|  |  |  |  |
| --- | --- | --- | --- |
| NPRR Number | [1224](https://www.ercot.com/mktrules/issues/NPRR1224) | NPRR Title | ECRS Manual Deployment Triggers |
|  |  |
| Date | June 6, 2024 |
|  |  |
| Submitter’s Information |
| Name | Adam Sinn |
| E-mail Address | asinn@aspirecommodities.com |
| Company | Aspire Power Ventures, LP |
| Phone Number |  |
| Cell Number |  |
| Market Segment | Not applicable |

|  |
| --- |
| Comments |

Nodal Protocol Revision Request (NPPR) 1224 is not a panacea to the issues surrounding the procurement and deployment of ERCOT Contingency Reserve Service (ECRS). NPPR1224 is simply a quick and easy fix that will hopefully reduce the likelihood of another disastrous summer like 2023.

We agree with the Independent Market Monitor’s (IMM’s) recommendation that there should be no “price” floor on released capacity – which we note is the same recommendation made initially by ERCOT. However, if the Board feels the need for a “price” floor then we believe this administered price should have some basis in existing actual practice. The $750 per MW price floor before the Board is an ad hoc number presented as a “compromise.” There was no analysis provided for this number.

While we do not support a price floor, if the Board reaches the conclusion that a price floor is needed, then we suggest that a floor be established between $75 and $250 per MW, i.e., at a level between the cost of capacity for Non-Spinning Reserve (Non-Spin) and the capacity for units that have been committed through the Reliability Unit Commitment (RUC) process. This would provide a price floor that is based on the current market design and reflects the value for reliability that is consistent with the existing market design and operation.

1. **ERCOT Should Seek to Minimize ECRS’s Adverse Effects on the Operation of the SCED dispatch tool and the resulting locational marginal prices.**

ERCOT’s well documented path to implementing and operating the current electricity market was neither quick nor easy. After several material detours and lengthy delays, ERCOT, with the implantation of the Nodal Market, had an electricity market that reflected much of the best practices for electricity market design and delivered measurable benefits to the State. The foundation of the nodal market is the operation of Security-Constrained Economic Dispatch (SCED) and the resulting creation of nodal, or locational marginal, prices across the ERCOT grid. These prices serve not only to guide generation and consumption decisions but also investment decisions. And while strictly not “market” prices, these prices are meant to replicate, or at least be consistent with, those that a market would produce if the time frames necessary to operate a reliable system allowed the price mechanism to balance supply and demand.

While there are many methodologies that can be used to reliably balance the real time supply and demand for electricity, only nodal pricing results in a spot price that non-discriminatorily allocates transmission capacity through a (spot) price that reflects actual supply and demand, the topology of the grid, and reliability considerations. It is this characteristic that gives rise to the third term in SCED, i.e., economic or equivalently, least cost. Nodal pricing via SCED is the only known mechanism capable of allocating transmission capacity in a reliable and least cost manner. In a process that took over a decade and cost hundreds of millions of dollars in direct and indirect costs, ERCOT eventually implemented an electricity market that provided reliability *at* least cost.

* Nodal, or locational marginal, pricing is the only known mechanism to operate an electricity system both reliably and at least cost.
1. **ECRS Distorts the Prices Resulting From SCED and This Distorting Effect Should Be Muted Where Possible.**

As an additional Ancillary Service, it was unfortunate and very costly that the implementation of ECRS was not subservient to the process of implementing the co-optimization of energy and Ancillary Services. That is, ECRS should not have been implemented before the implementation of Real-Time Co-optimization (RTC). Doing so, simply introduced another detour and additional costs in the ultimate development of an efficient market.

As implemented, ECRS operates by withholding generation capacity *ex ante* from the dispatch process. That is, ECRS imposes an additional constraint, i.e., reduced generation capacity, on the SCED optimization engine. While we do not doubt that SCED calculates things correctly, what we are left wondering is how to interpret the results themselves. There have been plenty of instances over the past year, i.e., since the implementation of ECRS, in which there has been a significant excess of reserves in a low natural gas price environment and yet prices have been materially higher than they “should” have been and were accordingly significantly higher than under similar circumstance before the implementation of ECRS.

* Since the implementation of ECRS, the prices produced by SCED often do not reflect the fundamentals of supply and demand, and reliable operation of the grid as they did before ECRS was included in the ERCOT market design.

In effect, the implementation of ECRS has materially affected the ability of SCED to produce prices that make sense in that they reflect the actual conditions of the grid in real time. The effects of this unintended consequence have rippled through the futures and forward markets, as well as the prices offered to retail customers. And in so doing, has dramatically raised the cost of ECRS beyond the amount determined by the IMM last December.[[1]](#footnote-1)

Given that implementation of ECRS took place prior to discussions and the eventual implementation of RTC, NPPR1224 is best viewed as a response to some of the issue that arose last summer. In particular, NPPR1224 is an attempt to “claw-back” some of the inefficiency identified by the IMM from the procurement and deployment of ECRS. It does this primarily by allowing ERCOT to “release” for dispatch, some of the capacity being held as ECRS, when certain (under generation) metrics are met. The second component of this NPPR establishes an administered “price” floor at which the “released” capacity will be used within the ERCOT dispatch algorithm, i.e., SCED.

While we continue to believe that the ECRS is a fundamentally flawed design, this is neither the right time or forum to have that discussion which will, appropriately, take place during the process of how best to implement the co-optimization of energy and ancillary services. Accordingly, we understand the need to think incrementally with respect to implementing potential improvements to ECRS in order to try and avoid the issues that occurred last year. Our “support” for this NPPR should be viewed within this context.

In general, we are fully supportive of the recommendations made by the IMM that were discussed, and subsequently rejected, at the TAC meeting on May 22, 2024. From the perspectives of both reliability and market efficiency we strongly believe those recommendations are far superior to those that were approved at the TAC meeting and forwarded to the Board for approval.

We listened carefully to the discussion on this NPPR at the May 22, 2024, TAC meeting. The discussion centered on each of the two aspects of the NPPR; (1) the triggering mechanism which would be the signal for capacity to be released from ECRS and made available for dispatch. Making capacity that was unavailable for dispatch last summer able to be dispatched this summer is a definite step in the right direction. Like the IMM, we believe that the triggers in the approved NPPR are too stringent and will continue to cause the market to be inordinately inefficient; and (2) whether there should be a price floor for the released capacity and, if so, what level the price floor should be set at.

Of the two, our particular concern is with the establishment of the price floor. The initial proposal before the most recent TAC meeting set the price floor for ECRS capacity released for dispatch at $1,000 per MW. To be clear this is an entirely administered “number” that is being called a “price” by certain classes of Market Participant. It is not a price. Neither is it the cost of providing that capacity. This number – be it $1,000, $750, or $500 – represents nothing more than easy, or free, money for generators, under the guise of valuing reliability.

While we agree with the IMM’s recommendation that there should be no “price” floor on this released capacity – which we note is the same recommendation made initially by ERCOT – if the Board feels the need to establish a “price” floor then we believe this administered price should have some basis in existing actual practice. The price floor before the Board - $750 per MW – is an *ad hoc* number presented at the TAC meeting as a “compromise” from the initial $1,000 floor. There was no analysis provided for this number. None. No argument as to why $750 was “better” than $1,000 but worse than $500 or $50 for that matter. It was simply a number offered at the meeting by a stakeholder which was subsequently approved by the Committee. This is not how decisions should be made on an issue of this importance.

The relevant question is, “exactly what is it that is being priced?” Once the capacity has been released and is made available for dispatch through SCED, for as long as it has been released it is no longer serving specifically as “ECRS capacity.” This capacity has already received a payment for serving as ECRS capacity, but for the relevant interval it has been released from providing this service. It is not the “job” of SCED to price energy and the reliability provided by ECRS – that is why ERCOT implemented the Operating Reserve Demand Curve (ORDC) framework.

Basing the price floor for the released ECRS capacity on a high and administered *ad hoc* value for reliability and then, in effect, forcing SCED to price both energy and the reliability provided by ECRS will have consequences. Specifically, it will further call into question the results obtained from SCED – prices that have already been distorted by the implementation of ECRS, will deviate even further from the fundamentals of supply, demand, and the grid. A result that will lead to higher prices without any associated benefit.

If, and again, we do not feel there is a need for a price floor, the Board reaches the conclusion that a price floor is needed then we suggest that a floor be established between $75 and $250 per MW, i.e., at a level between the cost of capacity for Non-Spin and the capacity for units that have been committed through the RUC process. This would provide a price floor that is based on the current market design and reflects the value for reliability that is consistent with the existing market design and operation.

* If a price floor is adopted for capacity that has been released for dispatch from ECRS, then the floor should not be $750 as it is in the proposal before the Board, but rather it should be between $75 and $250.

Finally, we urge the Board not to consider NPPR1224 as a panacea to the issues surrounding the procurement and deployment of ECRS. Because it is not. NPPR1224 is simply a quick and easy fix that will hopefully reduce the likelihood of another disastrous summer like 2023.

|  |
| --- |
| Revised Cover Page Language |

None

|  |
| --- |
| Revised Proposed Protocol Language |

None

1. See IMM presentation at [https://www.ercot.com/files/docs/2023/12/11/13%20Independent%20Market%20Monitor%20(IMM)%20Report.pdf](https://www.ercot.com/files/docs/2023/12/11/13%20Independent%20Market%20Monitor%20%28IMM%29%20Report.pdf) [↑](#footnote-ref-1)