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| Submitter’s Information | |
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| Market Segment | Municipal |

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| Comments |

CPS Energy appreciates the opportunity to provide comments to the interim bridging solutions proposed by ERCOT staff at the Phase 2 Bridging Options Workshop held on March 3, 2023. These comments reflect our views on the options as they are currently described by ERCOT and may evolve as the concepts evolve. We look forward to collaboratively working with ERCOT staff and stakeholders to refine the current options and identify new options for consideration.

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| Executive Summary |
| We support the effort to develop options targeted at preserving existing economically viable dispatchable generation capacity and incenting new dispatchable capacity. Efforts to address the risks posed by strong load growth and potential premature generator retirements are essential for the reliability of our grid and the continued prosperity of the state.  As a general policy matter, we feel that as ERCOT continues to develop its menu of bridging options, the mechanisms used to allocate cost be examined and that these mechanisms be designed to not impose additional costs, including default uplift cost, on entities that procure and maintain sufficient capacity levels to meet their demand obligations. On behalf of our customers, we have made significant investments in our generation and power supply portfolio to ensure that our obligations are met with sufficient power supply reserves to meet additional risks of load forecast error, generator contingencies, and unforeseen circumstances. We oppose efforts to impose additional costs on our customers that would effectively benefit market participants who are unable or unwilling to responsibly manage their demand obligations. Responsible market practices should be rewarded.  As we continue to develop and evolve the menu of bridging options, we request that ERCOT provide its view of the impacts that each option will have on grid reliability, resource adequacy, and cost to consumers. Specifically, we ask that ERCOT present its analysis of impacts on reserve margins, expected change in loss of load events (or some other similar and appropriate measure), expected levels of RUC capacity, and costs to the market. As we continue to develop the menu of bridging options this information will be essential to present to the ERCOT Board of Directors and the Public Utility Commission as they decide which solution best fits the needs of our growing state.  We support market-based solutions including modifying ancillary services procurement amounts or adjusting the Operating Reserve Demand Curve. We believe that these options best meet the needs of the market and appropriately incent generator investment with a goal of improving reliability and could be accomplished quickly. We also support the indicative PCM option if the PCM is ultimately adopted. This option would allow stakeholders to better understand the impacts to a market participants cash flows and expected changes to credit and collateral requirements.  We do not support the basic manual PCM, and the Backstop Reserve Service (BRS), or contracts for capacity are not our preferred options as they are currently contemplated. We believe the manual PCM would create financial risks for the market that do not outweigh the benefits. The backstop reserve would create artificial scarcity conditions and create a subset of capacity that would gain a competitive advantage over other generators in the market. The contract for capacity option is an inefficient use of customer dollars and would effectively create a cash-for-clunkers program. We do not support proposals to effectively force end of life assets to remain online, especially if these older resources provide little reliability to the ERCOT grid. |
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| Option 1: Implement a Basic settlement component of PCM manually |
| We do not support the limited and manual implementation of the Performance Credit Mechanism (PCM) primarily because of the numerous implementation details that remain to be defined and fully understood. This option would also carry a high financial obligation for market participants and financial risks to loads will be created. We believe setting a reliability standard and developing the sloped demand curve are just two of many important design factors that have yet to be thoroughly vetted through any public stakeholder driven or regulatory process. As the legislature considers improvements to the market design of ERCOT, it would be inappropriate to implement a bridging option that would be counter to policy direction from the legislature.  Additionally, this option would establish a new revenue stream – PCM credits – paid by loads to generators. There are many unknowns until after the fact, possibly causing loads to accrue a substantial financial burden over a year with a single settlement period expected. The accrual of a large financial burden on all loads is expected to increase the default uplift risk for all market participants and may result in market instability if the market is faced with paying for PCM settlements obligations and a default uplift charge. Without knowing the exact financial obligation created by the PCM, ERCOT would likely estimate the credit and collateral requirements for loads which would add to the financial burden on market participants as the credit obligation would be in addition to credit requirements for daily market operations.  We don’t believe the current level of uncertainty and the increased financial risk caused by the basic settlement option is a prudent path forward at this time.  We offer the following questions on this option for consideration:   * Are there benefits from using the existing ORDC mechanism (demand curve, settlement charges, etc) as a proxy for the PCM mechanism? This would be a PCM pricing run using parameters and mechanisms already defined in the ORDC process. * How many hours will be assessed (30, 60, 90, etc. hours)? * How many PCM settlement periods will ERCOT utilize, and will they be seasonal (Winter/Summer), yearly, monthly? * How will ERCOT determine Performance Credit Prices, and what will the price be tied to – Net Cost of New Entry (CONE) or some other value? What basis will be used to justify the prices? * How will PC’s be earned? By offering into the Day Ahead market? By a Current Operating Plan status other than “OUT”? * Will generators that are committed by the RUC process earn PCs? * How will Load Resources earn PCs? * What standard of reliability will be used to determine the hours a PC will be earned (Peak net load, lowest operating reserves, Committed capacity)? * Will there be a clawback mechanism for resource non-performance? * How will the credit and collateral requirements be established and managed? * What is the default uplift risk of this solution and how can we mitigate it? * Are there benefits to using a monthly or seasonal performance period and using an offer curve that is initially discounted (25%, 50%, 75%, 100%) to allow for the cost impacts to be better understood by the market? |

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| Option 2: Procure Additional Ancillary Services |
| We support further development of this option to provide additional clarity on the expected levels of capacity increases and their effectiveness in creating an investment signal for dispatchable generation. An increase of the procured capacity will serve to increase the demand of dispatchable capacity that can provide ancillary services. This proposal is more likely to send a strong price signal to both new and existing generators and is in line with our understanding of the desired direction of both the PUC and the legislature.  We offer the following questions on this option for consideration:   * What methodology or reliability measure will ERCOT utilize to determine the level of magnitude increase in the ancillary service procurement amounts of each service? * How will the incremental revenues earned by dispatchable generators be measured to ensure the incentives are appropriately established? Can the program be designed to meet a metric such as net CONE to ensure that the market incentives are appropriately sized? * How will Load Resource capacity be considered when increasing the ancillary service procurement amounts? Will the increases be targeted only to generation? * Can ERCOT analyze the necessary generator investment that will be needed to meet varying levels of ancillary service procurement amounts? * Can ERCOT develop a proposal within this option that they believe will reduce or eliminate the need to RUC generators? If enough generation is brought online to serve the new AS obligations RUCs may not be needed. Perhaps generator AS limits would need review to help obligate more generators that would normally remain offline? |

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| Option 3: Enhance the Operating Reserve Demand Curve (ORDC) |
| We support further development of this option as we feel it meets the understood and established legislative and regulatory goals in this effort. While the ORDC payments will remain based on scarcity, the adjustment to the shape of the curve will effectively increase payments to online generators in a self-correcting manner. There is also a tendency for the ORDC to pay higher revenues to dispatchable generators due to the correlation of low renewable production and high price adders created by the ORDC mechanism. This leads to higher energy values during times of system need which creates an incentive for generators to be available to the grid when needed, which is an operational performance mechanism. This option also incents loads to reduce consumption during the same high-risk times and is technology neutral. This quality allows existing renewable generators to adapt their operational capabilities to increase their benefits to reliability.  We offer the following questions on this option for consideration:   * How will the ORDC be changed and what basis will be used to justify the changes? * Is a piecewise linear curve a viable option as it would be a more explicitly defined curve that is representative of the desired value of reliability? * Will the price adder simply produce price adders at a lower reserve level, or will there be other changes to include applicability to generation resources? * Will there be any adjustments to reflect high system demand, inclement weather events, or emergency conditions? * What impact can we expect to see on ERCOT’s use of the RUC process as generators respond to the incentives of an increased ORDC? * If we modify the ORDC directly by further raising the minimum contingency level and/or the standard deviation parameter would that create a similar outcome as the PCM without the new administrative complexity? These tweaks may be quick and easy, and ERCOT has tweaked them many times in recent years. |

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| Option 4: Backstop Reserve Service (BRS) |
| This is not our preferred option, but believe it has merit if the backstop capacity allows ERCOT to substantially limit its use of the Reliability Unit Commitment (RUC) process. If ERCOT believes the BRS capacity maintains a margin of safety equivalent or better than the one currently achieved in the current practice of “conservative operations”, then we believe the practice of issuing RUC for capacity can cease.  The policy of creating artificial scarcity is likely to elevate market prices and incent investment, but we believe the initial implementation of the program is likely to procure older, less efficient and less reliable generators, which may not be a desired outcome of the program.    We offer the following questions on this option for consideration:   * Does ERCOT have the necessary level of staffing to handle the development of the BRS and the PCM simultaneously? * Related to the previous question, is this solution too complex to implement prior to the implementation of the PCM? * What are the expected pricing impacts to RT energy prices? * What resources would be able to participate in the BRS auction? Will there be reliability standards for generators who are contracted? * Will loads pay for older less reliable generators to improve reliability? * Would retiring generators (old and unreliable) be forced to remain online to participate? * How will ERCOT mitigate market manipulation by generators with large portfolios? * Will other market participants be forced to pay for the financial benefit of a few resources, or will any financial benefits be clawed back as generators are allowed to exit the program? |

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| Option 5: Contracts for Capacity |
| This is not our preferred option as we view this as a pure cash for clunkers option. Given the age and reliability levels of the retiring generators, it is unlikely that capacity contracts will be economically efficient, and they may not result in increased reliability. Older generators are more likely to experience catastrophic failures during operations.  One modification that may improve this option is to limit the contracts to resources that are retiring based on economics. Creating a metric that estimates the remaining life of and needed capital improvements of the resource may allow for a prudent economic evaluation of a generator that wishes to retire for economic reasons. However, we would not support contracts of retiring coal generators that have become uneconomic due to emissions control upgrade requirements. The magnitude of capital required for upgrades can be better used to build a new gas peaking plant or install storage assets to firm up the existing renewable fleet.  We offer the following questions on this option for consideration:   * What will the profit adder be set to/ how will this ensure that resource owners will voluntarily contract to keep old units running? * What are the operational risks that could be borne by resources over-running thermal generators? * How will ERCOT manage fuel contracts on generators it procures through this process?   + Generator owners may have unwound fuel contracts as part of retirement preparations, which can lead to high production costs for the generator if ERCOT uses short term fuel contracts. |
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| Option 6: Publish Indicative PCM Values |
| We support this option if the PCM is the market design which is ultimately approved or endorsed by the legislature. If the PCM is ultimately implemented, this option would provide for a backcast of the market and inform a forward view of the market as the full PCM version is developed and implemented. While there is a risk that a simulated market would have flaws including the inaccuracies caused by market participants actions not being influenced by the indicative data, the benefits of understanding mechanics, financial implications, and the ability to identify needed improvements or changes outweigh the risk of inaccuracy.   * What inputs (demand curve, reliability standard, performance periods) will be used for the simulation? Will multiple scenarios be simulated to allow for comparison of options? * How can credit and collateral requirements be simulated and reported? * How can default uplift risk be assessed and reported? * How will the forward market be simulated without any settlement or binding financial outcomes? |

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| Conclusion/Additional Comments |
| CPS Energy appreciates the opportunity to provide comments to the interim bridging solutions and we look forward to collaboratively working with ERCOT staff and stakeholders to refine the current options and identify new options for consideration. |