M14D: Generator Operational Requirements DESTF Manual Revisions

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PJM RSCS

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- The DESTF began meeting in October 2023 and held a series of 14 meetings.
- The CBIR process resulted in four packages proposed as follows. *(Reference Package Executive Summary Appendix)*
  - PJM Package A
  - IMM Package B
  - Calpine Package C
  - PJM Package D
- The DESTF voted following their October 2024 meeting.

DESTF Solution Overview

Notification Time

- Units that plan to participate in RPM must provide at least 12 months' notice prior to desired deactivation date
- Units that do not plan to participate in RPM due to deactivation must provide notice consistent with existing RPM must offer exception process
- Existing quarterly deactivation implementation process will continue

Compensation Mechanism

- Status Quo (maintain the Cost of Service Recovery Rate filing option and the existing Deactivation Avoidable Cost Credit formula) with the following changes to the Deactivation Avoidable Cost Credit:
  - Removal of the $2 million cap on Project Investment
  - Limit the yearly adder that is applied to Project Investment to 10%
  - Removal of the clause that triggers the credit to be paid using the Daily Deficiency Rate rather than Deactivation Avoidable Cost Rate (DACR) if DACR + Applicable Multiplier is greater than the Daily Deficiency Rate.

DESTF Solution Overview, cont.

Transparency

- Improvements on top of Status Quo to make additional details including deactivation response letters, IMM market power letters, and RMR arrangement notifications available to stakeholders
- Publish estimated RMR revenue allocation zonal rate for impacted zones

Modeling

- Status quo. No changes to Planning and Markets modeling of RMR units

M14D Updates: Notification Time

9.1.1 Generator Deactivation Notice

Any Generation Owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing to the Office of the Interconnection via the email address generatordeactivation@pjm.com at least twelve (12) months prior to the desired deactivation date.

The desired Deactivation Date may be no earlier than the following: (a) April ~~July~~ 1 of the following ~~current~~ calendar year, if the Transmission Provider receives the notice between January 1 and March 31; (b) July ~~October~~ 1 of the following ~~current~~ calendar year, if the Transmission Provider receives the notice between April 1 and June 30; (c) October~~January~~ 1 of the following calendar year, if the Transmission Provider receives the notice between July 1 and September 30; or (d) January ~~April~~ 1 of the second ~~following~~ calendar year, if the Transmission Provider receives the notice between October 1 and December 31.

Units that don't participate in RPM due to deactivation must provide notice consistent with the existing RPM must offer process.

M14D Updates: Compensation Mechanism

If the Generation Owner, or designated agent, chooses the compensation according to the Deactivation Avoidable Cost Credit in Part V of the PJM Tariff, compensation to the generator will begin as of the day following the filing, and will be net of revenues from the PJM markets. All revenues from the PJM markets and unit-specific bilateral contracts will be net of marginal cost of service recoverable under cost-based offers to sell energy from operating capacity of the PJM Interchange Energy market, not less than zero

- A 110% multiplier ~~adder~~ will initially be applied to the avoidable costs, and this multiplier ~~adder~~ will increase in future years. Applicable adders for future years are detailed and defined in Part V of the PJM Tariff.
- A 110% multiplier will also be applied to the cost of necessary investments to keep the unit in operable condition; however, this multiplier will not increase in future years.

M14D Updates: Transparency

9.3 Transparency Into Estimated Generation Deactivation Charges

In order to provide transparency into the generator deactivation charges that may be assessed to responsible parties over the life of a Reliability Must Run (RMR) Agreement, Market Sellers with units under an RMR agreement must provide PJM and the IMM with estimates of the costs to be recovered over the term of the RMR arrangement.

Estimates of the costs to be assessed in each month for the remainder of the RMR Agreement term shall be provided to PJM and the IMM at the intervals specified below. The estimated costs may exclude variable production costs and offsetting market revenues

PJM will post the estimates, including but not limited to the following information, at the intervals specified below to the PJM web site using the information provided by the Market Seller and PJM's estimation of how cost responsibility for the RMR Agreement will be allocated across responsible zones.

- Total monthly fixed costs
- Total monthly project investment costs
- Zonal cost allocation percentage
- Zonal rate ($/MW based on estimated zonal NSPL)

To the extent the estimated zonal cost allocation percentages are not available at the time of the initial posting, the zonal cost allocation percentage and rate will be omitted from the initial posting.

Initial Estimates

For units utilizing the Cost of Service Rate compensation method specified in Section 119 of Part V of the PJM OATT, such estimates must initially be provided to PJM and the IMM within one month after FERC acceptance of the initially proposed cost of service rate, including circumstances when FERC's acceptance of such rate is subject to refund and the outcome of hearing and/or settlement judge procedures. PJM will then post the estimated zonal RMR rate within a month of receiving the estimates.

For units utilizing the Deactivation Avoidable Cost Credit compensation method specified in Section 114 of Part V of the PJM OATT, such estimates must initially be provided to PJM and the IMM at least three months prior to the month in which cost recovery under the RMR arrangement will begin. PJM will then post the estimated zonal RMR rate within a month of receiving the estimates.

Ongoing Estimates

Market Sellers must provide updated estimates for each month in the remainder of the RMR term for each unit receiving compensation under an RMR arrangement on a semi-annual basis by May 1 and December 1 of each year. PJM will then post updates to the estimated monthly costs to be allocated to each zone by the end of the following month (June and January, respectively).

Endorsement:

- Operating Committee First Read: 7/10/2025
- Operating Committee Endorsement: 8/7/2025
- Markets and Reliability Committee First Read: 7/23/2025
- Markets and Reliability Committee Endorsement: 8/20/2025

Informational Updates:

- PC/MIC/SOS-G: Weeks of 6/30/2025 and 7/6/2025

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DESTF Solution Package First Read

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Appendix

Acronyms

Acronym	Term & Definition
RPM	**Reliability Pricing Model** is PJM's capacity market design that includes a series of auctions to satisfy the reliability requirements of the region PJM serves for a delivery year.
BRA	**Base Residual Auction** is the capacity auction conducted by PJM three years in advance of the delivery year to procure unforced capacity to satisfy reliability requirements on behalf of load-serving entities.
CETO	**Capacity Emergency Transfer Objective** is the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency.
CETL	**Capacity Emergency Transfer Limit** is the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM manuals.
DACR	**Deactivation Avoidable Cost Rate** is the default formula rate, as defined in OATT Part V, section 115, used for compensating for agenerating unit that continues operating beyond its desired deactivation date.
DACC	**Deactivation Avoidable Cost Credit** is the credit paid to a generating unit that continues operating beyond its desired deactivation date and elects to be compensated per the defined formula in OATT Part V, section 114, rather than electing to be credited based on a cost of service rate filed with the FERC.

PJM Glossary

Package Executive Summary

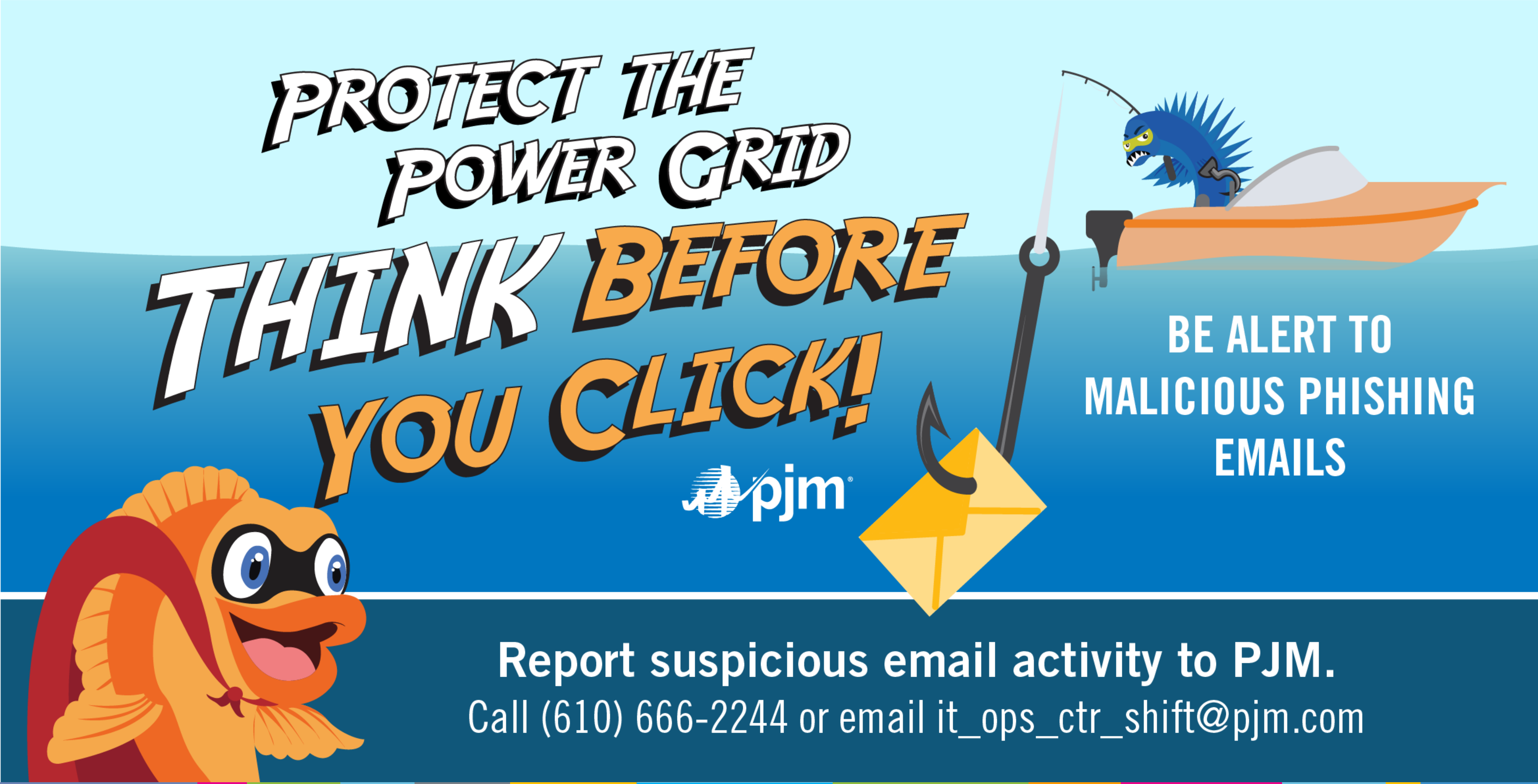
	Package A (PJM)	Package B (IMM)	Package C (Calpine)	Package D (PJM)
Compensation	IMM Option and Cost of Service Recovery Rate filing option	**Payment** a. Actual costs paid as incurred b. Plus a percent adder i. Propose 10 percent; subject to change c. No sunk costs d. Net revenues offset costs **Review process** a. IMM reviews project investments; invoices b. PJM reviews project investments; invoices **Nonperformance** a. Reduces incentive payments b. Based on algorithm for relative significance c. Evaluated at year end **Return to service as market unit** a. Pay back all project investment b. Pay back all major maintenance	Same as PJM Package D	Status Quo (maintain the Cost of Service Recovery Rate filing option and the existing Deactivation Avoidable Cost Credit formula) with the following changes to the Deactivation Avoidable Cost Credit: a. Removal of the $2 million cap on Project Investment b. Limit the yearly adder that is applied to Project Investment to 10%. c. Removal of the clause that triggers the credit to be paid using the Daily Deficiency Rate rather than DACR if DACR + Applicable Multiplier is greater than the Daily Deficiency Rate.

Package Executive Summary

	Package A (PJM)	Package B (IMM)	Package C (Calpine)	Package D (PJM)
Notification	• Units that participate in RPM must provide at least 12 months' notice prior to desired deactivation date • Unit that don't participate in RPM due to deactivation must provide notice consistent with existing RPM must offer exception process • Existing quarterly deactivation implementation process will continue	12 months prior to auction	Same as PJM Package A	Same as Package A
Transparency	Improvements on top of Status Quo to make additional details including deactivation response letters and RMR arrangement notifications available to stakeholders		Same as PJM Package A	Same as Package A

Package Executive Summary

	Package A (PJM)	Package B (IMM)	Package C (Calpine)	Package D (PJM)
Modeling Impacts	No changes to Planning and Markets modeling of RMR units	RMR in capacity market a. Include in CETO/CETL b. Include in supply curve at zero cost i. Not an offer from owner RMR in energy and ancillary services markets a. No must offer b. Committed and dispatched by PJM as needed for reliability	RMR units shall not participate in capacity market. No must offer requirement. Not included in CETO/CETL for RPM purposes. No PAI bonuses or PAI penalties Participation in energy market and reserve markets only allowed for reliability purposes limited to: 1. Needed for reactive/frequency/voltage support 2. Needed for a thermal constraint that cannot be relieved by other generating units through redispatch 3. Need in the case of an emergency alert, warning, and actions for a. "Capacity shortage emergency" encompassing the TO zone where the RMR unit is located b. "Transmission Security Emergencies" encompassing the TO zone where the RMR unit is located c. "Sabotage/Terrorism Emergencies" encompassing the TO zone where the RMR unit is located 4. Does not include market participation for "General Assistance to Adjacent Control Areas"	Same as Package A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THINK BEFORE YOU CLICK!
pjm
BE ALERT TO MALICIOUS PHISHING EMAILS
Report suspicious email activity to PJM.
Call (610) 666-2244 or email it_ops_ctr_shift@pjm.com