

percent based on IPM data. To make the compliance response and costs consistent with the economic performance of facilities in the IPM, EPA used projected IPM capacity utilization rates for 2008 (the first model-run year) for the NODA.

As a result of these two changes, of the 530 facilities modeled by the IPM at proposal, 19 facilities that had a capacity utilization rate of less than 15 percent for the proposal analysis have a rate of 15 percent or more for the NODA analysis (base case using the EPA electricity demand growth assumption). Conversely, 75 facilities that had a rate of 15 percent or more for the proposal analysis have a rate of less than 15 percent for the NODA analysis (base case using the EPA electricity demand growth assumption). The net effect of these changes is that for the NODA analysis more facilities are estimated to have the less stringent compliance requirements associated with a low capacity utilization rate than was the case for the proposal analysis.

- *Generation cap.* A final modification to the capacity utilization of Phase II facilities relates to the potential change in the utilization rate between the base case and the post-compliance cases. Because facilities with a baseline capacity utilization rate of less than 15 percent are potentially subject to less stringent compliance requirements (depending on the water body from which they withdraw and the technologies they already have in place), they would not be able to increase their post-compliance capacity utilization without incurring more stringent compliance requirements. In order to ensure that the capacity utilization rate in the post-compliance case is consistent with the costing assumptions, the generation of facilities with a steam-electric capacity of less than 15 percent in the base case was capped so that their post-compliance capacity utilization would remain below 15 percent.

4. Treatment of Installation Downtime

The IPM models the electric power market over the 26-year period 2005 to 2030. Due to the data-intensive processing procedures, the model is run for a limited number of years only. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. EPA selected the following run years for the Section 316(b) analyses: 2008, 2010, 2013, 2020, and 2026.⁷ 2005 to 2009 are

mapped into the 2008 run year; 2010 to 2012 are mapped into the 2010 run year; and 2013 to 2015 are mapped into the 2013 run year. The years that are mapped into a run year are assumed to have the same characteristics as the run year itself. This model characteristic creates a challenge in correctly representing estimated downtimes associated with recirculating systems and other compliance technologies exactly the way they are estimated to occur (downtimes assigned to a model run year are also assigned to non-run years, and downtimes assigned to non-run years are not taken into account).

There are different options of accounting for downtimes. At proposal, EPA decided to model the downtime for each facility in its estimated year of compliance. Since 2005 through 2009 are all mapped into 2008, a facility that had downtime in 2008 was modeled as if it also had downtimes in 2005, 2006, 2007, and 2009. This may have understated the net present value (NPV) of the facility's operations and therefore overestimated its closure decision. Conversely, a facility that had a downtime in a non-model run year was modeled as if it had no downtime at all. This may have overestimated its NPV and therefore understated its closure decision. While this approach potentially affected the facility-level analysis, it provided for a realistic snapshot of the market effect of downtimes in the model run year.

For the NODA analysis, EPA decided to change the representation of downtimes to an average over the years that are mapped into each model run year. For example, a facility with a downtime in 2008 was modeled as if 1/5th of its downtime occurred in each year between 2005 and 2009. This approach more closely models potential facility-level impacts as it accounts for the correct total amount of downtime for each facility. The potential drawback of this approach is that the snapshot of the market-level effect of downtimes during the model run year is the average effect; this approach does not model potential worst-case effects of above-average amounts of capacity being down in one NERC region during a specific year.

5. Correction of Errors

EPA corrected two IPM input errors that were discovered after publication of the proposed rule: (1) At proposal, the capital costs of compliance were erroneously considered sunk and were

not taken into account in making early retirement decisions; (2) The energy penalty was omitted for a few facilities costed with a recirculating system (one out of 49 facilities under the waterbody/capacity-based option and nine out of 408 facilities under the all closed-cycle option). These errors may have led the IPM to understate the modeled economic impacts at these facilities.

6. Other Changes Affecting the IPM Results

In addition to the modeling changes described above, a number of other changes affect the results presented below. These changes are outlined in Section III above and include the following: an increase in the estimated number of in-scope Phase II facilities from 550 to 551 (as a result, the number of Phase II facilities modeled by the IPM increased from 530 to 531); revisions of technology and permitting/monitoring costs; changes to the assumption of construction downtimes of recirculating cooling towers and other compliance technologies; an adjustment of energy penalties; changes in the estimation of the capacity utilization threshold; and adjustments to the compliance schedule.

EPA also notes that in 2010, non-dispatched capacity in the IPM base case (based on EPA's electricity demand growth assumption) is approximately 12 percent of total capacity, which is consistent with historical rates to ensure system reliability. (Non-dispatched facilities are those that operate on a stand-by basis throughout the year but are not called upon to generate and dispatch electricity.) Most of this capacity is oil/gas steam capacity (66 percent) and gas turbines (27 percent). Overall, 11 percent of steam electric capacity and 15 percent of non-steam capacity are modeled to be on stand-by. A large portion of the non-dispatched steam electric capacity is subject to Phase II regulation. In total, approximately 12 percent of Phase II steam electric capacity is not dispatched in the base case. This number is higher than historical data for these facilities. The main reason for this difference is that over time, existing capacity, especially oil/gas steam capacity, is expected to become less competitive relative to new capacity additions, especially combined-cycle facilities. Oil and gas steam units generally have (a) higher heat rates, (b) higher fuel costs, (c) higher variable O&M costs, and (d) higher emission rates than other steam electric capacity. As a result, some relatively inefficient oil and gas steam units are modeled to be idle in the IPM.

⁷ Model run years 2020 and 2026 were specified for model balance, while run years 2008, 2010, and

2013 were selected to provide output across the compliance period. Output for 2020 and 2026 is not used in EPA's analyses. For more information on IPM model run years, see Chapter B3, section B3-2.1.d of the EBA.