ALTERNATIVE MEASURES OF "REPRESENTATIVE MARKET PRICES" FOR FERC DELIVERED PRICE TESTS

John R. Morris,[*] Jéssica Dutra,[†] Tristan Snow Cobb[‡§]

Synopsis: The U.S. Federal Energy Regulatory Commission screens merger and acquisition applications by jurisdictional electric utilities, requiring applicants to calculate market shares and concentration. The shares and concentration are based on "Available Economic Capacity," (AEC) which is the generation capacity economically deliverable at a "representative market price" after excluding obligations to serve retail and wholesale customers under long-term contracts. Even small differences in price can significantly impact AEC. Traditionally applicants have used average prices based on historical data. Real-world price distributions are often skewed by outliers making average prices unrepresentative of typical market conditions. This article demonstrates that merger applicants inherently must either select prices and adjust generation levels or select generation levels and adjust prices to be consistent with those levels. It demonstrates that selecting prices consistent with other Delivered Price Test (DPT) data are more appropriate measures of representative market prices because they better replicate generation quantities and the incentive to exercise market power and, therefore, are more likely to separate anticompetitive mergers from those that are competitively benign.

[*] John R. Morris is a Principal at Economists Incorporated in Washington, DC. He studies competition in energy industries and submits expert reports before the U.S. Department of Justice, the Federal Energy Regulatory Commission, and other regulatory agencies. He may be contacted at morris.j@ei.com.

[†] Jéssica Dutra is a Senior Economist at Economists Incorporated in Washington, DC, where she consults on competition matters on a wide range of industries including the electric power industry. She may be contacted at dutra.j@ei.com.

[‡] Tristan Snow Cobb is an Energy Analyst at Economists Incorporated in Washington, DC. He may be contacted at snowcobb.t@ei.com.

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I. INTRODUCTION

The U.S. Federal Energy Regulatory Commission (FERC) reviews changes in ownership of jurisdictional electric utility assets in the United States.[1] Under section 203 of the Federal Power Act, FERC must find that a transaction is in the public interest in order to approve a merger or acquisition.[2] As part of its public interest review, FERC assesses transactions' effects on competition.[3] FERC uses a standardized five-step screening methodology to assess possible competitive effects. The steps are (1) to define relevant markets; (2) to identify potential suppliers to the market; (3) to calculate the size of those suppliers given generation capabilities and transmission limits, generation costs and market prices; (4) to calculate market shares and concentration; and (5) to make inferences about possible competitive effects from the shares and concentration.[4] For concentration screening thresholds, FERC uses the Herfindahl-Hirschman Index (HHI) measure of market concentration.[5] The HHI is the sum of the square of the market shares.[6] So, for example, the HHI for a market with four sellers having shares of 40, 30, 20, and 10% would have an HHI of 3,000.[7] FERC uses the HHI standards first

1. *See generally* Mark F Sundback, et al., *Electricity regulation in the United States: overview*, THOMSON REUTERS (July 1, 2020).

2. Federal Power Act, § 203(a)(4), 16 U.S.C. § 824b(a)(4) (2019) (" . . . the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction will be consistent with the public interest . . . ").

3. Order No. 642, *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, F.E.R.C. Stats. & Regs. ¶ 31,111, 65 Fed. Reg. 70,983 (2000) [hereinafter Order No. 642]. FERC also considers effects on rates and regulation. After repeal of the Public Utilities Holding Company Act, it also reviews effects on cross subsidization. *See* Federal Power Act § 203(a)(4), 16 U.S.C. § 824b(a)(4) (" . . . the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction . . . will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.").

4. Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, 61 Fed. Reg. 68,595 (1996), at p. 30,130 [hereinafter Order No. 592]; Order No. 642, *supra* note 3, at 31,882. If applicants fail the screens, they may cite to other factors indicating that the transaction is unlikely to be anticompetitive despite the screen failures. Order No. 642, *supra* note 3, at 31,879. For example, in *FirstEnergy* FERC found that three (of ten) screen failures were not a competitive concern "because they do not involve systematic failures in a highly concentrated market." *FirstEnergy Corp.*, 113 F.E.R.C. ¶ 61,222, at P 49 (2010).

5. *See* Orris C. Herfindahl, *Concentration in the U.S. Steel Industry*, unpublished dissertation, Columbia Univ., 1950; Albert O. Hirschman, *National Power and the Structure of Foreign Trade*, Berkeley, 1945. *See also* Albert O. Hirschman, *The Paternity of an Index*, 54 AM. ECON. REV. 761 (1964).

6. *Id*.

7. 402 + 302 + 202 + 102 = 1,600 + 900 + 400 + 100 = 3,000.

adopted by the U.S. Department of Justice in 1982.[8] When the post-transaction HHI is below 1,000, or below 1,800 and the HHI increase is less than 100, or the increase is less than fifty at any HHI level, the transaction passes the screens and no further analysis is needed.[9] When calculating the size of suppliers for the HHI, FERC requires two separate measures: Economic Capacity (EC) and Available Economic Capacity (AEC).[10] EC is the generation capacity that could economically be delivered at a "representative market price."[11] AEC is EC minus obligations to serve retail customers and wholesale customers under long-term contracts.[12] Because both EC and AEC are determined, in part, by the representative market price, the selection of the market price is an important determinant of the results of FERC's screening methodology.

Per FERC's screening methodology, applicants seeking to merge or acquire jurisdictional electric utility assets must provide representative market prices for representative periods in each destination market.[13] The screening methodology, also known as a Delivered Price Test (DPT), must be done for specific destination markets delineated by FERC.[14] Because supply and demand conditions vary significantly during a year, FERC mandates that the market concentration statistics must be calculated for specific periods.[15] Given the lack of long-term energy storage and the fact that interconnected transmission networks must balance supply and demand every second, some have claimed that every hour might be considered a relevant electric power market.[16] Rather than defining every hour as a market,

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8. U.S. DEP'T OF JUSTICE, MERGER GUIDELINES (1982), at § III.A.1, https://www.justice.gov/archives/atr/1982-merger-guidelines.

9. Order No. 592, *supra* note 4, at 30,134 ("If the Guidelines' thresholds are not exceeded, no further analysis need be provided in the application.").

10. *Id*.

11. Order No. 642, *supra* note 3, at 31,886, 31,891 (" . . . [T]he NOPR proposed that a supplier's ability to economically serve a destination market be measured by generating capacity controlled by the supplier rather than historical sales data. We also discussed in the NOPR two generating capacity measures we believed appropriate for the competitive analysis screen: economic capacity (EC) and available economic capacity (AEC). . . . The Commission also believes that selecting representative market prices in a sensible manner is among the most critical components of merger analysis when determining players in the relevant market.")

12. *See* 18 C.F.R. § 33.3 (2019).

13. *Id.*

14. Order No. 697, *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252, 72 Fed. Reg. 39,304 (2007) [hereinafter Order No. 697] at P 231 (" . . . [T]he Commission will continue to use a seller's balancing authority area or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket . . . ").

15. *Id*.

16. U.S. Department of Justice and Federal Trade Commission, Comments, FERC Docket No. RM16-021000, Nov. 28, 2016, Accession No. 20161128-5185, at 13 ("particular geographic markets may exist for less than a full year or even less than a full day, depending on variations in demand conditions."); Gregory J. Werden, *Identifying Market Power in Electric Generation*, PUB. UTIL. FORTNIGHTLY, at 18 (Feb. 15, 1996) ("Since electricity is not stored to any great extent, it is theoretically appropriate to delineate at least 8,760 separate hourly markets for short-term power within a year.")

the typical practice is to select ten representative periods covering a range of supply and demand conditions.[17] For the analysis to be meaningful, it is necessary to have representative demand levels, representative supply conditions, and a representative price level for each period.[18]

Delivered price test HHI results for AEC are typically much more sensitive to the representative market price than results for EC. As an example, we compared HHI levels for EC and AEC using two different price levels for PJM East of AP South market.[19] For EC, the average difference in HHI levels across ten DPT periods using the two prices was thirty, with a maximum difference of eighty-five. In contrast, the difference in HHI levels with the two price levels averaged 137 for AEC with a maximum of 453. Therefore, different representative prices have the potential to radically change market shares and the perceived competitive effects of a transaction. Recognizing the high sensitivity of HHI levels to prices, especially for AEC, FERC requires applicants to calculate HHIs using prices above and below the representative market prices.[20] This article explores different methodologies for selecting representative market prices and consequent inferences one may make about market power given the results of each methodology.

The merger filing requirements allow merger applicants to select the representative market prices used in their DPT.[21] This article demonstrates that the DPT methodology forces applicants to make a fundamental choice: either select price levels and adjust generation consistent with those prices or select generation levels and adjust prices to be consistent with those generation levels. It then evaluates four methodologies for estimating representative market prices. In order of our preference, they are (1) Implied Prices from historical generation levels and the DPT supply curves; (2) Modeled Prices calculated from a simple dispatch model given DPT data; (3) Median Prices during DPT periods based on historical data; and (4) Average Prices based on historical data. The first two methodologies are consistent with selecting generation levels and then adjusting prices, and the last two are consistent with selecting prices and then adjusting generation. Some form

17. *AEP Power Marketing, Inc.*, 107 F.E.R.C. ¶ 61,018, Appendix F (2004) (" . . . choose the season/load levels to analyze: Super-Peak, Peak, and Off-Peak, for winter, shoulder and summer periods, and an extreme Summer Peak, for a total of ten season/load levels . . . ").

18. Order No. 642, *supra* note 3, at 31,891 ("The Commission also believes that selecting representative market prices in a sensible manner is among the most critical components of merger analysis when determining players in the relevant market."); *see also id*. at 31,888-889 (" . . . as electricity markets change, the meaning of native load may change too, such that it is reasonable to consider it as part of a broader set of contractual commitments. We agree with commenters regarding the need to recognize the implications of retail access for evaluating AEC and EC results . . . As a result of these concerns, we encourage merger applicants who rely on estimates of retail access to provide sensitivity tests of their results showing how varying degrees of retail competition would affect.")

19. We compared HHI levels at the median price level based on historical prices and the median prices plus 10%.

20. 18 C.F.R. § 33.3(d)(6).

21. Order No. 642, *supra* note 3, at 31,890 ("We did not require a specific method for estimating market prices. However, we stated that the results must be supported and consistent with what one would expect in a competitive market. For example, we would expect prices to vary little from customer to customer in the same region during similar demand conditions (if there are no transmission constraints), but we would expect prices to vary between peak and off-peak periods.").

of the Average Price methodology, our least preferred, has been used by virtually all merger applicants in the past 20 years.[22] As demonstrated in section IV, historical market prices often present a skewed distribution in which the arithmetic average (mean) price is often substantially different from the median price level. Hence, we find that median prices often are more appropriate than averages in DPT analyses. More importantly, we find the most appropriate representative market prices are those consistent with other DPT data such as the load (demand) and generation costs.[23] Only prices consistent with generation levels support inferences about market power consistent with economic reality because any other measure will either understate or overstate the incentive and ability to exercise market power. This is because the incentive to exercise market power is related to the open generation position of sellers that would receive the benefit from withholding output and raising market prices.

This last point makes intuitive sense to economists and others studying market behavior. Price is a market clearing mechanism which reconciles supply and demand.[24] In other words, price is an endogenous result of underlying data on supply and demand conditions, not an exogenous factor that determines either supply or demand.[25] Because the objective for FERC is to evaluate the potential anti-competitive effects of mergers and acquisitions, a representative price is a price that is consistent with the supply and load data used to evaluate the transaction. Any other price provides a mismatch of data that is inconsistent with a market outcome. This is explained in more detail in section III, below. This concept is consistent with Order No. 592 where FERC used "competitive market price" instead of representative market price.[26] It is well known that in perfectly competitive markets, price equals marginal cost.[27] Therefore, the price found at the point where demand intersects the marginal cost supply curve in the DPT data is consistent with both economic and legal principles.

The remainder of the article is organized as follows: section II gives a history of how market prices have been calculated since the DPT methodology was adopted by FERC. It shows that the methodology has not remained constant but rather changed over time as FERC and practitioners have considered different factors relevant to the DPT methodology. Section III then discuss the difficulties of reconciling different pieces of historical data, such as demand levels, evidence of supply conditions, and historical market prices. When conducting DPT analyses

22. A recent exception is the NRG/Direct merger filing in 2020, which uses median prices instead of average prices. *See* Report and Affidavit of Dr. John R. Morris, NRG Energy Inc., *et al.*, FERC Docket No. EC20-96-000, (Aug. 31, 2020), Accession No. 20200831-5492. FERC approved the transaction. *See alos NRG Energy, Inc.,* 173 F.E.R.C. ¶ 62,103 (2020).

23. The quantity demanded is known as load in the electric power industry. This follows for the engineering concept that the amount of electric energy consumed places a load or resistance to the generators creating that energy. We will use the word load for demand throughout this article.

24. WALTER NICHOLSON & CHRISTOPHER M. SNYDER, INTERMEDIATE MICROECONOMICS AND ITS APPLICATION 406 (12th ed. 2017).

25. A notable exception is when price floors or price caps constrain prices from balancing supply and demand. But that is in the case in DPT analysis. If it were the case, one would simply use the price floor or cap.

26. Order No. 592, *supra* note 4, at p. 30,131.

27. *See, e.g.*, RICHARD LIPSEY & PETER STEINER, ECONOMICS 276 (4th ed. 1975) ("[Conditions of competitive equilibrium include] . . . [e]very firm produces where price equal marginal cost.").

applicants must either adjust prices to be consistent with underlying supply data or adjust generation levels to match historical measures of prices. Adjusting price levels rather than generation levels yields more accurate measures of market power because the incentive to exercise market power is proportional to the open generation (or energy) position of sellers. The traditional practice of adjusting generation levels to match some price level systematically leads to incorrect generation levels and inferences of market power. The section also shows that depending on the circumstances, higher market prices can have ambiguous effects on the HHI by either increasing or decreasing the measure of market concentration. Section IV then discusses the asymmetric nature of historical electricity prices and how that skewness drives average prices above median price levels. Section V evaluates the four methodologies for selecting representative market prices and demonstrates that methodologies consistent with other DPT data (implied prices and model prices) are more likely to produce economically meaningful results than are market prices based on historical price levels. Of the two historical price methodologies (median and average), median price levels are more likely to produce implied capacity factors closer to reality than are average prices. Section VI then discusses other factors relevant to selecting representative market prices. These factors include reliable methodologies in traditional markets where price data are scarce, considerations for the applicants' generation levels, load data, and considerations of the form or inclusion of intermittent generation and fuel costs. The common theme is that representative market price selection matters, and they should be determined with careful consideration of the other DPT data and structure. Finally, we present concluding thoughts in section VII.

II. History of Representative Market Prices

The DPT methodology for screening mergers was adopted by FERC on December 30, 1996, and the first merger applications using the methodology were filed in 1997.[28] Back then, most investor-owned utilities regulated by FERC were vertically integrated in traditional markets. That is, most FERC-regulated utilities owned generation, transmission, and distribution assets, and they generated most of the energy they delivered to their retail and long-term wholesale customers. As a result, relatively few short-term transactions existed with which to measure market price. Additionally FERC did not require filing of transaction data in a common format until 2002.[29] In the first application under the new rules in 1997, FERC staff estimated market prices by using system lambda data——a measure of the marginal generation cost of a utility.[30] Lambda data are reported by hour, so they can be matched to DPT periods based on system conditions (on-peak and off-peak) and load levels.[31] As FERC stated, in competitive markets, competition is

28. *See generally* Order No. 592, *supra* note 4.

29. Order No. 2001, *Revised Public Utility Filing Requirements*, F.E.R.C. STATS. & REGS. ¶ 31,127, 67 Fed. Reg. 31,043 (2002).

30. *Ohio Edison Co.*, 80 F.E.R.C. ¶ 61,039, at p. 61,105 (1997). System lambda data is a measure of the marginal cost of generation of the reporting utility.

31. The filing requirements specifies that the periods must be specified based on load levels. 18 C.F.R. § 33.3(c)(4) ("Because demand and supply conditions for a product can vary substantially over the year, periods corresponding to those distinct conditions must be identified by load level and analyzed as separate products.").

expected to drive prices down the marginal costs, so lambda data can be a valid proxy for market prices.[32] Several months later, Dr. Mark Frankena used average hourly system lambda data from 1996 for market prices in his DPT analysis for the Louisiana Gas and Electric Company/Kentucky Utilities Company (LG&E/KU) merger.[33] Thereafter, using average hourly system lambda data became common when conducting DPT analyses.

The use of system lambda data, however, was not universal. Regional Transmission Organizations (RTOs) with centralized dispatch were being formed at the same time. In those systems, generation owners received a market clearing price for the energy they generate, and load-serving entities paid that price for the energy they re-delivered to end uses. These were actual market prices, and applicants used the RTO prices for transactions within RTOs.[34] But the practice of using average prices during a DPT period remained.[35]

The use of lambda data was rejected by FERC in the Duke/Progress merger in 2011, when FERC required the use of market price data when available.[36] The justification was that system lambda data understated market prices, and artificially decreased the amount of AEC for applicants.[37] Instead of using system lambda data, FERC relied on prices from transactions reported in Electric Quarterly Reports (EQR).[38] Transactions reported in EQR data, however, may not be available for some, or even most, of a DPT period at some locations. Despite this, applicants have used averages of EQR prices to estimate market prices for DPT periods outside of RTOs.[39] With these EQR data, there is also a question as to how to best calculate representative market prices, as even "average" prices over DPT periods can be calculated or weighted in multiple ways. When calculating average prices for a section 206 review of market-based rates, FERC calculated volume-

But the historical practice has been to first split hours based on seasons and then on North American Electric Reliability Corporation (NERC) definitions of on-peak and off-peak hours, and then split the on-peak hours based on load levels. In *Bayou Cove*, FERC Staff challenged the traditional method and the applicants defended the historical practice. Supplemental Affidavit of Julie R. Solomon, FERC Docket No. EC18-63-000, June 15, 2018, at 9-11. Although FERC did not rule on the issue in *Bayou Cove*, it did accept the analyses submitted in NRG Wholesale Generation that were based on the traditional periods. *See* Report and Affidavit of Dr. John R. Morris, FERC Docket No. EC19-63-000, (Mar. 1, 2019), Attachment JM-9, at 1-2 [hereinafter Morris (2019)]; *NRG Wholesale Generation*, 168 F.E.R.C. ¶ 61,166 (2019).

32. 80 F.E.R.C. ¶ 61,039, at 61,106.

33. Mark Frankena, Louisville Gas and Electric Company *et al*., FERC Docket No. EC98-2-000, at 60 (Oct. 15, 1997) [hereinafter Frankena (1997)], which involved the merger of these companies. *See Louisville Gas and Electric Co.*, 82 F.E.R.C. ¶ 61,308 (1998).

34. *See, e.g.*, Workpapers of Dr. Joe Pace, Potomac Electric Power Company & Conectiv, FERC Docket No. EC01-101-000, May 1, 2001, Accession No. 20010516-0414; *Orion Power Holdings, Inc., et al.*, 98 F.E.R.C. ¶ 61,136, 61,396 (2002).

35. *Id.*, Report & Affidavit of Dr. John R. Morris, U.S. Gen New England, Inc., FERC Docket No. EC054-000, Attachment 3, at 17 (Oct. 8, 2004) [hereinafter Morris (2004)].

36. *Duke Energy Corp.*, 136 F.E.R.C. ¶ 61,245 (2011).

37. *Id*. at PP 119-129.

38. *Id*. at P 124.

39. *See, e.g.*, Duke Energy Corporation, Answer to Request for Additional Information, FERC Docket No. EC11-60-000, at 5 (Aug. 29, 2011).

weighted average prices by hour.[40] This provides some guidance on how to establish a "price" for an hour, but leaves open the question how to weight the prices across hours. To be consistent with RTO-based average prices, one would take the simple average across the DPT hours.

In many cases, EQR data are not available for every hour in a DPT period, which has prompted several solutions. For example, the *Bluegrass* case involved the attempt by Louisville Gas and Electric and affiliate Kentucky Utilities (LG&E/KU) to acquire a three-unit simple cycle merchant facility interconnected with the LG&E system.[41] EQR data were not available in many hours, so the applicants supplemented the EQR data with system lambda data for the hours in which no EQR data were available and then took averages by period.[42] FERC accepted this substitution of lambda data for the missing EQR data.[43] When destination markets are adjacent to an RTO, the RTO prices may provide an avenue to infer that destination's hourly prices. In addition to providing hourly prices for generation units and loads within the RTO, RTOs also provide data on the value of selling to or importing from adjacent markets—including those areas without hourly prices. The RTO price for that market can be a proxy for the market price within the destination market.[44] For example, in the LG&E/KU application to modify a prior merger condition, the economist used MISO hourly prices plus the transmission rate to LG&E/KU as proxies for prices in the LG&E/KU balancing authority area (BAA).[45] Eight BAAs in the western United States now participate in the Western Energy Imbalance Market (EIM), and eleven more are scheduled to enter from 2020 through 2022.[46] Sales to the EIM are made in five-minute intervals and are included in EQR data. These data can now provide good hourly price data for otherwise traditional utility markets.

Another innovation in selecting representative market prices was expanding the period over which they are calculated. In early applications, prices were calculated over a single year.[47] A single year, however, may not be representative of typical market conditions. For example, an unusually cool summer could depress prices, or an unusually hot summer could inflate prices. In light of this issue, FERC required applicants to submit two years of price data when it formalized its

40. *Alabama Power Company et. al.*, 157 F.E.R.C. ¶ 61,019 (2016), at Appendix A, Step 7.

41. *Bluegrass Generation Company, L.L.C.*, 139 F.E.R.C. ¶ 61,094 (2012). The acquisition was approved by FERC, but with conditions to remedy market power concerns. *Id*. LG&E/KU did not accept the conditions. East Kentucky Electric Cooperative then acquired the plant. *See* LS Power, LS Power Announces Sale of Bluegrass Generation facility to East Kentucky Power Cooperative, July 29, 2015, available at https://www.lspower.com/ ls-power-announces-sale-bluegrass-generation-facility-east-kentucky-power-cooperative/.

42. *Id*. at P 26.

43. *Id.*

44. The RTO price can be adjusted by the transmission costs to move energy to and from the RTO.

45. Prepared Testimony of Julie R. Solomon, Louisville Gas and Electric Company and Kentucky Utilities Company, FERC Docket No. EC98-2-001, Aug. 3, 2018, at Exhibit LG&E/KU 2.3, p. 10. Solomon also examined PJM prices and found that they produced similar price levels. *Id.*

46. *See* CAL. INDEPENDENT SYSTEM OPERATOR, WESTERN ENERGY IMBALANCE MARKET, https://www.westerneim.com/Pages/About/default.aspx.

47. *See, e.g.*, Frankena (1997), *supra* note 33.

filing requirements in Order No. 642 in 2000.[48] Due to yearly variation in the calendar, the number of hours in a DPT period vary by year. So, the practice began to calculate average prices for each of the two years, and then average the results across the two years.

Another issue addressed by FERC is the transformation of historical average prices to forward representative market prices. In initial filings, applicants used the historical average prices.[49] Merger analysis, however, is forward looking, and FERC now requires applicants to adjust the historical prices to forward prices.[50] Some applicants have used expected price changes based on comparison of forward natural gas prices to historical gas prices and assumed heat rates to adjust electric power prices to the forward period.[51] Others have used forward natural gas prices and statistical analysis of the relationship between natural gas prices and electric power prices to estimate forward market prices.[52] The advantage of using a statistical relationship is that the transformation of natural gas price changes to electric power price changes is based upon observed evidence and not on an assumed relationship. Another approach is to use the DPT data to simulate market prices in the historical base period and in the forward period for each of the DPT periods, calculate the difference in prices, and then add the differences to the historical average prices.[53] Some have tried using forward price forecasts, but FERC has rejected these.[54] FERC's rejection is consistent on its preference for prices to be based on actual market prices.[55] Others have used forward prices from bilateral transactions and reported in trade publications.[56]

Whichever the source of representative prices, they must conform to objective measures of competitive reality. Morris observed a disconnect between market prices used in DPT analyses and the underlying generation data used in those analyses.[57] While actual prices can be observed (over some period), the underlying

48. C.F.R. § 33.3(d)(6) ("*Destination market price*. The applicant must provide, for each relevant product and destination market, market prices for the most recent two years. The applicant may provide suitable proxies for market prices if actual market prices are unavailable. Estimated prices or price ranges must be supported and the data and approach used to estimate the prices must be included with the application. If the applicant relies on price ranges in the analysis, such ranges must be reconciled with any actual market prices that are supplied in the application. Applicants must demonstrate that the results of the analysis do not vary significantly in response to small variations in actual and/or estimated prices.").

49. *See* Frankena (1997), *supra* note 33, at 60; Morris (2004), *supra* note 35, at Attachment 3, at 17.

50. *See* Letter from Steve P. Rogers to David Tewksbury, FERC Docket No. EC14-14-000, at 2 (Dec. 5, 2013) [hereinafter Rogers Letter]. Other DPT is also moved forward, including load levels, the generation fleet, and fuel costs.

51. *See, e.g.*, Affidavit of Julie R. Solomon, Bayou Cove Peaking Power, LLC *et al*., FERC Docket No. EC18-63-000, Exhibit JRS-4, at 8 (Feb. 7, 2018).

52. *See, e.g.*, Report and Affidavit of John R. Morris, NRG Energy Holdings, Inc. *et al*., FERC Docket No. EC14-14-000 (Oct. 24, 2013).

53. Morris (2019), *supra* note 31, Attachment JM-9, at 16-19.

54. *See* 136 F.E.R.C. ¶ 61,245, at PP 84, 123.

55. *Id*. at 121.

56. *See* Affidavit of Joseph Cavicchi and Joseph Kalt, FERC Docket No. EC10-77-000, at PP 35-36 (June 28, 2010). The analysis was implicitly accepted in *PPL Corporation*, 133 F.E.R.C. ¶ 61,083, at P 14 (2010).

57. John R. Morris, *Finding Market Power in Electric Power Markets*, 7 INT. J. ECON. OF BUSINESS 167 (2000) [hereinafter Morris (2000)].

data on generation costs are cobbled together based on various public sources. As a result, it is possible that observed price levels would be higher than the price levels implied from the generation data. In such cases, AEC will be overstated. Morris advocates using the implied prices from the underlying DPT generation data for a measure of market prices, rather than relying on historical price data.[58] Although this method has not been used in any merger filings known to the authors, in the *Bluegrass* case, FERC acknowledged that representative prices should produce implied capacity factors for generation units in a DPT analysis that correspond to actual observed capacity factors.[59] Capacity factors are the amount of energy generated as a percentage of the energy that could be generated if a unit operated at full output.[60] Implied capacity factors can be calculated based on whether a generation unit is economic in each of the DPT periods.[61] FERC concluded that supplementing EQR data with lambda data was more accurate because the implied capacity factors were closer to actual capacity factors.[62]

The historic perspective in this section shows that the identification of representative prices used in merger analysis has not been static. Over time, various issues have been raised, important points have been identified, and practitioners have attempted to develop and implement methods that best address them. It is in this historic context that this article seeks to empirically evaluate representative price calculation methodologies.

III. First Principles for Selecting Representative Market Prices

The representative market price is an essential input to calculate the size of suppliers in the destination market. The DPT is aimed at determining if a supplier can economically serve a given market based on market prices, dispatch costs, and transmission costs, then finds the size of the suppliers based on that economic capacity.[63] Suppliers can be included if they can deliver the product to the relevant customers at a cost no greater than 105% of the competitive price to the customer.[64] This section discusses the underlying theory for DPT analyses and derives a set of principles for selecting representative market prices.

To provide some framework, consider a standard depiction of supply and demand. Figure 1 shows an example of supply and demand conditions in a market. The upward sloping curve is the supply curve and the vertical line is the demand curve, which is often assumed to be fixed for a short-term hourly market. The intersection of the two curves determine the price level ($20/MWh in the figure) and the output level. Few end users for electricity face actual hourly electric power

58. *Id.* at 177.

59. *Bluegrass Generation Co., L.L.C.*, 139 F.E.R.C. ¶ 61,094, at P 26 (2012).

60. Fed. Energy Regulatory Comm'n, Market Assessments Glossary (Aug. 31, 2020), https://www.ferc.gov/industries-data/market-assessments/overview/glossary.

61. 139 F.E.R.C. ¶ 61,094, at n.45.

62. *Id*. at P 26.

63. The potential size of the supplier is the capacity that can delivered economically (accounting for load obligations when calculating AEC). This amount is credited for supplies within the destination market. Suppliers outside of the destination market receive pro-rata shares of the import capability. Order No. 642, *supra* note 3, at 31,894.

64. Order No. 592, *supra* note 4, at 31,130-131.

prices and instead pay a price that based on average costs over long periods that includes other costs as well. The result of average cost retail pricing is that from the perspective of generation companies supplying energy, demand is essentially fixed in any given hour. Because the demand is fixed, the demand level also defines the output level.

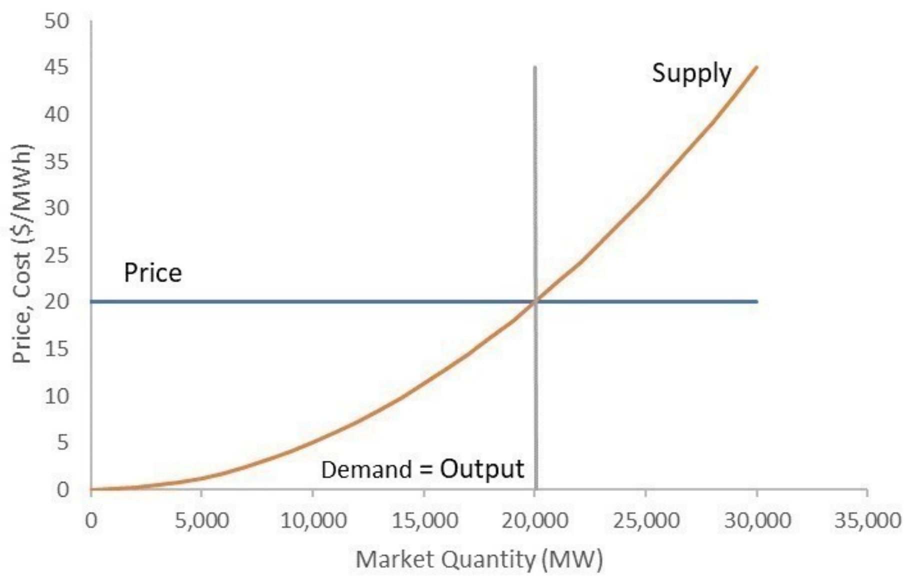

Figure 1: Supply and Demand Conditions in a Single Hour

One issue with DPT analyses is that the supply curve utilized does not necessarily match the actual supply curve in the market. Merger applicants do not know the availability and costs of generation for other suppliers, and FERC has specified specific methods for calculating the average availability of intermittent units such as hydroelectric, wind, and solar generation.[65] In addition, applicants typically "derate" the capacities of thermal generation units to take into account expected planned and forced outages during a season.[66] As a result, the supply curve in a DPT analysis is unlikely to match the actual supply curve during an hour.

Figure 2 shows the effects of having a supply curve that does not match the historical supply curve. In the figure, the estimated supply is more than the historical supply at any given price level. The increased supply necessitates at least

65. Order No. 642, *supra* note 3, at P 344.

66. 18 CFR § 33.3(d)(1) ("noting [f]or each generating plant or unit owned or controlled by each potential supplier, the applicant must provide . . . [s]ummer and winter capacity adjusted to reflect planned and forced outages and other factors, such as fuel supply and environmental restrictions.").

one of two possible adjustments in DPT calculations. The first potential adjustment is to lower the market price to the new price implied by the historical demand level intersecting the estimated demand curve. This implied price preserves the generation level at the historical generation level. Under the price adjustment option, the "representative market price" would not be a historical price, but the price internally consistent with the other DPT data. The second possible adjustment is to look for the intersection of the historical price level with the estimated supply curve and adjust generation to the implied generation level. The generation adjustment option preserves historical prices, but it is unlikely to do the same for generation. This is the adjustment many have made when using average historical prices and estimated supply curves. In the case of estimated supply being greater than historical supply, estimated generation will be greater than historical generation, producing more AEC than exists. If the estimated supply is less than the historical supply, the opposite would occur and the DPT calculations would underestimate AEC.

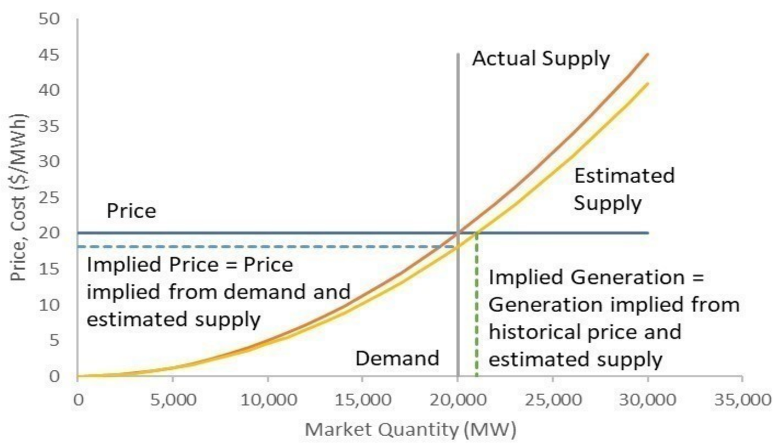

Figure 2: Effects of Estimated Supply Curves

Real-world supply curves can vary significantly for a given load level. Consider, for example, the summer peak period in PJM in 2018. Because the number of observations in the period is even, the median load level is the average of two observations, one from 9 p.m. on June 27 and one from 2 a.m. on June 29.[67] The two prices are $39.43/MWh and $29.10/MWh, a range of 30% of the midpoint![68] It is not clear which price is more representative of the median load level. Limiting the price sample to prices in the thirty hours with loads closest to the median load level, prices range from $27.43/MWh to $56.68/MWh, with an average of

67. Hitachi-ABB, VELOCITY SUITE, *PJM Historical Zonal Load*, 2018.

68. Hitachi-ABB, VELOCITY SUITE, *ISO Real Time & Day Ahead LMP Pricing - Hourly*, 2018

$34.87/MWh and a median of $32.75/MWh.[69] This range in prices ($19.25/MWh) is 61% of the median price compared to the corresponding range of loads of only 1% of the median load. Therefore, prices can, and often do, vary significantly in electric power markets for comparable load levels, which is to say the supply conditions can vary significantly for similar load levels.

The DPT is designed to identify when an acquisition might create or enhance market power. Market power is the ability profitably to restrict output and thereby raise market prices.[70] In electric power markets, especially the centrally-dispatched RTOs, generation owners must select combinations of generation levels at various price levels.[71] For a fleet of generation units, the owner provides a supply schedule to the market operator.[72] The market solution concept for this type of competition is known as supply function equilibrium (SFE).[73] Multiple solutions many be obtained for the SFE problem, ranging from perfectly competitive outcomes to the Cournot solution.[74] Rather than consider the total market solution, we can examine the incentives of an individual company, such as the post-merger entity.[75] The optimal offer for a unit at the company is given by:

$$\textit{Offer} = \textit{Marginal Cost} + \textit{Price Effect} \times (\textit{Inframarginal Energy} - \textit{Obligations}) \quad (1)$$ [76]

In words, equation (1) states that the generation offer is equal to the marginal cost plus the profit depressing effect of clearing the unit. That profit depressing

69. *Id*. Because this sample is taken from the middle of the load distribution, it is not surprising that the average and median in the sample are not substantially different from those of the entire period. Across all observations in the period, the average price is $34.89/MWh, and the median is $31.55/MWh.

70. *See, e.g.*, Morris (2004), *supra* note 35, at 10 ("Market power is the ability of a seller or group of sellers profitably to restrict output and to maintain prices above competitive levels for a significant period of time."); Order No. 592, *supra* note 4, at 68,607 ("[A]n entity with market power can raise the price of one product and buyers would have a limited ability to shift their purchases to other products."); U.S. DEP'T OF JUSTICE, 1992 MERGER GUIDELINES [hereinafter 1992 Guidelines] ("Market power to a seller is the ability profitably to maintain prices above competitive levels for a significant period of time.").

71. Richard J. Green & David M. Newbery, *Competition in the British Electricity Spot Market*, 10 J. POL. ECON. 929 (1992).

72. *Id.*

73. *Id.*

74. Paul D. Klemperer & Margaret A. Meyer, *Supply Function Equilibria in Oligopoly under Uncertainty,* 57 ECONOMETRICA 1243, 1243 (1989). A Cournot solution occurs when sellers select quantities so that no seller has an incentive to sell a different quantity given the quantities selected by the others. *See* ANTOINE AUGUSTIN COURNOT, RESEARCHES INTO THE MATHEMATICAL PRINCIPLES OF THE THEORY OF WEALTH (Nathaniel T. Bacon trans., Macmillan 1897) (1838); John F. Nash, *Equilibrium Points in N-Person Games*, 36 PROC. NAT'L ACAD. SCI. U.S. 48 (1950).

75. *See, e.g.*, Romkaew Broehm, Jeremy Verlinda, and James Reitzes, Comments, FERC Docket No. RM16-021-000 (Nov. 28, 2016), for a discussion of the profit-maximizing offers of a single generation owner.

76. Let new profits for firm i be represented by $\pi_i = p(l,g,q_i)(q_i - O_i) - C(g,q_i)$, where p is the market price—a function of market load l, fuel (e.g., natural gas) price g, and the output of generation owner q_i. O_i is the forward sales obligation, so the difference between q_i and O_i is the additional output associated with the new profit. C is the cost of production, which, like p, is a function of g and q_i. The additional profit is the product of the market price, p, and the additional output, q_i-O_i, minus the cost associated with the new output quantity C. Profits are maximized when the first derivative of the profit function with respect to quantity reaches 0, or $\partial\pi_i/\partial q_i = \partial p/\partial q_i(q_i - O_i) + p - \partial C/\partial q_i = 0$. Solving for p recognizing that the offer is equal to price of a marginal unit, gives *Offer* $p = \partial C/\partial q_i - \partial p/\partial q_i(q_i - O_i)$. This gives the relationship in equation (1). *See id.* at app. B(I).

effect is the price effect from not clearing the unit multiplied by the net position assuming the unit does not clear. The price effect is the absolute value of the slope of the company's demand curve.[77] The price effect is multiplied by the net position of the company if the unit does not clear. The net position is the inframarginal energy (i.e., the generation already clearing the market) minus the prior obligations. The obligations represent all the prior sales at prices that will not be affected by changing output.

Equation (1) indicates that offers will increase as marginal costs increase, price effects increase, and inframarginal energy increases, while offers will decrease as the amount of prior obligations increase. The potential effects of a merger can be seen in the equation. Efficiencies that may lower marginal cost are captured in the marginal cost term.[78] Potential price-increasing effects from a merger are captured in the price effect term and the infra-marginal energy term. A merger can decrease the competition faced by the pre-merger firms, which increases the potential price effect from increased offers, raising the incentive for higher offers. A merger of generation owners also increases inframarginal energy. This gives an incentive for higher offers because clearing the marginal unit decreases price over a greater amount of cleared generation. Consequently, the merged owner will demand greater compensation before clearing the unit. Finally, the obligations term captures effects from changing load obligations. It is well documented that load obligations and other forward sales diminish market power.[79] Therefore, combining load obligations decreases market power.

Equation (1) can be rearranged to form a Lerner Index, a well-known measure of market power.[80] Recognizing that for the marginal generation unit the offer is equal to price, the Lerner Index is:

$$\begin{aligned} L &= \frac{Price - Marginal\ Cost}{Price} \\ &= \frac{1}{|Firm\ Elasticity|} \times (Inframarginal\ Energy - Obligations) \end{aligned} \tag{2}$$

77. Even with perfectly inelastic market demand (e.g., see Figure 1), the demand curve for a single generation owner is downward sloping because of the competition from rival generation companies. Because the company demand is downward sloping by clearing an additional unit the company will reduce the market price by some amount. The company will want to be compensated for the price depressing effect of selling more. Hence, it is necessary to use the absolute (positive) value of the demand curve slope.

78. For more robust discussions of how efficiencies can be incorporated in marginal cost and how they affect post-merger prices, see J. Dutra & T. Sabarwal, *Antitrust analysis with upward pricing pressure and cost efficiencies*, 15(1) PLOS ONE e0227418 (2020).

79. *See* Frank Wolak, *An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market*, 14(2) INT'L ECON. J. 1 (2000). For the extent of forward sales and hedging by electric generation companies, *see* Market Power Rebuttal Testimony of Michael M. Schnitzer, In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc., Public Service Commission of Maryland, Case No. 9271 (Oct. 17, 2011).

80. A.P. Lerner, *The Concept of Monopoly and the Measurement of Market Power*, 1 REV. ECON. STUD. 157 (1934).

As been shown elsewhere, the Lerner Index can be related to the HHI measure of market concentration,[81] which FERC uses to screen mergers. The HHI can also be related to social welfare and the desirability to take government action, such as limiting mergers and acquisitions.[82] Hence, it provides a good basis for evaluating steps in the DPT methodology.

Equation (2) suggests it is likely better to use implied prices from DPT data instead of historical prices. The equation divides the measure of market power into two parts. The first part is the firm demand elasticity. The main driver of the firm elasticity is the supply availability from competitors. Although the value can change at different places along a supply curve (e.g., jumping from nuclear energy to coal or gas-fired energy), *a priori* there is no reason to believe that this value would change significantly with small changes in price or generation levels.[83] For estimating market power, elasticity can be considered fixed for any given time period and load level. The second term is a firm's net hourly energy position divided by the energy it generates. As discussed above, using historical prices with an estimated supply curve is likely to over- or understate the market's true generation level. This market level misspecification results in erroneous generation estimates for individual firms. These errors can be minimized by using the DPT's implied prices and attempting to match historical generation levels within the analysis.

$$L = \left|\frac{\%\,Change\ in\ Price}{Change\ in\ Quantity}\right| \times (Inframarginal\ Energy - Obligations) \qquad (3)$$

As before, this can be thought of as dividing the measure of market power into two parts. The first part is the ability to raise prices per unit change in output. The larger the effect, the greater the ability of the seller to raise market prices. The second part gives the incentive to raise market prices, which is the energy produced less the prior obligations to sell energy—the open market position. The greater the apparent open market position, the greater the market power—holding other factors constant.

Without transaction-specific information it is impossible to determine the effects of higher (or lower) measures of the relevant market price. In general, a higher price increases the likelihood that an applicant has AEC, but its competitors are also more likely to have additional AEC.

Given the HHI-based assessment methodology, the results of the screening method depend on the change in the size of the applicants relative to the change in the size of other suppliers. In RTO markets, higher representative prices often

81. *See, for example*, John Kwoka, *The Herfindahl Index in Theory and Practice*, 30 ANTITRUST BULL. 915, 924-5 (1985); Keith Cowling & Michael Waterson, *Price-Cost Margins and Market Structure*, 43 ECONOMICA 267, 268 (1976).

82. *See, e.g.,* Robert D. Willig, *Merger Analysis, Industrial Organization Theory, and Merger Guidelines*, BROOKINGS PAPERS ON ECONOMIC ACTIVITY: MICROECONOMICS, (1991) at 281; Janusz Ordover et al., *Herfindahl Concentration, Rivalry, and Mergers*, 95 HARVARD L. REV. 1857 (1982); Robert E. Dansby and Robert D. Willig, *Industry Performance Gradient Indexes*, 69 AM. ECON. REV. 249 (1979).

83. *See generally* Janusz Ordover et al., *supra* note 82, at 1867.

reduce market concentration and do not appreciably increase the risk of screen violations because most competitors are already within the market and their AEC increases along with applicants. Figure 3 shows a scatter plot of the relationship between HHI levels on the vertical axis and representative price level on the horizontal axis for the PJM RTO. Each dot represents a price level and the resulting market concentration in a DPT period.[84] For each of nine DPT periods with 2017-2018 price data, Figure 3 shows market concentration for the 10th percentile through the 90th percentile prices. So, in total, there are eighty-one dots in the figure. It shows that higher price levels can substantially reduce market concentration, especially in the off-peak periods.[85]

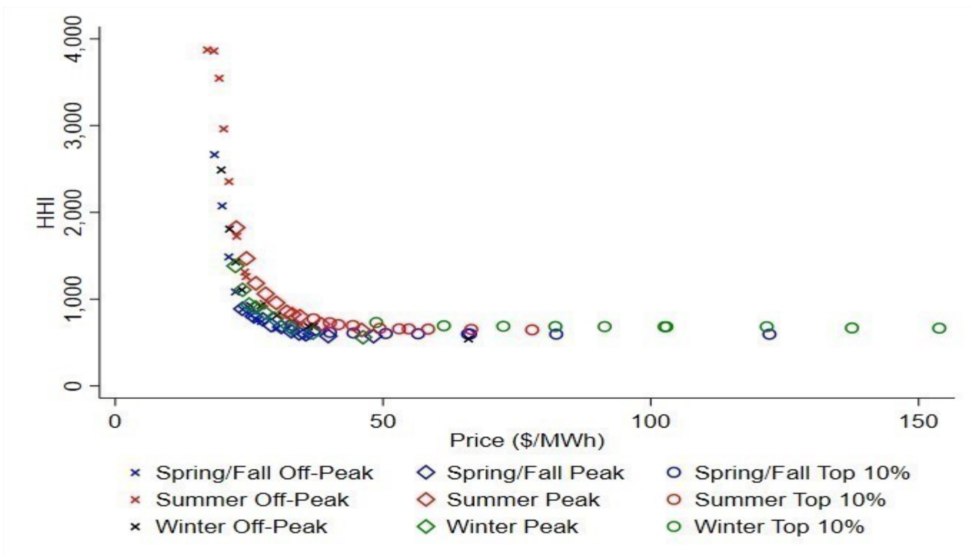

Figure 3: Relationship between market concentration and price level for AEC in PJM

In traditional markets with vertically integrated utilities, higher representative prices often increase HHI levels and the likelihood of HHI screen violations. Higher prices often increase the size of the applicant within the market (give the applicant more AEC), but the combined size of most competitors—located outside of the market—does not expand because the methodology limits outside suppliers by import capability.[86] Figure 4 shows a scatter plot between the HHI and market

84. The HHI levels were calculated using standard "off the shelf" generation cost, generation capability, and demand (load) data maintained by Economists Incorporated. The HHI's were calculated based on data for PJM and for the first-tier areas. For a more general description of the methodology, see Morris (2019), *supra* note 31, at Attachments JM-9 and JM-10 of the same report.

85. The figure will show different HHI's for similar price levels because it includes results from nine different DPT periods. For example, Spring/Fall Top 10% 40th percentile prices might be similar to Summer Peak 60th percentile prices but have different HHI levels due to the differences in generation availability across seasons.

86. Imports are limited by the both the transfer limits from other areas to the destination market and a simultaneous import limit required by FERC. *See* 18 CFR § 33.3(c)(4)(i)(c) ("Each potential supplier's economic

prices for the Tampa Electric balancing area in Florida in the same format as Figure 3. Unlike Figure 3, Figure 4 has no well-defined pattern between the HHI and the price level. In some DPT periods, higher prices raise market concentration because Tampa Electric is the largest supplier and higher prices increase its AEC while import limits prevent commensurate AEC increases for other suppliers.

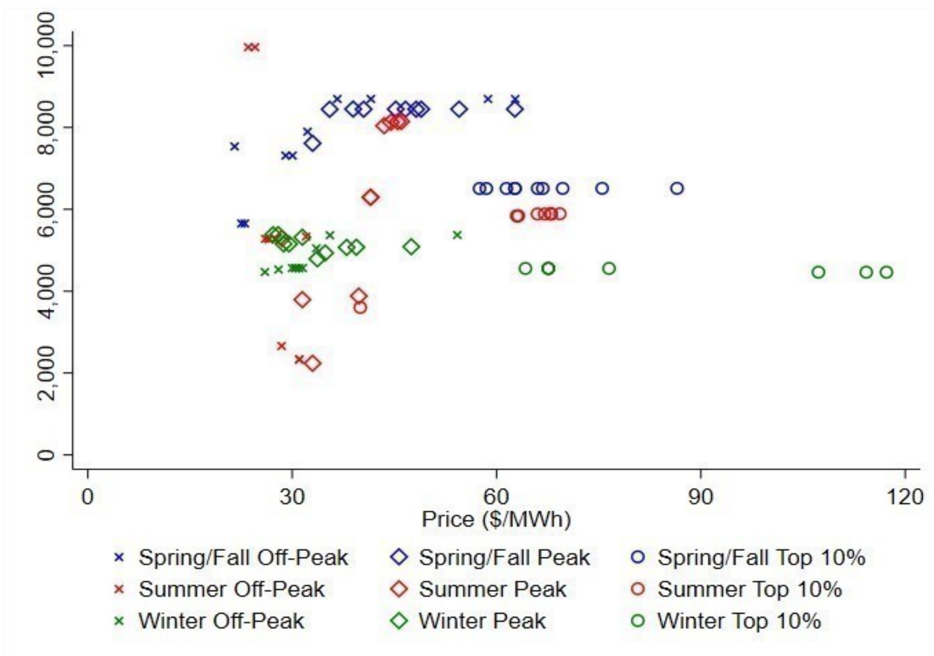

Figure 4: Relationship between market concentration and price level for AEC in Tampa Electric Balancing Area

IV. THE SKEWNESS OF ELECTRIC POWER PRICES

Basing representative market prices on average historical prices has two problems. First, as discussed in section III, the historical price data does not necessarily match the other data in the DPT analysis. But there is a second flaw with

capacity and available economic capacity (and any other measure used to determine the amount of relevant product that could be delivered to a destination market) must be adjusted to reflect available transmission capability to deliver each relevant product. The allocation to a potential supplier of limited capability of constrained transmission paths internal to the merging entities' systems or interconnecting the systems with other control areas must recognize both the transmission capability not subject to firm reservations by others and any firm transmission rights held by the potential supplier that are not committed to long-term transactions. For each such instance where limited transmission capability must be allocated among potential suppliers, the applicant must explain the method used and show the results of such allocation."); *See* Order No. 697, *supra* note 14, at 384 ("For the reasons stated herein regarding the need to as accurately as possible account for transmission limitations when considering power supplies that can be imported into the relevant market under study, the Commission adopts the requirement for use of the SIL [Simultaneous Import Limit] study as a basis for transmission access for both the indicative screens and the DPT analysis.").

average prices: Because price distributions are positively skewed, average prices might be substantially greater than the most common prices during a DPT period.

A two-paragraph primer on statistics helps to understand the issue. The statistical concept of a representative price is captured by what statisticians and economists call central tendency. But three measures of central tendency exist: mode, median, and mean. The mode is the most common value, the median is the value in the middle, and the mean is the arithmetic average. Each of these have advantages over the other depending upon the data and the use. When distributions of value are perfectly symmetric, the mode, median, and average are the same values and it does not matter which measure is used. But electric power prices are typical highly skewed with a positive skewness.[87] To understand skewness, it helpful to understand how statisticians describe distributions of data. They often speak of four "moments" of a distribution. The first moment measures the expected value, which is the mean. The second moment measures the distribution, and it is the standard deviation. The third moment is the measures whether the data are symmetric or asymmetric around the mean, and that is the skewness. The fourth moment measures how peaked the data are around centralized values, and that is a kurtosis.

The skewness of a set of observations measures whether prices are symmetric or asymmetric around the means and is measured as the third moment of the distribution, mathematically given (for a population) by $\Sigma(x_i - \bar{x})^3/ns^3$ where $\bar{x}$ is the average, n is the number of observations, and s is the standard deviation.[88] When skewness is negative, the distribution is skewed to the left and in most cases the average will be less than the median value. When looking at a negatively skewed distribution, the observer sees more observations to the left of the peak than the right. When skewness is a positive, the distribution is skewed to the right and in most cases the average will be greater than the median value. When looking at a positively skewed distribution, the observer sees more observations to the right of the peak than the left. When skewness is within +/- 0.5, then the data are approximately symmetric; when between the -1 and -0.5 or 0.5 and 1 the data are moderately skewed; and when less than -1 or greater than +1, the data are highly skewed.[89]

Figure 5 shows a histogram of the prices for the Southwest Power Pool (SPP) in the 2017 Spring/Fall Peak period, which is a typical example of highly skewed electric power prices.[90] Here, the average price level is about 22% higher than the median price level; as discussed below, around 22% is the typical amount the average diverges above the median. This distribution is also typical in that it has a large tail with some prices over \$400/MWh compared to the average of about \$27/MWh. As can be seen in Figure 5, relatively few observations with very high

87. Rafal Weron, *Research Report HSC/05/2 Heavy tails and electricity prices* 6 (2005), http://www.im.pwr.wroc.pl/~rweron.

88. *See, e.g.*, JOHN E. FREUND AND RONALD E. WALPOLE, MATHEMATICAL STATISTICS 137-148 (3d ed. 1980).

89. M.G. BULMER, PRINCIPLES OF STATISTICS 66 (Dover 1979).

90. Hitachi-ABB, VELOCITY SUITE, *ISO Real Time & Day Ahead LMP Pricing - Hourly*, 2017.

prices (*e.g.*, over $100/MWh compared to a median of $22/MWh) drive the average price significantly above the median. But even excluding the prices above $100/MWh, the distribution would still be skewed and the average would be above the median. Therefore, average prices levels can lead to representative prices that above the levels that most commonly occur during a DPT period.

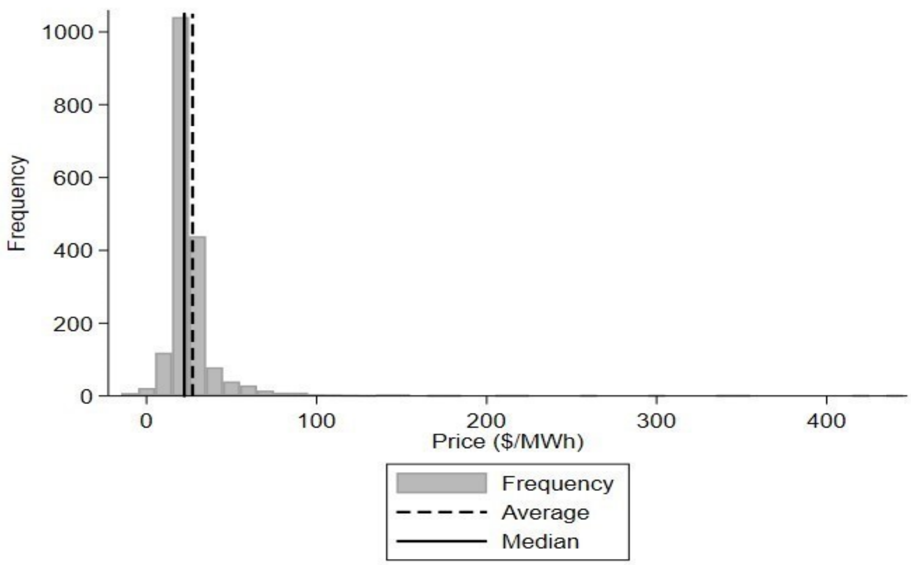

Figure 5: Distribution of SPP Spring Peak Prices[91]

The skewness shown in Figure 5 is not uncommon, as shown in Table 1. The table shows summary skewness measures for each of the RTOs in the United States. For each RTO, it shows the minimum measure, average, and maximum measure of skewness across eighteen periods. Although prices can be negatively skewed, typically prices exhibit positive skewness in which the averages are greater than the median values. In fact, prices are skewed negative in only three of the 126 periods. Each of these periods are off-peak, when excess supplies due to necessary commitments of generation for peak periods and the presence of wind or solar generation can drive prices extremely negative.[92] In all other periods, prices are highly skewed positively.

91. *Id.*

92. *See, e.g.,* GRAEME R.G. HOSTE ET AL., MATCHING HOURLY AND PEAK DEMAND BY COMBINING DIFFERENT RENEWABLE ENERGY SOURCES 2 (2020).

RTO	Minimum	Average	Maximum
CISO	-1.5	4.3	11.4
ERCOT	-0.5	9.9	30.8
ISONE	-0.3	4.2	27.3
MISO	2.0	5.7	13.4
NYISO	0.6	5.7	22.6
PJM	1.3	3.3	6.5
SPP	3.2	6.0	9.2

Table 1: Summary of RTO Price Skewness

The figures in Table 1 are calculated as follows. The table is based on calculating skewness measure for nine DPT periods for each RTO for 2017 and 2018.[93] Because the DPT periods are calculated by year and there are two years of data, each row of Table 1 is based on analyzing eighteen periods for each RTO.

From these data, we see that skewed price distributions can increase the average price level significantly above the median price level. We have also shown that different price levels can either artificially lower or artificially increase the HHI. Therefore, selecting the most appropriate measure of a representative price is an important element of FERC's competitive assessment methodology. We now examine whether the skewness of the prices makes a meaningful difference between average and median levels. If the differences are minor, then we would have less reason to question the current practice of relying on the historical average price. But if the differences between the two are great, that would suggest additional research is warranted to determine which price level is more appropriate when attempting to measure market concentration by price and load levels.

To measure the difference, we calculate the average and median price levels for each of the 126 market-periods discussed above. From these, we then calculate the difference between the average and median as a percentage of the median price. Table 2 presents a summary of the percentage differences in a format similar to Table 1, across the 126 periods for each RTO. In all cases, the average is

93. Although the DPT analysis is done for 10 periods, one period (typically the highest load conditions in summer) consists of either a single hour or a group of ten hours. Rogers Letter, *supra* note 50, at n.3 (specifying the top summer period as the single highest load hour or top 1% of on-peak summer hours based on load levels). This period is too small for meaningful analyses, so the analysis covers nine periods, consisting of the top 10% of on-peak hours, the remaining on-peak hours, and off-peak hours in each of the three seasons (spring/fall, summer, and winter).

greater than the median. This is true even in the three cases that showed some negative skew, although the differences are trivial in two of the three cases (CISO and ERCOT). But average prices typically are about 22% more than median prices. Moreover, one case–summer top 10% in CISO–the average price of $135/MWh is more than double the median price level of $58/MWh. These differences are great enough to make substantial differences in HHI calculations. We also find that in 117 of the 126 cases the average was statistically different from the median based upon a two-tailed test at a 5% significance level.[94]

RTO	Minimum	Average	Maximum
CISO	0.7	27.7	134.7
ERCOT	0.1	30.1	84.8
ISONE	4.5	21.3	57.1
MISO	7.6	16.7	42.7
NYISO	4.0	20.4	72.3
PJM	7.6	17.9	65.6
SPP	4.1	18.7	38.9

Table 2: Summary of Percentage Differences between Average and Median Prices by RTO

The highly skewed distribution of prices as revealed in Figure 5 is representative of most price distributions we examined. The right tail is very long, with some extreme observations and atypically high prices. We tested if excluding these outliers might make the differences between average and median price levels disappear. To identify outliers, we utilized Tukey's Fence.[95] Specifically, we dropped prices less than 1.5 times the interquartile range below the first quartile and more than 1.5 times the interquartile above the third quartile. Table 3 shows a summary of the percentage differences between averages calculated after excluding outliers and the medians. The average percentage difference is 3.4% (averaged over the RTOs) compared to 22% for prices including the outliers. But substantial differences can remain, with the revised average percent differences falling as much as 6.7% less than the median to 25.5% more than the median. In thirty-six of the 126 periods, the revised average is more than 5% greater than the median, and in thirty-

94. The significance level gives the probability that the we would conclude that the two values are different when in fact they are the same. The 5% threshold is standard in scientific work and has been accepted in courts. *See, e.g.*, Palmer v. Shultz, 815 F.2d 84, 92 (D.C. Cir. 1987) ("'the .05 level of significance . . . [is] certainly sufficient to support an inference of discrimination'") (quoting Segar v. Smith, 738 F.2d 1249, 1283 (D.C. Cir. 1984), *cert. denied*, 471 U.S. 1115 (1985))); United States v. Delaware, 2004 U.S. Dist. LEXIS 4560 (D. Del. Mar. 22, 2004) (stating that .05 is the normal standard chosen).

95. John W. Tukey, EXPLORATORY DATA ANALYSIS 27-47 (Addison-Wesley 1977). Let Q_1 denote the first quartile (*i.e.*, the 25th percentile) and Q_3 to denote the third quartile (*i.e.*, the 75th percentile). Then outliers occur when $x < Q1 - 1.5(Q3 - Q1)$ and when $x > Q3 + 1.5(Q3 - Q1)$. This is the most common version of Tukey's Fence.

four of the thirty-six, the difference is statistically significant at the 5% level. Based upon these data, we conclude that excluding outliers does not make the average prices comparable to the median prices.

RTO	Minimum	Average	Maximum
CISO	-1.5	3.5	16.7
ERCOT	-4.0	2.5	10.9
ISONE	-4.2	7.2	25.5
MISO	-0.1	3.7	11.4
NYISO	-6.7	2.3	12.7
PJM	0.6	3.4	9.9
SPP	-4.4	1.1	8.9

Table 3: Summary of Percentage Differences between Average and Median Prices by RTO, Dropping Outliers

V. EVALUATING METHODOLOGIES FOR SELECTING REPRESENTATIVE MARKET PRICES

The most appropriate method of calculating market prices depends on which method better represents market conditions. In section III, we show that how well the methodology replicates historical generation levels a fundamentally sound criterion for evaluating different price selection methodologies. For a single market with no imports or exports, the determining generation levels is straightforward because the load (demand) determines the output level. Actual markets, however, are interconnected and have imports and exports so that generation output can be more or less than the load level.[96] Fortunately, RTOs now post hourly generation levels.[97] These output levels can be matched to the hours defining the DPT periods, and we can calculate average historical generation levels during DPT periods.[98] These historical generation levels are our benchmark for judging representative market price selection methodologies.

We compare these historical generation levels against implied generation based on DPT generation data. For the implied generation levels, we use Hitachi-ABB data for generation unit heat rates, publicly available data on fuel costs, and

96. *See, e.g.,* ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: FACTORS AFFECTING ELECTRICITY PRICES (Dec. 16, 2020), https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php.

97. The Energy Information Administration (EIA) now requires balancing authority operators to report hourly generation by fuel type. This now provides an alternative source of hourly generation data. *See* ENERGY INFO. ADMIN., FREQUENTLY ASKED QUESTIONS: DOES EIA PUBLISH DATA ON PEAK OR HOURLY ELECTRICITY GENERATION, DEMAND, AND PRICES? (July 15, 2020), https://www.eia.gov/tools/faqs/faq.php?id=100&t=3.

98. Our examination of historical generation levels indicates that generation levels typically are not very skewed in DPT periods and the average and median are similar.

estimates of variable operations and maintenance expenses.[99] From these data, we estimate a dispatch cost and compare it to the putative market prices to see whether a unit is "on" or "off" during a DPT period. For unit capacity, we take publicly available capacity and then "derate"—that is, reduce the size—of the unit to account for planned and forced outages based on data reported by NERC in its Generation Availability Data System (GADS).[100] Although these outage data are not unit-specific, over the hundreds of units in an RTO they reasonably reflect generation availability on average.

We use four alternative measures of representative market prices: (1) implied prices based upon the historical generation levels and generation data in the DPT analysis; (2) modeled prices based upon a simple dispatch model matching supply to the demand in the DPT data; (3) median historical price levels by DPT period; and (4) average historical price levels by DPT period. The implied prices match historical generation levels almost perfectly because they are calculated to match the generation levels.[101] Model prices should also be close to the actual model levels because the main difference between actual and modeled output will be driven by imports and exports, which typically are small compared to the market size.[102] For reasons discussed in Morris (2000) and above, the median prices and average prices may produce DPT output levels substantially different from reality. In short, the underlying generation data in the DPT analysis may be substantially different from actual costs of operating an electric power system in the real world.

Table 4 gives annual average prices by RTO for each of the four pricing methodologies. The first column gives the RTO and the following columns give averages for the Implied, Model, Median, and Average methodologies. Annual average prices were calculated by weighting each DPT period by the number of hours in the period. Because the off-peak periods constitute over one-half of the hours in a year, the averages are heavily weighted to the off-peak periods. Nevertheless, the averages provide some indication of the range of results of the different methodologies. The implied price methodology produces the highest average for three RTOs: CISO, ISONE, and NYISO. The model methodology never produces the highest prices, but produces the lowest annual average for ERCOT, ISONE, and MISO. Interestingly, despite the skewness of historical price data, the median produces the highest annual average for three RTOs: MISO, PJM, and SPP. Yet, the median produces the lowest overall average across the RTOs. The average methodology produces the highest average for ERCOT, and overall.

99. These are data required in a DPT filing. 18 C.F.R. § 33.3(d)(2) (2000). For natural gas costs, we used averages of daily natural gas prices in each of the DPT periods.

100. Derating is required in a DPT analysis. 18 C.F.R. § 33.3(d)(1).

101. They do not match perfectly in all periods because many MW of capacity can have the same dispatch cost in DPT data. This creates as small range of uncertainty of output levels for a given price level. For example, if the price of $25/MWh is necessary to match an output level of 20,000 MW and there are 1,000 MW of capacity at $25/MWh, then the DPT capacity at that price can range from 20,000 MW to 20,999 MW.

102. CISO is an exception to this as imports account for as much as 40% of its demand in some hours. *See* Morris (2000), *supra* note 57.

RTO	Implied	Model	Median	Average
CISO	45.16	39.16	36.23	39.46
ERCOT	25.54	22.29	24.38	25.55
ISONE	39.62	31.30	38.74	37.91
MISO	26.06	25.90	29.36	25.50
NYISO	36.78	28.03	33.56	34.58
PJM	27.69	27.91	32.59	28.77
SPP	22.39	23.24	24.66	22.36
All	31.40	31.04	27.84	31.82

Table 4: Comparison of Annual Average Prices from Implied, Model, Median, and Average Methodologies

We have data for seven RTOs and nine time periods for each.[103] This gives sixty-three "tests" of the how well a price level predicts the historical generation level in the RTO. We utilize two metrics to determine which methodology fits best. First, we count which methodology best predicts generation levels among the sixty-three tests. The best methodology could be viewed as the one that predicts best most often. Second, we use a form of relative absolute error (RAE) known as Theil's U.[104] The RAE is unitless and gives the error as a fraction of the actual average value. We multiply this value by 100 to place it in percentage terms. For example, a RAE of thirty means that errors on average are 30% of the actual values.

Based upon the "closest most often" criteria, the implied price methodology has the best fit and the average price methodology is the worst. Table 5 shows the counts of the representative price methodology that most closely predicts the average generation level during a DPT period. The first column gives the methodology: implied, model, median, and average. The second column gives the results when all four methodologies are compared. The implied price methodology is the

103. Because DPT data are averaged over two years, we have only nine periods per RTO instead of the 18 per RTO used in section IV.

104. The RAE is calculated as:

$$RAE = \sqrt{\frac{\sum_i^n (p_i - a_i)^2}{\sum_i^n a_i^2}}$$

where p_i is the predicted value, a_i is the actual value, and n is the number of observations. *See* H. Theil, ECONOMIC FORECASTS AND POLICY (Amsterdam: North Holland, 1958), at 31-42; *See also* Stephanie Glen, *U Statistic: Definition, Different Types; Theil's U*, STATISTICS HOW TO (Jan. 12, 2017), https://www.statisticshowto.com/u-statistic-theils/.

closest most often, in fifty-six of the sixty-three tests. This is not surprising because the methodology is designed to produce a price level that closely matches the implied generation to the average historical generation level. Despite this design, the model prices are closer in six of the sixty-three tests and identical to the implied methodology in three, which produces a total of nine closest.[105] The third column excludes the implied price methodology to compare the model, median, and average methodologies. In this case, the model prices produce the generation levels closest to actual in fifty of sixty-three cases. The fourth column excludes the model methodology to compare the implied, median, and average methodologies. In this comparison, the implied prices produce the closest to historical generation levels in sixty-one of sixty-three of the tests, and the median methodology is closest in two. Finally, the fifth column show a head-to-head competition between median and average price levels. In this case, median prices are closest in forty-six of the sixty-three periods, while average prices produce generation levels closer to actual in only seventeen periods. When summing across the columns, the average price methodology has the lowest total. In other words, the methodology that is most used in DPT analyses is the worst at matching implied generation levels in the DPT to actual generation levels.

Comparison	Implied	Model	Median	Average	Total
All Four Methodologies	56	9	1	0	66
Model, Median & Average	–	50	8	5	63
Implied, Median & Average	61	–	2	0	63
Median & Average	–	–	46	17	63

Table 5: Number of tests each methodology predicts closest to actual generation levels

Our other criterion is the accuracy of the predicted DPT generation levels for each price methodology as measured by the relative absolute error. Table 6 shows the relative absolute errors on average for the RTOs and across all the RTOs. In each case, the relative absolute error for the implied price methodology is very small compared, ranging from 0 to 1.8%. Next closest is the model price methodology. In some RTOs (*e.g.*, ERCOT, MISO, PJM, and SPP) the model produced implied generation levels close to the actuals. Even when the model produced substantial error—*e.g.*, 19.7% in CISO—the model was much more accurate than the median and average methodologies based on actual price data. Overall, the average error for median prices was 26.7% and the average error for average prices was 30.3%. Once again, the traditional methodology produces the worst results, with average errors of 30.3% and errors for one RTO of 42.2%.

105. Because of the three ties for closest between the implied and the model methodologies, the total in the table is 66 instead of 63 for the second column.

RTO	Implied	Model	Median	Average
CISO	0.6	19.7	33.7	35.6
ERCOT	0.8	0.9	35.2	42.2
ISONE	1.8	15.5	30.8	33.4
MISO	0.3	6.4	32.8	38.6
NYISO	1.0	9.8	29.5	30.6
PJM	0.3	6.1	18.4	19.4
SPP	0.7	1.4	31.3	32.8
All	0.5	6.8	26.7	30.3

Table 6: Relative absolute error for each methodology by RTO

Another metric to measure the reasonableness of a methodology for selecting representative market prices is to examine the percentage of the year captured in the price sensitivity analysis. Recall that FERC requires that the HHI also be calculated at prices above and below the representative prices selected by the applicants.[106] The typical practice is to use prices 10% above and below the representative price.[107] This gives a range of prices over which the analysis covers, and this range of prices in turn defines a set of hours over which are implicitly covered in each DPT period and the year. For example, take the SPP Spring period in 2017 used in Figure 5. The median price is $22/MWh, which gives the range of $19.80/MWh to $24.20/MWh hour. All the prices that occur in this range comprise 27% of the DPT period. The average price is $27/MWh, which produces a range of $24.30/MWh to $29.70/MWh. Because the average price is higher than the median, the range is wider ($5.40 vs. $4.40), but because the average is further away from the middle of the distribution of prices, the range of prices for the average covers only 20% of the DPT period, which is less than the hours covered by the median range. Because range of hours covered by the price sensitivity (based on historical prices) is greater for median prices than for average prices, the median prices can be considered a superior measure of representative prices.

We applied this exercise to all the DPT periods for all the RTOs and methodologies for the 2017 and 2018 years, and the summary is in Table 7. It shows the percentage of the years that are within the price ranges calculated based upon each price methodology. In all cases, the range from the median price methodology covers more of the years than the range established by the other methodologies. On average, the median ranges cover about 30% more hours than do the

106. 18 C.F.R.§ 33.3(d)(6) (2019).

107. This is the range that has been required by FERC Staff. *See* 136 F.E.R.C. ¶ 61,245, at P 48 ("Applicants were directed to provide price sensitivity analyses for the Duke Energy Carolinas, Progress Energy Carolinas-East, and Progress Energy Carolinas-West BAAs under two different scenarios – a 10 percent price increase and a 10 percent price decrease.").

average ranges. The results provide another reason to favor median price levels over average price levels if historical prices are to be used as the basis of representative market prices. The implied and model methodologies on average also cover more hours than do average prices. This is to say that those methodologies often produce prices closer to the center of the price distribution than does the averaging methodology.

RTO	Implied	Model	Median	Average
CISO	12.9	14.3	19.4	18.0
ERCOT	24.2	24.3	30.4	26.2
ISONE	13.9	13.7	17.9	14.2
MISO	35.7	35.6	41.7	26.6
NYISO	16.3	16.1	21.2	17.3
PJM	24.2	26.6	31.9	21.3
SPP	25.2	25.1	24.8	20.4
All	21.8	22.3	26.8	20.6

Table 7: Percentage of Year Covered by the Price Range from each Price Selection Methodology

This coverage analysis can also be done with historical generation data. For instance, it is possible to take a price from a methodology and find the generation amount in the DPT data that corresponds with the plus and minus 10% range. For example, the Implied price in the Spring Peak period is $19.65/MWh, the -10% price is $17.69, and the +10% price is $21.62/MWh. The generation level corresponding to the price of $17.69/MWh is 21,429 MW, and the generation level for the $21.26/MWh price is 34,359 MW. During the Spring/Fall peak period in the base years, actual generation in SPP during the Spring/Fall Peak period fell in the range of 21,429 to 34,359 MW in 86% of the hours during the period. The very high share of hours generation output covered in the +/-10% price provides an indication that the Implied price is representative of market conditions, given the generation data in the DPT analysis.

We applied this exercise to all the DPT periods for all the RTOs and methodologies for the 2017 and 2018 years, and the summary is in Table 8. It shows the percentage of the years that are within the implied generation ranges calculated based upon each price methodology. In all cases, the generation range calculated from Implied and Model prices covers more of the years than the range established by the historical price-based other methodologies. On average, the Implied Model methodologies cover over twice the hours than do the ranges base the Average price methodology. In twenty-two of the sixty-three RTO/Periods tested, the Average price implied generation levels that never occurred during the DPT period! In thirty-seven of the sixty-three periods—over one-half—average price implied generation levels that occurred in less than 25% of the period. These results demonstrate conclusively that selecting prices consistent with the underlying DPT data are much more likely to produce generation levels consistent with actual generation levels, thereby the incentive to exercise market power as discussed with equation (3).

RTO	Implied	Model	Median	Average
CISO	58.6	27.2	22.5	23.6
ERCOT	97.8	97.8	56.4	36.6
ISONE	91.8	89.7	30.0	41.4
MISO	93.7	94.4	55.0	26.8
NYISO	88.2	74.6	24.0	38.4
PJM	77.1	74.3	46.1	27.7
SPP	84.0	84.0	47.3	42.7
Total	84.4	77.4	40.2	33.9

Table 8: Percentage of Year Covered by the Price Range from each Price Selection Methodology

These results show a significant disconnect between calculated generation levels based on average historical prices and DPT data on the one hand and actual historical generation levels on the other hand. How can such discrepancies exist? Although many factors likely drive the differences, we discuss two potential ones here. First, DPT analyses ignore daily unit commitment decisions that market operators make.[108] They essentially assume that generation units can be turned on or off costlessly depending upon small changes in price. On any given day in the real-world, many generation units are not committed to operation, which is to say the available fleet typically is less than the entire fleet that is available in a DPT analysis.[109] Given this, it is not surprising that real-world generation levels are less than those implied in DPT data given historical prices. Second, related to the first, DPT data include neither start-up nor no-load costs that generation units incur in actual operations.[110] This is especially problematic in contemporary electric power markets with natural gas prices often below the price of coal. Large coal-fired units that were designed to be base-load units with few starts per year are now intermediate units, or even peaking-type units in some cases.[111] It is very

108. John R. Morris, *The Good, the Bad, & the Ugly: A review of the Federal Energy Regulatory Commission's market-based rate (MBR) screens, from theory to application*, PUB. UTIL. FORTNIGHTLY (July 2005).

109. *Id*.

110. *Id*.

111. The coal-fired plants in Maryland ran only 17 days in 2019 and are expected to run only 14 days in 2020. *See* Samantha Hawkins, *Blue-Green Divide on Display as Workers Swarm Legislature to Oppose Coal*

costly to start a coal-fired unit, often running into the hundreds of thousands of dollars. The only costs included in the DPT are the average variable costs of a fully-loaded unit. So, there can be substantial costs missing in DPT analysis. Given the differences between real-world operations and DPT data, the results here are not surprising.

VI. OTHER CONSIDERATIONS

For the reasons discussed in section V, the implied, model, and median methodologies all perform better than the traditional average price methodology at replicating historical generation levels in a DPT analysis and at coverage of the year. In this section, we consider additional factors that one might consider when selecting representative price levels. These factors include trying to match to actual generations levels in traditional markets, matching generation levels and implied capacity factors for the applicant companies, the effects of FERC's mandate to use 105% of market prices for the DPT analysis and discuss price sensitivities, selecting representative load levels, and methodologies for selecting fuel costs.

A. Traditional markets and generation owner quantities

The analyses in section V can be performed for RTOs because they post substantial amounts of hourly data including generation levels, demand levels, electric energy flows into and out of the RTO, and prices. In contrast, as discussed in section II, good hourly price data may not be available in traditional markets outside of RTOs and proxies must be used. This leaves the problem of how to estimate representative market prices given a paucity of data. FERC has stated a preference for using EQR data in some fashion,[112] and has accepted lambda data or prices from adjacent RTOs when EQR data are sparse.[113] But even these proxies may not be available in all cases. For example, South Carolina Gas & Electric (SCG&E) is not directly adjacent to an RTO and has no reliable lambda data.[114]

One advantage of using either the implied price or model price methodologies is that they can be reliably used even when no historical price data are available. The prices are calculated to be consistent with the other underlying supply and demand data that FERC requires in the DPT analysis, as in Figure 2. These methodologies are also consistent with the *Bluegrass* decision where FERC accepted an alternative price methodology that better matched the implied capacity factors with the actual historical capacity factors.[115] Matching historical generation levels

Plant Shutdowns, MARYLAND MATTERS (Feb. 26, 2020), https://www.marylandmatters.org/2020/02/26/blue-green-divide-on-display-as-workers-swarm-legislature-to-oppose-coal-plant-shutdowns/.

112. *PJM Interconnection, L.L.C.*, 136 F.E.R.C. ¶ 61,245, at PP 119-129.

113. 139 F.E.R.C. ¶ 61,094, P 26; *Louisville Gas & Elec. Co. & Ky. Utilities Co*., 166 F.E.R.C. ¶ 61,206 (2019), *reh'g denied*, 168 F.E.R.C ¶ 61,152 (2019).

114. The lambda data for 2017 and 2018 filed at FERC are all zero. *See* F.E.R.C., OMB No. 1902-021, Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report (2017) (SCG&E's Q4, 2017 Report); F.E.R.C., OMB No. 1902-021, Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report (2018) (SCG&E's Q4, 2018 Report).

115. 139 F.E.R.C. ¶ 61,094, at P 26.

to the implied generation levels is another way to say that the implied price methodology is attempting to match the market capacity factor–*i.e.*, the amount of actual generation divided by the potential generation. As discussed in section V, the model price methodology also typically provides a close approximation to historical generation levels. Hourly net generation data is now available for most areas via EIA Form-930;[116] therefore, the implied price or modeling methodologies can be performed for most areas. When the hourly data are not available, the model methodology can be used.

Not only should FERC and practitioners examine the capacity of the total market, they should also examine the economic capacity of the applicants. Our discussion on price methodologies have been conducted on a market level, which is important because if the market level of generation is correct, then the amount of EC and AEC for that market would be correct. A market share calculation involves dividing a generation owner's capacity, the numerator, by the total market capacity, the denominator. Ensuring the correct capacity for the market ensures that the denominators are correct for market calculations. But just because the total capacity (denominator) is correct, does not mean that capacities for individual generation owners (the numerators) are correct. Because actual generation costs are not observable, any individual owner may have more or less economic generation capacity in a well-calibrated DPT study than its historical or expected future economic capacity. Therefore, it is also important to consider the economic capacity of the individual owners, especially the capacity of the applicants. In fact, it was an unrealistic implied generation level for an applicant that led FERC to accept a revised methodology in the *Bluegrass* matter, which involved LG&E/KU attempt to acquire a 495 MW peaking facility in Kentucky.[117] EQR data were sparse, covering only 11.5% of the year.[118] Using average EQR prices, the implied capacity factor for the assets to be acquired, the Bluegrass Facility was 28.7% whereas the facility actually ran in only 3.6% of hours and had only a 2.5% capacity factor.[119] Average EQR prices would clearly overstate the competitive significance of *Bluegrass*, so FERC allowed an alternative methodology.[120] Similarly, the opposite could occur so that one or both merger applicants would have less economic capacity than they actually would have or be expected to have in

116. EIA Form 930 provides hourly net generation, load, and interchange by balancing authority area. *See* U.S. ENERGY INFO. ADMIN., EIA-930 DATA USERS GUIDE AND KNOWN ISSUES (Jan. 11, 2018), https://www.eia.gov/realtime_grid/docs/userguide-knownissues.pdf.

117. 139 F.E.R.C. ¶ 61,094, at P 1.

118. *Id.*at P 14.

119. *Id*. at PP 15-16.

120. *Id.* at P 26.

the future.[121] Therefore, applicants and FERC should check that the implied capacity factors (*i.e.*, generation levels) in the DPT analysis reasonably match the historical levels of the applicants.[122]

Finally, when comparing implied capacity factors generation levels with historical data, the comparison should be based upon historical data and not the future test period. FERC requires the DPT analysis to be done for future periods and not a historical period.[123] Capacity factors can change going forward as demand, fuel prices, and generation capacities change. Other than through a study of likely future generation dispatch with fundamental model of supply and demand, expected capacity factors are not known. The historical data is preferable because we can observe what occurred. This can be compared to implied capacity factors based upon the historical data, including historical demand, fuel costs, and generation capacity. Once calibrated based on historical data, then the analysis can be brought into the future that includes all the expected changes to the fundamental determinants to market prices.

B. *Effects of Using Different Prices*

Another factor to consider in the selection of representative market prices is that the actual DPT analysis is not done with the representative market price selected, but 5% above the market price.[124] The exact reason for using a price that is 5% above the representative price is not clear. It likely comes from the DOJ and FTC Merger Guidelines in effect at the time.[125] The 1992 Guidelines defined markets "as a product or group of products and a geographic area in which it is produced or sold such that a hypothetical profit-maximizing firm, not subject to price regulation, that was the only present and future producer or seller of those products in that area likely would impose at least a 'small but significant and nontransitory' increase in price.'"[126] An earlier version of the Guidelines stated that when "attempting to determine objectively the effect of a 'small but significant and nontransitory' increase in price, the Department in most contexts will use a price increase of five percent lasting one year."[127] The 5% adder is also consistent

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121. Although FERC staff did not state it in their deficiency letter in Duke/Progress, this would provide a logical basis for requiring an alternative analysis with either higher representative market prices or lower generation costs; *See* 139 F.E.R.C. ¶ 61,094, at PP 26-27.

122. Because most DPT periods cover very large aggregation of hours, it is not possible perfectly match implied generation levels with actual levels. Nevertheless, the implied levels and actual levels should be within a zone of reasonableness; *See* 136 F.E.R.C. ¶ 61,245.

123. Order No. 642, *supra* note 3, at 31,887 ("… merger analysis should be as forward-looking as practicable …"). DPT analyses for market-based rate applicants may be historical. *See* FED. ENERGY REGULATORY COMM'N, HORIZONTAL MARKER POWER, https://www.ferc.gov/horizontal-market-power.

124. Order No. 592, *supra* note 4, at 31,130-131; 18 CFR *§* 33.3(c)(4) ("For each destination market, the applicant must calculate the amount of relevant product a potential supplier could deliver to the destination market from owned or controlled capacity at a price, including applicable transmission prices, loss factors and ancillary services costs, that is no more than five (5) percent above the pre-transaction market clearing price in the destination market.").

125. 1992 Guidelines, *supra* note 70.

126. *Id*.

127. U.S. DEP'T OF JUSTICE, MERGER GUIDELINES (1984), https://www.justice.gov/archives/atr/1984-merger-guidelines [hereinafter 1984 Guidelines].

with the current Horizontal Merger Guidelines that state that current suppliers are included as suppliers to a market and "[f]irms that are not current producers in a relevant market, but that would very likely provide rapid supply responses with direct competitive impact in the event of a SSNIP [small but significant and non-transitory increase in price], without incurring significant sunk costs, are also considered market participants."[128]

Using a price that is 5% above the representative market price of course increases the amount of economic capacity from all suppliers. To see the effect on generation levels from increasing prices by 5%, we start with the implied prices. We use this for the benchmark because it most closely matches implied generation to historical generation levels. We then increase the price by 5% and calculate the relative absolute errors from the historical generation levels, which provides a percentage difference measure. The results are shown in Table 9, which shows the increase in generation increasing from 5.7% for PJM to 19.4% for ISONE. The overall average increase is 8.7%. In other words, using the 5% adder can increase generation and increase apparent market power. But this is calculated for EC. The increase for AEC can be substantially more than this amount because it is the left-overs after subtracting load, which is typically at least 90% of generation levels. An increase in generation capacity of 10% could easily double AEC in some markets.

RTO	Percentage Increase
CISO	7.2
ERCOT	12.9
ISONE	19.4
MISO	10.6
NYISO	13.3
PJM	5.7
SPP	7.1
All	8.7

Table 9: Percentage Increase in Generation Capacity from Using 5% Higher Prices

But because of the uncertainty of market prices, FERC has required applicants to do price sensitivities of +/-10%.[129] Because of the 5% adder, the actual price sensitivities are 5.5 percent below the market price and 15.5% above the market price.[130] To see the effect on generation levels from increasing prices by

128. U.S. DEP'T OF JUSTICE AND FEDERAL TRADE COMM'N, HORIZONTAL MERGER GUIDELINES (Aug. 19, 2010), https://www.justice.gov/atr/file/810276/download [hereinafter 2010 Guidelines].

129. *See* section II.

130. 5.5 = 100 - (100 + 5) x (1 - 10%); 15.5 = (100 + 5) x (1 + 10%).

15.5%, we start with the implied prices and average prices. We use these for the benchmarks to see the range potential range off effects from the positive price sensitivity. We then increase the price by 15.5% and calculate the relative absolute errors from the actual generation levels, which provides the percentage difference measure. The results are shown in Table 10. Starting with the implied price base, the increase in generation from the +10% price sensitivity ranges from 14.3% for PJM to 36.8% for ISONE, with an overall average increase is 21.3%. With using average prices as the base, the increase in generation above historical levels from the +10% price sensitivity ranges from 26.6% for PJM to 47.1% for MISO, with an overall average increase is 36.6%. These levels are simply too far from historical levels to provide meaningful evidence. For instance, in thirty-nine of the sixty-three DPT periods examined in this article, the +10% price sensitivity and average prices produced implied generation levels that were greater than the maximum generation in the RTO in any single hour of the DPT period. Even using the implied prices, which almost perfectly match average generation levels, the +10% price sensitivity produced implied generation levels that were greater than the maximum generation in the RTO in any single hour of the DPT period in twenty-two of the sixty-three DPT periods.

RTO	Implied Price Base	Average Price Base
CISO	18.8	30.8
ERCOT	36.0	45.2
ISONE	36.8	45.3
MISO	24.4	47.1
NYISO	22.1	36.4
PJM	14.3	26.6
SPP	19.0	41.7
All	21.3	36.9

Table 10: Percentage Increase in Generation Capacity from Using 15.5% Higher Prices

It is fair to see if results are sensitive to small variations in assumptions. But the standard +/10% of market prices (including the 5% adder) does not appear supportable. Some alternatives might include using smaller changes (*e.g.*, 5%) or doing the changes only for the applicants. For example, raising and lowering the applicants' generation costs by 5% would provide information whether small changes in costs would substantially change the results. For example, results might change substantially if several applicant generation units had costs that were not economic in a period by less than $1/MWh. Another alternative would be to first focus and generation output and utilization and then on prices. For example, implied prices can be calculated to match the average generation level in the period. One might examine implied prices that would occur at one standard deviation above or below the average generation levels. That would then provide a range of prices that are within at least some bounds of reasonableness.

C. Demand data

As discussed above, the obligation of each supplier to serve demand is another important component of the AEC calculation. Demand in the electric power industry, which is dominated by engineers, is called load and is measured in megaWatts (MW) instantaneously or mega-Watthours (MWh) over time.[131] If median prices are better than average prices during a DPT period, then are median load levels better measures of representative load than average load levels?

Whether one uses median or average load levels during a DPT period is not likely to affect results significantly because the median and average load levels are similar. Table 11 shows the summary information for the percentage difference between average load levels and median load levels. In contrast to the differences for prices, the differences for load levels all fall in the range of -2.8% to 5.5%. Moreover, the average difference is only 1.3% and no more than 1.6% in any given RTO. Given these data, there is no reason *a priori* to believe that using either median or average load levels would substantially change the results of a DPT analysis.

RTO	Minimum	Average	Maximum
CISO	-0.6	1.4	5.1
ERCOT	-2.8	1.6	3.9
ISONE	-0.4	1.6	5.5
MISO	-1.0	1.0	4.1
NYISO	-0.3	1.0	4.7
PJM	-0.2	1.3	3.9
SPP	-1.6	1.0	3.0

Table 11: Summary of Percentage Differences between Average and Median Load Levels by RTO

D. Generation Costs

Generation costs make up the third major component of a DPT analysis. Above we have discussed how prices can be selected so that the prices, estimated supply curve, and demand can be consistent with a historical benchmark. If applicants were forced to use a price based upon historical data via FERC decision (*e.g.*, the median or average price), then applicants could adjust the supply curve to match the intersection of the historical price and historical demand. This could

131. *See* UNION OF CONCERNED SCIENTISTS, HOW THE ELECTRICITY GRID WORKS, https://www.ucsusa.org/resources/how-electricity-grid-works.

be accomplished by, for example, scaling the generation capacities or scaling the costs so that all three curves (price, demand, and supply) intersect at the same point. Different classes of generation units might be scaled differently to match historical capacity factors for that class of unit. For example, in *Bluegrass*,[132] the applicant could have raised the dispatch costs of the Bluegrass facility to match historical capacity factors at the average price level of the EQR data. But it seems unreliable to change thousands of data points in the generation data when just one point (the representative market price) can be adjusted to match the best knowledge available on generation. Therefore, we proceed assuming that applicants continue to seek the most representative supply curve given publicly available data and precedents set by FERC.

Many factors may vary generation costs within a DPT period. These factors be broken down into two main categories: (1) factors that vary capacities and (2) factors that vary costs given capacities.[133] Factors that affect capacity include unit outages, changes in thermal efficiencies based on weather, and the variation of in intermittent generation from hydroelectric, wind, and solar units. Only general information is known for many of these factors with no data available within a DPT period. Hourly data on intermittent generation are available. Factors that affect generation costs include unit heat rates, variable operations and maintenance expenses, and fuel costs. Most fuel costs do not vary appreciably within a DPT period. For example, coal contracts typically range from a quarter to three years. Natural gas prices, however, can change significantly within a DPT period as well as across a DPT period. We now turn to examining the two major sources of variation in supply with DPT periods.

Although generation output of intermittent generation such as hydroelectric, solar, and wind may vary substantially within a DPT period, the generation levels do not exhibit sufficient skewness in the distributions to substantially impact DPT analysis. For intermittent generation resources such as hydroelectric, solar, and wind, FERC requires applicants to use generation levels (capacity factors) averaged over five years.[134] Therefore, the question is whether averages are likely to substantially affect DPT results because averages mask skewness in generation levels within DPT periods.[135] Accordingly, we measured the skewness of total output from intermittent generation in the RTOs, and the summary results are on the left side of Table 12. Recalling that a skewness measure in the range of -0.5 to 0.5 is approximately symmetric, we can see that generation levels of intermittent generation resources typically are approximately symmetric. All but one of the minimum levels are in this range, and five of the seven averages are within the range. The two averages outside of the range are just above at 0.55 for CISO and

132. 139 F.E.R.C. ¶ 61,094.

133. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED (Mar. 19, 2020), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

134. *See* Order No. 697, *supra* note 14, at P 344 ("With regard to energy-limited resources, such as hydroelectric and wind capacity, . . . we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor.").

135. Hourly energy production for intermittent generation is not generally available on a unit or plant-specific basis. Historical generation and capacity factors can be calculated based on EIA Form 923 data, which contain data on energy generation by plant by month. *See* https://www.eia.gov/electricity/data/ eia923/.

0.54 for MISO. Some DPT periods, however, are highly skewed as indicated by the maximums being greater than 1. In these cases, we can expect the average level of generation being greater than the median or more typical level of generation, as shown on the right side of Table 12. Because intermittent generation has low marginal cost, using averages increases low-cost supplies and shifts out the supply curve relative to the median generation level. This can be one cause of estimated supply curves in DPT analyses having lower costs and implied prices than average price levels in the historical data.

	Skewness			Percentage Difference from Median		
RTO	Minimum	Average	Maximum	Minimum	Average	Maximum
CISO	-0.45	0.55	2.18	-5.55	2.9	14.94
ERCOT	-0.47	0.23	1.15	-4.26	3.84	13.05
ISONE	-0.37	0.43	1.7	-3.08	2.16	7.88
MISO	-0.01	0.54	1.42	2.07	8.73	21.31
NYISO	-0.28	0.13	0.81	-1.3	0.4	1.65
PJM	-0.62	0.36	1.43	-0.83	4.68	18.74
SPP	-0.35	0.12	0.79	-3.45	3.98	20.59

Table 12: Summary of Intermittent Generation Skewness by RTO

The second major source of variability of supply costs in DPT data is the price of natural gas, which can be skewed positive like electric power prices. To examine natural gas prices, we considered the two natural gas prices that are related to the largest quantity of gas-fired generation capacity for each of the seven RTOs.[136] We then match each hour in a DPT period to the two natural gas prices that for delivery in that hour. Based upon the hourly data, we then calculate skewness measures and the differences between the average prices and the median prices. The results are presented in Table 13, which shows that natural gas prices can be highly skewed positively. In five of the seven RTOs, on average, natural gas prices were highly skewed and every RTO had at least one period with highly skewed natural gas prices. And average natural gas prices averaged at least 10% more than median gas prices in each of the RTOs, and average gas prices could be double median gas prices in some RTOs (*e.g.*, NYISO and PJM). The difference between the average and median natural gas prices means that different processing methods for natural gas prices could have substantial effects on the estimated sup-

136. The Hitachi-ABB Velocity Suite database lists an ICE natural gas trading hub to each plant with a gas-fired unit. We then matched the ICE gas trading hubs to Gas Daily price points. We used the two price points that were matched to the greatest amount of generation capacity in each RTO.

ply curves in DPT analysis. This gives added impetus to verify that supply, demand, and representative market prices are consistent with each other in DPT market power studies.

	Skewness			Percentage Difference from Median		
RTO	Minimum	Average	Maximum	Minimum	Average	Maximum
CISO	-1.4	1.6	6.7	-2.2	14.7	68.7
ERCOT	-0.4	0.8	3.6	-0.5	13.5	74.1
ISONE	0.2	2.1	5.7	-1.6	30.1	95.8
MISO	-1.2	1.0	5.6	-1.4	10.8	80.8
NYISO	-0.2	2.6	10.5	-4.3	26.7	136.8
PJM	-0.4	2.1	7.3	-4.3	27.3	126.2
SPP	-1.2	0.5	2.7	-8.0	11.0	82.6

Table 13: Summary of Intermittent Generation Skewness by RTO

E. Effects on DPT Analyses

The data presented thus far indicates that different methodologies can produce different HHI results, but they do not demonstrate that different merger outcomes might be inferred from the different results. To demonstrate different inferences with different methodologies, in theory one could examine past filings and see how the results might be different with different methodologies for selecting representative market prices. Clearly different methodologies can produce different results. For example, in the Duke/Progress merger, applicants initially showed no screen violations during peak periods when accounting for the rate depancaking from the merger.[137] Using average prices based on the available EQR data, applicants showed one on-peak screen failure in Duke with the base prices and two with the +10% prices.[138] In *CPLE*, applicants showed two on-peak screen failures in the base prices and three in the +10% case.[139] This was sufficient for the Commission to require mitigation in approving the application.[140] Another method of selecting market prices could easily create a different result. Unfortu-

137. Duke Energy Corporation and Progress Energy, Inc., *Application for Authorization of Disposition of Jurisdictional Assets and Merger Under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act*, FERC Docket No. EC11-60-000, Accession No. 20110404-5212, Apr. 4, 2011, at 23, 26, 27.

138. *Id.*

139. Duke Energy Corporation and Progress Energy, Inc., *Answer of Duke Energy Corporation and Progress Energy, Inc.*, FERC Docket No. EC11-60-000, Accession No. 20110829-0016, Aug. 23, 2011, Exhibit A.

140. 136 F.E.R.C. ¶ 61,245, at PP 1, 134 (2011).

nately, the workpapers necessary to determine how different methodologies of selecting representative market prices would affect the HHI results are typically filed on a confidential bases and not available to the general public. Therefore, an alternative method is necessary to determine how different methodologies might affect HHI results for individual transactions.

To develop a systematic methodology of evaluating how price sensitivities might affect HHI results and inferences of market power, we used DPT data from our other analyses in this article, such as the amount of additional generation from 5% higher prices shown in Table 9.[141] Using these data, we exhaust the list of transactions among generation owners that that might have HHI screen violations. Specifically, we do a 2ab calculation and use a threshold of 100.[142] This standard would be met whenever both firms have shares of 7.1% or more, or a firm with a 15% share acquires a firm with a share of 3.4% or more. In total, we have sixty-nine hypothetical transaction that we analyze. For each transaction, we calculate the HHI levels and changes for ten DPT periods for both EC and AEC, and we do the price sensitivities. In total, there are 16,560 cases of post-transaction HHIs and their changes.

Table 14 gives the number of HHI screening violations (or failures) by the methodology of selecting representative market prices, the measure of capacity (AEC or EC) and the price sensitivity case (-10%, base prices, and +10%). Several patterns emerge from the AEC results. First, and except for those that do DPT analyses, with the average prices, the number of AEC violations increases with the price level. This is also true for the median and model price methodologies. Interestingly, this pattern does not remain with the implied price methodology. The most screen violations occur with the base prices, with fewer violations in the +/110% cases for the methodologies not relying on historical prices. Second, it does not appear that using average prices is conservative in terms of producing AEC screen violations. It appears that the implied and model methodologies can produce more screen violations, although none of these differences are statistically significant in two-tailed tests at the standard 5% confidence level. As for the EC results, as expected there is less variance in the results compared to the AEC results. None of the differences are statistically significant, and there is no clear pattern in the results.

141. *See supra* Table 9.

142. The 2ab method comes from the fact that the change in the HHI from combining firm a with firm b is equal 2 times the share of firm a times the share of firm b, or mathematically 2ab. This can be a very quick screening methodology based on installed capacity. *See, e.g.*, Market Power Experts, *Comments to the Federal Energy Regulatory Commission Concerning Notice of Inquiry: Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act*, FERC Docket No. RM16-21-000, Nov. 28, 2016, at 22-23.

Capacity Type	Price Case	Implied	Model	Median	Average
AEC	-10%	139	144	118	128
	Base	156	157	126	132
	+10%	148	160	135	136
EC	-10%	89	95	68	64
	Base	62	81	63	62
	+10%	63	76	71	73

Table 14: Number of DPT Screen Violations by Price Methodology, Capacity Measure, and Price Case

Table 14 gives information on which pricing methodology is most likely to produce screen failures, but it does not give information on whether the different methodologies identify the same transactions as being problematic. To address the issue of whether there is a relationship between the methodologies, we examine the number of screen violations across the methodologies. As before, we do this by the two capacity types. FERC requires mitigation only when the DPT analysis shows "systematic" screen failures,[143] but it has never explicitly stated what it considers systematic. For a definition of systematic screen failure, we use the criteria that a systematic screen failure exists if five or more of the twenty-one on-peak HHIs for either AEC or EC are above the screens.[144]

Table 15 shows the results for the relationship between the mergers likely to require mitigation and the methodology for the representative market price. As before, the results are divided between AEC and EC. To understand the data, consider the first row, for the implied methodology for AEC. It indicates that the implied methodology identified twenty of the sixty-nine transactions as requiring mitigation. Of those twenty transactions, all twenty were also identified by the model and median price methodologies, but only eighteen were identified by the average price methodology. In other words, the implied price methodology identified two transactions that the historical average method did not. Consider the next row, the model methodology identifies twenty-three transaction as needing mitigation. Of those twenty-three, the implied price and median price methodologies identify twenty and the average price methodology identifies eighteen of the twenty-three transactions as requiring mitigation. As for the standard average pricing methodology, it identifies eighteen transactions, and all eighteen would be

143. 136 F.E.R.C. ¶ 61,245, at P 134; *CP&L Holdings, Inc.*, 92 F.E.R.C. ¶ 61,023, at 61,054 (2000).

144. Three of the ten DPT periods are off-peak and seven are on-peak. With three price levels (-10%, base, and +10%), that gives 21 on-peak periods tested for each destination market in a transaction. We limit this screen to on-peak periods because FERC is traditionally more concerned with on-peak periods. *Bayou Cove*, 165 F.E.R.C. ¶ 61,226, at P 67 (2012) ("In determining whether an alternative geographic market is relevant for purposes of analyzing a transaction, the Commission examines 'whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching customers within the [proposed alternative geographic market].'").

identified with the other methodologies. As expected from the results in Table 14, the EC results show fewer transactions requiring mitigation and less variance across the results. Nevertheless, the pattern remains that the different methodologies at the margin identify different transactions as being problematic. Although we note that none of these results differ by a statistically significant amount based on capacity type, they do not support the position that the average price methodology is more likely to find screen violations than the other methodologies.

Capacity Type	Methodology	Implied	Model	Median	Average
AEC	Implied	20	20	20	18
	Model	20	23	20	18
	Median	20	20	20	18
	Average	18	18	18	18
EC	Implied	9	9	8	8
	Model	9	10	8	8
	Median	8	8	10	9
	Average	8	8	9	9

Table 15: Transactions with Systematic Violations by Price Methodology and Capacity Measure

Another metric to consider is the amount of divested capacity that would be required to eliminate the screen failures. At times, crafting divestiture packages can be difficult because it is possible that divesting enough capacity in one time period ends up created screen failures in other time periods. In general, divesting the minimum of the two companies' capacities would eliminate the screen failure.[145] To find the amount that is necessary to divest to solve all screen failures, we take the maximum of the divestiture amounts across all the screen failures.[146] If screen violations are deemed systematic, then the divestiture amount is the amount to eliminate all the screen violations.

Table 16 shows the results on estimating divestiture amounts by representative price methodology. The first column gives the capacity type, AEC or EC. We give capacity types because some markets are driven more by EC considerations (*e.g.,* ISONE) and others are driven more by AEC (*e.g.*, SPP). The second column lists four different types of data calculated. The first row gives the number of transactions requiring divestiture out of a possible sixty-nine. The second row

145. At least any HHI changes are not driven by an increase in market share by the acquiring party.

146. In total, there could be up to 60 screen failures to consider (10 DPT periods, three price sensitivities, and two capacity types) for a transaction. In practice, the number of screen failures to consider are considerably less in most cases.

gives the minimum of the divestiture amount for those transaction requiring divestiture. The third row gives the average amount of divestitures necessary to mitigate the screen violations. The fourth row gives the maximum amount of divested capacity necessary for mitigation. The pattern repeats itself for the EC measure of capacity. For AEC, the divestiture numbers do not vary substantially across the pricing methodologies, but for EC, the implied and model methodologies on average produce lower divestiture amounts of up to 12%. To the extent that divestiture amounts can be viewed as a tax or penalty for mergers, the historical pricing methodologies appear to levy greater penalties without a corresponding increase of detecting anticompetitive mergers.

Capacity Type	Statistic	Implied	Model	Median	Average
AEC	Number of Transactions	20	23	20	18
	Minimum Divestiture (MW)	599	599	599	599
	Average Divestiture (MW)	3134	3300	3151	3025
	Maximum Divestiture (MW)	9234	9308	8623	8035
EC	Number of Transactions	9	10	10	9
	Minimum Divestiture (MW)	2669	2676	949	2656
	Average Divestiture (MW)	5540	5508	5806	6208
	Maximum Divestiture (MW)	8887	8737	9550	9550

Table 16: Transaction and Divestiture Amounts by Price Methodology

F. The Importance of Getting the DPT Inferences Correct

From the perspective of promoting the public interest, correctly assessing the competitive impacts of a merger is important because mergers can substantially reduce costs and improve consumer welfare. This can be seen through the increased efficiency gains from the changing ownership structure of power plants.[147] The most studied effects are with nuclear power plants.[148] An article by Davis and Wolfram found that divesting electric power plants increased nuclear plant operating performance by 10% and decreased wholesale power prices by $2.5 billion per year.[149] Although the article does not separately examine the effects of consolidation of ownership of deregulated (*i.e.*, divested) plants, it does show that larger fleets of regulated plants increase efficiency.[150] In PJM, Exelon operates

147. James B. Bushnell & Catherine Wolfram, *Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants*, CTR. FOR THE STUDY OF ENERGY MKTS., at 3-5 (Mar. 2005).

148. *Id.* at 4-5; Lucas W. Davis & Catherine Wolfram, *Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power*, 4 AM. ECON. J.: APPLIED ECON. 194, 207 (2012) [hereinafter Davis & Wolfram].

149. Davis & Wolfram, *supra* note 148, at 207-09.

150. *Id.* at 208-09.

about 50% of the nuclear capacity,[151] and its capacity factor from 2015 through 2019 was 96% compared to 92% for the other five owners.[152] This four-percentage point difference is about 0.8 GW of additional generation each hour. We estimate that each additional GW of nuclear generation reduces PJM system costs by about $0.49/MWh. The additional generation translates to about $300 million per year in lower energy prices in PJM. We also note that Calpine owns the largest fleet of gas-fired combined cycle plants in ERCOT, with about a 20% share of that generation technology.[153] Its average capacity factor is 68% compared to 47% for other generation owners with smaller fleets of gas-fired combined cycle units.[154] This also suggests that larger fleets can lead to efficiencies that increase output and lowers prices. More general work has also demonstrated that greater consolidation in the electric power industry is related to lower prices.[155] In summary, benefits can and do occur with larger generation fleets, especially when owners operate plants with similar technology.

Therefore, from the perspective of promoting the public interest, FERC should balance the procompetitive effects of mergers with the possible anticompetitive effects. In assessing these effects, two types of errors inevitably occur.[156] Type I errors are false positives, finding a market power problem when one does not exist. Type II errors are false negatives, not finding a market power problem that does exist.[157] Some have argued that FERC would seek to minimize false negatives and that FERC could safely ignore false positives because the cost of false negatives are large and the cost of false positives are non-existent.[158] But such a view totally discounts the efficiencies discussed above, and ignores the fact that any potential anticompetitive effects are likely to be short-lived. Entry in electric power markets is ongoing, and can now be accomplished rapidly.[159] The average amount of entry is more than enough to offset any reasonable anticompetitive withholding scenario within two years.[160] In addition, substantially more capacity sits in the generation queue, so the amount of entry can easily expand whenever economic conditions warrant it.[161] In summary, available data on possible

151. Hitachi-ABB, VELOCITY SUITE, *Unit Generation & Emissions – Annual*, 2015-2019.

152. *Id.*

153. *Id.*

154. *Id.*

155. *See, e.g.*, David A. Becher, J. Harold Mulherin, & Ralph A. Walking, *Sources of Gains in Corporate Mergers: Refined Tests from a Neglected Industry*, 47 J. OF FIN. & QUANTITATIVE ANALYSIS 57, 60, 86 (2012).

156. *See, e.g.,* Lawrence J. White, *Antitrust and Merger Policy: A Review and Critique*, 1 J. OF ECON. PERSP. 13, 14-16 (1987).

157. For a discussion on false positives and negatives on merger analysis, see J. Dutra & T. Sabarwal, *Antitrust analysis with upward pricing pressure and cost efficiencies*, PLOS ONE 15(1) e0227418 (2020).

158. *See, e.g.*, Mark J. Niefer, *Explaining the Divide Between DOJ and FERC on Electric Power Merger Policy*, 32 ENERGY L.J. 505, 529 (2012) ("Although there is a fairly substantial body of theoretical and empirical work suggesting that generators can, and sometimes do, exercise market power, there is little work concerning the net effect on consumers of electric power mergers – which can involve increased efficiencies benefiting consumers or increased market power harming consumers.").

159. John R. Morris, Jessica R.S. Dutra & Tristan Snow Cobb, *Should Market Power Still be a Concern in the U.S. Electric Power Industry?*, 33 ELEC. J. 106,725 (2020).

160. *Id.*

161. *Id.*

effects of mergers and acquisitions in the electric power industry suggest that a careful weighing of the relevant facts is important and that any assessment methodology should not be biased for or against mergers. In other words, the costs of false positives and false negatives should be considered in assessing whether mergers are in the public interest.

Despite this, the DPT methodology is conservative in that it is more likely to find market power. For example, on numerous occasions FERC has stated the DPT methodology is conservative.[162] Others have also observed that the methodology is conservative in the sense that FERC is more likely to require divestitures than is DOJ.[163] This is now in part because FERC maintained the old HHI screening thresholds whereas DOJ raised its HHI thresholds in 2010, so the minimum requirement to challenge a merger is a post-transaction HHI of 1,500 and an increase of at least 100.[164]

VII. CONCLUSION

As part of its section 203 merger review process, FERC requires applicants to calculate available economic capacity, which is very sensitive to "representative market prices."[165] Other than requiring applicants to supply two-years of price data, however, FERC does not specify how applicants are to determine representative market prices. Most applicants have used some variation of calculating average prices to determine the representative prices. Our theoretical and empirical investigation of Implied, Model, Median, and Average prices leads us to conclude that the traditional practice of using average prices is likely the least reliable method of selecting representative prices.

In order to be representative of market conditions, representative prices need to be able to reproduce generation levels and implicit capacity factors. Because of the inherent disconnect between historical prices and the estimated supply curves in DPT analyses, Implied prices from historical generation levels and DPT data, and Model prices based on DPT data alone, can be superior at replicating actual generation levels. Implied generation levels and capacity factors from Average prices are often greater than the historical capacity factors, which reinforces the idea that the Average price levels are not representative market prices. Moreover, the 5% adder used in DPT HHI calculations and price sensitivities can result

162. 138 F.E.R.C. ¶ 61,109, at PP 5, 35, 39, 56, 58; Order No. 592, *supra* note 4, at 68,600, 68,607. *See also Analysis of Horizontal Market Power under the Federal Power Act*, 138 F.E.R.C. ¶ 61,109, at PP 5, 35 (2016); Merger Policy Statement, *supra* note 4, at p. 30,119.

163. *Comment of the U.S. Department of Justice and the Federal Trade Commission*, FERC Docket No. RM16-21-000 (Nov. 28, 2016) [hereinafter F.E.R.C. Docket No. RM16-21-000]; *see also* Market Power Experts, *supra* note 142, at p. 4.

164. U.S. DEP'T OF JUST. & THE FED. TRADE COMM'N, HORIZONTAL MERGER GUIDELINES 21-22 (2010), https://www.justice.gov/atr/file/810276/download; FERC Docket No. RM16-21-000, *supra* note 163; 138 F.E.R.C. ¶ 61,109 at P 39; 2010 Guidelines, *supra* note 128, at section 5.3; Market Power Experts, *supra* note 142, at p. 5.; 138 F.E.R.C. ¶ 61,109, at P 39.

165. Order No. 642, *supra* note 3.

in Average prices producing implied DPT generation levels that rarely or never occur in actual market operations.[166]

We also show that using the +/- 10% price sensitivity cases provide too wide of a range of generation outputs, producing implied generation levels that never occur during DPT periods. Therefore, a smaller range to test for price sensitivity, such as +/- 5%, would be more appropriate.

Because merger analysis is forward looking, representative prices must be transformed from a selection based on historical data to represent expected prices in future market conditions. Therefore, we recommend that the representative price in the future test period for the DPT analysis be consistent with the other DPT data for that period. In that sense, a Model price would be a representative market price because it is the price that matches the supply and demand in the forward-looking DPT data. The study of potential transactions in this article demonstrates that this change would not reduce the likelihood of detecting anti-competitive mergers and, in fact, may more correctly identify truly anticompetitive mergers. This would be a logical next step in the evolution of the DPT analyses.

DATA APPENDIX

This exhibit describes data and assumptions used in the delivered price test study (study) carried out by us for this paper.

Transaction choices The study considers all transactions of generation owners in the U.S. ISOs (ERCOT, CAISO, ISONE, NYISO, PJM, MISO, and SPP) in which an HHI based on installed capacity would increase by 100 or more. The assigned ownership is based on Economists Incorporated's ownership data as of 2019. Base period data are from 2017 and 2018, and the forward period for the study is 2021. This criterion gives sixty-nine possible transactions to consider. If the data were not limited to HHI increases of 100 or more, there would be over 150,000 possible transactions, of which all but sixty-nine would have no likelihood of anticompetitive effects.

Periods The paper calculates market shares and concentration indexes for electric energy for ten representative periods during the year.

Geographic Regions The destination markets are each of the seven ISOs. The geographic market (supply area) includes the destination market plus each of the balancing authority areas in the US directly connected to the ISO.

Generation The study includes generating units located in the geographic region that are connected to the power grid. The study uses data for summer and winter capability at the unit level reported in the Velocity Suite Generation Unit Capacity database available from Hitachi-ABB PowerGrid. The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs.

Loads The report uses estimates of load obligations from information available from public sources such as EIA Form 861. The calculation is performed in

166. The 5% adder accounts for easy entry (i.e., responses of other generators if a seller attempts to exercise market power). It is appropriate only if it is applied to a proper base price. As shown above, Average Prices tend to be higher than representative market prices; therefore, adding another 5% compounds the errors from using Average Prices.

five steps. First, the hours in each period are identified based on time and load level for the destinations. Second, load "shapes" are calculated so that the annual load level in EIA 861 data can be translated into a load amount during each of the ten periods. Third, the annual loads served by state and balancing area are then merged with the shapes to give the expected load level served in each period. Fourth, when actual hourly load data for an entity are available (e.g., from Form 714), we use the actual hourly load data. Finally, an "obligation" amount is applied to each of the calculated load levels. These obligation amounts are 100% for municipal cooperative, and regulated IOU systems without retail competition, 90% for IOU systems with limited retail competition (e.g., Detroit Edison), 60% for IOUs with competitive retail access, and 30% for retail power marketers.

Transmission The paper incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas in each Region is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed. Transfer capabilities are based on OASIS postings. Transmission rates and losses are based on tariff filings and OASIS postings.

Market Prices The calculation of market prices during base periods is discussed in the article. The base period prices were moved to the forward period based on a simulation consistent with the data. For example, if the base period average price during a DPT period were \$20.00/MWh and the change from the base period to the forward period is -\$0.50/MWh, then the price for the average methodology in the forward period would be \$19.50/MWh.