with peak, net-peak, or scarcity conditions will result in avoidable uplift costs.

[5] Yes Energy Time Series Analysis – ERCOT Market Region RT Wind Data on 11-26-2022 14:00-22:00

V. As proposed, the PCM does not fulfill the objectives of SB3

If one were to accept the premise that PCM is a necessary market addition, it is still a reality that actual implementation will be challenging and several years off. Texas is looking to adjust its market construct because of weaknesses and shortcomings that have been exposed during Winter Storm Uri, record-breaking demand, and net load ramping events. It will take a significant amount of time – up to four years according to E3's report – for complete development and integration of the PCM software/infrastructure. Four years is too long for Texans to wait for a product that may or may not yield the construction of generation assets. This process will require several engagements with market participants, testing iterations, and studies within ERCOT to ensure the product will function and can be supported. The PCM would be a new product in the ERCOT market. Meanwhile, uplift costs from units that are not flexibly dispatchable will elevate costs to end consumers.

Additionally, the PCM does not address the operational or locational attributes that may drive scarcity. Specifically, some scarcity is driven by ramping/flexibility shortfalls, not inadequate capacity. Qualifications, such as ramp rates or start times are not addressed in the PCM proposal. These operational attributes have been highlighted by the IMM, ERCOT, and PUCT as needed to address intermittency of renewable generation and seasonal outage concerns and should be a part of the ultimate market enhancements that result from SB3. Further, capacity built and available in west Texas will not help solve scarcity in Houston or Dallas/Fort Worth because of transmission congestion. These issues require much more attention to ensure that PCM would be a useful market addition.

It will take significant time to develop, implement, and yield results for specific rules and metrics for existing resources, let alone identify potential opportunities/value to attract new resources. For example, there are unclear rules on performance assessment and penalties behind the PCM. The definition of "available" is critical to the PCM payment and penalty scheme. However, the term is not defined adequately to assess day-ahead versus real-time availability. More precisely, long-start resources without day-ahead commitments will not be "available" in real-time. Additionally, even the idea of scarcity is not well defined. Day-ahead may have abundant resources, while real-time is scarce due to inadequate day-ahead commitment decisions. Although these seem like simple questions, history in other ISOs/RTOs shows that they are foundational and take significant time to resolve. The effectiveness of the PCM construct could be completely undermined through these definitions.

As noted above, actual operations and penalties around the PCM require significant refinement. It is unclear, during an assessment period, if a generator can be compensated by being available instead of producing power. For example, if a generator cleared the forward PCM market at the beginning of the year, but did not clear the day ahead energy market and is not dispatched in real-time, because of long start-up times and/or high costs, would this generator receive a penalty? As such, the PCM's penalty would need to be assessed not only on "availability" during targeted hours, but also on actual performance when dispatched during that hour to incentivize exit of older equipment from the market.

One other concern is the forward PCM market does not have a MW floor value required to offer a generating asset. A generator could offer 1 MW during the voluntary forward market to mitigate any nonperformance penalties, while collecting the benefits of the PCM by over producing during PCM-eligible events throughout the year. Conversely generators may place high offers into the forward market with the intention of gathering PCM money throughout the year without actually having its offers cleared in the energy markets. These items remain unclear and blur the line of value added from equipment that can work to solve grid balancing.

VI. Additional incentives are likely needed to spur new generation in the short and possibly long-term

It is not clear that PCM will create sufficient incentives for new capacity additions. While it would provide support to keep existing resources online, it is unclear how it would support a long-term capacity addition. Thus, and at best, a temporary bridge product would still be needed to support existing resources and even support investment in new resources in the immediate term.

As noted above, even if one accepts PCM as necessary, Wärtsilä does not see it as capable of addressing the objectives of SB3 for several years. Although Wärtsilä supports continued exploration of an energy market-based uncertainty product, more immediate support for new, flexible, dispatchable generation may be needed in the short-term. As discussed at the Senate Committee on Business and Commerce Meeting on November 17, 2022, a bridge product, like state backed low-interest loans[6] and RMR contracts, could cover the short-term task of building or upgrading existing equipment to provide more operational flexibility, reliability, and cost control until other market products are ready. The state backed loans will work to build more flexible, dispatchable resources immediately and the RMR contracts will financially support the aged fleet until the newer units can begin operating.[7]

VII. Conclusion

Wärtsilä encourages and supports the continued development of the Ancillary Service Uncertainty Product. The PCM has a number of issues ranging from unclear penalties that materially impact economic signals of entry/exit to the ERCOT market, lengthy implementation times delaying signals for needed capacity additions, and no requirements on PCM product qualifications. These items can delay the ERCOT market's access to equipment that better addresses system needs, including renewable intermittency, forced outages, and errors in load forecast that impact real time operations and uplift cost to consumers. The IMM's ASUP more appropriately addresses the operational short-term needs of the system. To function efficiently the ASUP needs to quantify the metrics of qualifications behind the elements of dispatchability.

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[6] Senate Committee on Business and Commerce Meeting - 11/17/2022 -Lois Kolkhorst Time Stamp 03:14:00

[7] Wärtsilä acknowledges that mechanisms like the state backed loans discussed here are outside of PUCT authority and require legislative action.

This means minimizing start up time, minimum run time, minimum down time, and minimum operating level constraints while maximizing ramp speeds and duration limits. The ASUP will take significantly less time to implement than the PCM and in the event extra short-term alleviations are needed a bridge like an RMR contract or state backed loans could be utilized. Wärtsilä thanks the Public Utility Commission of Texas for the opportunity to bring forth our comments and opinions on this very important matter.

VIII. Answers to Specific Commission Questions

As a preface, Wärtsilä greatly appreciates the time, effort, and rigor that PUCT staff and E3 put into their analysis and the efforts taken to explore a variety of options. Wärtsilä offers these comments not as a demonstration of support to proceed with the PCM at this time. However, Wärtsilä offers these comments in an effort to help the PUCT should it elect to move forward with PCM in spite of the discussion provided above.

1. **The E3's report observes that the PCM has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?**

Wärtsilä believes that the PCM will face timeline challenges during implementation given the complexity and novelty of the capacity framework. In E3's report it referenced 2 years as time allotted to analytical tasks to stand up the PCM in the ERCOT market.[8] This would include processes and procedures that involve stakeholder engagement to determine number of PCs to issue in the market, rules behind which operating hours the PC's would apply to, and market clearing and transparency. This process alone, even with a streamlined procedure, could take a year or two.

Although not exactly analogous to the PCM model put forward in the E3 report, there is precedent in other ISOs for after-the-fact performance assessments. ISO-NE and CAISO have both implemented after the fact assessments for upfront obligations. In both cases, the policy development was prolonged and contentious. Definition for "availability" was critical and there was a consistent push for exemptions and dead-bands that would allow some level of "non-availability" without penalty and complex substitution rules for outages.[9] The implementation in

[8] Page 82 Assessment of Market Reform Options to Enhance Reliability of the ERCOT System by E3
[9] As an example, planned outages are exempt outages in the calculation of availability in CAISO.

both ISOs was extremely complex and, in the case of CAISO, needed to be reopened to correct errors in the initial availability calculations. The final outcome of these processes was several years of policy debate and implementation of after-the-fact assessments that likely have had little to no impact on the availability during peak times.

Additionally, once the PCM framework is built and market participants have a solid idea of how they will be compensated, it could take another two or three years before a plant is built through compensation modeled by the PCM. Conservative operations will need to continue, unless replaced with a shorter term uncertainty product, until new generation can replace older inflexible units. This equates to large system costs consumers will bear that the IMM has been highlighting in the committee meetings from extra non-spin procurements, reliability unit commitment procurements, and the system wide offer cap pricing adjustment.[10]

2. **Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?**

There are too many unknowns about the market design at this time to make any definitive assessments of the PCM's efficiency of incenting current, new, and old generation appropriately. Wartsila recommends additional assessments of an uncertainty product before committing to the PCM. We remain unconvinced that the existing energy-only market is unable to deliver the right incentives to maintain resource adequacy and that making incremental reforms and improvements, such as adding an uncertainty product, furthering ORDC reform, loan guarantees, and as a last resort RMR contracts, may do the trick without resorting to a complex, untested,

[10] Senate Committee on Business and Commerce Meeting - 11/17/2022 Time Stamp 02:11:30

and potentially expensive capacity mechanism that creates no guarantee of sufficient capacity additions.

Does a PCM capacity compensation mechanism incentivize the financing, construction, and operation of new, more efficient, and more flexible capacity? The design appears to swap energy market compensation for fixed capacity payments delivered *ex post* as opposed to the more common *ex ante* mechanisms found in California and the Southwest Power Pool (SPP). More predictable revenues may have the effect of creating a more stable business case for investment. However, according to the E3 analysis, energy market compensation declines due to a reduction in price volatility and ORDC events. Wartsila views the volatility and scarcity pricing as a necessary element of an energy only market, as these serve as valuable price signals that flexible dispatchable resources such as BESS and RICE are needed for system balancing and net peak capacity.

One major problem with capacity mechanisms, aside from their notorious administrative complexity and unintended consequences, is that they compensate all MW equally. This can have the perverse impact of keeping old inefficient units around longer than they should. One innovative feature of the PCM is that generators do not know ahead of time which hours will be deemed the PCM eligible hours, therefore it incentivizes availability throughout the year. Older units that should be retired will have a more difficult time staying available than newer generation. Wartsila believes this signal should be strengthened, whereas generators who do not perform during the assessment hours not only miss out on extra compensation, but also incur penalties for non-performance.

3. **What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If**

recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

The 1-in-10 loss of load (LOLE) expectation is a long precented and widely accepted standard to ensure resource adequacy in a power system. Wärtsilä does not believe there is a reason to abandon this metric, however a simple reliance on the LOLE standard is not sufficient in a rapidly evolving grid. Two recent publications highlight the need to update resource adequacy frameworks. They are "Redefining Resource Adequacy for Modern Power Systems" by the Energy System Integration Group (ESIG)[11] and "Resource Adequacy Modeling for a High Renewable Future," by Mauch, Millar, and Dorris from Ascend Analytics[12]. The ESIG report states, "LOLE is an inadequate metric in a world of more varied shortfall events because it provides limited information on shortfall events' size and duration. This makes it difficult to know the true impact of potential shortfalls and nearly impossible to determine the types of resources necessary to reduce the number of shortfalls." The ESIG report also states, "the [LOLE] criterion was developed in the middle of the 20th century, with limited rationale as to its selection and limited evaluation of the costs and benefits of achieving this definition of reliability. The arbitrary nature of the 1-day-in-10-year LOLE criterion is concerning, despite its use as the de facto reliability standard across a wide range of different systems having heterogeneous resource mixes, consumer needs, regulatory structures, and markets." The Ascend paper deep dives into considerations for resource adequacy modeling under high renewables, and establishes the need for 1) using simulation techniques using weather as a fundamental driver of power system conditions, 2) modeling correlation structures amongst variables to accurately quantify tail risks, 3) evaluating LOLE and other metrics not only at the mean of the simulations

[11] https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf
[12] https://tinyurl.com/ydk53882

but also at the p95 (low-probability, high impact scenario), and 4) modeling increasingly extreme weather outcomes due to the impact of climate change.

Wärtsilä recommends ERCOT increase and expand its analytical capabilities in resource adequacy planning and working with stakeholders to determine economically appropriate targets for a suite of resource adequacy metrics (LOLE, EUE, MW short, duration, etc.) as well as identify which resource technologies best fill the gaps highlighted by the analysis. For example, analysis that shows heightened risk for long stretches of windless winter days may highlight the need for varying amounts of flexible firm fuel supply service.

4. The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?

Wärtsilä notes that in 2022 ERCOT exceeded its previous system peak more than 30 *days*. Furthermore, E3's report focuses on 30 of the most constrained hours in a year which would more than likely fall in the summer months only and possibly within a single high load week within a year. Wärtsilä recognizes that reliability is a problem that persists throughout the year and not only during times when all generators would be available and at their max in the summer. Wärtsilä believes the IMM's daily uncertainty product is better equipped to handle reliability throughout the year. If pursuit of the PCM is unavoidable, Wärtsilä proposes to increase the PCM hours to, at a minimum of 48 or more across a year and assign a minimum of four hours each month. These hours could be based on high peak net load when available flexibly dispatchable capacity falls below a monthly determined reliability threshold, which more appropriately addresses the need for flexible dispatchable resources in SB3 as net load is served by generation other than wind or solar. Alternatively, the metric could be based shortest real-time available dispatchable capacity. Additionally, a two-tiered approach could be applied. First at least some set number of hours in each month to ensure value for each month. Additionally, the month could also add any hour in which the available real-time dispatchable capacity falls below some threshold. That threshold could be defined in terms of MW or percent relative to load. These metrics allows for a more balanced approach throughout the year rather than just tight reserves on hot or cold day. A monthly minimum 4-hour product would more closely align with the uncertainty product which takes aim as a daily 4-hour product.

5. Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?

Wärtsilä believes the Ancillary Service Uncertainty Product offers a more comprehensive coverage due to the product being procured daily. That being said, some of our thoughts on improving the PCM are as follows. The period should be determined on at least a seasonal summer and winter period settled at monthly intervals. As described above peak net load paired with hours of lowest dispatchable capacity should be considered as a guiding principle on which hours should be chosen each month. This could be done with an annual analysis performed at a monthly interval. For example, ERCOT could study bi-annually a rolling 12-month time frame and publish the results before that start of the summer or winter season. Increasing the frequency of when the product is settled will create a more evenly distributed revenue stream as well as reliability benefits, such improved outage management, throughout the year and not just during the summer. Generators can more easily manage and metric monthly products, like the PCM, that have penalties based on real time availability. This monthly settlement will bring visibility to how the PCM product is offered, cleared, and settled. It should be noted the daily settlement of ASUP would also provide this visibility. The monthly allocation will more accurately reflect the availability of generators and give flexibility to the market participants when they would like to provide the service.

6. **Would a voluntary forward market for generation offers and a mandatory residual settlement process for LSE procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?**

Alone the PCM may not incentivize new generation without penalties. The voluntary forward market is not enough to incentivize resource availability or operational certainty without a stout penalty based on generation instead of availability. Reliance on the energy markets high prices is the correct way to ensure dispatch in real time operations not an ex-post payment. As highlighted by the IMM, as well as in section III, there is an uncertainty problem that needs more flexible capacity.

7. **Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?**

Wärtsilä has no comments on this question.

8. **If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service, to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?**

Yes. As mentioned earlier in section VI low-cost state backed loans paired with RMR contracts would be able to support injecting new generation into ERCOT's portfolio as well as maintaining the older units until enough flexible dispatchable power can replace their capacity and the PCM and/or Ancillary Service Uncertainty Product can go live.

9. If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?

There should be no reason why state back financing or reliability must run contracts would delay the completion of a new market product. Specifically, because the state of Texas and ERCOT would have complete control over the length of the contracts and their effectiveness. As an alternative the Ancillary Service Uncertainty Product could be implemented very quickly with small adjustments and clarifications.

10. What is the impact of the PCM on consumer costs?

The current E3 analysis of the PCM shows an impact to customers through extended timelines for the product to operationalize. While the rules and regulations are being discussed and implemented by ERCOT with the appropriate stakeholder engagement, ERCOT will need to continue conservative operations until new flexible generation comes online. Carrie Bivens (IMM) has stated that extra procurements of non-spin, adjustment of the scarcity pricing mechanism, and reliability unit commitments have added material dollars to the cost of operating the market[13] which ultimately filter down to consumers.

The other cost burden will be the market uplift caused by having to run legacy units with low flexible/dispatchable attributes under the PCM. This would include old, large steam units that can take 12 to 18 hours to start and have limited mobility once online and generating. These older units would continue to operate for the next 4 to 5 years, and possibly much longer, while the PCM or other market options are under construction.

[13] Senate Committee on Business and Commerce Meeting - 11/17/2022 Time Stamp 02:11:30

11. What is the fastest and most efficient manner to build a " bridge " product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.

A more direct way to "bridge" the market, as PCM or other product implementations occurs, would be to offer low-cost state backed loans for a defined set of flexible dispatchable attributes. This must be paired with RMR contracts for units like, old gas fired steam plants, that will need financial support due to their lack of flexible attributes but importance to reliability across tight supply conditions during peak net loads.

First, the state of Texas would need to appropriate dollars into a Texas Trust Fund to manage, invest, and safeguard state funds. The target amount would vary as different technologies have different costs but E3's estimate to add 5,630 MW of dispatchable resources to bring LOLE to a 0.1 days/year is a good start.[14] The use of these funds would be solely to finance flexible dispatchable electric generation. These funds would be available to existing facilities in the ERCOT market that are making upgrades or rerates to enable flexible dispatch.

Second, generation that is financed through this method will provide a more immediate relief to the market reducing price volatility and increasing dispatchable capacity. The new installed or upgraded units would be the most attractive to the ASUP product and begin to earn revenues as soon as the product would go live because of their attributes. This will provide the state with assurances that the debt will be repaid in a timely manner.

12. In what ways could the Dispatchable Energy Credit (DEC) design be modified through quantity and resource eligibility requirements, e.g. new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

[14] Page 50 Assessment of Market Reform Options to Enhance Reliability of the ERCOT System by E3

Wärtsilä has no comments on this question.

Date December 15, 2022

Respectfully submitted,

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PUC PROJECT NO. 54335

WHOLESALE ELECTRIC MARKET REFORM ASSESSMENT BY E3	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

Executive Summary

- Wärtsilä supports the continued development of the Ancillary Service Uncertainty Product. The ancillary service uncertainty product (ASUP) has a much faster implementation time and more closely addresses the real time operations issues of net load ramping due to intermittent renewables as well as error in load forecasting. The ASUP product has a few undefined rules like what attributes are required to qualify for the product and how a nonperformance penalty, beyond decertification, will be enforced to incent entry/exit of generators.

- Timeliness of implementation is extremely important because many of the proposed market redesign projects can take years to complete. The PCM's timeline is too long with much of the upfront process going to rule making and testing before the product can be bankable. The ancillary service uncertainty product (ASUP) can be implemented much more quickly as much of the framework of an additional ancillary service is familiar and already in place at ERCOT.

- Wärtsilä believes the PCM has shortcomings and complications that would make its effectiveness to add capacity into the market at speed a challenge. At best, with ambiguous penalties that can be skirted by less flexible units, market signals will not be focused enough to cause older units to exit and new generation to be constructed.

- A bridge product in the form of low-cost state-backed loans for new flexible dispatchable resources paired with RMR contracts to prevent early retirements could bridge the market for the 5,630 MW E3 reported. This would give time to the market to stand up a new product to support these assets on a forward basis.

- Given the main areas of uncertainty which include net load ramping from intermittent power, error in forecast from load, and forced generator outages. The PUCT and ERCOT should be focused on products that deliver flexible dispatch characteristics to alleviate these uncertainties. These generating assets are more effective if they can minimize start-up time, minimum run time, minimum down time, and minimum operating level while maximizing ramp speed and operating duration.