

only be supplied by the applicant's uncommitted generation resources. This represents a time when the applicant may have the potential to exercise market power. While this model is interesting, the data needed to verify the applicant and control area information is not readily available (hourly data). However, in the alternatives discussed below, many of the aspects of the SDI (*i.e.*, pivotal supplier concept) have been incorporated.¹²

- CAISO proposed the Residual Supplier Index (RSI). The RSI determines if a supplier is pivotal during a specified set of hours or all hours, *i.e.*, without the applicant's supply the market demand cannot be met. Because applying a model down to the hour creates insurmountable data and administrative difficulties, this model is not practical. In particular, obtaining hourly data for markets outside of an organized market is not practical nor is monitoring such markets on an hourly basis. However, some of the critical concepts of the model have been incorporated into the Capacity Surplus Index (CSI) screen.¹³

- Lastly, Old Dominion Electric Cooperative proposed the Market Simulation Analysis. This modeling technique attempts to simulate market conditions using loadflow algorithms which identify parallel/looping power flows, and seasonal variations. While such models can identify load pockets, daily and seasonal variations, and may provide a more precise measure of generation market power, such models require extensive data from all market participants (including small merchants), could take up to 9 months or more to create, and it is unclear how such a model would be applied on a case-by-case basis. Accordingly, Staff does not consider this alternative to be viable as an interim generation market power screen.¹⁴

IV. Possible Revisions to the SMA Mitigation

With respect to the SMA mitigation measures, among other things, many commenters object to the spot market energy sales mitigation, and in particular to the split-the-savings requirement. Commenters also oppose as ineffective and harmful to the competitive market the requirement to post incremental/decremental cost information.

Set forth below are alternative mitigation approaches for discussion at the technical conference that address many of the concerns expressed by commenters. In each approach, Staff proposes that the mitigation being considered be applied seasonally.¹⁵ If the applicant fails any month of a season, it would thus be mitigated for the entire season (but only that season).

In addition, to address some commenters' concerns, applicants that fail the screen, to the extent necessary, could be required to file incremental and decremental cost

information only with the Commission on a confidential basis.

A. Traditional Cost-based Rate

This alternative would require mitigated sellers to have on file an up to rate or a cost-based rate for periods when they are mitigated. The cost-based rate could be based on an average cost of the units expected to run to meet peak demand with an annual revenue cap, or an average system or regionwide rate could be established.

B. Single Market Clearing Price

Under the single market clearing price approach, all transactions of the failing applicant would be executed at a single market clearing price instead of at multiple split-the-savings prices. The applicant would still be required to provide its own 24 hourly incremental and decremental energy costs by noon for the following trading day.¹⁶ The incremental costs would represent offers to sell and the decremental costs would represent bids to buy energy during each hour of the trading day. All additional requests to purchase and offers to sell energy that are received by 6 p.m. for the following trading day would, in combination with the applicant's bids and offers, be used to determine a market clearing price for energy in each hour of the trading day. The market clearing price for any hour would be a price that corresponds to a total quantity of energy that just balances the accepted supply offers with the accepted purchase bids. That is, it is a price that is at least as great as any accepted supply offer and is no higher than any accepted purchase bid. It is also a price at which no entities whose bids and offers were not accepted would be willing to transact.

Appendix A—Data Definitions

The following definitions are recommended for use in the proposed generation market power screens.

Applicant's Peak Demand—Represents the largest electric power requirement (based on net energy for load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts, for the Native Load and Firm Sales that the applicant has an "obligation to serve".

Applicant's Total Capacity—Represents the applicant's and their affiliate's installed generation nameplate capacity, adjusted for seasonal deratings, plus firm purchases.

Applicant's Uncommitted Capacity—This calculation takes the applicant's installed capacity and subtracts the applicant's planned outages and the peak demand and operating reserves; which then isolates the amount of capacity that is available for wholesale competition. The calculation follows:

Total Applicant Capacity (including imports)
—Planned Outages
—Peak Demand
—Operating Reserves

¹⁶ In lieu of disclosing this information publicly, the mitigated applicant could be required to provide the Commission on a confidential basis with all relevant information that supports the clearing price.

—Applicant Uncommitted Capacity

Control Area Peak Demand—For the control area, this represents the largest electric power requirement (based on net energy for load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts, for the native load and firm sales that are under an "obligation to serve".

Control Area Uncommitted Capacity—This calculation takes the total control area capacity, adds imports and subtracts the planned outages and the peak demand and operating reserves; which then isolates the amount of capacity that is available for wholesale competition. The calculation follows:

Total Control Area Capacity
—Planned Outages
+Imports
—Peak Demand
—Operating Reserves

Control Area Uncommitted Capacity

Imports—The lesser of either the uncommitted capacity (Installed capacity less peak load and operating reserves) from each adjacent control area or the total transfer capability between each Adjacent Control Area.

Installed Capacity—Total generating resources (installed generation plus firm purchases).

Operating Reserves—Any operating reserves the applicant is required to carry by NERC regional reliability councils or by their state utility regulatory commissions to ensure system reliability. To accommodate this operating requirement, each applicant will submit and support the amount of operating reserves that are mandated.

Planned Outages—Refers to generators that are normally in an operating or stand-by status, but are derated or unavailable due to routine service or planned maintenance.

Relevant Geographic Market—The control area in which the applicant owns the bulk of its generation and the interconnected control areas adjacent to that control area.

Total Control Area Capacity—Total capacity capability for the control area, includes installed generation and firm purchases.

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ENVIRONMENTAL PROTECTION AGENCY

[OPP-2003-0004; FRL-7603-9]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; Application for Experimental Use Permit (EUP) to Ship and Use a Pesticide for Experimental Purposes Only

AGENCY: Environmental Protection Agency (EPA).

¹² Comments of Reliant Resources, Inc., pages 5–8.

¹³ Comments of the California Independent System Operator Corporation, pages 13–18.

¹⁴ Comments of Old Dominion Electric Cooperative, pages 8–10.

¹⁵ The four seasons considered are: Summer (June/July/August); Fall (September, October, November); Winter (December/January/February), and Spring (March/April/May).