Opinion on
System Market Power Mitigation

by

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I. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the ISO's proposal to commence a stakeholder proceeding to consider the possible implementation of a process to mitigate what is referred to as system-level market power in its markets.[1] The term system market power is used to refer to the potential for the exercise of market power across a region that encompasses most or all of the CAISO balancing area, in contrast to the exercise of local market power within a transmission constrained sub-region within the CAISO balancing area. The proposed proceeding follows a set of ISO and Department of Market Monitoring (DMM) analyses that identified hours during 2018 during which the CAISO day-ahead market (Integrated Forward Market, IFM) exhibited structural conditions, in the form of failure of a three pivotal supplier test, that could allow the exercise of system market power.[2] Further, those studies indicated that system market power could become more of a potential problem in the future as supply conditions in the ISO markets tighten due to the planned retirement of once-through cooled generating units. The issues and analyses leading to this proposed proceeding have been addressed during MSC meetings on June 7, 2018 and April 5, June 7, Aug. 19, and Oct. 11, 2019.

The MSC has previously written a number of opinions on the design of local market power mitigation (LMPM) procedures in the ISO's Market Redesign and Technology Upgrade, as well as in the Energy Imbalance Market. These opinions have addressed a range of issues, including

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[1] California ISO, "System-Level Market Power Mitigation Initiative Scoping Document", www.caiso.com/Documents/ScopingDocument-SystemMarketPowerMitigation.pdf

[2] California ISO, "Analysis of Structural System-Level Competitiveness in the CAISO Balancing Authority Area," April 29, 2019, www.caiso.com/Documents/SystemMarketPowerAnalysis-May6-2019.pdf ; CAISO Department of Market Monitoring, "Comments on CAISO's Analysis of Structural System-Level Competiveness," May 20, 2019, www.caiso.com/Documents/DMMComments-SystemMarketPowerAnalysis.pdf .

implementation of LMPM in the energy imbalance market (EIM),[3] dynamic assessment of competitive paths,[4] and procedures for mitigating commitment cost offers,[5] while accounting for local market power, fluctuations in natural gas prices, opportunity costs, and revisions in bid cost recovery rules. Relevant to our consideration here of system market power is the 2013 report that the MSC prepared in response to a Federal Energy Regulatory Commission request on the appropriateness of the 3-pivotal supplier (3PS) test and other competitive screens in LMPM procedures.[6] In that report, we analyzed CAISO data, and concluded that there is no compelling justification for changing the 3PS screen in the LMPM competitive path assessment at that time.

The ISO's present proposal[7] to start a proceeding on system market power first outlines a set of design principles, and then outlines the proposed scope, which would be in two phases. In the first phase, the ISO proposes to implement system market power in the real-time market only, and then only when imports into California are constrained (tentatively when the three major in-

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[3] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on LMPM Implementation in the Energy Imbalance Market," July 7, 2014, www.caiso.com/Documents/FinalOpinion-LocalMarketPowerMitigationImplemenation-EnergyImbalanceMarket-July7_2014.pdf

[4] J. Bushnell, S. Harvey, and B. Hobbs, "Opinion on Local Market Power Mitigation and Dynamic Competitive Path Assessment," July 1, 2011, www.caiso.com/Documents/110713Decision_LocalMarketPowerMitigationEnhancements-MSC%20Opinion.pdf

[5] F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Start-Up and Minimum Load Bid Caps Under MRTU," Aug. 2007, www.caiso.com/Documents/FinalOpiniononStart-upandMinimumLoadBidCapsUnderMRTU.pdf; F. Wolak, J. Bushnell, B. Hobbs, "Comments on Changes to Bidding Start-Up and Minimum Load," July 9, 2009, www.caiso.com/Documents/DraftOpiniononStart-UpandMinimumLoadBiddingRules.pdf; F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Changes to Bidding and Mitigation of Commitment Costs," June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf; J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement," May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf; J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on Commitment Cost Enhancements," Sept. 8, 2014, www.caiso.com/Documents/MSC_FinalOpinionCommittmentCostEnhancements-Sept2014.pdf; J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, Opinion on Reliability Services Phase 1 and Commitment Costs Enhancements Phase 2, March 23, 2015, www.caiso.com/Documents/Decision_ReliabilityServicesPhase1-MSC_Opinion-Mar2015.pdf; J. Bushnell, S. Harvey and B. Hobbs, Opinion on Commitment Cost Bidding Improvements," March 10, 2016, www.caiso.com/Documents/MSC_Opinion_CommitmentCostBiddingImprovements-Mar10_2016.pdf' J. Bushnell, S. Harvey, and B. Hobbs, "Opinion on Commitment Costs and Default Energy Bid Enhancements (CCDEBE)," March 5, 2018, www.caiso.com/Documents/MSCOpinionCommitmentCost-DefaultEnergyBidEnhancements-Mar5_2018.pdf.

[6] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, Report on the Appropriateness of the Three Pivotal Supplier Test and Alternative Competitive Screens, June 27, 2013, www.caiso.com/Documents/Report-Appropriateness-ThreePivotalSupplierTest-AlternativeCompetitiveScreens.pdf

[7] Footnote 1, supra.

terties are constrained). At such times, the criterion for invoking mitigation would be failure of the 3PS test for the entire CAISO balancing area; in implementing that criterion, there are several choices to be made regarding which supplies are included and how to treat load serving obligations. If the 3PS test failed, then resource offers internal to the CAISO balancing area would be mitigated to their default energy bid, although whether all offers or just those from larger (potentially jointly pivotal) suppliers would be mitigated is a design choice. This first phase is the focus of this Opinion. A second phase would consider extension of the mitigation mechanism to other balancing authority areas (BAAs) within the Western Energy Imbalance Market, as well as possible extension to the day-ahead market.

This Opinion is structured as follows. First, in Section II, we summarize our recommendations whether a proceeding concerning design of a system market power mitigation mechanism should be commenced, and several issues concerning the design of such a mitigation. Then we provide some general background in Section III on market power mitigation in the ISO markets since the implementation of the Market Redesign and Technology Upgrade in 2008. In Section IV, we review several specific issues that would require addressing in the design of a system market power mitigation procedure in the ISO real-time and/or day-ahead markets. Finally, two appendices are provided. Appendix A is a review of CAISO day-ahead market outcomes for two sets of hours during 2018 in order to identify the conditions, including the potential exercise of market power, that may have contributed to high prices during those hours. In particular, that appendix addresses three questions:

1. *Was local market power mitigation appropriately triggered by the existence of transmission congestion?*
2. *Was the level of import supply constrained by congestion on the major interties, or was it constrained by internal CAISO congestion, potentially contributing to an exercise of system market power?*
3. *Is there clear evidence that prices materially exceeded competitive levels in these hours, reflecting the exercise of system market power?*

Appendix B provides a simple economic model that explores whether mitigation of market power in the real-time market could effectively mitigate its exercise in the day-ahead market; it establishes that there are narrow circumstances in which such mitigation is completely effective, and that it is likely to have some beneficial effect.

II. Summary of Recommendations

The MSC has reviewed the analyses by both the DMM and CAISO staff on historic supply conditions.[8] Our assessments are summarized in more detail in Appendix A. We take from these analyses that pivotal supplier tests indicate that there might have been some limited potential for market power at the system level, but, according to analyses of prices and costs that have been carried out to date, this market power has not been exploited very frequently or aggressively.

[8] Footnote 2, supra.

Retroactive analysis by DMM indicates that little to no market power was exercised in most hours in which the three pivotal supplier test "failed" according to these analyses. Based upon analysis of 2018 outcomes, the development of a design for system-level market power mitigation would not appear to offer significant benefits. However, there is growing concern that market conditions may evolve in a way that exacerbates the potential for system-level market power. If retiring natural gas resources are not replaced by resources with the ability to meet system energy and flexibility needs, this could lead to periods in which a smaller number of resources would be capable of meeting those needs, potentially leading to shortages and high prices. Moreover, if the CAISO becomes increasingly dependent on resources outside the CAISO to meet CAISO load, there would be a potential for the CAISO to become transmission constrained to a degree that has not occurred in the past and which might enable the exercise of system market power by a limited set of dispatchable resources remaining within the CAISO.

Adding to concerns over future supply conditions is the fact that California currently operates under an arguably less stringent mitigation criterion than other balancing area authorities (BAAs) in the EIM with respect to the application of market power mitigation when the balancing area as a whole is transmission constrained. Given this fact, it seems that a reasonable place to start is a proceeding that would develop mitigation protocols that are analogous to those applied outside of California in the EIM with respect to constraints on import supply. It is our understanding that this is essentially what CAISO management is proposing as Phase I of a system market power stakeholder proceeding.

Therefore, we support the next step of a stakeholder proceeding that would further refine the details of system-level market power mitigation. We note that application of market power mitigation only in real-time may not constrain the exercise of market power as tightly as if it were also applied in the IFM as well, and there are some risks of unintended consequences of applying this mitigation only to real-time, and not in the day-ahead market. However, these risks appear to be outweighed by the advantages of starting by applying system market power mitigation only in the real-time market. First, there is a much better prospect of timely implementation of what would effectively be an extension of the existing EIM mitigation framework. Second, there are several difficult technical and policy questions that arise when extending mitigation to the day-ahead market that would likely require a lengthier stakeholder process to resolve. Third, the day-ahead market may itself change in non-trivial ways under current initiatives and with the prospect of extension to other EIM entities. This creates the risk that any system market power mitigation design developed for the current IFM design might be used for a very short period of time, or perhaps not used at all, before changes in the IFM might require implementation of a materially different market power mitigation design. Fourth, our theoretical analysis (Appendix B) indicates that real-time mitigation together with convergence bidding are likely to be at least partially effective in mitigating market power in the day-ahead market. These factors argue for starting with the real-time market and coordinating extension to day-ahead with other policy initiatives as a second phase.

We are also supportive of the principle articulated in the CAISO Initiative Scoping Document[9] that system mitigation should be limited to resources within the CAISO footprint. Mitigation of

[9] Footnote 1, supra.

import bids not subject to resource adequacy (RA) requirements would likely prove ineffectual at best and counter-productive at worst. The application of market power mitigation to RA imports raises other policy issues that should likely first be addressed in ongoing RA proceedings. For example, deficiencies in the must offer obligation for import supply would be better addressed within the RA framework than with market power mitigation rules that would only apply when triggered by the potential for the exercise of market power.

An additional issue that would require addressing if imports were subject to market power mitigation would concern the format of import offers. In particular, application of cost-based offer price mitigation to import offers in the IFM would require modifications to the IFM design for imports that would allow import RA suppliers to submit resource specific 3-part bids for start-up costs, minimum load costs, incremental energy, as well as physical parameters such as start-up time, minimum run time, minimum down time, and the other parameters submitted by internal resources.

Under any mitigation regime choice, California will need to continue the process of regional integration and will likely need to increasingly rely upon imported supply to support a reliable and competitive market in California. Forward contracting for imports will be important and, as we discuss in Appendix A, the current policy for evaluating import-based RA is flawed. However, import supply offered at $1000/MWh does not necessarily reflect an effort to exercise WECC-wide market power. Instead, at least in some cases, it signals the existence of WECC-wide scarcity or represents RA supply that is not supported by any physical resource.

We furthermore support the principle that mitigation at this time should, as with other EIM areas, be limited to periods where the CAISO is import constrained due to transmission limitations. Mitigation of California generation in the absence of import constraints can be justified only under an assumption that the Western Electricity Coordinating Council area as a whole is structurally uncompetitive at times, and we have not seen evidence supporting such an assumption. Absent changes to the 3PS test and other aspects of the mitigation process, application of systemwide mitigation even in the absence of congestion could result in much more frequent mitigation of all resources in California. Therefore, we believe that a change to mitigate resources even in the absence of transmission congestion would need to be done in conjunction with a detailed review of many other aspects of the mitigation process. This would not be practical as part of a Phase I plan for system-wide mitigation. However, if the CAISO initiates a second phase of the proposed proceeding in which mitigation of both day-ahead and real-time markets would be considered, there would be an opportunity to reconsider the conditions under which mitigation should be triggered.

III. Background: Market Power Mitigation in the CAISO

In U.S. electricity systems, all ISOs attempt to balance the goal of benefiting from the incentive and informational benefits provided by markets with the need to limit the exercise of market power, to which power markets can be particularly vulnerable. Since neither perfect competition nor perfect regulation should be expected, most ISOs attempt to limit the application of ex ante offer price mitigation to the circumstances in which it is anticipated that there would be the greatest potential for the exercise of material market power.

While aggressive application of ex ante offer price mitigation to resource offers may be viewed as a prudent path that will lower risk that consumers will pay inflated prices for power, while imposing minimal costs on market parties if markets are actually competitive, this is not necessarily the case. The application of ex ante offer price mitigation can distort operations in both the long and short run. Fundamentally, the application of beneficial mitigation relies upon the ability of the ISO to reasonably approximate the marginal costs of the resources being mitigated. This has been becoming increasingly difficult across the EIM over the last several years as: (1) the market has expanded into areas with less liquid and transparent natural gas markets; (2) there has been an expansion in the need to dispatch use limited resources in a more flexible manner than in the past to balance unpredictable variations in net load; and (3) the amounts of hydro resources with difficult to accurately measure opportunity costs have increased; and (4) the loss of substantial natural gas storage in southern California after the Aliso Canyon incident, which has made southern California gas prices more volatile and difficult to predict. Moreover, the accurate development of cost-based offer prices will likely become even more challenging with increased reliance on electricity storage resources, and potentially a wide variety of storage resources become available with disparate trade-offs between their long run costs and use patterns, to balance net load. One great advantage of competitive markets is their ability to reveal, through the behavior of their participants, the true underlying costs of various resources under various conditions. If administrative estimates of costs are too low, the resulting market dispatch can create inefficiencies and in the extreme reliability concerns. Over the longer-run, persistent and chronic mitigation of resources could in theory distort the incentives of resource owners with respect to investment and operational efficiencies of their plants.

In the CAISO, such concerns influenced the Local Market Power Mitigation (LMPM) approach that is currently applied. Since the introduction of the LMP-based market design, the organizing philosophy around market power mitigation has been to focus mitigation on times and regions where the market is likely to be structurally uncompetitive in a non-transitory fashion. The primary conditions that meet this description are local, transmission-constrained areas where a limited number of resources and suppliers are physically capable of providing supply.

The mechanical application of LMPM in California has also significantly evolved since the original design was implemented in 2009. The original process of designating uncompetitive paths based upon an annual evaluation of generation and transmission capacities was supplanted by a dynamic assessment of each path, implemented in April 11, 2012 in SCUC, May 1, 2013 in RTPD/RTD, and May 2, 2017 in the advisory intervals of RTD. The dynamic path assessment in a sense combines aspects of both "conduct" as well as "structure," since the available supply that is offered at any given point in time, upon which the structural test is now based, is itself the result of conduct choices made by market participants.

LMPM has continued to evolve in other ways, most recently in its extension to the Energy Imbalance Market (EIM). Mitigation in EIM for BAAs outside of California is based on a 3PS test, and will potentially mitigate the entire BAA when that BAA is import constrained. In this sense suppliers, in the EIM BAAs, unlike CAISO, are currently subject to the equivalent of a "system-wide" mitigation for their individual systems when their balancing area is import constrained.

The LMPM approach has rested upon the assumption that the overall CAISO market itself was workably competitive, or that the "provisions in the CAISO tariff are based upon the principle that, market-wide, the market is large enough and includes enough competitors to provide reasonable, competitive outcomes."[10] This assumption in turn stems from experiences with wholesale electricity markets in which "many actual and potential suppliers, and robust forward contracting can provide competitive prices and supply."

This perspective highlights the important role of forward energy contracting in fostering competitive markets. In a market that is not transmission constrained, the hedging of energy purchase costs through forward contracts can promote more competitive outcomes in both the short- and long-terms. In the short-term, even under tight supply conditions, if suppliers have committed most of their production at fixed prices in advance, their incentive to raise short-term prices is diminished, since most of their MWh sold will not benefit from higher prices. Only if they anticipate that they can affect the terms of future long-term contracts by raising short-term prices would raising the latter be profitable. In the long-term, if the market is structurally competitive, sellers will have to compete with other existing and potentially new suppliers for the supply of energy under forward contracts, helping to keep contract prices reasonably competitive. By contrast, in local transmission constrained markets where entry of new resources is limited, forward procurement is much less effective at reducing supplier market power. If a seller knows that it will enjoy local market power now and into the future, it has much less incentive to enter into a competitively priced forward contract. This logic strongly influenced the focus in California on local market power as the subject of mitigation.

With this as background, we acknowledge that there is growing concern that the CAISO system as a whole may experience periods where it is not structurally competitive. Both the DMM and CAISO staff have performed retroactive quasi-structural analysis of the CAISO system and found a range between 20 to 301 hours (depending on the assumptions and whether based on a one or three pivotal supplier test) in 2018 where the test for local mitigation, known as the three pivotal supplier (3PS) test would have failed at the system level.[11]

Since, as we discuss below, the 3PS test as currently implemented is both a blunt and conservative test of competitiveness, it does not necessarily indicate that there is a potential for the exercise of material market power, and does not show that any market power was exercised. Hence, other methods, such as estimation of actual residual demand curves, would be necessary to accurately assess the potential for the exercise of material market power. Further, an assessment of the degree to which there has actually been a material exercise of market power must also be

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[10] J. Bushnell et al., cited in Note 6, supra.

[11] CAISO and DMM analyses, cited in Note 2, supra. The CAISO September 3, 2019 analysis showed failures of the 3PS in 201 hours, the 2PS in 66 hours and the 1PS in 20 hours during 2018) for the case based on the CAISO demand forecast, self- scheduled exports and losses and input bid supply plus net virtual supply (p, 30).

based on other analyses, such as the competitive benchmark analyses performed by DMM. Such benchmarks can potentially estimate the degree to which actual market prices exceeded a hypothetical perfectly competitive price, to the extent that they are based on accurate estimates of supplier costs.

As summarized in Appendix A of this opinion, these analyses reveal about 20 hours where prices exceeded estimated competitive levels by at least $20/MWh during 2018. During five of these hours, it is very likely that the estimate of the competitive price level is too low, because it is based on a 3-day weekend gas price, rather than the cost of buying gas for that day. Since all 20 of these hours were hours with very high gas prices on SOCAL GAS system, more detailed analysis of these days and the location of the resources with the offers that impacted clearing prices would be needed to assess whether there was an exercise of market power in any of these 20 hours.

These possibly uncompetitive hours do seem correlated to concentration of supply (as measured by pivotal supplier tests), but not completely. Of the 20 high mark-up hours, 18 featured a RSI3 less than 1.0,.0 and 11 of these hours in addition had an RSI1 that was less than 1.0. On the other hand, there were many more hours during 2018 that also failed the 3PS test and did not produce significant mark-ups according the DMM benchmark analysis.

Importantly, all of the analyses described above were limited to the supply offered in the day-ahead Integrated Forward Market (IFM) and did not evaluate supply available in the real-time markets. However, the CAISO proposal as it currently stands would be limited to the real-time markets. Thus, there is somewhat of an analytical mismatch between the ISO's and DMM's backward-looking analyses of system market power and the approach that the ISO proposes be considered in a stakeholder proceeding.

Based upon the results of 2018 alone, the assessment in Appendix A indicates that system-level mitigation would not appear to offer significant benefit. However, there is growing concern that market conditions will continue to evolve in a way that exacerbates the potential for system-level market power. The retirement of once-through cooled natural gas resources and replacement with renewable production that is unable to meet load during the same time periods as the retired generation could lead to some periods having a smaller number of resources within California that are be capable of meeting system needs when imports are constrained. These periods could include post-sunset peaks or fast ramps, potentially leading to shortages and high prices. Resource adequacy requirements could, but would not necessarily, mitigate that effect, particularly if RA does not replace the retired capacity with equally flexible capacity.[12]

[12] Whether competition is strengthened or not within California depends on what type of resources replace retired gas-fired capacity and who owns the resources.

1. If retired capacity is replaced with different resources, with the same capability yet different owners, the market will likely become more competitive and the supply balance will be unchanged.
2. If gas-fired capacity is retired and not replaced, the California market will become less competitive, and there will also be tighter supply conditions. If there was not surplus supply to meet RA needs, there will be shortage conditions.
3. If gas-fired capacity is retired and partly replaced, California supply conditions will be tighter but

Added to concerns over future supply conditions is the fact that California currently operates under an arguably less stringent mitigation criterion than other BAAs in the EIM with respect to import congestion. While this has not been an issue historically because overall import capacity on the major ties has greatly exceeded actual imports, this may not always be the case if the future if the output of retired gas fired generation within California is replaced with import supply. Given this fact, it seems that a reasonable place to start is a proceeding that would develop mitigation protocols that are at least analogous to those applied outside of California in the EIM when EIM balancing areas are import constrained. This is basically what the CAISO is proposing for its first phase of the stakeholder proceeding.

IV. General Issues in Designing SMP Mitigation

In this section, we discuss some of the key design choices that will need to be considered in the development of a system market power mitigation scheme in the proposed proceeding. It is a process that becomes more complicated if extended to the day-ahead IFM. Such complications are the primary reason why an initial focus on real-time mitigation alone seems reasonable in the first phase of the proceeding.

The issues are discussed in five groups of market design choices: use of the pivotal supplier test used to trigger mitigation; geographic issues, including the geographic scope of system market power mitigation system; the definition of when a system is import constrained and the mitigation criterion should be applied; the time frame of mitigation; and miscellaneous issues (Sections IV.A-IV.E, respectively).

IV.A Use of the 3 Pivotal Supplier Test to Trigger Mitigation

While it might appear simplest to base a test for system market power on a 3PS test, there would be a number of difficult issues in utilizing a pivotal supplier test to trigger mitigation of system market power. These issues would impact the workability of a number of the other design choices discussed below.

The best approach to resolving these issues might be to extensively modify the current pivotal supplier test; we suggest some ways to do so in this subsection and elsewhere in Section IV. Possible reforms of the test should be addressed in the proposed proceeding or as part of the Phase 2 process proposed in the CAISO Initiative Scoping Document. Alternatively, a shift to a fundamentally different approach for testing for the existence and or exercise of system market power, such as a conduct-and-impact test might ultimately be preferable. As we note below, a number of the problems discussed in this subsection would not afflict the conduct-and-impact test, which accounts for offer prices in calculating schedules and resulting impacts on prices while accounting for the interaction of offers with transmission constraints. We are not recom-

whether the market will become more or less competitive depends on the amount and ownership of the capacity that is retired, and whether imports are constrained. If there was not surplus supply to meet resource adequacy needs, there will be some increase in shortage conditions.

mending consideration and implementation of a conduct-and-impact test or a shift to some other type of test at this time for the practical reason that it is desirable to have a relatively rapid implementation of a system market power mitigation scheme based on the present EIM procedure.

- *Generation Pockets*

The 3PS test as it is applied by the CAISO does not account for generation pockets. This limitation is likely to be more serious when testing for system market power across the CAISO BAA (which will likely include more generation pockets than the constrained areas tested for local market power mitigation). This limitation of pivotal supplier tests is likely to be even more problematic if the test for system market power includes supply from resources located outside the CAISO. The magnitude of the potential problem within just the current Western EIM footprint is shown by the recent analysis of deliverability constraints for flexiramp which found that as much as 50% of the flexiramp scheduled in the 15 minute market (FMM) could not be dispatched to balance CAISO load.[13] This extent of bottled-up generation would likely have a major impact on the accuracy of a pivotal supplier test for system market power.

This limitation of pivotal supplier tests will interact with choices regarding geographic scope of market power mitigation. Modifications to the 3PS test could better account for this problem if it were possible to identify likely major generation pockets in advance. Possible alternatives, such as the conduct-and-impact tests do not share this limitation because they directly test whether competitive supply can be dispatched to meet load.

- *High Cost Supply*

The 3PS test as applied by the CAISO does not account for the cost-effectiveness of fringe supply. Thus, for example, $1000/MWh bids would be counted as supply even if they are very unlikely to be taken and provide a huge amount of head room for the exercise market power. One specific feature of the ISO's implementation of the 3PS requires that the test only include *cleared* virtual supply when testing for local market power in order to prevent the test from being circumvented by the submission of very high cost virtual supply offers in the IFM. This limitation of the CAISO 3PS will require similar restrictions on consideration of virtual supply offers when testing for system market power. In addition, this feature of pivotal supplier tests will be problematic when accounting for import supply as the 3PS test for system market power could be circumvented by the submission of many high cost import supply offers that might not even reflect actual supply. This is already a concern with respect to high cost offers for imported RA.

These limitations of pivotal supplier tests could be addressed by only including cleared virtual supply and cleared imports in the 3PS test's calculation of the residual supply index (RSI), but such an approach could so greatly understate actual supply that the result of the 3PS test would have little relationship to the actual degree of competition. This limitation of pivotal supplier

[13] California ISO, "CAISO Energy Markets Price Performance Report," September 23, 2019, www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

tests would be less of an issue if the test were only applied when the CAISO was import constrained as import supply would in fact be limited to the amount that cleared.

This limitation of pivotal supplier tests would interact with choices regarding geographic scope of market power mitigation and the time frame for mitigation. The conduct-and-impact test would not share these problems because it directly accounts for the level of offer prices in the dispatch and resulting effect on prices.

- *Price-Taking Supply*

The CAISO's application of the 3PS test treats price-taking supply offered by a potentially pivotal supplier as being withheld when testing for pivotality. This assumption is plainly incorrect but it likely simplifies application of the pivotal supplier test. Furthermore, it likely does not materially impact the results within the CAISO because of the exemption given to net buyers who are likely to be the suppliers that have large amounts of price-taking intermittent resource supply under contract. This assumption will be a much more problematic design feature if tests for pivotality were to be applied to load serving entities outside the CAISO who might not always be net buyers but would have large amounts of price-taking intermittent resource output under contract (or if large load serving entities within the CAISO cease to be net buyers).

This limitation of the pivotal supplier test would interact with choices regarding the geographic scope of tests for pivotality. Although this may not be an issue in Phase 1 (if mitigation is limited to the CAISO BAA), it would potentially arise if expansion of day-ahead mitigation to CAISO imports is contemplated. This is not a concern with conduct-and-impact tests, which automatically account for the effect of the level of offers on schedules and prices. This limitation of the CAISO's implementation of the 3PS could be addressed by excluding supply offered at price of 0 or less from the pivotality calculation.

- *Load Serving Obligations*

The CAISO does not test net buyers for pivotality, but it does not account for the magnitude of load serving obligations when testing net sellers for pivotality. This has not been an issue when applying the pivotal supplier test within the CAISO to date because the load serving entities with large amounts of supply have all been excluded from the pivotality test as net buyers. Furthermore, there is a reasonable expectation that under present conditions, suppliers with large load serving obligations would not offer large amounts of supply at high prices because they would have to buy power to meet their load serving obligations at those prices. However, this situation may cease to be the case within the CAISO with shifts in load serving obligations due to the rise of community choice aggregators, and will certainly be an issue if a pivotal supplier test were to be used to test for pivotality for system market power outside the CAISO .

The potential importance of the treatment of load serving entities can be seen in the CAISO September 3 report on system level competitiveness.[14] The CAISO 3PS calculations showed that while a 3PS based on physical output and excluding net buyers failed the 3PS during 577 hours when applied to the CAISO day-ahead forecast + self-scheduled exports, it would have failed in 8759 hours without the net buyer exclusion. Similarly, while the 2PS would have been failed in 270 hours for this scenario if net buyers were excluded, it would have been failed in 8491 hours if they were not excluded.[15]

While similar results were not reported for the impact of the net buyer exclusion for an alternative calculation that used the day-ahead load forecast + exports + losses compared to physical inputs + net virtual supply, the importance of the net buyer exclusion is clear. If SCE and/or PG&E cease to be net buyers and become even small net sellers, the 3PS as currently applied could trigger system market power mitigation in almost every hour. This would mean that the offer of every resource in California, including small batteries, hydro resources, and municipal gas generators, could have its offer price replaced with the DEB in almost every hour of the year. This would create the potential for enormous efficiency losses from inaccurate DEBs.

This limitation of the pivotal supplier test would interact with choices regarding the geographic scope of tests for pivotality. Expanding the application of a pivotal supplier test to balancing areas outside the CAISO in which the large suppliers also have large load serving obligations would make it even more important to account for load serving obligations in determining pivotality. This is less of an issue with conduct-and-impact tests, which account for actual offer prices when calculating whether anti-competitive impacts occur. Suppliers with large net load serving obligations would only trigger the conduct test if they actually offered their supply at high prices, while the CAISO 3PS simply assumes that they will. This limitation of the CAISO's implementation of the 3PS could be addressed by taking load serving obligations into account in some manner in applying the pivotality test. Moreover, it would be essential that this issue be addressed in applying system market power mitigation, as a failure to address this issue could have the result that mitigation would be triggered in a very large number of hours in which there is actually almost no potential for the exercise of system market power. The adverse consequences of this limitation of the current design would be reduced if mitigation were only triggered when the CAISO was import constrained.

- *Load Forecast Triggered*

The CAISO applies the pivotal supplier test using its own load forecast in the IFM, rather than the amount of load bid into the market. This design would allow load serving entities to distort the RSI and deliberately trigger mitigation by withholding both supply and load from the IFM. This can occur because the withheld supply would not be included in the supply available to meet the load forecast, but the load that is not bid into the IFM would still be included in the load forecast used to apply the pivotal supplier test.

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[14] California ISO, "Analysis of Structural System Level Competitiveness in the CAISO Balancing Authority Area," September 3, 2019, www.caiso.com/Documents/RevisedWhitePaper-SystemMarketPowerAnalysis.pdf.

[15] Ibid., pp. 24-25

This limitation of the pivotal supplier test would interact with choices regarding the application of the test in the IFM. Conduct-and-impact tests do not share this limitation because they are based on bid load, including price-capped bids.

IV.B Geographic Scope of Pivotality Test, Geographic Scope of Mitigation, and Trigger for Mitigation

There will be a series of interrelated choices regarding whether offer price mitigation should be applied to resources located outside the CAISO, whether suppliers outside the CAISO should be tested for pivotality, and whether the trigger for mitigation should be based in part on the existence of transmission congestion that limits the geographic extent of the market.

A design calling for the application of cost-based market power mitigation to resources located outside the CAISO could not be implemented in the IFM because the CAISO does not receive resource specific bids from external resources. Moreover, the IFM offers of external resources, including those located within the western EIM, are one-part bids, which cannot be related to the commitment costs of particular external resources. This would preclude the application of a mitigation design based on estimates of cost-based offer prices.[16] A design calling for the application of market power to resources located outside the CAISO but within the western EIM could be applied in the FMM and real-time dispatch (RTD) but risks having the effect of reducing the supply offered by EIM entities to the minimum required to meet the Western EIM resource sufficiency test, thereby raising rather than lowering prices in the CAISO.

It is also uncertain whether FERC would approve the use of the current form of the 3PS test to trigger mitigation outside the CAISO, in light of the flaws in the current design's treatment of price-taking supply and load serving obligations, discussed in Section IV.A, above. Limiting the geographic scope of mitigation to the CAISO and using a mitigation trigger based on import congestion would reduce the impact of many of the limitations of pivotal supplier tests that we have described.

The submission of import RA supply offers at $1000/MWh does not necessarily reflect the exercise of market power, and cannot be effectively addressed through system market power mitigation. These resources cannot meet load within California when the CAISO is import constrained due to transmission limits. The converse possibility, that the owners of these resources have WECC-wide market power and are offering their supply at $1000/MWh in order to economically withhold it from the WECC market and elevate prices throughout the WECC is not remotely

[16] Import default energy bids could be based on rough estimates of average incremental costs plus a relatively generous margin to allow for error (i.e., much more than the 110% of costs in the ISO's LMPM system), which could restrain the exercise of more extreme amounts of market power. However, since this offer price cap would have little relationship to the costs thermal resources would incur to supply power in a single hour, there is a significant risk that it would have the effect of discouraging RA from being offered supported by thermal resources located outside California, perhaps significantly reducing the RA resources available to meet CAISO load. Similar estimates would be needed in order for the ISO to develop a cost screen for bids above $1000/MWh, as it is doing under the CCDEBE initiative.

plausible. As has been discussed at a number of MSC meetings, the potential issue with the RA imports offered at $1000/MWh is the likelihood that there is no resource supporting the offer, which of course means that no supply is being withheld from the WECC because the seller has no supply to withhold. The submission of $1000/MWh offers by import RA is an issue relating to the CAISO/California Public Utilities Commission resource adequacy design and needs to be addressed as such.

IV.C Import Competition Trigger

There is a potential for the increasing reliance of the CAISO on imports to meet load during periods of low intermittent resource output to increase the frequency of import constrained conditions in the CAISO market. This could have the following result: that supply for meeting incremental load would at times be limited to resources internal to the CAISO balancing area, increasing the risk of system level market power. If this is the major potential source of system market power, then this would imply that it is worthwhile to trigger the test for system market power only if several major interties were import constrained.

On the other hand, it could be the case that there are suppliers located within the CAISO that control so much supply they can exercise WECC-wide market power by withholding their supply even if CAISO is not import constrained. If there was such a potential during some market conditions, it would be appropriate to apply a test for system market power without regard to the existence of import constraints. If suppliers within the CAISO were to possess this degree of WECC-wide market power, then the CAISO should be able to observe substantial withholding of supply within the CAISO in real-time, with the output (and associated exports from the CAISO) replaced by lower cost energy within the Western EIM.[17] To our knowledge, such cases of WECC-wide market power have not been reported. In the absence of such reports, we do not see a need to consider mitigation to address the potential for the exercise of WECC-wide market power. The possibility that import supply might only be available at high prices during tight system conditions when high cost resources are used to meet load does not reflect the exercise of market power.

On the other hand, one might take the view that testing for system market power when the CAISO was not import constrained would not have any downside, since mitigation would not be triggered unless suppliers failed the pivotal supplier test, indicating the possible existence of system market power. However, under the current mitigation framework this is almost certainly not the case. As we discussed above, the limitations of the pivotal supplier test in taking account of virtual and import supply would likely require the test to be based on cleared virtual and import supply, rather than cost-effective import supply. The omission of cost-effective virtual and im-

[17] Real-time import supply not only includes hourly transactions that could be scheduled in the HASP but also includes the flexible capacity offered by each EIM entity and available for dispatch in real-time. The Western EIM's economic dispatch would in the course of its routine operation replace high cost energy offers within the CAISO with lower cost energy from resources that would have other otherwise provided flexiramp capacity elsewhere in the WECC. The dispatch would then use the high cost supply within the CAISO to provide flexiramp. This shifting of output would be constrained by amount of 15-minute ramp rate limited capacity within the CAISO that had been offered at high prices

port supply could potentially cause such a pivotal supplier test for system market power to trigger mitigation when there is in fact no potential for the exercise of system market power. Similarly, the potential for the current 3PS test to trigger mitigation in almost every interval as a result of the treatment of price-taking supply and load serving entities is another reason to limit the application of the 3PS trigger to circumstances in which there is a significant potential for the exercise of system market power.

A related consideration would be that since HASP imports are priced in the FMM, the potential for widespread application of system market power mitigation to gas fired generation throughout California when there actually is little potential for the exercise of system market power might reduce or even eliminate import supply in the HASP because of the risk that FMM prices at the interties would be determined by DEBs that did not reflect actual western gas prices. The application of system market power would create much less reliability risk if it were only applied when the CAISO is import constrained and prices would be higher inside the CAISO than outside.

It might also be argued that the application of system market power mitigation throughout the west is necessary because there are suppliers located outside the CAISO that possess substantial WECC-wide system market power. However, to our knowledge, there has been no analysis suggesting the existence of such WECC-wide market power, and the entities controlling large amounts of generation outside California also have large load-serving obligations. Hence, these entities have a limited ability to withhold supply from the market in order to sell power at prices inflated by the exercise of market power, as withholding supply from the market could result in them having to buy power at high prices in order meet their own obligations or very slightly raising prices with large proportionate reductions in small net sales.

For the reasons outlined in Section IV.A, we conclude that the CAISO's 3PS test would be a very problematic method of testing for the possession or exercise of market power by suppliers located outside the CAISO. This is because the test accounts neither for price-taking supply, nor for the load-serving obligations of most suppliers located outside the CAISO. This point applies both to system-level and local market power detection but is more of an issue in broader regions in which there is effective competition but the 3PS would find there is not.

There has been some discussion by stakeholders of the design of a trigger for import congestion. While this can be discussed in the stakeholder process, we observe that such an import congestion trigger in the IFM and HASP could be applied based on binding scheduling limits. In the FMM and RTD, mitigation could be triggered by import congestion using the same mitigation reference bus design used to trigger LMPM. LMPM mitigation is currently triggered based on congestion components calculated relative to two internal reference buses. System market power mitigation could be triggered applying the same methodology to reference buses at each of the 3 major ties, with system market power triggered at any location having a positive congestion component relative to all three of the intertie reference buses. This test would account for loopflow congestion impacts as well as scheduling limits.

IV.D Time Frame for Mitigation

A fourth core choice will be whether the CAISO should attempt to test for and mitigate system market power in both the IFM and real-time, or just in real-time. Ideally, it would be preferable to apply system market power mitigation in all the CAISO's interrelated spot markets, including the IFM, short-term unit commitment (STUC), real-time pre-dispatch (RTPD), FMM, and RTD. There would, however, be some complex issues to resolve in applying system market power mitigation in the IFM and STUC.

One such issue, as observed above, is the inability of the pivotal supplier test to account for the cost-effectiveness of virtual and import supply in tests for pivotality. This issue could be addressed by only including cleared imports and cleared virtual supply in the supply used in the test. However, this approach could exclude so much supply from the pivotality calculation, regardless of its ability to contest in the market, that the pivotal supplier test result would have little relationship to the actual level of competition.

We agree that the application of system market power mitigation in real-time (STUC, RTPD, FMM and RTD) would somewhat constrain but not completely preclude the exercise of system market power in the IFM through the impact of real-time mitigation on price-capped load bids and virtual supply offers in the IFM. Some theoretical reasons for this conclusion are provided in Appendix B of this opinion. While as noted above, the exercise of system market power would be most effectively constrained by the application of mitigation in the IFM and STUC as well as in the FMM and RTD, we understand that the CAISO could implement system market power sooner, and with less diversion of resources from other needs, if it were limited to real-time. Since it is not clear that there is a potential for the exercise of system market power, there are advantages to a design that can be implemented quickly and without delaying many other projects. Additional resources could be devoted to system market power mitigation design and implementation if there is evidence of need for a more complete and complex design.

It is not clear from the CAISO and DMM analyses reported to date that there is any supplier or group of suppliers that possess substantial system market power in the IFM. However, if some suppliers did possess such market power, and mitigation were only applied in real-time, then it would be important to test for system market power and apply mitigation in real-time commitment processes such as STUC and RTPD, as well is in the FMM and RTD. Not only would the application of a pivotal supplier test in STUC need to account for the possibility that import supply might be offered at very high prices,[18] both commitment decisions and the application of any kind of system market power test in STUC would need to take account of the fact that real-time import supply offers would not be binding until the HASP time frame. Hence real-time import supply could be offered in STUC, and then not offered in HASP, at which point it might be too late to commit some units to make up for the lost supply. This consideration might require that only import and export supply offers that cleared in the IFM be included in the application of STUC market power mitigation tests.

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[18] We noted in Section IV.A that if mitigation were based on the 3PS test, that test's inability to accurately account for the cost of fringe supply would likely require including only cleared import supply in applying a test in STUC or HASP

In addition to questions relating to the effectiveness of real-time mitigation in constraining prices in the IFM, there are additional issues to consider regarding the lack of financial schedules for resources that did not clear in the IFM but received residual unit commitment (RUC) schedules. One such question is: would the real-time offers of resources committed in RUC be mitigated based on day-ahead gas market prices or real-time gas market prices?

IV.E Other Issues

- *Scope of Mitigation*

Under the current implementation of LMPM, when mitigation is triggered by the failure of a 3PS test the resulting mitigation of offer prices is applied to *all* supply resources, not just those who are considered pivotal under the test. If the same approach is applied at the system level, this means that all internal units in California could have their offer prices potentially adjusted when systemwide market power mitigation is triggered. Given the increasing difficulty in developing default energy bids, particularly for non-gas fired resources, this feature of the current system is growing more problematic even in the current LMPM framework. Alternative approaches could consider only mitigating pivotal suppliers or to develop a "safe-harbor" criterion that would exempt suppliers of a given size from mitigation.

- *Ex post market power and ramp assumptions*

Another important design choice relating to system market power mitigation is how the amount of supply that could be withheld by potentially pivotal suppliers would be calculated in HASP, FMM and RTD, after the day-ahead commitment decisions have already been made. This is sometimes termed "ex post" market power. The current pivotality test does not assume that the potentially pivotal suppliers could withhold their entire output from the real-time market. Instead the test is based on the amount by which the potentially pivotal suppliers could ramp their output down in FMM or RTD if their offer did not clear and they were dispatched down. A particular concern with the current methodology is that the application of this assumption to price-taking intermittent resource output located outside constrained regions with high downward ramp rates could result in high frequency of 3PS failures that would be unrelated to the potential for the exercise of market power. This would be particularly important if the large load serving entities ceased to be net buyers and the 3PS were applied to their gross supply. The potential for such spurious triggering of mitigation should be greatly reduced if supply offered at low prices were excluded from the pivotality calculation.

- *Mitigation and Efficiency of RUC Commitment*

A further design choice concerns mitigation in the RUC process. If system market power mitigation were to be applied only in real-time, would any mitigation be applied to the commitment cost offers of resources committed in RUC?

At present, commitment cost offers in the IFM, RUC, and real-time would be capped at 125% of the default energy bids. This rule would limit the potential for suppliers possessing system market power to exercise that market power through inflated start-up and minimum load offers for long start resources that would need to be committed in RUC in order to be available to operate in real-time. This issue would need to be considered further when the cap on commitment cost offers is raised.

The current RUC objective function minimizes commitment costs rather than the cost of meeting load. This is appropriate in the current design as the RUC process is intended to support reliability, not supplant decisions to procure power by load serving entities. However, the RUC objective function would reduce the efficiency of the unit commitment if suppliers controlling long start resources were to attempt to exercise system market power by raising offer prices in the IFM, as the RUC objective function would not result in the least cost commitment. If, following the implementation of a real-time mitigation design for system market power, there appears to be issues with actual attempts to exercise system market power and a need for a more efficient RUC commitment, this could be addressed either by extending system market power mitigation to the IFM or changes to the RUC design. On the other hand, if there is no evidence of the existence or any effort to exercise system market power, the development of a more complex framework could be deferred.

Finally, the application of system market power mitigation within RUC, or a potential successor, would need to be considered further in the context of potential future day-ahead market design choices in which suppliers would bid into RUC, and the CAISO would subsequently clear RUC offers against the CAISO load forecast.

- *Mitigation Threshold*

Another issue is whether mitigation should be based on the 10% margin over estimated incremental costs that is currently used in calculating default energy bids for local market power mitigation. Alternatively, should a larger margin be applied in mitigating the potential exercise of system market power? Reasons for doing this would include the likelihood that the regions within the CAISO balancing area but outside the regions in which local market power mitigation is typically triggered may include more resources with difficult to estimate opportunity costs or gas supply costs that are not accurately represented by the indexes used to calculate default energy bids. Stakeholders have noted that higher thresholds for triggering offer price mitigation would be less likely to routinely mitigate the offers of energy and use limited resources or trigger mitigation for mis-measured gas costs, while still preventing material exercises of market power when conditions allowing the exercise of market power may sporadically exist.

- *Load Conformance Limiter*

The current operation of the load conformance limiter serves to set prices based on the highest offer price, rather than the power balance violation penalty when the power balance violation is due in part to load conformance adjustments.

This pay-as-bid element of real-time pricing tends to incent this submission of high offer prices for the last megawatt of supply. While normally such high offer prices would be associated with attempted exercise of market power, in these cases it could be argued that high offer prices reflect actual scarcity value that is suppressed by the load-conference limiter, The 3PS test would necessarily be failed and mitigation triggered for any interval in which the power balance violation was projected in the advisory dispatch. Consequently, the operation of the load conformance limiter might have a more material impact on real-time prices following implementation of real-time system market power mitigation, particularly if high-priced demand response offers were also removed from the bid stack. Continued reform and reduced application of the load conformance limiter would help obviate this concern.

Appendix A
System Market Power Analysis[19]

Whether the exercise of system market power has contributed to high prices in some hours over the past few years is an important empirical question, as is what factors may have enabled the exercise of system market power. The Market Surveillance Committee has limited resources to investigate these questions, so we have focused on a review of IFM outcomes for two sets of hours during 2018.

- The first are the 13 hours in which one or more of the SCE, SDG&E or PG&E LAP prices exceeded $500.[20]
- The second set includes the 20 hours during 2018 in which the California ISO Department of Market Monitoring found a difference of $20 or more between (i) a simulated IFM clearing price calculated using the actual offer prices used to clear the IFM and (ii) a simulated IFM clearing price calculated using the lower of the actual offer price or the default energy bid for each gas-fired resource that was committed in the actual IFM solution.

There is some overlap in these two sets of hours, so they cover a total of 29 hours over 10 days in 2018.

The review in this Appendix focuses on examining the following three issues in these hours:

- *Was local market power mitigation appropriately triggered by the existence of transmission congestion? (Section A.1)*
- *Was the level of import supply constrained by congestion on one or more of the major interties, or was it constrained by congestion internal to the CAISO, potentially contributing to an exercise of system market power? (Section A.2)*
- *Is there clear evidence that IFM market prices materially exceeded the competitive level in these hours, reflecting the exercise of system market power? (Section A.3)*

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[19] Most of the analyses reported in this appendix were discussed at the August 19, 2019 MSC meeting (S. Harvey, "System Market Power Discussion," www.caiso.com/Documents/SystemMarketPowerFTI-Presentation-Aug19_2019.pdf). Some gaps in the analysis presented at that meeting have been filled in and some issues have been clarified through subsequent discussions with the CAISO and the Department of Market Monitoring.

[20] Although we do not show LAP prices for the SDG&E or VEA LAPS in most of the tables in this Appendix, we have included hours 15-17 during July 25, 2018 in the analysis. The LAP prices exceeded $500/MWh, in these hours for the SDG&E and sometimes VEA LAPSs, but prices were less than $500/MWh in both the SCE and PG&E LAPS.

In addition, we discuss issues involved in mitigating resource adequacy (RA) import bids (Section A.4), and incentives to actually deliver them in real time.[21]

A.1 Performance of the CAISO Local Market Power Mitigation Design.

While local market power mitigation is not intended nor designed to prevent the exercise of system market power, it is intended to prevent the exercise of significant local market power. There was significant congestion within the CAISO during 12 of the high priced hours we examined and substantial congestion in six of those hours. Hence, in assessing whether market prices may have been materially impacted in these hours by the exercise of system market power, it is important to assess whether there are any indications that local market power mitigation was sometimes *not* triggered when it should have been, thereby contributing to high prices. Hence, the first question we address is whether local market power mitigation appears to have been appropriately triggered by the existence of transmission congestion.

The CAISO LMPM design developed in 2011 and implemented in stages over following years was intended to ensure that local market power mitigation would be triggered by transmission congestion without regard to where the transmission constraint and resource were located relative to the system reference bus. This intent, however, does not ensure that the software has performed as intended. The performance of the two reference buses used to trigger local market power mitigation was examined by the CAISO in 2011, with the conclusion that the two reference nodes were sufficient to trigger mitigation and determine an appropriate competitive LMP price.[22]

We believe it is appropriate to validate these conclusions as part of the current system market power evaluation by examining whether there was congestion relative to the interties or across the LAPS in any of the high priced hours in which local market power mitigation did *not* trigger. We have therefore:

- reviewed the pattern of congestion between the LAPs, and between the LAPs and the Palo Verde, Malin and NOB ties to identify hours with material congestion, and
- then examined whether local market power mitigation was appropriately triggered in the hours in which it was apparent from the LAP and intertie congestion components that there was material congestion within California.

The CAISO provided the MSC with data on whether local market power mitigation was triggered (and additional data on which constraints and whether the 3PS was passed or failed). Our conclusion is that local market power mitigation was triggered in all of the high price hours in

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[21] J. Bushnell, S. Harvey, and B.F. Hobbs, "Opinion on Reliability Must Run and Capacity Procurement Mechanism Enhancements", Market Surveillance Committee of the CAISO, March 20, 2019, www.caiso.com/Documents/MSC-Opiniononreliabilitymustrunandcapacityprocurementmechanismenhancements-Mar20_2019.pdf

[22] See L. Xu, "A Retrospective Analysis of Local Market Power Mitigation Enhancements," May 9, 2011, p.7, www.caiso.com/Documents/ARetrospectiveAnalysis-LocalMarketPowerMitigationEnhancements.pdf ; L. Xu, "Addendum," June 23, 2011, pp. 4-6, www.caiso.com/Documents/Addendum_RetrospectiveAnalysis_LocalMarketPowerMitigationEnhancements.pdf . The competitive LMP is the price at each resource location in the initial local market power run of the IFM, with the congestion component set to zero for any transmission constraint that failed the 3PS test.

which there was material transmission congestion and there were no apparent issues relating to the location of the reference bus.

Table 1 below shows that there was material congestion within the CAISO during 13 of the 29 high priced hours studied. In these hours, market power mitigation was triggered; then, if supply offers failed the 3PS test, offers in excess of the higher of the DEB or competitive LMP would have been subjected to offer price mitigation.[23] However, there was very little transmission congestion within the CAISO during many of the high price hours over the period July 23 to 28, with only generation pockets or very local transmission constraints binding in the LMPM pass, with the result that there was no congestion at the LAP level in the LMPM runs.

[23] It can be seen in Table 1 that there are some hours in which the LAP prices in the LMPM run are lower than the prices in the market run (e.g., July 23 hours 19 and 20, July 24, hour 21, July 25 hours 20 to 22, July 26 hours 19 and 20, July 27 hour 19, August 7 hour 19, and August 10 hour 20). We understand from discussions with the CAISO that this outcome sometime reflects issues with the resources modeled in the LMPM runs and sometimes reflects the enforcement of tighter transmission limits in the IFM run than in the LMPM run.

Table 1. IFM and LMPM Prices and Mitigation

	SCE DLAP		PGE DLAP		DMM Data				
`	LMP IFM	LMP LMPM	LMP IFM	LMP LMPM	LMPM Trigger	Price Difference	RSI	Monday?	Weekend?
Feb 21, 2018									
7	$ 189.99	$ 190.00	$ 94.26	$ 102.41	yes	25.46	1.12	no	no
19	$ 343.53	$ 345.35	$ 76.21	$ 90.48	yes	28.96	1.07	no	no
July 23, 2018									
17	$ 243.47	$ 262.81	$ 215.03	$ 200.70	yes	29.91	0.88	Yes	no
18	$ 282.87	$ 283.81	$ 265.15	$ 262.79	yes	66.9	0.94	yes	no
19	$ 348.23	$ 336.19	$ 329.12	$ 315.98	yes	29.93	0.83	Yes	no
20	$ 483.53	$ 418.82	$ 460.96	$ 397.22	yes	46.03	0.81	Yes	no
July 24, 2018									
17	$ 497.46	519.19	$ 413.72	399.32	yes	43.86	0.83	no	no
18	$ 629.01	629.01	$ 584.09	580.77	yes	27.05	0.81	no	no
19	$ 934.72	948.14	$ 885.62	893.44	yes	29.33	0.77	no	no
20	$ 999.98	999.98	$ 946.36	941.96	yes	0	0.77	no	no
21	$ 638.17	619.43	$ 597.79	578.06	yes	119.43	0.80	no	no
July 25, 2018					yes				
15	$ 252.42	$ 294.91	$ 142.18	$ 147.15	yes	1.18	0.85	no	no
16	$ 346.42	$ 424.69	$ 219.43	$ 247.75	yes	19.21	0.81	no	no
17	$ 458.74	$ 483.78	$ 325.23	$ 333.84	yes	7.5	0.80	no	no
18	$ 584.51	$ 551.00	$ 500.06	$ 478.90	yes	1.19	0.78	no	no
19	$ 773.80	$ 770.85	$ 737.28	$ 731.13	yes	0	0.76	no	no
20	$ 885.55	$ 858.06	$ 847.21	$ 817.27	yes	4.17	0.75	no	no
21	$ 465.38	$ 445.92	$ 444.74	$ 425.02	yes	49.89	0.78	no	no
22	$ 235.50	$ 233.06	$ 221.17	$ 218.06	yes	38.96	0.83	no	no
July 26, 2018									
17	$ 260.25	$ 260.62	$ 193.23	$ 193.24	ye	32.33	0.85	no	no
19	$ 342.06	$ 340.30	$ 325.96	$ 324.29	yes	97.49	0.82	no	no
20	$ 377.46	$ 367.22	$ 361.82	$ 352.01	yes	23.33	0.80	no	no
July 27, 2018									
18	$ 196.83	$ 196.83	$ 181.63	$ 181.63	yes	21.51	0.91	no	no
19	$ 233.12	$ 229.02	$ 219.86	$ 215.99	yes	20.71	0.89	no	no
July 28, 2018									
20	$ 154.44	$ 154.96	$ 149.13	$ 149.56	yes	20	0.91	no	yes
August 7, 2018									
19	$ 707.70	$ 574.24	$ 444.13	$ 449.63	yes	0	0.83	no	no
20	$ 698.12	$ 732.26	$ 485.41	$ 494.24	yes	0	0.81	no	no
August 8, 2018									
19	$ 365.82	$ 397.25	$ 325.57	$ 329.62	yes	31.23	0.84	no	no
August 10, 2018									
20	$ 270.59	$ 259.61	$ 221.00	$ 208.30	yes	32.11	0.93	no	no

CAISO data shows that local market power mitigation was triggered and the 3PS test failed on one or more constraints in all of the 13 hours in which there was transmission congestion across the CAISO, as indicated by differences in congestion components across the CAISO in the LMPM pass. In six of these hours the clearing prices for the SCE and SDGE LAPs were materially constrained up relative to prices for the PG&E LAP, so the competitive LMP should have been substantially lower than the mitigated clearing price in the SCE and/or SDGE LAPs. Hence, if the 3PS test was failed, the offers of gas fired resources located in the SCE and SDG&E LAPS should have been mitigated to their default energy bids or to competitive LMP prices that were materially lower than the LAP clearing price.

- When offer price mitigation is applied, prices within the constrained regions would have been set by mitigated offer prices, by price capped load bids, or by virtual demand or supply bids. While offer prices could be mitigated based on the competitive LMP, rather than the supplier's default energy bid, this would generally not have been the case if there was material congestion in the IFM, but might have been the case in the hours in which IFM prices were higher than those in the LMPM pass due to the factors mentioned in Footnote 25, above.
- However, in the remaining 16 hours there was no congestion within the CAISO (other than possibly out of generation pockets) in either the LMPM or IFM runs. Hence, no local market power mitigation would have been triggered or applied. Hence, while it is possible for local market power mitigation to be applied to mitigate offers down to the competitive LMP with the result that there is congestion in the LMPM run but not in the market run, this does not appear to have been the case in any of these 16 hours. However, the result of applying local market power mitigation in hour 17 on July 23 was only small amounts of transmission congestion in the IFM run. This congestion could have reflected minor differences between LMPM and IFM runs, with the prices within the constrained region set by offers capped at the competitive LMP calculated in the LMPM run.

It would provide a further check on the performance of the LMPM design to calculate the competitive LMP for each LAP based on the competitive LMP actually applied at each node, in the hours in which the competitive LMP should have been materially below the LAP clearing prices. This calculation would either confirm that the competitive LMPs used in the mitigation process were at least roughly consistent with expectations, or indicate that there is some kind of unintended outcome that needs to be examined. We have not carried out such an analysis.

A.2 Effectiveness of Import Competition

A second question concerns the effectiveness of import competition in constraining the exercise of system market power in the 29 high price hours we have reviewed in some detail.

Occurrence of Internal CAISO Congestion During High Price Hours. It is clear from this review that import supply was not fully effective in constraining the exercise of market power in the SCE and or/or SDG&E LAPs during 13 of these hours because of congestion within the CAISO, as discussed above. However, we also found that local market power mitigation was triggered in these hours. Moreover, import competition was likely completely ineffective in constraining the level of prices within the SCE and SDG&E LAPs during 6 of these hours in which price differences across the CAISO exceeded $100 per MWh (although as noted above local market power mitigation was triggered in all of these hours). However, constraints on import supply only appear to have limited the ability of import supply to constrain prices in the PG&E

LAP during four of these 13 congested hours; hours 19 and 20 on August 7, hour 19 on August 8, and hour 20 on August 10 when there was congestion on import supply at NOB.[24]

Table 2 below shows that in the remaining 16 hours,[25] there was no congestion within the CAISO to limit the competition provided by import supply. Moreover, congestion on the interties only limited import competition in five of these hours,[26] and in these five hours, transmission congestion only limited supply from Malin in four hours and from NOB in 1 hour.

Table 2. IFM Import Congestion Patterns

	SCE DLAP			PGE DLAP			Malin	Malin	Malin	NOB	NOB	NOB	PV	PV	PV
Hour	LMP	Loss	Congestion	LMP	Loss	Congestion	LMP	Congestion	Tie Import	LMP	Cong	Tie Import	LMP	Cong	Tie Import
	IFM	Comp	Component	IFM	Comp	Component	IFM	Component	Congestion	IFM		Congestion	IFM		Congestion
Feb 21, 2018															
7	$ 189.99	$ -	$ 37.55	$ 94.26	$ -	$ (58.17)	95	-57.43	no	91.31	-61.11	no	114.14	-38.29	no
19	$ 343.53	$ -	$ 104.23	$ 76.21	$ -	$ (163.09)	78.03	-161.26	no	68.2	-171.1	no	127.2	-112.1	no
July 23, 2018															
17	$ 243.47	6.49	$ 5.05	$ 215.03	-11.06	$ (5.83)	198.99	-5.66	no	225.89	-0.35	no	217.34	-4.12	no
18	$ 282.87	6.47	$ -	$ 265.15	-11.25	$ -	245.89	0	no	270.93	0	no	266.87	0	no
19	$ 348.23	7.03	$ -	$ 329.12	-12.08	$ -	304.25	0	no	335.57	0	no	332.57	0	no
20	$ 483.53	8.46	$ -	$ 460.96	-14.11	$ -	426.28	0	no	468.09	0	no	464.76	0	no
July 24, 2018															
17	$ 497.46	$ 15.81	$ 15.42	$ 413.72	$ (27.65)	$ (24.87)	$ 393.45	$ (23.88)	no	$ 420.78	$ (39.72)	no	$ 439.41	$ (9.95)	no
18	$ 629.01	$ 16.24	$ -	$ 584.09	$ (28.68)	$ -	$ 554.31	$ -	no	$ 567.79	$ (33.89)	no	$ 590.71	$ -	no
19	$ 934.72	$ 18.60	$ -	$ 885.62	$ (30.51)	$ -	$ 839.17	$ -	no	$ 903.21	$ -	no	887.1745	0	no
20	$ 999.98	$ 21.43	$ -	$ 946.36	$ (32.19)	$ -	$ 893.02	$ -	no	$ 966.71	$ -	no	949.1933	0	no
21	$ 638.17	$ 16.05	$ -	$ 597.79	$ (24.32)	$ -	$ 500.00	$ (63.52)	yes	$ 614.65	$ -	no	602.4604	0	no
July 25, 2018															
15	$ 252.42	$ 3.87	$ 36.01	$ 142.18	$ (8.20)	$ (62.16)	$ 140.73	$ (52.33)	no	$ 250.00	$ 41.13	no	238.94	33.99	no
16	$ 346.42	$ 7.44	$ 39.08	$ 219.43	$ (14.10)	$ (66.38)	$ 205.28	$ (62.72)	no	$ 254.19	$ (41.40)	no	270.71	-18.76	no
17	$ 458.74	$ 8.42	$ 41.71	$ 325.23	$ (16.39)	$ (66.99)	$ 303.00	$ (64.46)	no	$ 341.15	$ (59.41)	no	392.92	0	no
18	$ 584.51	$ 11.84	$ 19.52	$ 500.06	$ (22.35)	$ (30.75)	$ 467.52	$ (30.16)	no	$ 515.28	$ (27.21)	no	534.57	0	no
19	$ 773.80	$ 12.93	$ -	$ 737.28	$ (23.59)	$ -	$ 690.64	$ -	no	$ 749.00	$ -	no	738.73	0	no
20	$ 885.55	$ 14.12	$ -	$ 847.21	$ (24.23)	$ -	$ 303.00	$ (486.52)	YES	$ 858.54	$ -	no	848.69	0	no
21	$ 465.38	$ 7.60	$ -	$ 444.74	$ (13.05)	$ -	$ 300.00	$ (114.11)	Yes	$ 450.00	$ -	No	$ 444.78	$ -	No
22	$ 235.50	$ 5.45	$ -	$ 221.17	$ (8.88)	$ -	$ 206.49	$ -	No	$ 277.13	$ -	No	$ 274.05	$ -	No
July 26, 2018															
17	$ 260.25	$ 6.16	$ 20.00	$ 193.23	$ (10.25)	$ (30.61)	$ 180.00	$ (29.37)	NO	$ 204.71	25.36	NO	224	0	NO
19	$ 342.06	$ 6.02	$ -	$ 325.96	$ (10.80)	$ -	$ 303.75	$ -	NO	$ 330.50	$ -	NO	$ 324.99	$ -	NO
20	$ 377.46	$ 6.09	$ -	$ 361.82	$ (9.54)	$ -	$ 250.00	$ (86.68)	YES	$ 365.42	$ -	NO	$ 359.74	$ -	NO
July 27, 2018															
18	$ 197.16	$ 6.18	$ -	$ 180.96	$ (10.09)	$ -	$ 168.58	$ -	NO	$ 174.94	$ (13.20)	NO	$ 181.03	$ -	NO
19	$ 233.54	$ 5.70	$ -	$ 218.97	$ (8.86)	$ -	$ 202.59	$ -	NO	$ 225.19	$ -	NO	$ 217.94	$ -	NO
July 28, 2018															
20	$ 154.44	$ 2.31	$ -	$ 149.13	$ (3.00)	$ -	$ 138.01	$ -	NO	$ 150.00	$ -	NO	$ 147.14	$ -	NO
August 7, 2018															
19	$ 707.70	$ 4.18	$ 97.43	$ 444.13	$ (7.21)	(154.74)	$ 437.99	$ (133.25)	No	$ 527.92	$ (64.17)	YES	$ 666.44	$ 81.38	NO
20	$ 698.12	$ 5.15	$ 79.61	$ 485.41	$ (7.85)	(120.10)	$ 475.05	$ (101.45)	NO	$ 494.36	$ (106.36)	YES	$ 662.04	$ 67.33	NO
August 8, 2018															
19	$ 365.82	$ 5.85	$ 9.77	$ 325.57	$ (9.98)	$ (14.64)	$ 313.25	$ (12.32)	NO	$ 294.88	$ (49.18)	YES	$ 344.95	$ 8.27	No
August 10, 2018															
20	$ 270.59	$ 4.63	$ 15.95	$ 221.00	$ (7.65)	$ (21.37)	208.36	-17.81	NO	75	-169.32	YES	251.44	13.57	NO

[24] Because the SCE LAP was slightly constrained up relative to PG&E during hour 20 on August 10, increased supply from NOB would have only indirectly constrained prices in PG&E to the extent it eliminated congestion in SCE.

[25] Hours 18-20 on July 23, hours 18-21 on July 24, hours 19-22 on July 25, hours 19 and 20 on July 26, hours 19 and 20 on July 27, and hour 20 on July 28.

[26] Hours 18 and 21 on July 24, hours 20 and 21 on July 25, and hour 20 on July 26.

Hence, we found that there was no pattern of the CAISO as a whole being consistently insulated from competition from import supply on the major ties during hours with high prices. However, the availability of import supply from the rest of the WECC was limited by congestion on one or more of the major ties during some of the hours with high prices that we reviewed. While congestion appears to have limited import supply to California as a whole on one of the major ties during a few of these high priced hours, imports were not constrained by congestion on more than one major tie during any of the high priced hours we reviewed.

Another impact of import competition on CAISO prices during these 29 high priced hours was the extent to which the CAISO was exporting power on one or more interties during these hours. The CAISO data reported in Table 3 shows that the CAISO was a net importer on all three of the major ties during all 29 of the high priced hours studied, although net imports fell to quite low levels during hours 17-19 on July 24.

Table 3. IFM Import Congestion and Flow Patterns

Hour	SCE DLAP LMP IFM	PGE DLAP LMP IFM	Malin LMP IFM	Malin Net Flow	Malin Import Congestion	NOB LMP IFM	NOB net Flow	NOB Import Congestion	PV LMP IFM	PV Net Flow	PV Import Congestion
Feb 21, 2018											
7	$ 189.99	$ 94.26	95	2112	NO	91.31	718	NO	114.14	1758	NO
19	$ 343.53	$ 76.21	78.03	2180	NO	68.20	634	NO	127.20	2287	NO
	July 23, 2018										
17	$ 243.47	$ 215.03	$198.99	1,984	NO	225.89	754	NO	217.34	773	NO
18	$ 282.87	$ 265.15	$245.89	2,238	NO	270.93	764	NO	266.87	763	NO
19	$ 348.23	$ 329.12	$304.25	2,429	NO	335.57	1,194	NO	332.57	887	NO
20	$ 483.53	$ 460.96	$426.28	2,617	NO	468.09	1,203	NO	464.76	1,037	NO
	July 24, 2018										
17	$ 497.46	$ 413.72	$393.45	2,109	NO	420.78	1,351	NO	439.41	272	NO
18	$ 629.01	$ 584.09	$554.31	2,410	NO	567.79	1,354	NO	590.71	311	NO
19	$ 934.72	$ 885.62	$839.17	2,408	NO	903.21	1,367	NO	887.17	405	NO
20	$ 999.98	$ 946.36	$893.02	2,692	NO	966.71	1,389	NO	949.19	730	NO
21	$ 638.17	$ 597.79	$500.00	2830	YES	614.65	1,430	NO	602.46	1,152	NO
	July 25, 2018										
15	$ 252.42	$ 142.18	$140.73	2,159	NO	250.00	1,072	NO	238.94	634	NO
16	$ 346.42	$ 219.43	$205.28	2,436	NO	254.19	1,166	NO	270.71	632	NO
17	$ 458.74	$ 325.23	$303.00	2,512	NO	341.15	1,229	NO	392.92	683	NO
18	$ 584.51	$ 500.06	$467.52	2,522	NO	515.28	1,463	NO	534.57	699	NO
19	$ 773.80	$ 737.28	$690.64	2,570	NO	749.00	1,474	NO	738.73	941	NO
20	$ 885.55	$ 847.21	$303.00	2,830	YES	858.54	1,540	NO	848.69	1,191	NO
21	$ 465.38	$ 444.74	$300.00	2,830	YES	450.00	1,470	NO	444.78	1,483	NO
22	$ 235.50	$ 221.17	$206.49	2,810	NO	277.13	1,396	NO	274.05	1,435	NO
	July 26, 2018										
17	$ 260.25	$ 193.23	$180.00	1,959	NO	204.71	1,202	NO	224.00	1,217	NO
19	$ 342.06	$ 325.96	$303.75	2,740	NO	330.50	1,474	NO	324.99	1,335	NO
20	$ 377.46	$ 361.82	$250.00	2,830	YES	365.42	1,478	NO	359.74	1,677	NO
	July 27, 2018										
18	$ 196.83	$ 181.63	$168.58	2,590	NO	174.94	1,330	NO	181.03	1,687	NO
19	$ 233.12	$ 219.86	$202.59	2,797	NO	225.19	1,425	NO	217.94	1,863	NO
	July 28, 2018										
20	$ 154.44	$ 149.13	$138.01	2,608	NO	150.00	1,263	NO	147.14	1,936	NO
	August 7, 2018										
19	$ 707.70	$ 444.13	$437.99	620	NO	527.92	1622	YES	666.44	1,393	NO
20	$ 698.12	$ 485.41	$475.05	755	NO	494.36	1622	YES	662.04	1,592	NO
	August 8, 2018										
19	$ 365.82	$ 325.57	$313.25	924	NO	294.88	1622	YES	344.95	2,195	No
	August 10, 2018										
20	$ 270.59	$ 221.00	$208.36	2687	NO	75.00	1622	YES	251.44	3,033	NO

Relationship of High CAISO Prices to WECC-wide Prices. Another test of the effectiveness of import competition is the extent to which CAISO day-ahead market prices are consistent with prices in the WECC more generally. While the CAISO coordinates the only transparent spot energy market in the west, there is bilateral trading of on- and off-peak power at several trading hubs. While there is limited trading of hourly products at these trading hubs, the cost of power over the 16-hour on-peak blocks that are commonly traded in a day-ahead time frame similar to the IFM and reported in the trade press can be compared to the cost of power in the CAISO IFM over the same hours.

The CAISO has assisted the MSC in compiling the comparison of prices at bilateral trading hubs and the CAISO over the days with hours among the 29 high price hours listed in Table 2. Table 4 compares average 16-hour on-peak block prices at the CAISO Load Aggregation Points and interties with the prices for 16-hour on-peak blocks in bilateral trades at three western trading hubs on these days.

Table 4 shows that day-ahead prices at the external trading hubs were generally in line with or above IFM prices at the corresponding CAISO interties, Malin and Palo Verde.[27] Because gas-fired generation would generally be on the margin during a number of the hours included in the 16-hour block, we expect that CAISO IFM prices would be somewhat higher (other things being equal) than the prices at the external trading hubs, reflecting GHG emission costs, as well as some transmission charges.

The bilateral prices provide a benchmark for the price level outside the CAISO and the degree to which CAISO prices are in line with prices in the WECC more generally. The prices of 16-hour block power provide an imperfect measure of supply available during a particular hour, as external suppliers have an imperfect ability to arbitrage hourly CAISO prices and 16-hour block bilateral prices. This is because traders cannot buy power for individual hours at the 16-hour block price and they cannot offer a price based 16-hour block transaction in the CAISO day-ahead market. Nevertheless, the 16-hour bilateral block prices provide a measure of the consistency of CAISO prices with market conditions in the rest of the WECC and hence insight into whether import competition generally constrains prices within the CAISO.

Table 4. CAISO and Bilateral On-Peak (16-Hour) Prices

	Average	Number	LAP Prices			CAISO Intertie Prices			Platts MW Daily		
	Markup	RSI Fail	PG&E	SCE	SDGE	Malin	NOB	Palo Verde	MID C	Palo Verde	COB
21-Feb	4.62	0	48.77	151.78	201.43	47.91	44.83	66.05	38.11	49	48.33
23-Jul	11.94	9	135.09	168.57	176.79	126.31	160.37	155.40	196.23	261.50	222.50
24-Jul	14.32	10	278.65	392.97	396.95	264.85	355.01	357.93	219.37	348.75	294.50
25-Jul	8.12	10	243.06	315.98	379.96	191.75	292.53	291.17	216.54	260.00	251.00
26-Jul	12.22	9	140.99	176.48	188.07	127.50	161.94	161.13	195.57	225.25	228.00
27-Jul	3.90	7	108.65	131.87	143.82	90.21	118.71	117.82	87.24	99.25	95.00
28-Jul	3.09	3	66.56	72.78	74.76	61.97	70.63	67.70	87.24	99.25	95.00
7-Aug	0.37	5	139.33	291.90	292.39	142.58	254.86	266.70	300.00	377.50	310.22
8-Aug	4.19	5	112.64	173.47	176.81	111.45	146.41	156.76	147.66	175.00	148.50
10-Aug	4.16	0	94.79	135.77	149.78	84.53	77.60	61.22	53.41	94.66	65.00

[27] Mid C spot prices are also reported in Table 4. Mid C prices tend to be somewhat lower than COB prices in these hours, likely reflecting the cost of transmission from Mid C to COB when the CAISO is importing and may at times /be lower due to transmission congestion out of Mid C.

Some examples of disparities between the bilateral and CAISO prices are now discussed. The Palo Verde bilateral price averaged about $17/MWh below the prices at the CAISO Palo Verde tie in the IFM for February 21, 2018, yet there was no congestion at Palo Verde in the IFM; furthermore, Table 3 above shows that the flows were far below the limit during the hours with high prices, which were hours 7 and 19. On July 25, 2018, the CAISO prices at the Palo Verde tie averaged about $40/MWh higher in the IFM than the price in the bilateral market despite no congestion at the Palo Verde tie. While there were substantial flows on the ties in the IFM for hours 15-22, the flows were less than half the limit. Finally, on August 10, CAISO prices at Malin in the IFM averaged about $19/MWh above the bilateral price at COB. While there was congestion into the CAISO at NOB and Palo Verde during some hours in the IFM for August 10, there was no congestion at the Malin tie.

Conversely, the COB bilateral price averaged substantially less than the CAISO Malin prices in the IFM for a number of these days, around $100/MWh or more lower on July 23 and 26 and August 7, and about $60/MWh lower on July 25. It is not apparent why CAISO prices would be so much lower than bilateral prices in the Pacific Northwest on these days. While some of the power flowing into California on these days was likely self-scheduled by California utilities to meet RPS targets, it is surprising that the much lower CAISO IFM prices did not incent the scheduling of greater exports that would have increased prices in the CAISO day-ahead market, and lowered those in the bilateral external, markets on these days.

The bilateral price at Palo Verde similarly averaged more than $100/MWh lower than the CAISO Palo Verde price in the IFM for July 23 and August 7, while averaging more than $60/MWh lower than IFM prices on July 26. It is again not apparent why the CAISO IFM prices would have been so low relative to the Palo Verde price on these days without incenting the scheduling of exports.

The CAISO Department of Market Monitoring very recently released an analysis of the high priced hours on September 25, 2019. The CAISO Department of Market Monitoring found that the bilateral prices at the COB and Palo Verde trading hubs were materially higher than CAISO LAP prices in the IFM. It is noteworthy that we understand from the CAISO that the three major CAISO ties were all import constrained during hours 19 and 20 (the high priced hours in which DMM found that supply failed the pivotal supplier test).[28] The existence of import constraints implies that prices should be higher inside the CAISO than in other EIM markets. It is the potential for the exercise of system market power within the CAISO when such import congestion exists that the CAISO's proposed system market power mitigation design would address.

A related question regarding import supply is why the additional import supply that is available for sale in CAISO markets in real-time is not offered in the IFM. The CAISO's analysis of supply on a peak day in 2018 shows that more import supply was available in real-time (and at low-

[28] See California ISO, Department of Market Monitoring, "Report on Day-Ahead Market Competitiveness: For September 25, 2019, October 30, 2019", www.caiso.com/Documents/Reportonday-aheadmarketcompetitivenessforSeptember252019-Oct302019.pdf , pp. 2-4, 6.

er prices) than was offered in the IFM.[29] This raises the question of why this import supply was not offered in the IFM. One conjecture is that this import supply comes from EIM participants that could not offer this supply in the IFM and as this would have required that they include the exports to the CAISO in their base schedules, while they may have needed to hold this capacity back to meet the EIM resource sufficiency test. Alternatively, it is possible that some of the real-time import supply came from suppliers outside the EIM that wait until real-time to determine whether supply is excess to their load serving needs and then offer the excess in the real-time market. It is likely that some of virtual supply offered in the IFM reflects this expected real-time import supply but it is impossible to know for sure exactly what expectations for real-time physical supply or other factors underlie virtual supply offers.

A final consideration relating to the effectiveness of import competition is that the IFM offer structure for import supply is based on independent offers for each hour. Import supply does not have the ability to submit offers in the IFM reflecting the start-up, minimum load cost and minimum run time for thermal resources such as combined cycles. This design element of the IFM may reduce the elasticity of import supply on days in which the CAISO depends on high levels of import supply. Hence, the future effectiveness of import competition might be increased, and the cost of meeting CAISO load might be reduced by modifying the treatment of supply bids at the interties to allow the submission of resource level 3-part supply bids, at least for physical resources used to meet California RA requirements. On the other hand, this kind of functionality might become largely redundant with the anticipated expansion of the CAISO IFM to cover the Western EIM footprint, but there may continue to be resources used for California resource adequacy that are outside the footprint of the Western EIM.

A.3 Evidence of the Exercise of Material System Market Power

The final question addressed in this Appendix is whether there is evidence of a material exercise of system market power in CAISO markets in recent years.

Three Pivotal Supplier Test. Some market participants, and some statements by the California ISO, have suggested that a failure of supply offers to pass a 3PS test at the CAISO level indicates the existence of system market power. This is not the case. The 3PS test is by design a conservative test that can be failed when no supplier possesses market power. The Market Surveillance Committee pointed this out in our 2013 report to FERC on the pivotal supplier test.[30] We further observed that this conservative design is necessitated by some of the inherent weaknesses of pivotal supplier tests that can cause them to understate the potential for the exercise of market power.

We concluded that the conservatism implicit in using a 3PS test rather than a one or two pivotal supplier test is appropriate in order to compensate for the possibility of competition being less than indicated by the 3PS test as a result of factors such as generation pockets and high cost supply offers that are not accounted for in a pivotal supplier test. This conservatism has the conse-

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[29] See J. Wang and G. Bautista Alderete, "System Market Power Discussion," California ISO, Presented at the April 5, 2019 Market Surveillance Committee Meeting, pp.17-18, www.caiso.com/Documents/SystemMarketPower-Presentation-Apr5_2019.pdf

[30] See pp. 3, 16-17 in J. Bushnell et al., cited in Note 6, supra.

quence that the 3PS test may be failed when the market is highly competitive and there are no material generation pockets or large amounts of supply offered at high prices that would cause the test to overstate the competition provide by fringe suppliers.

In addition, the failure to pass a three pivotal supplier test for system market power mitigation in forward markets such as the IFM can be in part a result of the bidding strategies of load serving entities with respect to intermittent resource output and how virtual bids are accounted for in the pivotal supplier calculation.[31] Finally, a pivotal supplier test can at most show the potential for the exercise of market power, it cannot be used to assess whether market power has been exercised.

DMM Clearing Price Analysis. The primary evidence bearing on the question of whether there has been a material exercise of system market power in recent years is analysis undertaken by the CAISO Department of Market Monitoring. This analysis assesses the market impact in the IFM of offers in excess of the default energy bid that might reflect the exercise of market power.

In most prior years the DMM has utilized a version of the IFM market engine to carry out these counterfactual simulations. However, we understand that the Department has been unable to re-run the IFM market engine to replicate day-ahead market outcomes using default energy bids for the last two years.

As explained in the 2018 Report on Market Issues & Performance, the DMM has, as a substitute, carried out two simulated dispatches to meet IFM load bids using the bid stack of IFM supply, but not using the IFM market engine. One dispatch uses the same offer prices that were used to clear the IFM, and the second dispatch uses the lower of the IFM offer prices or the default energy bids of gas-fired generation.[32] An important design element of the DMM analysis is that it compares simulated prices to simulated prices. This is a good structure which reduces the potential for spurious conclusions that would be likely if simulated prices were compared to actual market prices, because actual market prices are likely to differ from simulated prices for many reasons unrelated to the level of offer prices.

Our original understanding was that the base case IFM simulations reported by DMM in Section 7.3.1 of the 2018 Annual Report on Market Issues & Performance were based on unmitigated bids. That is, the offers used in that analysis did not reflect the extent to which offer prices were reduced by the application of local market power. However, following the discussion of the DMM analysis at the August 19, 2019 Market Surveillance Committee meeting, the Department reviewed their methodology and informed the MSC that the base case price calculation was in fact based on IFM offer prices as mitigated by the application of LMPM. We agree with DMM that this is the appropriate methodology for this comparison.

The DMM's simulated dispatch does not directly take account of commitment costs or ancillary service requirements. However, our understanding is that the DMM has accounted for these fac-

[31] It is also possible for the bidding strategies of load serving entities relating to their load and intermittent resource output to cause spurious failures of the 3PS test as discussed below.

[32] See California ISO, Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance, pp. 154-157.

tors by limiting the bid stack used in the simulations to the resources that were committed in that hour of IFM and by excluding capacity segments from the bid stack that were scheduled to provide ancillary services in the IFM.

We observed above that the DMM calculations compare simulated outcomes to simulated outcomes, which by itself reduces the likelihood of finding spurious differences in price levels that are attributable to differences in commitment or ancillary service schedules rather than to the exercise of market power. In addition, however, we think the DMM methodology for accounting for commitment costs and ancillary service requirements in the dispatch simulations is a reasonable approach, given the inability to rerun the actual IFM. The approach applied by the DMM reduces the potential for spurious conclusions that could arise if the resources available to be dispatched to meet load in the simulations differed materially from the resources actually available to meet load in the IFM.

Nonetheless, this methodology for accounting for commitment costs and reserve schedules could understate the impact of the exercise of system market power if the market power were exercised in part through inflated commitment costs. Further, the inability to re-optimize reserve schedules based on default energy bids could raise the clearing prices that DMM calculated using the lower of the unmitigated offer price or the default energy bid. However, we do not believe there is an obviously better approach the DMM could have taken to accounting for commitment costs and reserve schedules without rerunning the actual IFM model.

Another simplification of DMM's calculations was the omission of transmission congestion. The inability to account for congestion in these calculations might either increase or decrease the difference in the calculated clearing prices. The relationship between the simulated prices and actual prices is therefore closest for the hours in which there was little or no transmission congestion, either internal to the CAISO or on particular interties. There were 11 such hours included in Table 5, but the gas price used to calculate the default energy bids was likely materially inaccurate for four of these hours.[33]

Results of the DMM Analysis. The findings from the DMM analysis were reported in the California ISO's Department of Market Monitoring's 2018 Annual Report on Market Issues & Performance and in presentations at previous MSC meetings.[34] The DMM analysis shows that clearing prices simulated using the lower of actual IFM offers or the default energy bid would have been $20 per megawatt hour lower than the prices simulated using actual offers in 20 hours over 2018, with most of these hours falling over a few days in July 2018.

In addition, the California ISO Department of Market Monitoring made available to the MSC the hour-by-hour simulated clearing prices, as well as historical gas prices and LAP prices. We reviewed this data, particularly the 20 hours in 2018 in which the clearing price calculated using

[33]As discussed below, July 23 was a Monday and July 28 was a Saturday, days on which the gas price used to calculate the default energy bid was a three-day strip price rather than the cost of gas purchased to meet load on Monday or Saturday.

[34] A. Blanke, California ISO, Department of Market Monitoring, "Analysis of System Level Market Power," Presentation, Market Surveillance Committee Meeting, June 7, 2019, www.caiso.com/Documents/Presentation-AnalysisOfSystemLevelMarketPowerDMM-June7_2019.pdf .

the unmitigated offer prices exceeded the clearing price calculated using the lower of the unmitigated offers or the mitigated offer by $20 or more. We observed that there are many hours that despite low residual supply index values exhibited low or zero differences in the calculated clearing prices.

The California ISO Department of Market Monitoring has given us permission to present the data in the below table pertaining to the 20 hours with the largest price differences between the calculated clearing prices as shown in Table 5.

Table 5. High Markup Hours 2018

Year	Date	Hour	Base-case Price	Gas @ Min. (DEB,DA) Price	Markup	RSI_1	RSI_2	RSI_3	PG&E DLAP LMP IFM ($/MWh)	SCE DLAP LMP IFM ($/MWh)
2018	24Jul2018	21	$619.43	$500.00	$119.43	0.961	0.879	0.799	$597.79	$638.17
2018	26Jul2018	19	$324.99	$227.50	$97.49	0.973	0.896	0.819	$325.96	$342.06
2018	23Jul2018	18	$293.06	$226.16	$66.90	1.018	0.940	0.863	$265.15	$282.87
2018	25Jul2018	21	$450.00	$400.11	$49.89	0.938	0.858	0.780	$444.74	$465.38
2018	23Jul2018	20	$483.53	$437.50	$46.03	0.975	0.893	0.813	$460.96	$483.53
2018	24Jul2018	17	$478.17	$434.31	$43.86	0.974	0.900	0.827	$413.72	$497.46
2018	25Jul2018	22	$245.00	$206.04	$38.96	0.993	0.908	0.825	$221.17	$235.50
2018	26Jul2018	17	$213.18	$180.85	$32.33	1.003	0.928	0.853	$193.23	$260.25
2018	10Aug2018	20	$220.11	$188.00	$32.11	1.082	0.999	0.928	$221.00	$270.59
2018	08Aug2018	19	$346.11	$314.88	$31.23	0.992	0.910	0.844	$325.57	$365.82
2018	23Jul2018	19	$353.93	$324.00	$29.93	0.991	0.911	0.833	$329.12	$348.23
2018	23Jul2018	17	$230.16	$200.25	$29.91	1.034	0.956	0.878	$215.03	$243.47
2018	24Jul2018	19	$928.33	$899.00	$29.33	0.923	0.848	0.774	$885.62	$934.72
2018	21Feb2018	19	$171.00	$142.04	$28.96	1.197	1.122	1.074	$76.21	$343.53
2018	24Jul2018	18	$629.01	$601.96	$27.05	0.952	0.879	0.806	$584.09	$629.01
2018	21Feb2018	7	$169.94	$144.48	$25.46	1.267	1.183	1.122	$94.26	$189.99
2018	26Jul2018	20	$369.59	$346.26	$23.33	0.962	0.883	0.804	$361.82	$377.46
2018	27Jul2018	18	$179.50	$157.99	$21.51	1.068	0.990	0.911	$181.63	$196.83
2018	27Jul2018	19	$235.30	$214.59	$20.71	1.046	0.965	0.885	$219.86	$233.12
2018	28Jul2018	20	$145.00	$125.00	$20.00	1.073	0.982	0.906	$149.13	$154.44

We have five observations about these results:

1. Except for 2 hours on February 21, all of the hours shown in Table 5 had an RSI-3 value of less than 1, in fact less than 0.93. Second, except for these 2 hours on February 21, all of these hours had an RSI-1 of less than 1.1.[35] Regarding estimated mark-ups, there were only 20 hours over 2018 in which the difference in the two calculated clearing prices was $20 per MWh or more. Furthermore, the difference in clearing prices was very small in

[35] It should be kept in mind in reviewing these data that the DMM RSI calculations do not include any virtual supply, so they may somewhat understate the supply actually available in the IFM. However, although the CAISO RSI-3 calculations for these hours are sometimes 0.05 or more higher as a result of including net virtual supply offers, the RSI-3 index is still less than 1.0 in 17 of these 20 hours that had large differences in simulated clearing prices. The one difference is hour 20 on August 10, which apparently had a 3PS test in excess of 1.0 in the CAISO calculations, compared to 0.928 in the DMM calculations.

most of the hours in which the 3PS index was less than 1. The magnitude of differences were therefore frequently relatively small compared to possible errors in estimating gas prices.

2. The DMM methodology in which the smaller of the DEB-based offer and actual offer is used in the competitive simulation is likely to result in a systematic overstatement of the degree to which the two clearing prices differ as a result of the exercise of system market power. This is particularly the case on days in which gas system constraints created the potential for differences between the cost of gas in the morning trading period (the index used to calculate default energy bid) and its cost later in the day when day-ahead market schedules posted (the expected price which suppliers would incorporate in their offers if the market were competitive)

3. The 20 hours with the highest differences in clearing prices were all hours with high SOCAL citygate gas prices. There was only 1 hour among these 20 in which the SOCAL citygate gas price used to calculate the default energy bids was less than $13/MMBTU and it exceeded $8.50/MMBTU on that day (Saturday, July 28). Moreover, all of the days on which the gas price used to calculate default energy bid was less than around $15 were Mondays or weekend days in which the gas price used to calculate the default energy bid was a weekend strip price that likely understated the cost of buying gas to meet load on those days. Hence, these were all days on which the SOCAL Gas system was expected to be constrained, which would introduce uncertainty into the cost of buying gas for the real-time markets for gas fired generation supplied by the SOCAL Gas pipeline.

4. A market impact that has not been assessed on these high priced days is the price impact of physical withholding of intermittent resource output from the IFM.

5. Hours with differences in estimated clearing prices of $20 or more were all hours with high gas prices in Southern California as just noted. In addition, all but one of these hours were also hours over the evening solar ramp in which the cost of meeting load would have been impacted by the cost of committing additional generation to run for several hours (due to min run time constraints) in order to meet peak load in a particular hour.

We discuss these five observations in more detail below.

First, there were only 20 hours within 2018 in which the clearing price simulated using the unmitigated offer prices exceeded by $20/MWh or more the clearing price simulated using the lower of the unmitigated offer price and the mitigated offer price for that gas fired resource. There were only 10 hours over the year in which the difference in the calculated clearing prices exceeded $30/MWh. There were only two hours over the year in which the difference in the calculated clearing prices exceeded $90/MWh. Hence, even if the price differences calculated by DMM reflected the exercise of system market power, the impact was significant in very small number of hours.

DMM calculations indicate that a system market power test based on a 3PS test of 1 or less would have triggered during 273 hours in 2018. In these hours, the difference between the clearing price calculated using the unmitigated offer price and the lower of the unmitigated offer price and the default energy bid (as calculated by DMM without accounting for the impact of LMPM on offer prices) was distributed as follows:

- exceeded $0/MWh in 212 of these hours,
- was $1/MWh or more in 161 of these hours,
- was $2/MWh or more in 111 hours,
- was $5/MWh or more in 61 of these hours
- was $10/MWh or more in 37 hours, and
- equaled or exceeded $20/MWh in 18 of these hours.[36]

The similar figures for the CAISO 201 hours with an RSI-3 less than 1.0 were:[37]

- exceeded $0/MWh in 152 of these hours,
- was $1/MWh or more in 116 of these hours,
- was $2/MWh or more in 87 hours,
- was $5/MWh or more in 54 of these hours
- was $10/MWh or more in 32 hours, and
- equaled or exceeded $20/MWh in 17 of these hours.

At a 10,000 MMBTU/kWh heat rate, the calculated price differences could be accounted for in 55- 60% of these hours by a 20 cent/MMBTU difference in the expected price of gas and would have been accounted for by a 50 cent/MMBTU difference in 73-7%% of these hours. Hence, even small differences between the gas price used to calculate the default energy bid and the actual expected gas cost reflected in IFM offer prices could account for the calculated difference in clearing prices in all but a small number of hours.

Second, in evaluating the implications of the small magnitude of most of the calculated price differences, it is important to take account of some implications of the gas scheduling process and the methodology DMM used to calculate the DEB-based clearing price. The CAISO IFM market closes after the most liquid morning gas trading period, with IFM schedules posted in time for gas-fired generators to schedule gas in the evening cycle or in the market day intraday cycles. While the DEB is calculated based on an index of gas prices in the morning trading period, gas fired generators have to submit IFM offer prices that in part reflect the opportunity cost of burning gas they purchased prior to submitting the bids, and that in part reflects the expected cost of buying additional gas to cover IFM schedules that will be scheduled in later gas pipeline scheduling cycles.

On days when the interstate pipelines and SOCAL Gas pipeline are not constrained, the supply of gas will generally be fairly liquid around the clearing price in the day-ahead market, so the

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36 These figures are somewhat lower than those included in the presentation on system market power on August 19, 2019. Since August 19, we determined that a number of hours were listed multiple times in the file we received from DMM, apparently reflecting hours with price corrections. The calculations included here are based on a file we subsequently received from DMM that did not include these duplicate entries.

37 See California ISO "CAISO Energy Markets Performance Report, " September 23, 2019,.The CAISO provided the MSC with the CAISO's hourly RSI calculations.

cost of buying gas to schedule in the later pipeline cycles will usually not be materially higher than the cost in the morning gas market. But on days when the interstate pipelines or the SOCAL Gas pipeline are constrained, as evidenced by high SOCAL citygate prices, the supply of gas will be less liquid around the morning clearing price and gas may be available for scheduling in later cycles at materially higher prices or at materially lower prices, depending on how gas market conditions have changed.

This gas price uncertainty is relevant to assessing the significance of the hours in which the simulated clearing prices differed by amounts that would be consistent with very small differences between the gas price used to calculate the default energy bid and expected gas costs. While gas prices should not always be higher when buying gas for later pipeline cycles than in the morning trading period, it is important to recall that the DEB-based clearing price is not calculated just using the default energy bid, it is calculated based on the lower of the actual IFM offer price or the default energy bid.

If gas-fired generators sometimes submit IFM offer prices for power reflecting higher expected gas prices in later cycles, and at other times submit offer prices for power reflecting lower expected gas prices in later cycles, the DMM methodology results in a systematic downward bias in its estimates of cost-based offers. In particular, it uses the IFM offer prices reflecting lower gas price expectations when they are lower than the DEB price but instead applies the DEB when the IFM offer prices reflect higher gas price expectations. Moreover, if some suppliers submitted offers lower than the DEB and others submitted offers higher than the DEB, reflecting diverse gas price expectations, the DMM methodology would use the lower offers to calculate the mitigated clearing price while substituting the DEB for the higher offers in calculating the mitigated clearing price.

Hence, even if actual IFM offer prices were centered around a value below the DEB, the DMM methodology would find that IFM offers yielded a higher clearing price than the DEB-based offers, because the DMM methodology would only use the DEB when it was lower than the IFM offer price. While the default energy bids include a 10% margin over the estimated cost-based bid, the simulation methodology uses the lower of the actual IFM offer or the DEB to calculate the mitigated clearing price without regard to the level of the actual IFM offer relative to the DEB.

A simulation-based comparison of IFM and DEB-based offer prices that would be less impacted by gas price uncertainty could be provided by, first, calculating the clearing prices always using a DEB with a 10% margin and always using a DEB with a 0% margin, and, second, comparing these two sets of clearing prices to the clearing prices calculated using actual IFM offer prices.

With these gas market dynamics in mind, we examined the relationship between gas system constraints and the calculated difference between the clearing price calculated using unmitigated offer prices and the lower of the unmitigated offer prices and the default energy bid. We limited the comparison to hours 16 to 21 when gas fired generation was likely to be needed to meet load. Table 6 shows that high gas prices clearly appear to be associated with larger differences in the simulated clearing prices. This is consistent with the expectation that the DMM methodology would be biased towards finding a difference in the simulated clearing prices on days with high gas prices.

Table 6. Gas Price Levels and Differences in Clearing Prices

	Difference in Simulated Prices ($/MWh)	
SOCAL Citygate Gas Price	All Months	Non-Summer(Oct-May)[38]
$20/MMBTU or greater	$6.61	$0.28 (6 observations)
$10 to $19.99/MMBTU	$5.54	$2.59 ($2.41 combined)
$5 to $9.99/MMBTU	$1.57	$1.00
Gas price < $ 5/MMBTU	$0.40	$0.80

The pattern shown in Table 6 does not establish that the difference in clearing prices is attributable to variations in gas prices, because high gas prices can be correlated with other factors that might be correlated with the potential for the exercise of system market power. In the summer, for example, high gas prices would tend to be correlated with high power system gas demand, which in turn might be correlated with the potential to exercise system market power. We therefore also examined the relationship between the level of gas prices and the difference in clearing prices in the winter and shoulder months. This comparison, presented on the right side of Table 6, also found larger average differences in calculated clearing prices on days with high gas prices, although the magnitude of the differences in clearing prices was smaller than over all hours.

A further test of whether offer prices in excess of the default energy bids on these days likely reflected an effort to exercise system market power or reflected gas price uncertainty would be to test whether the offers in excess of the default energy bid were submitted only by gas fired generation controlled by the 3 pivotal suppliers or were also submitted by other suppliers, including net buyers.[39] If offers in excess of the default energy bid were largely submitted only by one or more of the 3 largest suppliers and not by other suppliers served by the same gas pipelines, this would tend to suggest that the high offer prices reflected an attempt to exercise market power. Conversely, if the offer prices in excess of the default energy bids in these hours is common across a variety of suppliers served by the same gas pipeline, this would tend to suggest that the offer prices reflect gas market conditions and the limitations of the default energy bid calculations.

Third, a related observation is that a significant commonality across the 20 hours with the largest differences in the calculated clearing prices is that these were all days with high gas prices on the SOCAL gas system. The lowest SOCAL citygate price for any of these days was above $8.50/MMBTU, and that was the only one of these 20 hours+ with a SOCAL citygate price low-

[38] These figures are slightly different from those included in the system market power presentation on August 19, 2019 (www.caiso.com/Documents/SystemMarketPowerFTI-Presentation-Aug19_2019.pdf) because of the inclusion of duplicate entries (apparently related to price corrections) in the file used for the calculations in the August 19 presentation. The figures in Table 7 are based on the new file received from DMM. The figures for non-summer months were not impacted because most of the duplicate entries in the original file were for summer months.

[39] Recall that the DEB based simulated price was calculated using the lower of the default energy bid and the actual offer price for all gas-fired generators, including the gas-fired generation of net buyers. See California ISO, Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance, p. 155, Footnote 157. Moreover, Figure 7.1 shows that net buyers as well as net sellers offered some gas-fired generation at prices well above the default energy bid on July 24.

er than \$13/MBTU. Moreover, as noted above, all of the days with gas prices lower than \$15/MBTU were days in which the gas price used to calculate the default energy bid was a 3 day weekend strip price which would not have reflected the actual cost of buying gas to meet load on the high priced days. The IFM offer prices used to calculate these clearing prices reflect these high SOCAL citygate prices, but they do not reflect the expected cost of buying gas in later cycles on days with tight gas market conditions. Since it is not apparent why there would only be a potential for the exercise of material system market power on days with high gas prices, an alternative (and we believe more plausible explanation) for this relationship is that there is more potential for the expected cost of buying additional gas to exceed the default energy bid used to calculate the clearing prices on these days.

Four of the 20 hours with the largest differences in clearing prices were on a Monday (July 23), a day of the week when the default energy bid is particularly likely to understate actual gas costs because the gas index price used to calculate the default energy bid is the price for a 3 day gas price strip, not the price for gas delivered on Monday.[40]. Gas price data provided by the CAISO indicates that same-day gas prices were far higher than the gas price used to calculate the default energy bid on July 23. IFM prices may have too low rather than too high relative to the cost of buying gas to meet incremental load on this day.

Another hour, hour 20 on July 28 was a weekend hour in which the gas price used to calculate the DEB was the 3 day gas price for deliveries over Saturday, Sunday and Monday, not the price of gas for Saturday delivery. Hence, the calculated difference in clearing prices on this day may also be a result on an inaccurate DEB rather than an indication of the exercise of system market power.

A fourth observation is that a market impact that has not been assessed on these high priced days is the price impact of physical withholding of intermittent resource output from the IFM. CAISO analysis has shown that a substantial amount of real-time intermittent resource output is not offered in the day-ahead market by suppliers during the high priced hours on one of these days.[41] We do not have access to the data needed to assess whether this is a typical pattern or if instead the day examined in detail by the CAISO, July 25, 2018, was an anomaly. In recent years this supply has apparently also not been offered in the form of virtual supply by load serving entities, although we similarly lack information regarding the extent to which this has typically been the case on high priced days.[42] It is likely that the expected output of these intermittent resources is one of the factors reflected in the virtual supply offers of other market participants. However, it is impossible to draw a direct relationship between (i) the offer quantity or price of virtual supply bids and (ii) any particular difference between day-ahead and real-time market conditions, and then to use this relationship to assess the extent to which virtual supply offers effectively compensated for intermittent resource output that is physically withheld.

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[40]The mismeasurement of Monday gas prices associated with use of the three-day weekend gas price has been pointed out by DMM for several years, most recently in the 2018 market report (see California ISO, Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance, pp. 98-99).

[41] See Wang and Bautista-Alderete, cited in Note 31, supra, and California ISO, "CAISO Energy Markets Price Performance Report," cited in Note 14, supra, pp. 113-118.

[42] Virtual supply offers by loads appear to have fallen to token levels in 2018, see California ISO, Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance, Table 5.1, p. 138.

If this additional intermittent resource output were offered in the IFM either by its scheduling coordinator or by the load serving entities to which it is under contract, this additional supply would displace some cleared virtual supply offers from financial market participants. On the other hand, supply offered by the scheduling coordinator or load serving entity that has contracted for the output should be offered at lower prices and thereby overall reduce clearing prices in the day-ahead market. The load serving entities should be able to estimate real-time output more accurately than financial traders and therefore offer more of this supply in the IFM at a lower price than is the case with virtual supply offers today.

It would be informative to better understand the magnitude of the physical withholding of intermittent resource output on high priced days. If this physical withholding were found to be material on these days, there should be discussion of whether CPUC or CAISO rules or policies are deterring load serving entities from submitting some form of supply bids in the IFM for intermittent resource output under contract to them. Reduced withholding of this output in the IFM might help lower IFM prices on high priced days.

The manner in which intermittent resource output is offered in the day-ahead market also impacts 3PS calculations by the CAISO and DMM, which are based on the load CAISO load forecasts rather than load bids. If load serving entities account for the intermittent resource output that is under contract to them but is not offered in the IFM, then by reducing the power they buy in the IFM by the amount of intermittent resource output they do not offer in the IFM, this behavior would introduce a downward bias into pivotal supplier calculations based on the CAISO load forecast. This would occur because this bidding strategy would reduce the supply included in the pivotal supplier calculation while the CAISO load forecast would remain unchanged.[43] The impact of such a bidding strategy by load serving entities on pivotal supplier calculations in the IFM could be corrected for by basing IFM pivotal supplier calculations on cleared IFM load (physical and virtual) rather than the CAISO load forecast. However, such a change would introduce other issues in the pivotal supplier calculation, such as the potential for low priced physical load, export or virtual demand bids to lower the RSI, while never clearing in the market.

Fifth, the hours with differences in clearing prices in excess of $20 not only all fell on high gas price days, they were all evening ramp hours, potentially with high commitment costs. The actual cost of meeting load in these hours not only reflected high incremental energy offers, it was also impacted by the high cost of committing additional generation to meet peak load in one or two hours on days with high gas prices (and hence higher start up and minimum load costs).

The DMM simulations fixed the unit commitment, which was therefore the same between the calculation using IFM offer prices and the lower of the IFM offers and the default energy bid. Hence these high commitment costs do not directly impact the clearing price comparisons. Nev-

[43] The CAISO and DMM 3PS analysis for system market power is based on the CAISO load forecast and actual supply offers. If load serving entities are reducing their intermittent supply offers and offsetting this with reductions in load bids, this would tend to lower the RSI calculated for both local and system market power. Intermittent resource outputs that are not offered in the IFM but are offset by load that is not offered in the IFM would not incent the submission of virtual supply offers by financial participants because both supply and demand in the IFM are reduced by this strategy.

ertheless, the level of commitment costs is important in understanding the level of actual LAP prices in these hours compared to 16-hour bilateral prices at external trading hubs.

In addition, the role of commitment costs would be important in applying market power mitigation to external resources. It is likely not economic to commit a combined cycle to meet load in the IFM if prices are materially above incremental costs only in one or two hours. While many of the hours with differences in the calculated clearing prices of $20/MWh or more fell on the July 23-28 days in which there were a number of hours with high prices, some of the hours with large differences in calculated clearing prices occurred on days on which there were only a few very high price hours. Therefore, commitment costs may have materially impacted supply.

Looking forward to years in which there may be greater dependence on imports to meet load over the evening solar ramp down, the CAISO and its stakeholders should recognize that import suppliers are currently effectively limited to offering supply using one-part bids to reflect commitment costs. This design likely results in less elastic supply in the evening ramp hours, and may also contribute to the observation that there are frequently imports that clear in the day-ahead market but do not flow in real-time.

This limitation of the current market design would be addressed by the expansion of the CAISO day-ahead market to cover additional balancing areas in the west. However, if the timing of that expansion is uncertain, the CAISO may want to develop in parallel the ability in its scheduling software to commit import supply at interties based on three-part bids, either just for RA imports or for any supplier that chooses to offer in this manner. Such an ability to evaluate the commitment of intertie resources based on start-up and minimum load costs as well as incremental energy offer prices would be a precondition to the ability to applying market power mitigation to RA imports.

We understand that DMM is carrying out an ongoing simulation of 2019 IFM outcomes using the IFM solution engine. The results of those simulations will contribute to an understanding of the need to implement system market power mitigation. The DMM has published an analysis of one day in 2019, September 25, 2019.[44] DMM calculated differences in average simulated LAP clearing prices of between $7.37 MWh and $8.13 MWh in hours 19 and 20, which failed a 3PS test, and of over $16 MWh in hour 18. We understand from the CAISO that the three major interties were constrained in the IFM solution in these hours, which would have contributed to high prices and would have significantly reduced import competition, which might have enabled some exercise of market power within the CAISO.

We understand that the DMM September 25 simulation took account of commitment costs (unlike the 2018 simulations which held the commitment fixed). It is interesting that the DMM simulations identified substantial amounts of capacity with low incremental energy offers that were not committed because of commitment costs.[45] However, Figure 3.8 in the DMM report appears to show a large amount of energy offered at -$250/MWh from resources that were not committed. This outcome appears unlikely and we understand from the CAISO that while there were gas-fired resources with infra-marginal energy offers that were uncommitted in the actual

[44] See California ISO, Department of Market Monitoring, op. cit. in Footnote 30, above.

[45] Ibid., p. 12 and Figure 3-8.

IFM, those resources were not offering energy at -$250/MWh. This discrepancy suggests that there is either some error in the interpretation of the data or in the simulated unit commitment. Hence, it would be good to review these results in more detail as part of any stakeholder process in assessing the need implement system market power mitigation,

A.4 RA imports

It is our understanding that some import supply offered to cover resource adequacy obligations is offered at or near the bid cap ($1000/MWh). Rather than reflecting an attempt to exercise market power, this import supply could be offered at the price cap to avoid being scheduled in the day-ahead market because there might in fact be no supply backing the resource adequacy contract. In addition, because real-time shortage pricing in the CAISO is capped at $1000/MWh, an import supplier that offers supply in the day-ahead market at $1000/MWh is unlikely to incur material losses if its offer clears in the day-ahead market and the supplier is unable to deliver this power in real-time.

As observed above, the submission of import RA supply offers at $1000/MWh does not necessarily reflect an attempt to exercise system market power. Any resources associated with these offers could not meet load within California when the CAISO is import constrained due to transmission limits. The converse possibility, that the owners of these resources have WECC-wide market power and offer the output of these resources at $1000/MWh in the CAISO IFM in order to economically withhold the output from the WECC market and elevate prices throughout the WECC is not remotely plausible. As has been discussed at a number of MSC meetings, the potential issue with RA imports offered at $1000/MWh is the likelihood that there is no resource supporting the high priced import RA offer offers, which of course means that no supply is being withheld from the WECC because the seller has no supply to withhold. The submission of $1000/MWh offers by import RA is an issue relating to the CAISO/California Public Utility Commission resource adequacy design and needs to be addressed as such.

It is noteworthy in this context that the way real-time shortage pricing is implemented in NYISO, MISO, PJM, and ISO New England, as well as of course in ERCOT, an import supplier (as well as any other supplier) could pay *much* more than $1000/MWh for power scheduled in the day-ahead market that it is unable to supply in real-time. The CAISO approach is not a good design from either a market or reliability perspective because there are low consequences to non-performance on days on which high IFM prices reflect expectations of stressed system conditions in real-time.

Appendix B
Market Power Mitigation in the Real Time Market Does Not Completely Mitigate IFM Market Power If RT Supply Elasticity is Smaller than IFM Supply Elasticity[46]

B.1 Propositions

This Appendix addresses the following three propositions by solving a simple analytical model of the two settlement (IFM-DA/RT) market where suppliers have market power day ahead, but are mitigated in real time. Convergence bidders play a crucial role. In sum, it is possible for RT market power mitigation to mitigate DA market power completely (under restrictive assumptions concerning symmetry of supply in RT and DA)--but if DA supply elasticity is greater than RT supply elasticity, the mitigation of DA market power is incomplete and some market power is exercised. This Appendix documents the basic model and some variants, and some simulation results.

Simplifying assumptions are made for purposes of ease of exposition:

1. the RT market is perfectly forecast day-ahead,
2. suppliers in the DA market only optimize against their DA marginal cost curve and don't consider how their DA supply will affect RT marginal costs,
3. DA reliability unit commitment (RUC) is disregarded (or, equivalently, RUC decisions don't change supply decisions in the RT market)
4. mitigation is perfect (offers are set equal to marginal cost exactly).
5. all oligopolists are identical (have the same cost functions)

However, the first assumption is not anticipated to change the basic results. Meanwhile this Appendix shows that the basic qualitative results (Proposition 1 and 2) don't change if the second assumption is altered. RUC could significantly change the results if the units that are RUC'd are the optimal units to dispatch if all demand was met at the mitigated price in the day-ahead market. The result is that the RT offer curve would follow the DA marginal costs, and the market outcomes would be the same as Proposition 1 below (all market power mitigated). If mitigation is not perfect, market power could persist if RT mitigated offers are above marginal cost. Finally, assumption 5 is not anticipated to qualitatively change the results (for instance, if there are some smaller fringe suppliers).

The propositions are as follows:

Proposition 1: Under perfect arbitrage (convergence bidding) and a monopoly or oligopolistic suppliers, if the IFM supply (MC) curves are the same as the RT supply demand curves, *then mitigating just the RT market will result in the competitive solution in both markets.* (This assumes that monopolist does not anticipate how its IFM decision will affect the amount of virtual supply – i.e., the Cournot oligopolistic conjecture.) Demand elasticities don't affect this result.

[46] This Appendix is a revised version of the background documentation for B.F. Hobbs, "Can RT Market Power Mitigation Also Mitigate DA Market Power? Some Theory", presented at the Oct. 11, 2019 Market Surveillance Committee (presentation: www.caiso.com/Documents/SystemMarketPowerDiscussionHobbs-Presentation-Oct11_2019.pdf ; original version of documentation: www.caiso.com/Documents/MSC_RealTimeMitigation-Day-AheadMarketPowerTheory-Hobbs-Oct11-2019.pdf).

Proposition 2: Under perfect arbitrage (VB) and a monopoly or oligopolistic suppliers, if the RT supply curve is less elastic than the IFM supply curve, *then mitigating just the RT market will still allow some residual market power to be exercised in the DA market.*

Proposition 3: However, the mark-up in the latter case will be less than if either (a) there is no mitigation in either market, or (b) if the monopolist anticipates how arbitrage and RT prices will change if it changes IFM supply. (Case (b) is sometimes referred to as a "closed loop monopoly" by market modelers rather than a Cournot solution.)

These propositions are illustrated below for linear supply and demand assumptions. The upshot is that RT mitigation is not enough to prevent market power in the IFM if RT supply is less elastic than IFM supply, but it helps. (Lower elasticity in real time is expected since long start units cannot change their status in the short run/RT.) What happens is that the monopolist or oligopolist restricts supply in the IFM, so that prices are higher in the IFM, enticing some convergence supply to be provided DA. As a result, there is RT production, and the mitigated but less elastic supply curve in the RT sets a higher price than would be the case if the IFM was competitive. Market power in the IFM results in IFM supply restriction and increased (and inefficient) production in the RT market, raising prices in both markets, and lowering consumption.

First, we show these propositions for the case of a single firm (monopoly) in the IFM, then we generalize the model to the oligopoly case.

B.2 Example 1: Monopoly in the IFM

Notation:

g_1=Total IFM production by the monopolist

g_2=Total incremental production in RT by the monopolist

vs_1 = virtual supply in IFM (settled as virtual demand in RT)

d_1=quantity demanded in IFM, equal to $g_1 + vs_1$

d_2=incremental quantity demanded in RT, equal to $g_2 - vs_1$

$P_1(d_1) = P_{1o} – B_1*d_1$ = IFM demand curve

$P_2(d_2|d_1) = P_{1o} – B_1*d_1 – B_2*d_2$ = RT demand curve ($B_2>B_1$ if less elastic than in IFM)

$MC_1(g_1) = MC_{1o} + C_1*g_1$ = IFM marginal cost curve

$MC_2(g_2|g_1) = MC_{1o} + C_1*g_1 + C_2*g_2$ = RT marginal cost curve ($C_2>C_1$ if RT supply less elastic than in IFM)

There are 5 unknowns (generation and load in each market, and IFM virtual supply) and 5 equations ((1)-(5)) as follows that give the market equilibrium:

IFM (market 1): served by a monopolist subject to elastic demand and virtual supply (which the monopolist is Cournot against). Monopolist maximizes its DA profit, equal to revenue minus IFM cost: $P_1(d_1)*g_1 – (MC_{1o}*g_1+C_1*g_1^2/2)$, subject to its recognition that load equals its supply plus virtual supply ($d_1= g_1 + vs_1$). (This is a naïve monopolist who doesn't anticipate how IFM decisions affect its RT costs; see the Appendix for a more general model where the monopolist anticipates that if it supplies more DA, its MC in the RT market will increase. The results are not qualitatively different). The first order condition for profit maximization is:

$$\text{Marginal Revenue} = P_1'(d_1)*g_1 + P_1 = MC_1(g_1) \qquad (1)$$

Market clearing in IFM:

$$d_1 = g_1 + vs_1 \qquad (2)$$

No arbitrage condition (efficient convergence bidding), implying that IFM and RT prices are equal:

$$P_1(d_1) = P_2(d_2|d_1) \qquad (3)$$

RT mitigated market solution results in price = marginal cost:

$$P_2(d_2|d_1) = MC_{1o} + C_1*g_1 + C_2*g_2 \qquad (4)$$

Market clearing in RT:

$$d_2 = g_2 - vs_1 \qquad (5)$$

We could use algebra to define g_1, g_2, d_1, d_2, and vs_1 as explicit functions of the parameters. One immediate result is that no arbitrage (3) means that $d_2 = 0$, $g_2 = vs_1$, and the demand price elasticity (represented by coefficient B_2) in RT doesn't matter. (With uncertainty of supply or demand in real time, though, this would not be generally true.)

Here's an example. We solve (1)-(5) with the following parameters.

Demand	P_{1o} =	100
	B_1 =	1
	B_2 =	1.3
Supply	MC_{1o} =	10
	C_1 =	1.5
	C_2 =	1.8

So the incremental supply curve in RT is 20% steeper than the IFM supply (marginal cost) curve.

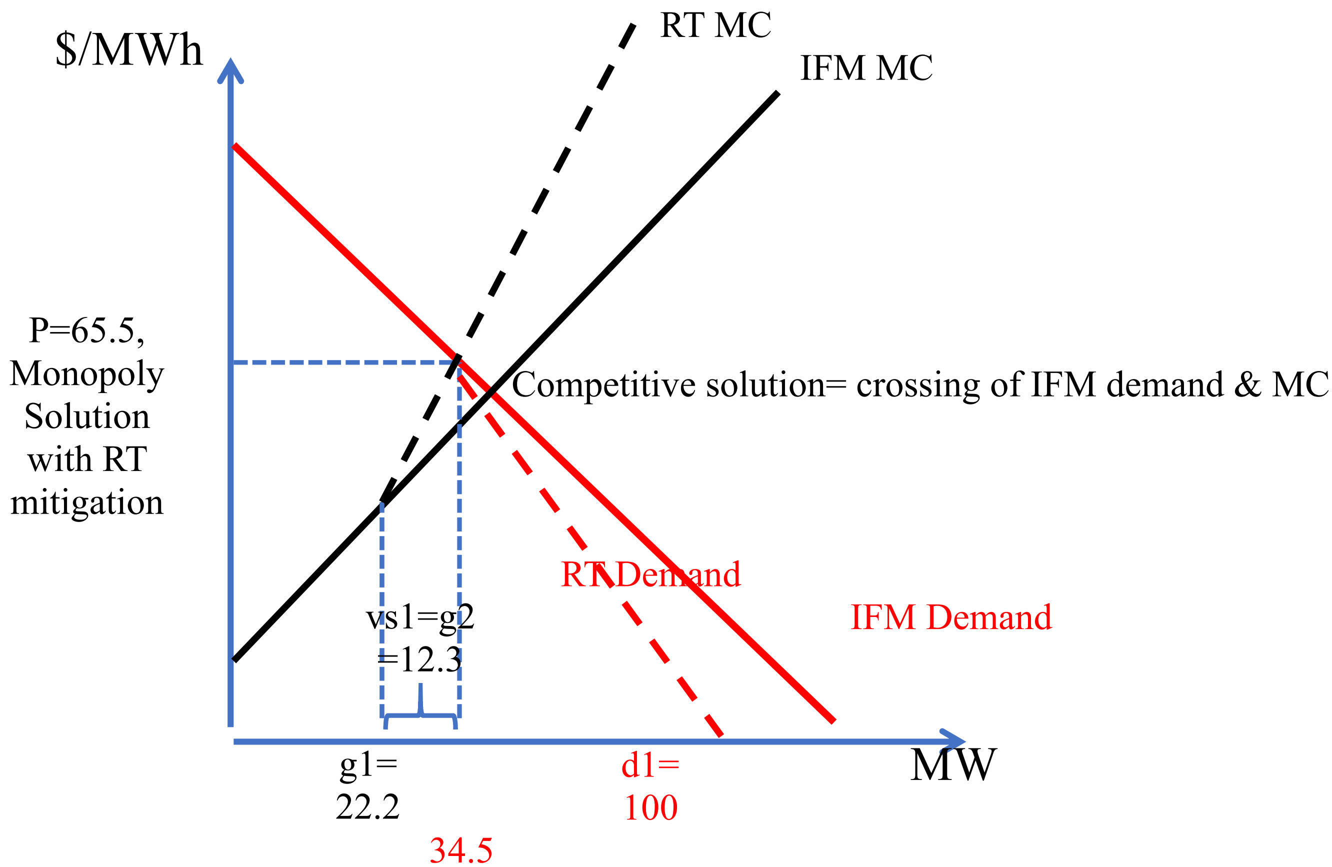
The solution is:

d_1	d_2	g_1	g_2	vs_1
34.52	0.00	22.19	12.33	12.33

With price in both DA and RT equal to \$65.48/MWh. If instead the IFM was perfectly competitive, then the solution would be:

d1	d2	g1	g2	vs1
36	0.00	36	0	0

Which has a lower price (64 \$/MWh) and higher market surplus. This illustrates Proposition 2. These two solutions are shown graphically below.



Note that RT supply starts from the point on the IFM supply curve corresponding to g1. Similarly, RT demand starts from the point on the IFM demand curve corresponding to d1. RT lines are steeper in both cases.

Proposition 1 is illustrated by setting B_1=B_2=1, and C_1=C_2=1.5 (same IFM and RT elasticities). Then the solution is:

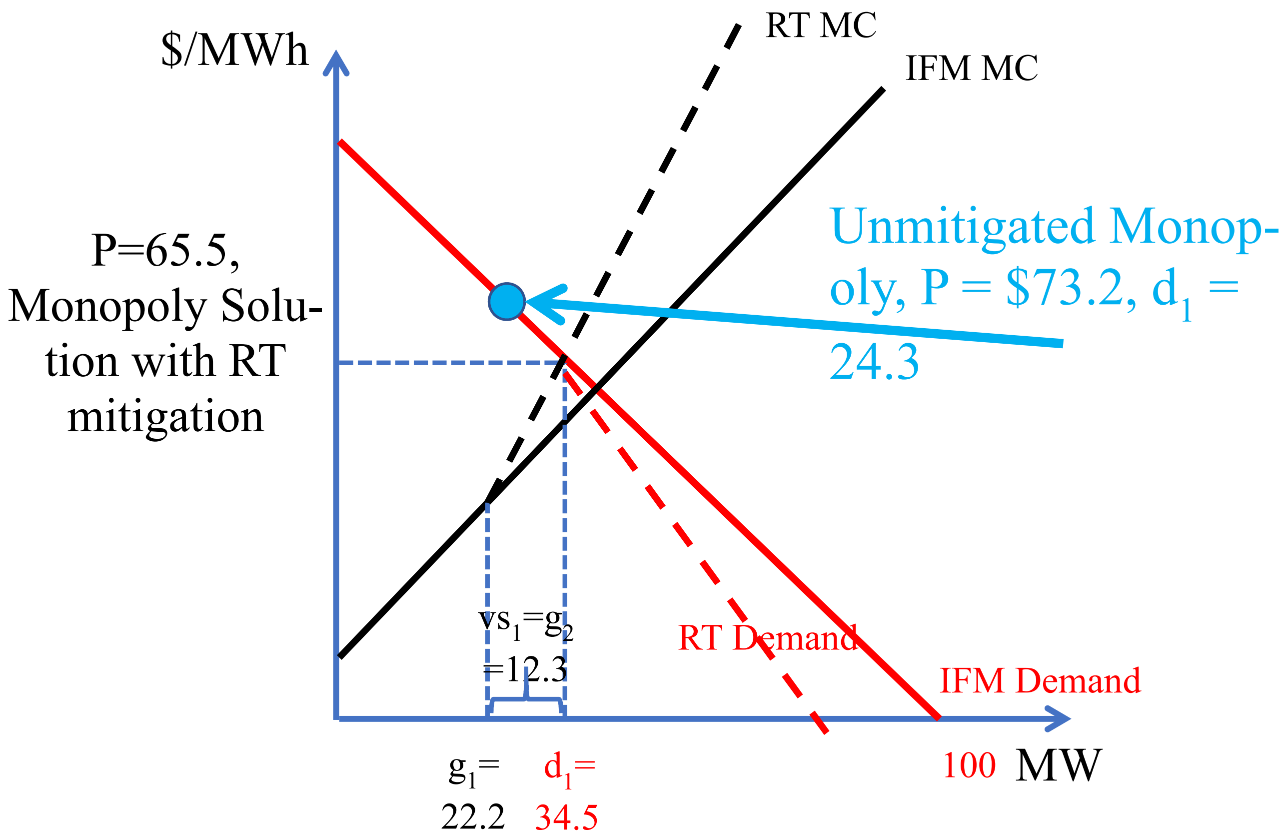
d_1	d_2	g_1	g_2	vs_1
36	0	21.6	14.4	14.4

Which is the same quantity, price (\$64), and market surplus as the competitive solution.

Proposition 3 is illustrated by the following profit maximizing (maximal market power) solution in which the monopolist recognizes that it should produce everything in the IFM (which is cheaper than producing in RT) and nothing in the second period. Then:

d_1	d_2	g_1	g_2	vs_1
24.325	0.000	24.324	0.000	0.000

Which yields a price of 73.2 \$/MWh, and much less efficiency (see the figure below). So comparing this with the previous solutions, the RT mitigation succeeds in moving the market much closer to the competitive solution (i.e., mitigated in both markets), but there is residual market power.



To the extent that the RT supply elasticity is less than the IFM, the solution will approach the maximal market power solution, and diverge from the competitive solution. For instance, if the RT supply elasticity was one-half the IFM elasticity (increasing C_2 to 3), the equilibrium price increases to 68.7\$/MWh (compared to the competitive level of \$64 and the maximal market power level of \$73.2.)

B.3 Example 2: Oligopoly in the IFM

Assume there are n oligopolists. Notation is as follows:

g_1=Total IFM production by oligopolists. g_{1i} is production by oligopolist i

g_2=Total incremental production in RT by oligopolists, and g_{2i} is production by oligopolist i

vs_1 = virtual supply in IFM (settled as virtual demand in RT), as in monopoly model

d_1=quantity demanded in IFM, equal to $\Sigma_i\, g_{1i} + vs_1$

d_2=incremental quantity demanded in RT, equal to $\Sigma_i\, g_{2i}$ - vs_1

$P_1(d_1) = P_{1o} – B_1*d_1$ = IFM demand curve

$P_2(d_2|d_1) = P_{1o} – B_1*d_1 – B_2*d_2$ = RT demand curve ($B_2>B_1$ if less elastic than in IFM)

$MC_1(g_{1i}) = MC_{1o} + n*C_1*g_{1i}$ = IFM marginal cost curve (assume same all i)

$MC_2(g_{2i}|g_{1i}) = MC_{1o} + n*C_1*g_{1i} + n*C_2*g_{2i}$ = RT marginal cost curve ($C_2>C_1$ if supply less elastic than in IFM) (assume same all i)

There are 5 unknowns and 5 equations ((1')-(5')) as follows that give the market solution. Solving these is made easier if we assume that by symmetry all $g_{1i} = g_1/n$, and $g_{2i} = g_2/n$. The five equations are developed below.

IFM (market 1): served by n Cournot oligopolists subject to elastic demand and the quantities provided by virtual supply and other physical suppliers (both assumed to be fixed by the Cournot oligopolist). The oligopolist chooses its g_{1i} to maximize revenue minus cost $P_1(d_1)*g_{1i} – (MC_{1o}\ g_{1i} + n*C_1*g_{1i}^2/2)$, while recognizing that $d_1 = \Sigma_i\ g_{1i} + vs_1$. The resulting first order condition is:

Marginal Revenue = $P_1'(d_1)*g_{1i} + P_1 = MC_1(g_{1i})$, for all i (1')

Market clearing in IFM:

$d_1 = \Sigma_i\ g_{1i} + vs_1$ (2')

No arbitrage condition (efficient convergence bidding) => IFM and RT prices are equal:

$P_1(d_1) = P_2(d_2|d_1)$ (3')

RT mitigated market solution is price = marginal cost for all i:

$P_2(d_2|d_1) = MC_2(g_{2i}|g_{1i})$, for all i (4')

Market clearing in RT:

$d_2 = \Sigma_i\ g_{2i} - vs_1$ (5')

We could use algebra to define g1i, g2i, d_1, d_2, and vs_1 as explicit functions of the parameters, but it is a bit messy, so just some sample numerical results are shown. One immediate result is that no arbitrage condition (3) means that $d_2 = 0$, g_{2i} = vs1/n, and the demand price elasticity in RT (represented by coefficient B_2) doesn't matter. (With uncertainty, this would not be generally true.)

Here is an example. We solve (1')-(5') with the following parameters.

Demand	P_{1o} =	100
	B_1 =	1
	B_2 =	1.3
Supply	MC_{1o} =	10
	C_1 =	1.5
	C_2 =	1.8
Firms	n =	3

So the incremental supply curve in RT is 20% steeper than the IFM supply curve.

The solution is:

d_1	d_2	g_1	g_2	vs_1
35.337	0.000	29.816	5.521	5.521

With price $64.66/MWh.

If instead the IFM was perfectly competitive, then the solution would be (as before):

d_1	d_2	g_1	g_2	vs_1
36	0.00	36	0	0

Which has a lower price (64 $/MWh) and higher market surplus. This illustrates Proposition 2 for the oligopoly case. Note that the oligopoly (n=3) markup is $0.66, which is about 45% of the monopoly marketup.

Proposition 1 for the oligopoly (n=3) case is illustrated by setting $B_1=B_2=1$, and $C_1=C_2=1.5$ (same IFM and RT elasticities). Then the solution is:

d_1	d_2	g_1	g_2	vs_1
36.000	0.000	29.455	6.545	6.545

Which is the same quantity, price ($64), and market surplus as the competitive solution.

Proposition 3 is illustrated by the following profit maximizing (no mitigation of market power) solution in which the oligopolists recognize that they should produce everything in the IFM (which is cheaper) and nothing in the second period. Then:

d_1	d_2	g_1	g_2	vs_1
31.77	0.000	31.76	0.0	0.0

Which yields a price of 68.2 $/MWh, and much less efficiency. So in this case, a comparison of this unmitigated solution with the previous RT mitigation solution (immediately above) shows that RT mitigation succeeds in moving the market much closer to the competitive solution (i.e., mitigated in both markets), but there is residual market power.

To the extent that the RT supply elasticity is less than the IFM, the solution will approach the maximal market power solution even if RT mitigation is in place, and diverge from the competitive solution. For instance, if the RT supply elasticity was one-half the IFM elasticity ($C_2 = 3$), the equilibrium price increases to 66.04$/MWh (compared to the competitive level of $64 and the no mitigation market power level of $68.23.) It turns out that, like the monopoly case, demand elasticities in RT don't affect the solution.

For n=3, the use of RT mitigation reduces the mark-up to 16% of the unmitigated value (for $C_2=1.8$, 20% reduction in supply elasticity) or 48% (for $C_2 = 3$, half the supply elasticity). These reductions are almost exactly the same as for the monopoly case (14% and 46% respectively). So the fact that the markets are oligopolistic rather than monopolistic doesn't appreciably change the percentage that market power-driven mark-ups are reduced relatively to unmitigated levels.

B.4 Addendum: Generators Anticipate Effect of DA Supply Decisions on RT Costs

What if each supplier optimizes over both markets at once, recognizing that producing more in period 1 will increase her cost in period 2?

Choose $\{g_{1i},g_{2i}\}$ in order to maximize profit over both periods:

$$\{P_1(d_1)*g_{1i} - (MC_{1o}\, g_{1i} + n*C_1*g_{1i}^2/2)\} + \{P_2*g_{2i} - [(MC_{1o} + n*C_1*g_{1i})g_{2i} + n*C_2*g_{2i}{}^2/2]\}$$

Note that P_2 is exogenous in this profit expression, which is equivalent to mitigation of RT prices, because it results in price being set equal to i's marginal cost (the second first order condition below). The first order conditions are:

Marginal Revenue DA = $P_1'(d_1)*g_{1i} + P_1 = MC_1(g_{1i}) + n*C_1*g_{2i}$, all i (1")

$P_2 = P_2(d_2|d_1) = MC_2(g_{2i}|g_{1i})$, all i (4')

So condition (1') has changed to condition (1"); now the producer is equating marginal revenue in the first period with the marginal cost *that would occur* if it supplied all $g_{1i} + g_{2i}$ in the first period, rather than just g_{1i}, not its first period marginal cost of just supplying g_{1i}. If there is a positive second period supply, this implies that the perceived marginal cost of supply in the first period increases, which motivates the firm to sell even less in the first period than it would in the original model, which will ultimately increase the first price further, and, if $C_2>C_1$, increase costs by increasing second period production whose marginal cost is greater than if the same production occurred in period 1. Condition (4) is unchanged (price equals marginal cost in the second period)

Simulations (solving (1"),(2')-(5')) with the same parameters as considered in the body of this Appendix result in the following comparison with the original model results:

(a) Same results (no market power in DA) if supply elasticity is the same in both RT and DA
(b) More market power in DA if supply elasticity is more in DA

As an illustration, here is the example as before, but solving (1"),(2')-(5') rather than (1')-(5') with the following parameters.

Demand	P_{1o} =	100
	B_1 =	1
	B_2 =	1.3
Supply	MC_{1o} =	10
	C_1 =	1.5
	C_2 =	1.8
Firms	n =	3

So the incremental supply curve in RT is 20% steeper than the IFM supply curve.

The solution is:

d_1	d_2	g_1	g_2	vs_1
33.861	0.000	16.040	17.822	17.822

with price \$66.13/MWh. So the price is higher than the \$64.66 price in the original model in which the supplier doesn't consider impact on second period marginal cost of first period decision, while three times as much virtual supply is being provided in the DA market (so there is three times as much RT generation). Thus, more market power is being exercised under this model.