June 3, 2015

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: **California Independent System Operator Corporation**

Docket Nos. ER06-615-____ and ER02-1656-____
Compliance Filing

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this filing to comply with the Commission's orders issued on September 21, 2006, and June 3, 2014, in the above-referenced proceedings.[1] The September 2006 order imposed a variety of compliance obligations on the CAISO, including eventual further disaggregation of the load aggregation point (LAP) zones.[2] On June 3, 2014, the Commission rejected the CAISO's request for permanent waiver of that requirement and extended the deadline for complying with the Commission's directive to disaggregate existing LAPs in the CAISO's balancing authority area by one year.[3]

Although the Commission denied the request for a permanent waiver of the September 2006 requirements, it also stated that if the CAISO were to request further relief from the disaggregation requirements, the request must include specific details "to allow the Commission to reasonably evaluate the effects of implementing a greater level of disaggregation."[4] In compliance with both orders, the CAISO provides the details requested by the Commission and requests that the Commission accept the current number of LAPs as just and reasonable based on the study results and information provide in this compliance filing. The CAISO study indicates minimal price dispersion

[1] *Cal. Indep. Sys. Operator Corp*., 147 FERC ¶ 61,181 (2014) (June 2014 order); *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 (2006) (September 2006 order).

[2] Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff.

[3] In the September 21 order, the Commission conditionally accepted for filing the CAISO's proposed tariff necessary to implement its new market design. The key elements of the new design were adding a day-ahead Integrated Forward Market to the Real-Time Market and shifting from a zonal to a nodal market. The new design was referred to as the Market Redesign and Technology Upgrade (MRTU)

[4] June 2014 order, at P 20.

among the load nodes in the CAISO system, and thus minimal benefit from pursuing further load disaggregation. Additionally, the CAISO foresees significant implementation costs from load settlement disaggregation that would far outweigh the foreseeable benefits. Accordingly, the CAISO requests that the Commission find the CAISO to have met its obligations arising from the September 2006 order.

I. Background

The CAISO clears and settles all CAISO load at LAPs, which are aggregations of individual pricing nodes. The CAISO clears and settles the majority of load at one of the Default LAPs, which correspond to the service territories of Pacific Gas and Electric Co. (PG&E), Southern California Edison Co. (SCE), San Diego Gas and Electric Co. (SDG&E), and the Valley Electric Authority (VEA).[5] For each Default LAP, the CAISO calculates a zonal locational marginal price based on the distribution of system load at the constituent pricing nodes within the applicable Default LAP. The CAISO determines the Default LAP prices by the effectiveness of the load within the default load aggregation point in relieving a transmission constraint.[6] The CAISO settles a scheduling coordinator's load at the applicable locational marginal price for the Default LAP in which that load is located.[7] In addition to the Default LAPs, the CAISO also settles some load at Custom LAPs, which are specially designed LAPs ranging in size from a single node to a sub-LAP. The CAISO makes Custom LAPs available for settlement of certain types of load such as proxy demand resources and station power under the CAISO's Station Power Protocol.[8]

In justifying its new market structure (*i.e.,* the Market Redesign and Technology Upgrade or "MRTU"), the CAISO explained that settling load at the Default LAPs would protect consumers in load pockets from high nodal prices and ensure that most consumers pay an average zonal price for energy regardless of their location on the grid.[9] The CAISO further explained that such approach was consistent with retail rate

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[5] The CAISO Tariff defines the term "Default LAP" as the "TAC Area at which all Bids for Demand shall be submitted and settled . . . ." The "TAC Areas" are in turn defined in Section 3 of Schedule 3 of Appendix F. At the start of the CAISO's new market in 2009, there were three Default LAPs, which corresponded to the service territories of the three major California investor-owned utilities. With the integration of Valley Electric Association into the CAISO grid as a participating transmission owner in 2013, the CAISO created a fourth Default LAP corresponding to Valley Electric's service territory.

[6] *See* CAISO Tariff Section 27.2.2. Prior to the Commission's approval of modifications to that tariff section in a letter order issued April 3, 2013 in Docket No. ER13-957, the ISO's pricing for load aggregation points was based on a weighted average of the nodal prices within the default load aggregation point.

[7] *See, e.g.*, ISO tariff section 11.2.1.2.

[8] CAISO Tariff, Appendix I, Section 5.

[9] September 2006 order at PP 595-96.

design in the CAISO balancing authority area. The retail rate structure for most of California, as determined by the California Public Utilities Commission (CPUC), was and continues to be an average rate across the three investor-owned utilities. Therefore, the retail rate does not reflect any locational price differences within the load serving entity service territories.

The Commission's consideration of the CAISO's MRTU proposal extended across a multitude of CAISO filings and Commission orders. Throughout the process, the Commission expressed some concern regarding the CAISO's proposal to settle most load at the highly aggregated Default LAPs.[10] In the September 2006 order, however, the Commission approved, on a time-limited basis, the CAISO's proposal to settle load in this manner, finding that it was "a reasonable and simplified approach" that provided "an acceptable starting point."[11] The Commission stated that "consistent with the Commission's prior guidance, we direct the CAISO to increase the number of LAP zones for [MRTU] Release 2,"[12] which was expected to be within the first three years of the new market's operation.[13] The stated basis of this requirement was the Commission's belief "that increasing the number of LAP zones will provide more accurate price signals and assist participants in the hedging of congestion charges.**"**

In 2011, the CAISO requested an extension of time, until the fourth quarter of 2014, to increase the number of Default LAPs. The CAISO explained that, based on its analysis of locational pricing trends during the first 16 months of the new market design and in anticipation of market enhancements likely to alter pricing trends, insufficient data existed to support disaggregating the Default LAPs. The CAISO further explained that the stakeholder process revealed a nearly unanimous consensus opposing disaggregation of the Default LAPs based, in part, on the value of forging greater alignment between the respective designs of the retail rate market and the wholesale market. The Commission granted the CAISO request.[14]

In 2014, the CAISO requested a permanent waiver of the load disaggregation requirement. The CAISO presented analysis showing that the costs of disaggregation

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[10] 112 FERC ¶ 61,310, PP 16-19 (2005) (September 2005 order); 112 FERC ¶ 61,013, P 36 (2005) (July 2005 order) ("We encourage the CAISO to consider an eventual move to nodal demand pricing, but we will accept zonal demand pricing. There are many advantages to full nodal pricing"); *California Independent System Operator Corp.*, 105 FERC ¶ 61,140, P 65 (2003) (October 2003 order)

[11] September 2006 order at P 611.

[12] *Id.*

[13] When the CAISO filed the tariff language to enable its new market design, it explained that software limitations prevented it from including all of the market design features it wished to include when the new market went live. It stated that within three years of market operations it intended to implement "MRTU Release 2," which would include a variety of market design refinements.

[14] *California Independent System Operator Corp.*, 136 FERC ¶ 61,055, at P 15 (2011) (July 2011 order).

were likely to outweigh significantly the benefits. The CAISO further explained that there was broad and strong stakeholder support for the waiver request. Finally, the CAISO noted that it would initiate a new stakeholder process to consider further disaggregation if changed circumstances warranted reconsideration. The Commission rejected the CAISO request, finding that the CAISO did not meet the Commission's waiver criteria.[15] It also noted that the CAISO request was not sufficiently supported. The Commission found that the CAISO analysis did not, among other things, address sufficiently how the observed price differences would impact market outcomes, substantiate the metrics used in the analysis, or analyze the entire CAISO footprint.[16] The Commission nevertheless recognized that the CAISO raised legitimate concerns about the feasibility of complying by the then-pending October 1, 2014, disaggregation deadline. The Commission accordingly granted the CAISO a one-year extension for compliance and offered that:

> should CAISO seek further relief from the disaggregation requirement, any such request must include an analysis with sufficient detail to allow the Commission to reasonably evaluate the effects of implementing a greater level of disaggregation. To the extent that CAISO uses a study like the Pricing Study to support its request, it should include additional information or changes such as the following:
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> > (1) A detailed description of the underlying data used, such as daily prices at individual sub-LAPs, or daily price differences between scenarios;
> > (2) An analysis of a reasonable range of different alternative levels of disaggregation;
> > (3) Focused discussion on those areas exhibiting the largest price differences;
> > (4) Properly supported estimates of implementation costs for different levels of disaggregation with complete explanations of the methodology and assumptions that led to those estimates; and
> > (5) Analysis of the entire CAISO footprint (including SDG&E).[17]

II. Explanation of CAISO Load Disaggregation Study

In response to the June 2014 order, the CAISO conducted a fully nodal pricing study incorporating the five elements the Commission identified in the order. To evaluate the projected market impacts of load disaggregation, the CAISO study evaluated three distinct elements: (1) day-ahead nodal pricing trends and price divergence patterns between Default LAPs and individual load nodes; (2) implementation costs of various levels of disaggregation; and (3) benefits of fully nodal

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[15] *California Independent System Operator Corp.*, 147 FERC ¶ 61,181, at P 17 (2014) (June 2014 order).

[16] *Id.* at P 18.

[17] *Id.* at P 20.

disaggregation, given the observed spatial price dispersion.[18] The CAISO conducted its pricing study in conjunction with a stakeholder process.

A. Price Dispersion Analysis

The CAISO conducted a four-part fully nodal spatial price dispersion analysis, analyzing hourly energy prices from the day-ahead market for the period of January 1, 2011 through November 14, 2014.[19] With the exception of the Greater Fresno Area,[20] no part of the analysis suggested a feasible level of load settlement disaggregation short of fully nodal load settlement. Also, the results show that, given the de minimis level of price dispersion there is no compelling basis for nodal disaggregation. Further, the implementation costs of modal disaggregation are significant and outweigh the inconsequential benefits.

1. Simple Average Nodal Price Analysis

The CAISO first reviewed the simple average nodal price at each load node during the review period.[21] The simple average price at each load node can reflect: (1) spatial variation across the system of average prices; and (2) areas where groups of nodal prices have tended to be higher or lower than other nodal prices. The CAISO analyzed pricing trends geographically and temporally to identify contiguous regions that it could use to define more granular zones and to ascertain an expectation of continued persistence of any significant pricing trends. The data indicated that prices at load nodes tended to fall in a relatively narrow range, with 90 percent of those average prices falling between $44/MWh and $35/MWh.[22] With the exception of the Greater Fresno Area, discussed in more detail below, the load nodes with particularly high or low average prices were dispersed throughout the three major Default LAPs rather than

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[18] Significant additional detail regarding the CAISO study is included in the Load Granularity Refinements Draft Final Proposal, available at: http://www.caiso.com/Documents/DraftFinalProposal_LoadGranularityRefinements.pdf.

[19] The CAISO used day-ahead prices rather than real-time market prices because: 1) the ISO generally schedules over 95 percent of real time load in the day-ahead market, and 2) the day-ahead market is the only market into which load is bid. Studying real-time prices would have increased the volume of data by a factor of 12 (12 five-minute intervals per hour in the real-time market vs. one 60-minute interval for the day-ahead market) while unlikely to add meaningful analytic value.

[20] The Greater Fresno Area is defined as Fresno, Madera, Merced, Mariposa, and Kings Counties.

[21] The CAISO used a simple average price at each node rather than a load-weighted average because the load distribution factor at a given node does not significantly change from one hour to the next. A load weighted average nodal price, with the same weight each hour, would be the same as the un-weighted average price. Consequently, the study results would not have changed significantly had the CAISO tried to account for this additional complexity.

[22] Draft Final Proposal at 8.

being concentrated in one, and the average price variation across the system was relatively stable from year-to-year. The fact that the few "outlier" nodes were dispersed widely throughout the Default LAPs suggests that it would be difficult to define more disaggregated load settlement areas short of fully nodal disaggregation. The stability from year-to-year suggests that the results are durable.

2. Comparison of Nodal Prices to Default LAP Prices.

The CAISO then analyzed the relative amount of load served at nodes with prices close to the Default LAP price as compared to the amount of load served at nodes with significantly different prices from the Default LAPs. Analyzing these differences can reflect the extent to which load within each Default LAP is currently settled at a lower/higher average Default LAP price relative to the nodal price. Overall, most of the day-ahead CAISO load during the study period was located at nodes with hourly LMPs within $2/MWh of the hourly Default LAP LMP. In PG&E, SCE, SDG&E, and VEA, 85 percent, 89 percent, 94 percent, and 98 percent, respectively, of the day-ahead load during the study period was located at nodes with prices that were within $2 of the Default LAP price.[23] These results demonstrate that the majority of load is located at nodes with nodal LMPs close to the Default LAP LMPs. Therefore, load serving entities are not paying materially higher or lower average prices at the currently defined Default LAPs than they would under a fully nodal market. If the prices that load serving entities would pay would not be significantly changed with even fully nodal disaggregation, then it is questionable as to whether the incentives that load serving entities face from the CAISO energy markets would change in any meaningful way.

3. Spatial Distribution of Nodes with Price Divergent from Default LAPs

The CAISO also evaluated the spatial distribution of load nodes whose prices diverged significantly from the Default LAP price for at least some hours to identify any potential pricing trends that may have been weakened in previous analyses which averaged the pricing trends over the study period. The CAISO identified all load nodes in its market that experienced a nodal price that was different from the Default LAP price by more than $25/MWh in at least one hour during the study period. The frequency and spatial distribution of these instances of high variation between the nodal and Default LAP prices can reflect the extent to which significant differences are concentrated to a few nodes or distributed among several nodes within a particular Default LAP. Any observed patterns could be instructive in considering further disaggregation of LAPs. The CAISO analysis reflects that significant price divergence events have been relatively rare and have not been concentrated at geographically adjacent load nodes.

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[23] *Id.* at 14.

Instead, nodes that have exhibited these price divergences have been scattered throughout the Default LAPs. Therefore, there are no contiguous regions with similar pricing trends that have been significant and persistent enough to be used in defining a more granular load aggregation point.

There were only six nodes in SCE and no nodes in VEA in which the nodal price differed from the Default LAP price by more than $25/MWh for more than one percent of the hours.[24] Approximately ten percent of SDG&E nodes had over one percent of hours in which the nodal price differed from the Default LAP price by more than $25/MWh. Importantly, the average load located at those nodes was relatively small. Approximately 18 percent of the nodes in the PG&E Default LAP had significant divergence from the Default LAP price in more than one percent of hours. However, almost 40 percent of those nodes are in the Greater Fresno Area, and the CAISO addresses the unique circumstances in that region below. Setting aside the Greater Fresno Area, the PG&E area is comparable to SDG&E with respect to the percentage of nodes that differed from the Default LAP price by more than $25/MWh. As with the other three Default LAP areas, only in a very small percentage of the hours evaluated and at only a small percentage of the nodes did the load located at the nodes in the PG&E Default LAP show significant divergence from the Default LAP price.

These results suggest that there are no contiguous regions with similar and persistent pricing trends that would allow for a natural way to further disaggregate load settlement.

4. Regression of Nodal Prices on Default LAP Prices

Finally, the CAISO performed a regression analysis to ascertain the relationship between the nodal and Default LAP prices. The CAISO regressed day-ahead nodal prices on the Default LAP prices during the study period. In all four Default LAPs, the majority of regression results indicated that prices have moved consistently with Default LAP prices and that the average nodal LMPs were not significantly different from the average Default LAP LMPs.[25] Therefore the pricing signals in the nodal LMPs are also reflected in the Default LAP LMPs and no additional transparency would be realized through nodal pricing. The only meaningful exception was the Greater Fresno Area in 2014. These results suggest the price signals would not significantly differ with more granular disaggregation.

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[24] The $25/MWh threshold was chosen to align with the tails ends of distribution charts included in parts of the CAISO analysis and to ensure that the analysis did not overlook pricing trends in those tail ends due to the averaging of previous analyses.

[25] *Id.* at 21-25.

5. Unique Considerations Regarding the Greater Fresno Area.

The CAISO analysis indicated that the Greater Fresno Area had higher average nodal prices that were, on average, $3 above the Default LAP price. This pricing trend, and the price separation between the Fresno nodes and the rest of the PG&E Default LAP, suggests that the CAISO consider creating a Fresno-based Default LAP. The CAISO assessed this possibility but believes the pricing trend observed in the study is transitory and unlikely to persist over time.

The CAISO analyzed the pricing trends by year and found that the significant price separation between the Greater Fresno Area and the remainder of the PG&E Default LAP materialized in summer 2014.[26] The Fresno area contains several significant hydropower resources. Under normal hydrologic conditions, these units generate during the day to serve high summer load in Fresno area. Because of the current drought, however, output from these units has been at historical lows. Absent output from these resources, the CAISO has had to rely on the transmission system to serve in this area. This has resulted in congestion into the Fresno area during peak hours. This congestion produced generally higher locational marginal prices in the Greater Fresno Area. The congestion was partially relieved by dispatching the Helms pumped hydro unit, which is located within the Greater Fresno Area. However, dispatching Helms more frequently in turn requires Helms to replenish its water supply more often, thereby increasing the net load in the Greater Fresno Area during off-peak hours. Although Helms could pump in off-peak hours, doing so increases off-peak congestion.

An important additional factor is that the CAISO's 2012-2013 Transmission Plan identified reliability-driven transmission projects to address potential overload and voltage concerns in the Greater Fresno area, including the Gates-Gregg 230 kV Line.[27] In the 2012-2013 Transmission Planning Process, the CAISO's economic assessment of the Greater Fresno Area modeled the Gates-Gregg 230kV line as in service. This economic assessment showed that there would be no significant congestion in the Greater Fresno Area. With this expanded transmission capacity into the Greater Fresno Area, the price separation observed in 2014 is unlikely to recur at the levels it did even if poor hydrologic conditions persist.

[26] The Greater Fresno periodically experienced higher prices and price separation from the Default LAP LMP in prior years as well, but the pricing trend was not persistent until the summer months of 2014.

[27] More details on projects identified to address concerns in the Greater Fresno area are provided in the CAISO's 2012-2013 Transmission Plan, *available at* http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx

B. Cost Estimates of Load Settlement Disaggregation

To evaluate the implementation costs of disaggregating load settlement, the CAISO requested that stakeholders provide their estimates for nine categories of implementation costs incurred under four possible levels of load settlement disaggregation. The four levels of disaggregation included: (1) slight disaggregation, such as creating two default LAPs for SCE and PG&E; (2) load aggregation to minimize error with creation of 23 Default LAPs; (3) customized LAPs for each load serving entity; and (4) fully nodal load settlement. The nine cost categories included: load forecasting; metering and telemetry; price forecasting; bidding and scheduling; settlements and billing; demand response CRR procurement and settlement; data integration and storage; and other business costs. For each cost category, the CAISO asked stakeholders to identify whether the cost would be a one-time implementation cost, capital cost, or an ongoing annual expense. Eight stakeholders provided cost estimates, representing approximately 80 percent of scheduled day-ahead load. The CAISO also developed estimates of the costs it would incur under the four scenarios.

Table 3 in the Draft Final Proposal, reproduced below, provides the combined stakeholder and CAISO cost estimates for the four disaggregation scenarios.[28]

	Slight Disaggregation			LAPs to minimize error			Custom LSE Specific LAPs			Fully Nodal		
	One Time costs	Capital Costs	Yearly Costs	One Time	Capital Costs	Yearly Costs	One time	Capital Costs	Yearly Costs	One time	Capital Costs	Yearly Costs
Load Forecasting	$ 310,776	$ 3,600,000	$ 456,492	$ 1,138,646	$ 6,750,000	$ 692,492	$ 473,422	$ 3,300,000	$ 249,820	$ 2,174,052	$ 10,850,000	$ 1,249,820
Metering and Telemetry	$ 734,776	$ 4,400,000	$ 821,164	$ 1,909,646	$ 20,150,000	$ 2,349,164	$ 1,340,422	$ 10,800,000	$ 932,328	$ 2,340,052	$ 45,600,000	$ 3,420,328
Price Forecasting	$ 129,000	$ 520,000	$ 110,000	$ 339,000	$ 1,410,000	$ 473,000	$ 94,000	$ 650,000	$ 85,000	$ 489,000	$ 1,850,000	$ 523,000
Bidding and Scheduling	$ 182,500	$ 550,000	$ 85,164	$ 421,000	$ 1,532,000	$ 230,746	$ 337,000	$ 650,000	$ 171,328	$ 911,000	$ 2,575,000	$ 1,028,910
Settlements and Billing	$ 294,776	$ 1,050,000	$ 155,576	$ 715,646	$ 4,420,000	$ 275,582	$ 615,422	$ 1,500,000	$ 231,164	$ 1,254,052	$ 5,942,000	$ 406,164
Demand Response	$ 20,000	$ 100,000	$ 150,000	$ 220,000	$ 1,100,000	$ 300,000	$ 50,000	$ 500,000	$ 50,000	$ 440,000	$ 2,200,000	$ 575,000
CRR Procurement/Settlement	$ 159,000	$ 110,000	$ 91,740	$ 267,810	$ 110,000	$ 126,746	$ 160,810	$ 100,000	$ 82,328	$ 654,900	$ 120,000	$ 282,328
Data Integration and Storage	$ 233,000	$ 700,000	$ 112,000	$ 977,000	$ 2,400,000	$ 307,000	$ 442,000	$ 950,000	$ 132,000	$ 1,283,000	$ 6,200,000	$ 1,506,000
Other Business Integration Costs	$ 1,088,800	$ 7,566,120	$ 486,000	$ 3,185,900	$ 24,729,380	$ 1,582,200	$ 1,189,750	$ 7,296,500	$ 111,600	$ 5,061,150	$ 57,258,940	$ 3,630,700
Total	**$ 3,152,628**	**$ 18,596,120**	**$ 2,468,136**	**$ 9,174,648**	**$ 62,601,380**	**$ 6,336,930**	**$ 4,702,826**	**$ 25,746,500**	**$ 2,045,568**	**$ 14,607,206**	**$ 132,595,940**	**$ 12,622,250**

C. Benefit Estimates of Load Settlement Disaggregation

The CAISO and stakeholders identified the following potential benefits from load settlement disaggregation including: (1) increased investment incentives due to more accurate price signals; (2) improved congestion hedging opportunities; and (3) a more efficient day-ahead market.

In quantifying the benefits, the CAISO and stakeholders generally agreed that any benefit assessment should be made in light of two key factors. First, the CAISO

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[28] Draft Final Proposal at 30. The CAISO requested that the cost estimates only include costs that would be incurred as a result of disaggregation and that they exclude any retail-side billing costs. The CAISO also iterated with the stakeholders providing the cost estimates to understanding the deeper assumptions made and costs included in the estimates. Entities providing the estimated costs noted capital costs are likely to be incurred every five to seven years as systems need to be upgraded over time.

analysis should focus on wholesale-side benefits that may be realized without regulatory changes in the retail rate structure. Retail electricity rates in California are established by the CPUC and other Local Regulatory Authorities. These retail rates do not reflect locational price differences between regions within the existing Default LAPs, and the CPUC is unlikely to make meaningful changes to this aspect of the status quo in the foreseeable future. Second, the CAISO analysis only should consider benefits that are incremental to the benefits that already can be realized through existing products and processes. A benefit should not be credited as resulting from load settlement disaggregation unless that benefit could not be realized but for further CAISO load settlement disaggregation.

1. ***Quantifying Benefits*** **– Investment Incentives Created by More Accurate Price Signals**

In theory, granular load settlement could provide investment signals for transmission, generation, and even participating load. The CAISO analysis, however, indicated that further disaggregation would not incrementally improve these signals, and that these benefits can be achieved through existing CAISO processes and procedures.

Investment in transmission projects has the potential to relieve congestion and lower price dispersion between nodes and Default LAPs. Accurate price signals can signal to potential investors where transmission is needed most. However, the CAISO's Transmission Planning Process already performs a cost benefit analysis of transmission projects using CAISO market results. Therefore, the accurate price signals are already available and being used to identify where new transmission investment is needed most. For example, although the Gates-Gregg line was primarily a reliability project, the CAISO analysis also showed that it provided public policy and economic benefits. Therefore, nodal disaggregation would provide not incremental benefit because there is no need for additional price signals to incent transmission investment. The CAISO's transmission planning process already adequately addresses this matter.[29]

Accurate price signals also have the potential to incent investment in generation projects, which can potentially relieve congestion and lower price dispersion. This potential benefit is unlikely to materialize, though, because the CAISO already posts nodal load LMPs on its OASIS site and settles supply based on the nodal prices. In other words nodal prices already provide signals to guide potential generation investment decisions. Therefore, there is no need for additional price signals to incent investment in generation, and nodal disaggregation would provide no incremental benefit.[30]

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[29] *Id.* at 33.

[30] *Id.* at 33.

Participating load and proxy demand response resources have an existing incentive to locate at higher priced nodes to maximize the value of their demand response. Accurate price signals are essential when determining if, and where, demand response resources should locate. However, participating load resources already have the option to schedule and settle at a more granular level in the current market by using Custom LAPs. Custom LAPs can be comprised of a single node to several nodes, and a participating load is scheduled and settled at the Custom LAP price. Also nodal prices already are already posted on OASIS for potential demand response providers to utilize in any economic assessment. Because existing price signals are already sufficient to incent demand response and proxy demand response resources can opt for Custom LAPs, providing load settlement disaggregation would not provide incremental benefits in terms of providing more accurate investment signals.[31]

2. ***Quantifying Benefits*** – Increased Congestion Hedging Opportunities

More granular load settlement potentially could allow increased allocation of congestion revenue rights in the first tier of the annual allocation process. In turn, increasing released congestion revenue rights could impact the congestion revenue rights revenue adequacy. The CAISO analysis indicated that disaggregating load settlement likely would generate tangible, although relatively small, benefits by increasing load serving entities' ability to hedge against congestion. Essentially, in allocating congestion rights "sinked" to a Default LAP the process limits the allocation to whatever energy can flow to the most constrained node within the Default LAP. In theory, including fewer nodes within a Default LAP would reduce the frequency of an allocation being curtailed because a single node within the Default LAP was constrained. The CAISO estimated the foregone congestion hedge by identifying all congestion revenue rights that were nominated but not allocated in the first tier of the annual allocation process, and then valuing[32] the additional congestion revenue rights. The CAISO analysis identified the amount this benefit to be between $1.08 million and $2.75 million per year.[33]

In addition, the CAISO examined the impact load disaggregation may have on revenue adequacy. Revenue inadequacy occurs when the funds collected from congestion in the energy market are insufficient to meet congestion revenue rights settlement obligations. Past instances of revenue inadequacy primarily have been

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[31] *Id.* at 33.

[32] The valuation varies depending on whether the analysis values the benefit as: (1) the average monthly auction price for each season and time of use; (2) the average monthly auction price for each season and time of use, excluding negatively priced congestion revenue rights; or (3) the hourly day-ahead marginal congestion components of the source and sink nodes.

[33] Draft Final Proposal at 35.

driven by differences in the congestion revenue rights market model and day-ahead market model. These differences are exacerbated by releasing too many congestion revenue rights. Changes in load settlement would not improve consistency between the two network models, and therefore are unlikely to improve revenue adequacy. The CAISO notes that other efforts are ongoing to reduce the modeling inconsistencies that largely drive revenue inadequacy. Starting in the 2015 annual process, the congestion revenue rights model not only increased the enforced constraints and contingencies, but also updated the list of constraints and contingencies based on more recent information. In addition, the CAISO now applies the break-even analysis to internal paths rather than just to interties. Through the break-even analysis, the congestion revenue rights model determines the limit on constraints based on the quantity of congestion rights that could have been released and remained revenue neutral using data from the previous three years. As previously noted, load disaggregation has the potential to increase allocated congestion revenue rights, and revenue inadequacy has historically been driven by releasing too many congestion revenue rights. Furthermore, an increase in allocated congestion revenue rights may decrease congestion revenue rights awarded through the auction. This in turn would decrease auction revenues used to fund the balancing account. Therefore, load disaggregation potentially could increase, rather than decrease, revenue inadequacy because of the need to settle more congestion revenue rights and the potential decrease in the auction revenues that are used to fund the CRR balancing account. Therefore, nodal disaggregation provides no incremental benefits toward reducing revenue inadequacy.[34]

3. *Quantifying Benefits* – More Efficient Day-Ahead Market Outcomes

Granular load settlement also theoretically could provide a more efficient day-ahead market by ensuring that loads and resources are optimized at a more precise level. Currently, in the day-ahead market the optimization may have to adjust load to solve a constraint. When load is adjusted, it is adjusted at the Default LAP level, which means that all nodes within the Default LAP move up or down in lockstep according to their load distribution factors until the constraint is solved. If the Default LAPs were disaggregated, then in theory the optimization may be able to adjust load at an individual node by a fraction of the amount to solve the constraint.

However, virtual bidding already in large part provides the theoretical benefit of more fine-tuned load adjustments. Virtual supply bids submitted in the day-ahead market can provide the market optimization with a more efficient way to solve constraints. Currently, a market participant can submit a virtual supply bid at a node effective in solving a constraint. The day-ahead market can then use the virtual supply to potentially solve the constraint rather than adjusting load at the Default LAP level.

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[34] *Id.* at 36-37.

The extent to which virtual supply bids would be effective in providing the same benefit as disaggregated load depends on: (1) the ability and willingness of market participants to submit virtual supply bids at the effective nodes; and (2) the bid price of the virtual bid. Even if an effective virtual supply bid were submitted, depending on the bid price, it still may be less costly to adjust load at the Default LAP to solve the constraint rather than utilize the virtual supply bid at a node with a higher effectiveness factor.

Given the hours in the day-ahead market in 2014 with significant congestion where load disaggregation may have resulted in a less costly market solution, the average shadow price during hours the Default LAP bid was marginal is less than the average shadow price during hours the Default LAP bid was not marginal. This indicates that the market efficiency gained between solving a constraint by adjusting load at the Default LAP as opposed to simply adjusting supply at more granular location would be minimal. Therefore, the CAISO does not believe that nodal disaggregation would provide any incremental benefit in terms of a more efficient market outcome.[35]

III. Explanation of Compliance

The results of the recent load disaggregation study conducted by the CAISO, reviewed by stakeholders, and evaluated by the Market Surveillance Committee, support the conclusion that the current aggregation of load settlement points is just and reasonable and that departing from the current level of aggregation is unwarranted at this time. The CAISO analysis reveals that there is minimal and largely unsystematic price dispersion in the CAISO balancing authority area. The only notable price dispersion – observed in the Greater Fresno Area – is unlikely to persist because it is due to historically atypical hydrologic conditions and is expected to be resolved by pending transmission projects. Because there has been limited price dispersion, disaggregation would result in minimal tangible market benefits. The minimal benefits need to be considered in light of the significant implementation costs identified by the CAISO. The total estimated annual benefit of $1.08 - $2.75 million amounts to only approximately 15 percent of the estimated annual costs of disaggregation, and that does not include covering any of the $14.6 million in one-time implementation costs or $132.6 million in capital costs. Accordingly, the CAISO, with the overwhelming support of its stakeholders, requests that the Commission find the CAISO has met its outstanding load settlement compliance obligations from the September 2006 order.

The June 2014 order indicated that the Commission was amenable to granting further relief if the CAISO could support its request with a study that incorporated five considerations. The CAISO's request to maintain the status quo is guided directly by a pricing study that incorporates each of these elements. The first factor the Commission mentioned was that the study should include detailed description of the underlying data.

[35] *Id.* at 40.

The CAISO's draft final proposal contained extensive discussion of data used in the analysis. There has been significant transparency as to the data the CAISO used as the basis of its study. The second factor was that the study should evaluate a range of potential levels of disaggregation. As discussed above, the CAISO conducted a fully nodal pricing study, which it also used to identify other potential levels of disaggregation. Given that the pricing study results consistently indicated there was no other level of granularity, short of nodal, that could be used to create a new Default LAP, and the benefits of fully granular disaggregation were minimal, there was no other level of disaggregation for the CAISO to evaluate. The third factor was that the study should focus on areas showing the greatest price divergences. The pricing study, as well as the stakeholder process, devoted substantial attention to the Greater Fresno Area. This was the only area that showed any notable price divergences. As discussed above, the CAISO determined that the price divergences in that area are unlikely to persist. The fourth factor was the study should have support for the estimated implementation costs. Rather than relying on conjecture, the CAISO received cost estimates from eight stakeholders, representing approximately 80 percent of day-ahead scheduled load. The CAISO scrutinized stakeholders' submitted implementation costs for reasonableness and internal consistency. For example, the CAISO considered whether different stakeholders serving a similar number of customers submitted comparable cost estimates and whether cost increases and decreases seen between stakeholders that served more or fewer customers, respectively, were reasonably proportionate. Finally, the Commission noted that the analysis should cover the entire CAISO footprint. The CAISO study was robust and covered the entire CAISO footprint.

In addition to complying with all five elements the Commission identified as necessary in any request for further relief, the CAISO's retention of the current level of disaggregation is just and reasonable and not unduly discriminatory. The Commission must find that rates are just and reasonable. The CAISO's current load settlement approach is just and reasonable because it protects consumers in load pockets from high nodal LMPs and ensures that most consumers pay an average zonal price for energy regardless of their location on the grid. Protecting consumers in this way is an important aspect of recognizing that, as was the case when the CAISO's nodal market was first proposed, the transmission grid in the CAISO footprint was not built with the expectation that the system would be used to support a nodal market.

Although the Commission need not find that a proposal yields the most just rate possible and it need not consider the merits of alternative proposals,[36] it is also

[36] *Calpine Corp. v. California Independent System Operator Corp.*, 128 FERC ¶ 61,271, P 41 (2009). *See also California Independent System Operator Corp.*, 141 FERC ¶ 61,135, P 44 (2012) ("Upon finding that CAISO's Proposal is just and reasonable, we need not consider the merits of alternative proposals."); *New England Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd sub nom. Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992), *citing City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (rate design proposed need not be perfect, it merely needs to be just and reasonable).

instructive in this case that the CAISO does not see any reasonable alternatives to maintaining the status quo. Although further disaggregation might theoretically provide a de minimis level of benefits, it is not reasonable to pursue a change given that the minimal benefits are outweighed by the significant cost associated with additional disaggregation. The CAISO analysis indicates that increasing the number of Default LAPs would neither be particularly effective at providing more accurate price signals nor would it provide increased opportunities for hedging congestion.

Finally, stakeholders fully support the CAISO's proposal to retain the current level of aggregation and unanimously oppose further disaggregation. Any proposal to disaggregate load aggregation points further would garner significant opposition in this or other proceedings. The overwhelming lack of evidence for the need of further disaggregation supports retaining the current level of aggregation and avoiding such controversy.

IV. Stakeholder Process

The CAISO initiated a stakeholder process in September 2014 to consider the June 2014 order and discuss the parameters of potential studies that would inform the CAISO and its stakeholders as to whether the costs of disaggregation would still likely outweigh any related benefits.[37] The stakeholder process proceeded with the CAISO discussing potential study design and initial results. The CAISO determined that the further study should encompass the five elements mentioned in the September 2014 order. The CAISO made multiple adjustments to its study based on stakeholder feedback and input from the Market Surveillance Committee. These adjustments included: accounting for the load currently settled at lower/higher Default LAP prices relative to the higher/lower nodal prices; creating more detailed analysis of estimated benefits of disaggregation; and incorporating greater detail on projected congestion conditions in the greater Fresno area. After posting the study results the CAISO then posted a straw proposal and draft final proposal in which the CAISO presented its proposed retention of the current load settlement methodology. This proposed approach was met with universal stakeholder support, as well as support from the Market Surveillance Committee in its written opinion.

The Market Surveillance Committee discussed the CAISO's pricing study at three Market Surveillance Committee meetings and participated in the stakeholder process. In their adopted opinion on Load Granularity Refinements, the Committee states: "Our major conclusion is that we support the ISO's recommendation against further

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[37] Details on the CAISO stakeholder process are available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/LoadGranularityRefinements.aspx

disaggregation at this time because the likely benefits are small in the near future, and are likely to be well outweighed by the reported costs of implementation."[38]

The stakeholder process is summarized in the table below.

August 22, 2014	MSC Meeting discussion
September 22, 2014	Issue Paper posted
September 29, 2014	Stakeholder Meeting to discuss issue paper
October 13, 2014	Stakeholder commends on Issue Paper due
October 28, 2014	Posted paper on pricing study design
November 6, 2014	Stakeholder call to discuss pricing study design
November 20, 2014	Implementation cost data due from Stakeholders
December 15, 2014	Posted preliminary pricing study results
December 16, 2014	MSC Meeting to discuss preliminary results
January 14, 2015	Posted pricing study results paper
January 21, 2015	Stakeholder call to discuss pricing study results
January 30, 2015	Stakeholder comments on pricing study results due
February 19, 2015	MSC Meeting to discuss pricing study results
February 19, 2015	Posted Straw Proposal
March 3, 2015	Stakeholder meeting to discuss Straw Proposal
March 13, 2015	Stakeholder comments on Straw Proposal due
March 24, 2015	Post Draft Final Proposal
March 31, 2015	Stakeholder call to discuss Draft Final Proposal
April 10, 2015	Stakeholder comments on Draft Final Proposal due
May 13, 2015	Draft MSC Opinion posted
May 18, 2015	Stakeholder call to adopt MSC Opinion
May 22, 2015	Draft MSC Opinion completed

[38] Market Surveillance Committee Load Granularity Refinements Opinion, at 3.

V. Communications

Correspondence and other communications regarding this filing should be directed to:

Anna A. McKenna
Assistant General Counsel
David S. Zlotlow
Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7222
amckenna@caiso.com
dzlotlow@caiso.com

VI. Service

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with Scheduling Coordinator Agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

VII. Contents of this Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	CAISO Load Granularity Refinements Draft Final Proposal, March 24, 2015.
Attachment B	CAISO Market Surveillance Committee Opinion on Load Granularity Refinements.

VIII. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission find the CAISO to have met its load settlement disaggregation obligations arising from the September 2006 order.

Respectfully submitted,

By: *<u>/s/ David S. Zlotlow</u>*

Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
David S. Zlotlow
Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7222
dzlotlow@caiso.com

Counsel for the California Independent
System Operator Corporation

ATTACHMENT A

CAISO Load Granularity Refinements Draft Final Proposal, March 24, 2015

Load Granularity Refinements

Draft Final Proposal

March 24, 2015

Table of Contents

The Load Granularity Issue paper is a separate document which can be located at:
http://www.caiso.com/Documents/IssuePaper_LoadGranularityRefinements.pdf

I. Executive Summary

In 2014, the California Independent System Operator (ISO) requested a permanent waiver from the Federal Energy Regulatory Commission (FERC) for the ISO's obligation to further disaggregate Default Load Aggregation Points (DLAPs) by MRTU Release 2. FERC denied that request. In the Order denying the waiver, FERC granted the ISO a one-year extension to either comply with, or seek further relief from, the ISO's obligation to disaggregate the DLAPs by June 3, 2015. Based on more detailed analysis conducted since its 2014 request, the ISO intends to request that it be relieved of its obligation to further disaggregate its DLAPs.

The ISO conducted a fully nodal pricing study to evaluate the impacts of load granularity pricing refinements in the CAISO market. Day-ahead nodal locational marginal prices (LMPs) were analyzed in four dimensions: average nodal LMPs, differences of nodal and DLAP LMPs, nodal volatility of differences, and a regression of nodal LMPs on DLAP LMPs.

The results indicate that nodal price dispersion across the system and variation from the DLAP LMPs are minimal. With the exception of the Greater Fresno area, the observed price dispersion and variation was sporadic and not contiguous enough to be used to efficiently create more granular load zones. The congestion-driven pricing observed will likely dissipate as already approved transmission enhancements become operational in the future.

As requested by FERC in its order denying the ISO's 2014 waiver request, the ISO determined estimate implementation costs. The ISO collected implementation cost estimates from eight stakeholders and estimated the ISO implementation costs. Cost estimates total $3.2 million in one-time implementation costs, $18.6 million in capital costs, and $2.5 million annually for slight disaggregation. Estimated implementation costs for fully nodal disaggregation total $14.6 million in one-time implementation costs, $132.6 million in capital costs, and $12.6 million annually.

More granular load pricing does have the potential to provide benefits. Those benefits are expected to be negligible given the pricing study results. Furthermore, there are other factors that will impact the magnitude of benefits such as existing market products and processes that can be used to capitalize on the same benefits, and the probability of changes to the current retail rate structure. The ISO estimated benefits in three areas assuming fully nodal disaggregation. Benefits related to more accurate price signals to incent investment, congestion revenue rights, and more efficient market outcomes have been estimated to range between $1.08 million and $2.75 million annually. This estimate does not take into account potential costs related to revenue adequacy (or inadequacy), therefore considered by the ISO to be an over-estimate of wholesale side benefits.

At this time, the ISO plans to maintain the status quo and not seek to further disaggregate the current DLAPs. The ISO will file at FERC by June 3, 2015, presenting a case that the current DLAPs are just and reasonable.

II. Revisions to the February 19th straw proposal and response to stakeholder comments

A. Pricing study results

Most stakeholders supported the methodology used in the pricing study and stated the analysis was comprehensive and addressed FERC's order denying the ISO's 2014 waiver request. A few additional requests were submitted. PG&E requested the ISO estimate the impact the transmission projects will have on congestion in the Greater Fresno area by re-running analyses excluding summer of 2014. CDWR asked the ISO to report when major market changes were implemented and to assess any changes in the pricing study results. In addition, CDWR also requested the ISO to consider how prices may adjust as more renewable resources are integrated, once-through cooling, and load growth returns to normal conditions. CDWR also asked the ISO to quantify the dollar value associated with the load at nodes with price differences between nodal and DLAP LMPs. The ISO addresses these comments below.

<u>The ISO has made the following changes to the pricing study portion of the Load Granularity Refinements Initiative:</u>

- In response to CDWR's request, the ISO has noted the dates of major market changes and introduction of new products that occurred during the study period (2011-2014). The pricing study results were assessed to determine the impact the market changes or new products had on pricing trends.

- To estimate congestion conditions in the Greater Fresno area after currently approved transmission projects become operational, the ISO has presented the average nodal prices and average price differences between nodal and DLAP LMPs excluding summer of 2014.

- In response to input from the Market Surveillance Committee (MSC), the ISO has included an additional heat map of the nodal and DLAP LMP differences. The LMP differences are weighted by load to determine if the more material differences occur during peak load or low load hours.

B. Estimated implementation costs

The ISO conducted an internal review of the cost estimates to fully understand the data collected from market participants that submitted estimated implementation costs. PG&E asks that the ISO communicate with stakeholders that an internal review was conducted and also provide details on each cost category. PG&E also suggested the ISO submit an affidavit along with the FERC filing, affirming our own evaluation of the cost estimates.

<u>The ISO has made the following changes to the estimated implementation cost portion of the Load Granularity Refinements Initiative:</u>

- In the straw proposal, the ISO committed to reporting the percentage of load represented by the entities which provided estimated implementation costs. This information is provided in the draft final proposal.

- The ISO has communicated to stakeholders the additional internal review conducted of the estimated implementation costs.

- Additional discussion is provided on each cost category along with assumptions made when estimating the implementation costs.

C. Estimated benefits

Stakeholders were appreciative of the ISO's effort in estimating the potential benefits of load granularity in response to submitted comments on the previous paper. Most entities agreed with the methodology and reasoning used to determine the estimated benefits. PG&E asked the ISO to explicitly list the current ISO market products and processes that provide the same benefits as load disaggregation. CDWR suggested the ISO estimate the benefit of increased allocated Congestion Revenue Rights (CRRs) by valuing the additional CRRs using the day-ahead marginal congestion components rather than the average monthly auction price.

<u>The ISO has made the following changes to the estimated benefits portion of the Load Granularity Refinements Initiative:</u>

- The ISO has clearly noted existing market products and processes that provide the same benefits load disaggregation would provide.

- The ISO has estimated the benefit of increased allocated CRRs by using: 1) average monthly auction price including negative priced CRRs, 2) average monthly auction price excluding negatively priced CRRs, and 3) the day-ahead marginal congestion components.

D. Requests for changes not included in draft final proposal

- The ISO maintains its position that predicting pricing and how pricing trends may change in the future as system conditions and the grid evolve would be challenging. Therefore, it would be challenging to accurately reflect the impact retiring once-through cooling resources, increased renewable generation, and transmission improvements would have on day-ahead energy LMPs.

- While most stakeholders support the thoroughness of the pricing study, CDWR has asked for additional analysis on the differences between nodal and DLAP LMPs. The ISO believes that it has thoroughly analyzed the potential benefits related to price differences between nodal and DLAP LMPs. In this draft final proposal the ISO presents the percentage of load located at nodes with varying price differences and an additional, new analysis that shows the load weighted average price differences on a heat map.

- The ISO acknowledges the benefit of adopting the MSC's Opinion prior to the final policy paper. However, given the tight schedule of the initiative to make a timely FERC filing, the ISO and MSC are unable to draft and adopt an opinion before posting the draft final proposal. The ISO and MSC are currently planning to have an opinion adopted in May.

- The ISO appreciates PG&E's suggestions of providing an affidavit validating the consistency and scope of the estimated implementation costs with the FERC filing and conducting a legal analysis to determine the most effective method to seek relief from disaggregation. The ISO will take these suggestions into consideration when developing its filing strategy.

III. Background

FERC's original September 21st, 2006 Order on MRTU found the DLAP approach reasonable and a simplified method for introducing LMP pricing, while minimizing its impact on load. However, FERC also directed the ISO to increase the number of LAP zones to provide more accurate price signals and assist participants in hedging of congestion charges, after three years of experience with the new market.

In 2010, the ISO initiated a stakeholder process to evaluate LAP disaggregation. The ISO conducted a pricing study, which found that except for one small area, prices in sub-LAP regions did not differ significantly from the DLAPs. The MSC did a spatial pricing study showing that short of nodal pricing, there was no efficient way to group nodes in large zones. Stakeholders indicated that they would face significant implementation hurdles and that many potential benefits were already available to them through other ISO processes, or would be soon. FERC accepted the ISO's request to delay disaggregation of LAPs: "*We find that more pricing information and additional experience with the MRTU design changes, such as proxy demand response and convergence bidding will allow CAISO to develop a proposal to further disaggregate the default LAPs, as directed*."[1] FERC extended the deadline to disaggregate LAPs until October 1, 2014.

In 2013, the ISO initiated a stakeholder process to again evaluate with stakeholders disaggregation of the existing LAPs. The ISO performed a simple pricing analysis comparing prices in the existing sub-LAPs to the DLAPs, which indicated there were no major price disparities. Based on this information, and stakeholder input indicating that they did not see enough price disparity and they would incur substantial costs from disaggregating the DLAPs, the ISO filed a motion for a permanent waiver of FERC's directive to disaggregate the LAPs.

On June 3, 2014, FERC issued an order that denied the ISO's request for a permanent waiver to comply with FERC's previous orders to disaggregate existing LAPs.[2] The order extended for one year from the date of the order the time for the ISO to comply, or seek further relief from the disaggregation request.

[1] *Cal. Indep. Sys. Operator Corp.*, 136 FERC ¶ 61,055, at P 6 (2011).
[2] *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,181 (2014).

The ISO initiated another stakeholder process to evaluate LAP disaggregation in September 2014 with an issue paper and stakeholder meeting that also presented a proposal for a study of pricing dispersion between demand nodes and the current DLAPs. Pricing study results, estimated implementation costs, and a discussion of potential benefits were posted, followed by a stakeholder conference call in January 2015. A straw proposal with revised pricing study results, updated implementation costs, and an estimate of potential benefits was posted February 19th followed by a stakeholder meeting on March 3, 2015. This paper presents the final set of pricing study results, cost and benefit assessment, and the ISO's proposal.

IV. Schedule for Stakeholder Engagement

The ISO will host a stakeholder call on March 31, 2015 to allow stakeholders to ask questions or comment on the draft final proposal. Written comments from stakeholders should be sent to the ISO by April 10, 2015.

This will be followed by the ISO filing at FERC and presenting a case that the current DLAP structure is just and reasonable.

The schedule for stakeholder engagement is listed below.

Date	Milestone
March 24	Post draft final proposal
March 31	Hold stakeholder call
April 10	Receive written comments from stakeholders
May	Adopt MSC opinion
June 3	File at FERC

V. Pricing Study Results

The pricing study that was conducted over the last several months by the ISO reflected a fully nodal spatial price dispersion analysis to evaluate the impacts of load granularity pricing refinements in the ISO market. Specifically, we focused on whether there are significant price differences between nodal LMPs and DLAPs, and the cause of any large differences. The study analyzed day-ahead LMPs at all load nodes on the system in four methods. We used day-ahead hourly energy prices from 2011 through November 14, 2014 in the study[3]. First we conducted a historical review of average nodal LMPs at all load nodes from 2011- 2014. Second, we analyzed the amount of load by difference of nodal and DLAP LMPs. Third, we analyzed the volatility of those price differences at each load node. Last, we performed a regression analysis to ascertain the relationship between the nodal LMPs and the DLAP LMPs. In

[3] February 6 and 7 of 2014 were excluded due to anomalous gas prices contributing to significantly higher day-ahead energy prices.

addition to evaluating the magnitude of price dispersion, this study also analyzes the consistency of any price dispersion over time and by location.

Pricing study results were presented in a paper posted on January 14, 2015 followed by a stakeholder call on January 21st. In response to stakeholder feedback, additional analysis was conducted, which was presented in the straw proposal posted on February 19th. A subsequent stakeholder meeting was held March 3rd, 2015. Below is a discussion of the final set of pricing study results presented in previous papers or as amended throughout the stakeholder process.

A. Average nodal LMPs (2011-2014)

First, we reviewed historical nodal prices by taking the simple average nodal price at each load node over the four year period between 2011 and 2014 from the day-ahead market. We examined the simple average price at each load node to determine (1) the spatial variation across the system of average prices, and (2) the areas where groups of nodal LMPS are on average higher or lower than other nodal LMPs. A simple average price at each node was calculated as opposed to a weighted average price because the load distribution factor (LDF) at a given node does not significantly change from one hour to the next. The results would not be significantly impacted by accounting for variations over time. A load weighted average nodal price, with the same weight each hour, would be the same as the un-weighted average price.

Figure 1 shows the simple average LMP at each load node using hourly day-ahead energy prices from 2011-2014. Each point represents the average LMP at an individual load node. Average nodal prices across the system range from $52/MWh to $26/MWh with 90% of average prices between $44/MWh and $35/MWh. We also analyzed the average nodal prices by Load Aggregation Point and by year to identify any regions or time periods where a subset of nodes have consistently higher or lower average prices compared to the other load nodes.

Figure 1 Range of average day-ahead nodal LMPs (2011-2014)

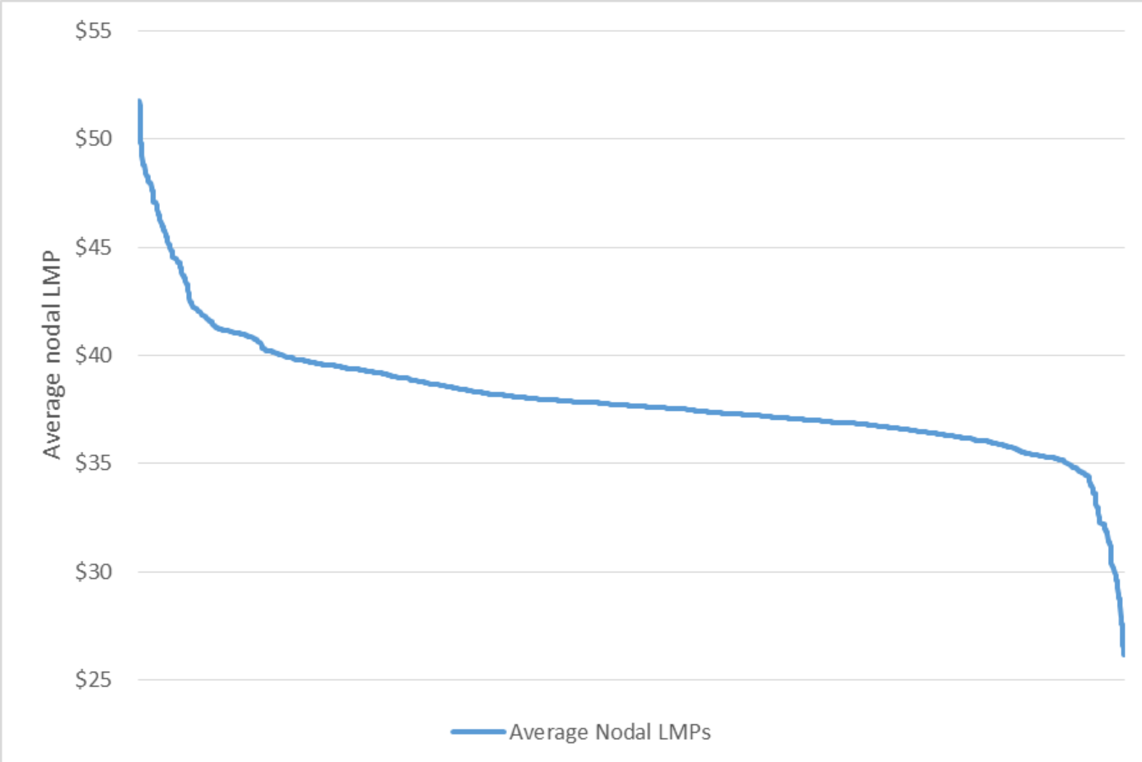
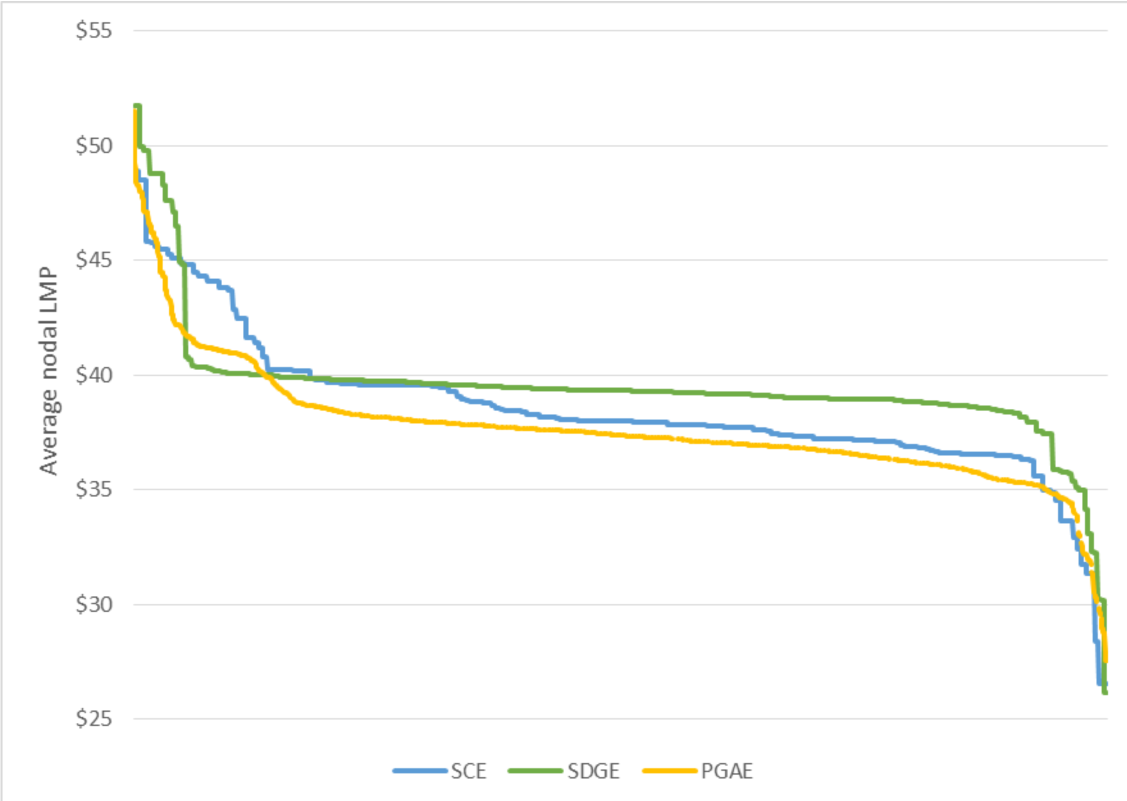


Figure 2 and Figure 3 below examine the average nodal prices geographically. Figure 2 uses the same average prices in Figure 1 but shows them by LAP. The three major DLAPs have similar price variations. This indicates that the load nodes with higher or lower average LMPs from Figure 1 are dispersed throughout the three major DLAPs rather than being concentrated in one.

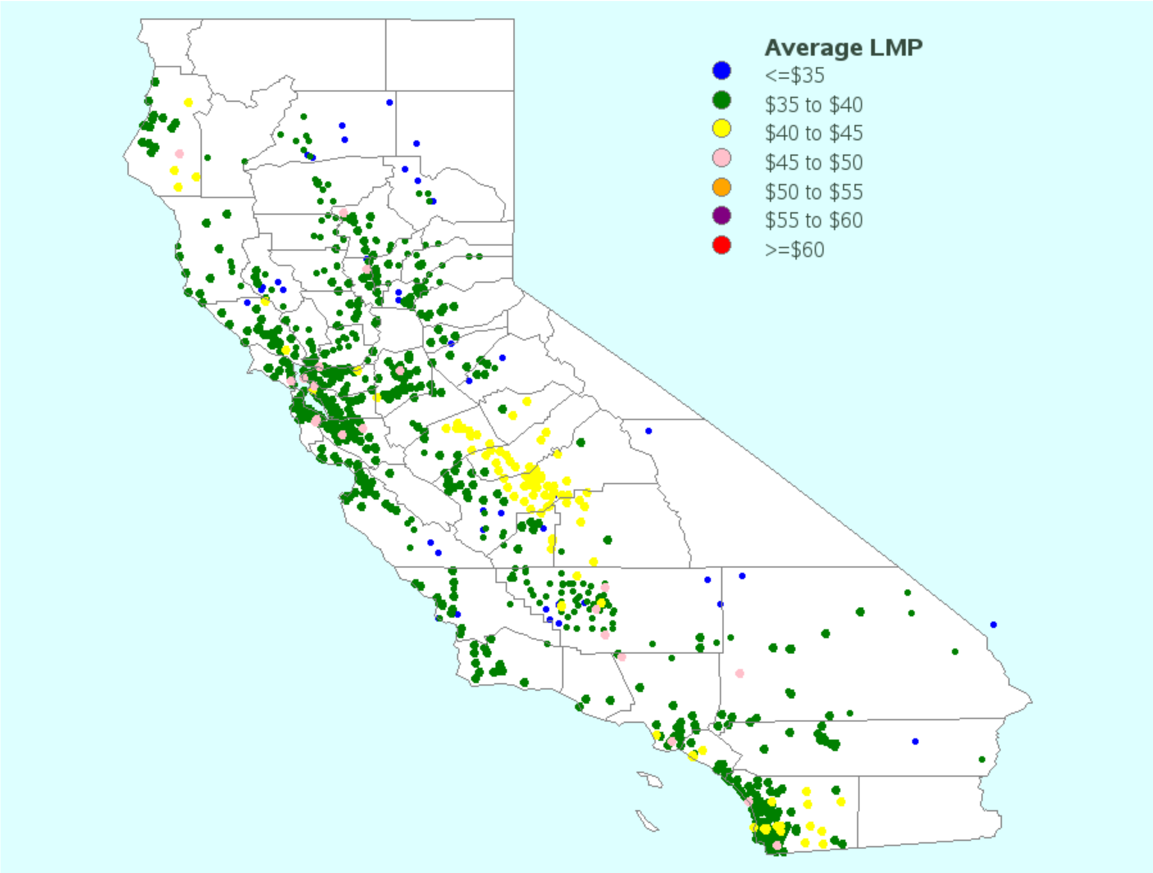
Figure 3 plots the average prices in Figure 1 and Figure 2 on a map of California to determine if there are regions within each LAP that have higher or lower average priced load nodes. The majority of load nodes have an average LMP in the $35-$40/MWh range (green). Load nodes with lower average prices (blue) and higher average prices (pink) are scattered throughout California. There is a cluster of nodes in the $40-$45/MWh range (yellow) concentrated in the Fresno, Madera, Modesto, and Mariposa Counties.

Figure 2 Range of average day-ahead nodal LMPs by DLAP (2011-2014)[4]



[4] Valley Electric Association (VEA) is not included in this chart because there is only two years' worth of data (2013-2014), which made it appear as though VEA had consistently higher average prices than the other three DLAPs.

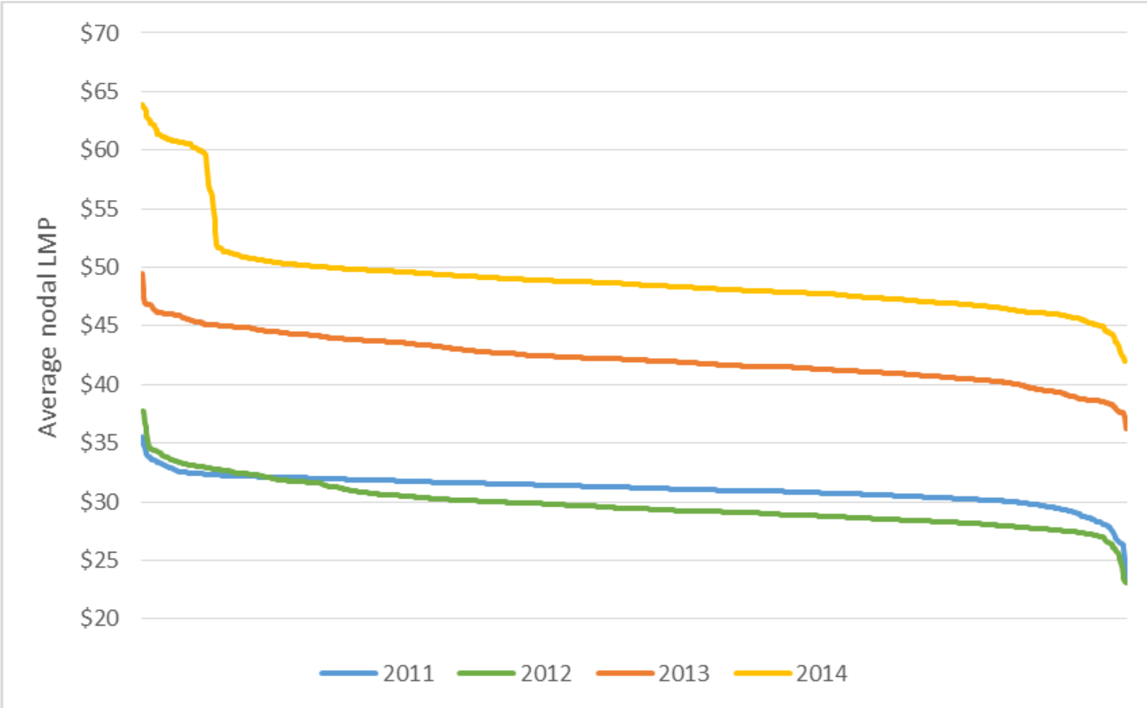
Figure 3 Simple average nodal LMPs heat map (2011-2014)



To assess if there are significant changes in the average price variation year to year, the average nodal prices by year were also analyzed. Figure 4 shows the average nodal price variation across the system were similar in 2011 and 2012. The average nodal prices shift up in 2013 and then again in 2014. Greenhouse gas emission compliance costs and higher gas prices contributed to the upward shift in 2013. The upward shift in 2014 can be contributed to an increase in greenhouse gas compliance cost and extreme hydro conditions.

Despite higher prices in 2013, the price variation (difference between the highest average and lowest average nodal LMP) remains the same compared to 2011 and 2012, approximately a $15/MWh variation. In 2014, the price variation increased to approximately a $22/MWh difference due to higher average LMPs in the Greater Fresno area. Prices in the Greater Fresno area did not increase until 2014 and were driven by congestion on lower voltage transmission lines during July and August.

Figure 4 Range of average day-ahead nodal LMPs by year (2011-2014)



Given the change in variation of average prices in 2014 compared to the other years, we plotted the average nodal prices for each year on a map of California to identify the location of those load nodes. The maps for 2011 (Figure 5) and 2014 (Figure 6) are shown below[5]. Average LMPs in 2011 were primarily in the $30-$35/MWh range (pink) with a few higher priced nodes (orange) scattered throughout California.

The average LMP map for 2014 shows significant changes in both the average LMPs overall (note the change in price categories defined in the legend) as well as higher average LMPs in Fresno and surrounding counties. Prices in the Greater Fresno area did not increase until 2014 due to congestion on lower voltage transmission lines.

[5] The map for 2012 is similar to 2011. The map for 2013 is similar to that of 2014 without the significant change in average LMPs in Fresno and surrounding counties.

Figure 5 Simple average day-ahead nodal LMPs heat map (2011)

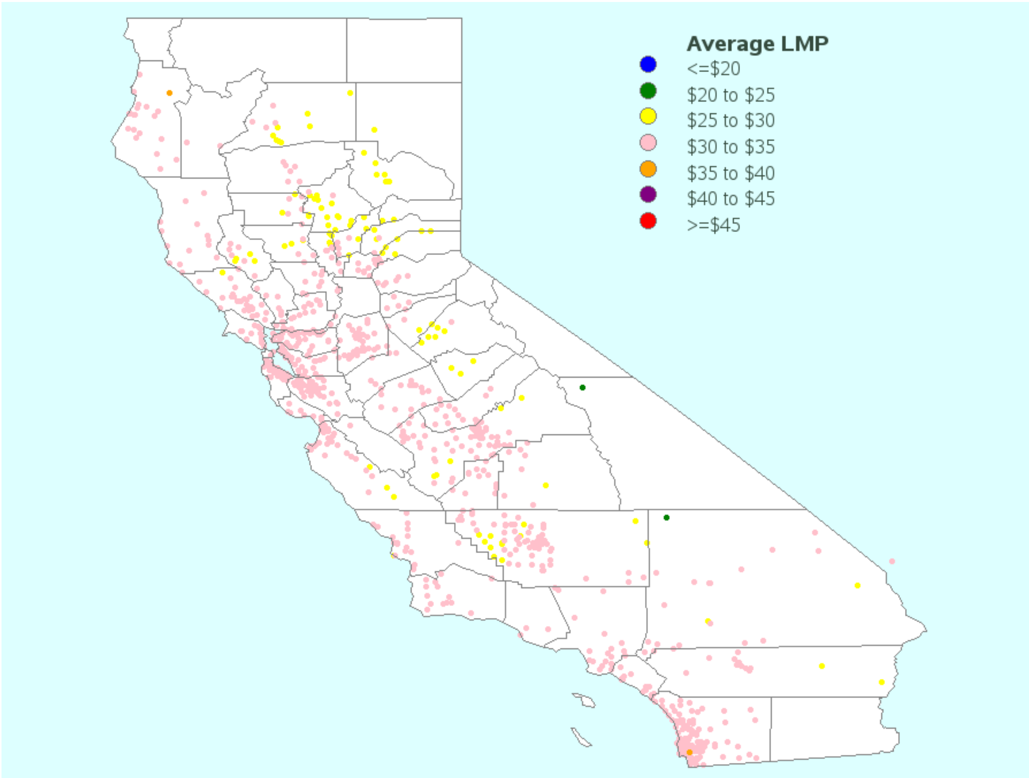
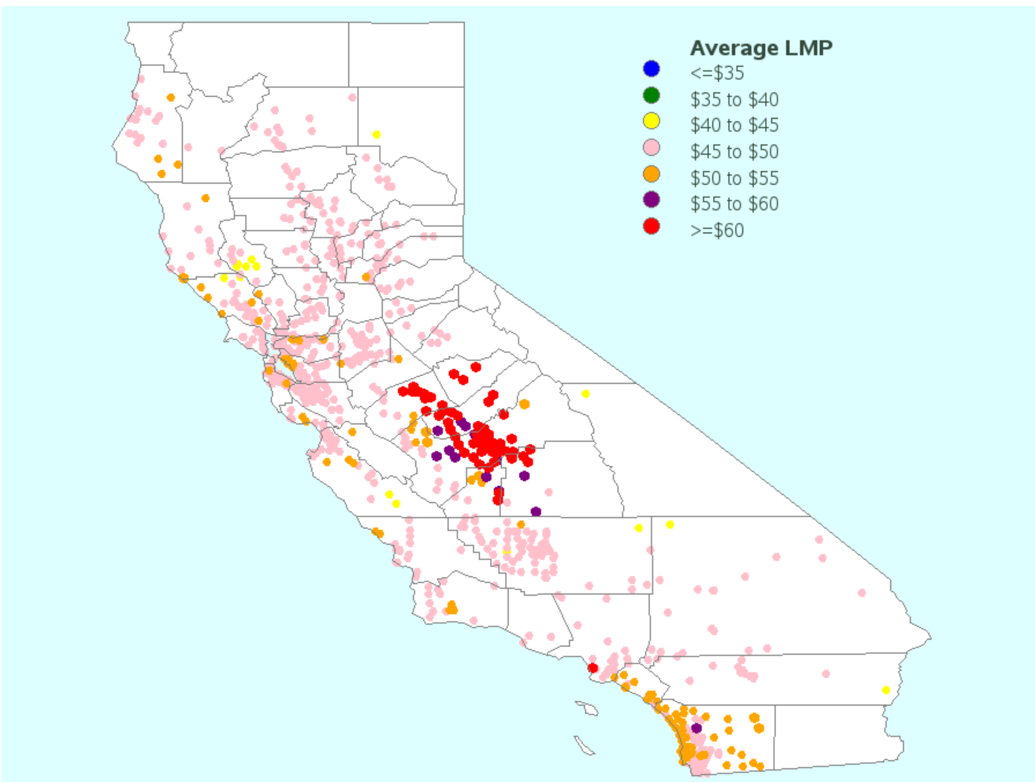


Figure 6 Simple average day-ahead nodal LMPs heat map (2014)



Assessing the average nodal prices from 2011-2014 has shown that the variation in average prices across the system continues to remain minimal and is consistent year to year. Except for the Greater Fresno area in 2014, there is no contiguous group of nodes that are on average higher or lower relative to the other nodes on the system, making disaggregation challenging short of fully nodal.

B. Difference of nodal and DLAP LMPs

Currently, day-ahead load is bid in and settled at the DLAP LMP as opposed to the nodal LMP. Within a LAP, some load nodes have higher LMPs and some lower LMPs relative to the DLAP LMP. Because they are all within the same LAP, all load is charged the same DLAP LMP. Analyzing the difference between the nodal LMPs at load nodes and the DLAP LMP for which the node resides will indicate the extent to which lower/higher priced nodes are being charged a higher/lower average DLAP price.

The following four figures show the percent of load from 2011-2014 at nodes with nodal LMPs above and below the DLAP LMP. The figures reflect the percentage of load in each LAP by the difference of each hourly nodal LMP and DLAP LMP[6] from 2011 – 2014, except for Valley Electric Association (VEA) which only has hourly LMPs from 2013-2014. The load each hour at each load node was categorized by the difference between the nodal LMP and DLAP LMP from 2011-2014. The figures below show the percentage of total DLAP load from 2011-2014 that was located at a node in the given categories based on the difference between the nodal LMP and DLAP LMP.

Reporting the percentage of load at each node as opposed to the frequency of hourly nodes ensures differences at nodes where more load is served has a weight higher than differences at nodes with less load. Load at nodes with hourly LMPs that have a difference less than $0/MWh (i.e. negative) are those being charged a higher DLAP LMP relative to the nodal LMP. Load at nodes with hourly LMPs that have a difference greater than $0/MWh (i.e. positive) are being charged a lower DLAP LMP relative to the nodal LMP. Overall, most of the load is at nodes with hourly LMPs within $2/MWh of the hourly DLAP LMP, representing less than 5% of a $40/MWh or greater DLAP LMP.

Pacific Gas and Electric (Figure 7) and Southern California Edison (Figure 8) LAPs have similar distributions. Approximately 44% of load in PGAE and 57% in SCE are at nodes with nodal LMPs within $0.50/MWh of the DLAP LMP; 85% of load in PGAE and 89% of load in SCE are at nodes within $2/MWh of the corresponding DLAP LMP. The distribution of price differences in PGAE and SCE are slightly skewed to the left. In other words, there is more load at nodes with LMPs in those LAPs that are lower than the DLAP LMP.

[6] We calculated the difference as the hourly nodal LMP minus the hourly DLAP LMP.

Figure 7 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – PGAE

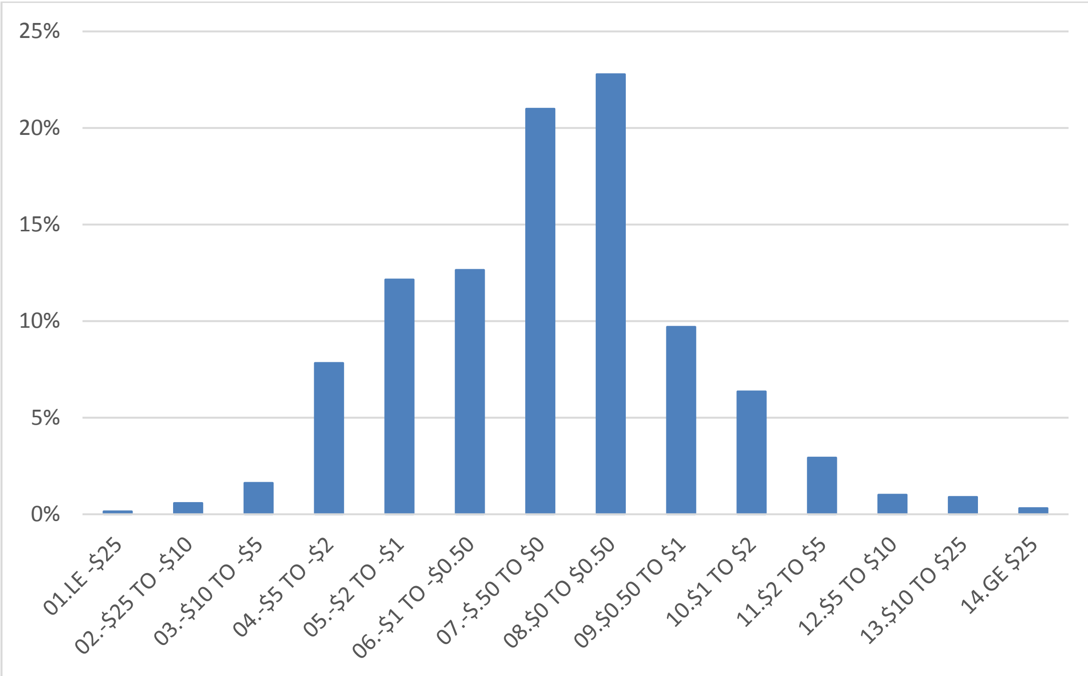
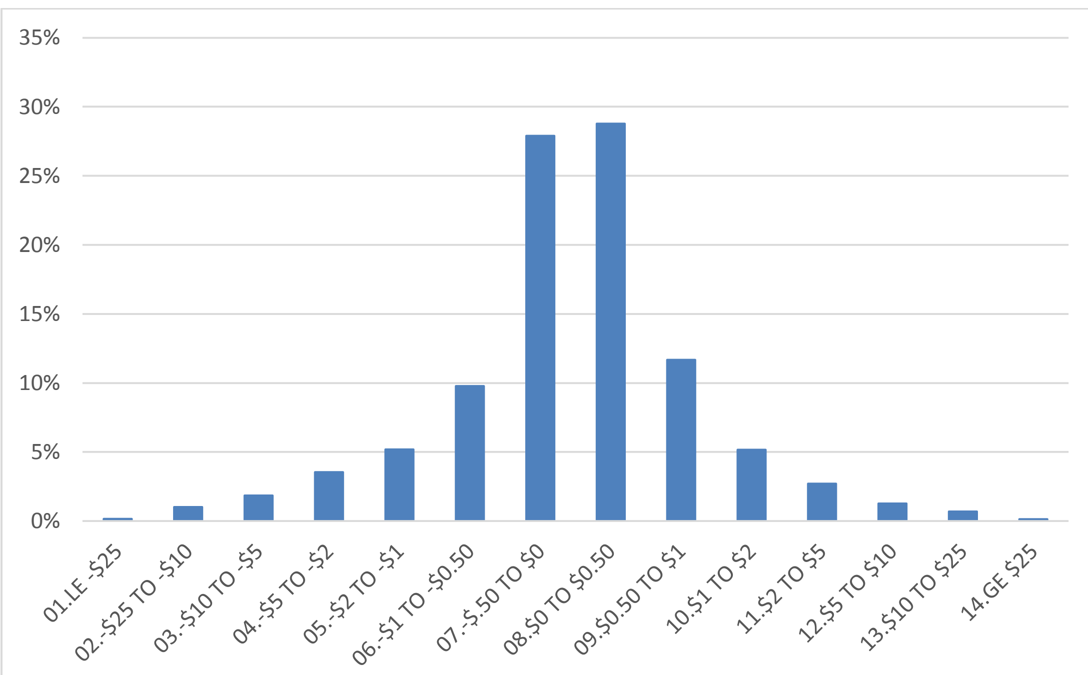


Figure 8 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – SCE



The distribution of LMP differences in SDG&E (Figure 9) and VEA (Figure 10) LAPs are centered on $0/MWh. The SDG&E LAP has almost 80% of load at nodes with nodal LMPs within $0.50/MWh of the DLAP LMP and 94% are within $2/MWh of the DLAP LMP. Valley Electric has 96% of load at nodes with nodal LMPs within $0.50/MWh of the DLAP LMP and 98% is within $2/MWh of the DLAP LMP. The majority of load is located at nodes with nodal LMPs close to the DLAP LMPs, therefore the extent to which load is paying a higher/lower average DLAP price as opposed to the lower/higher nodal price is minimal.

Figure 9 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – SDGE

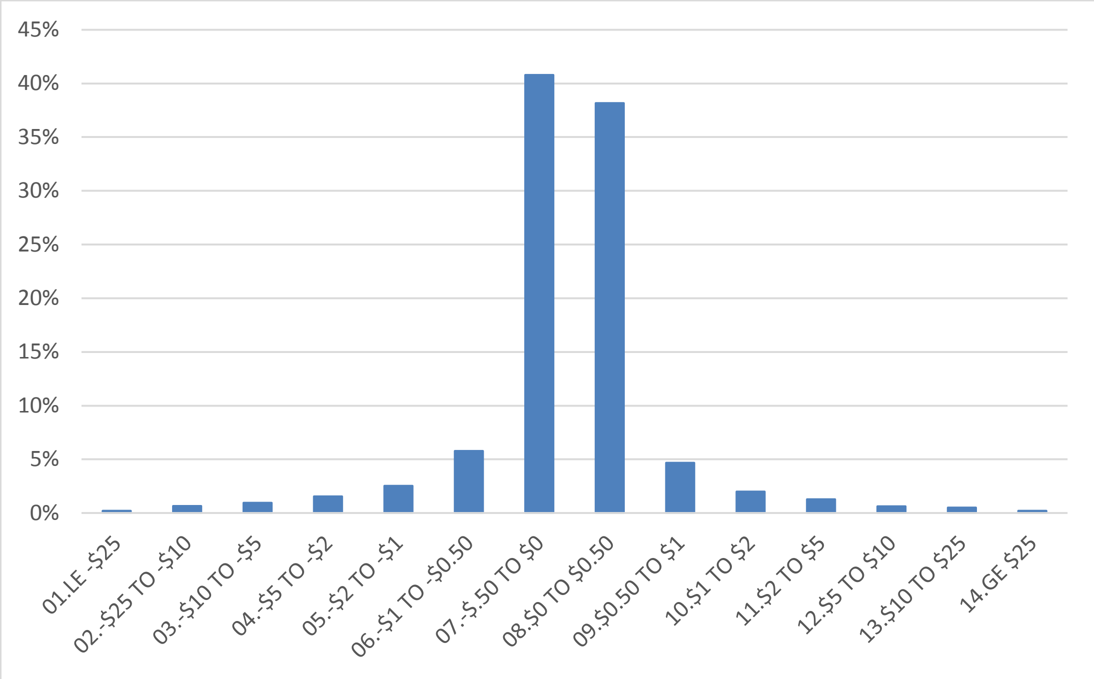


Figure 10 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – VEA

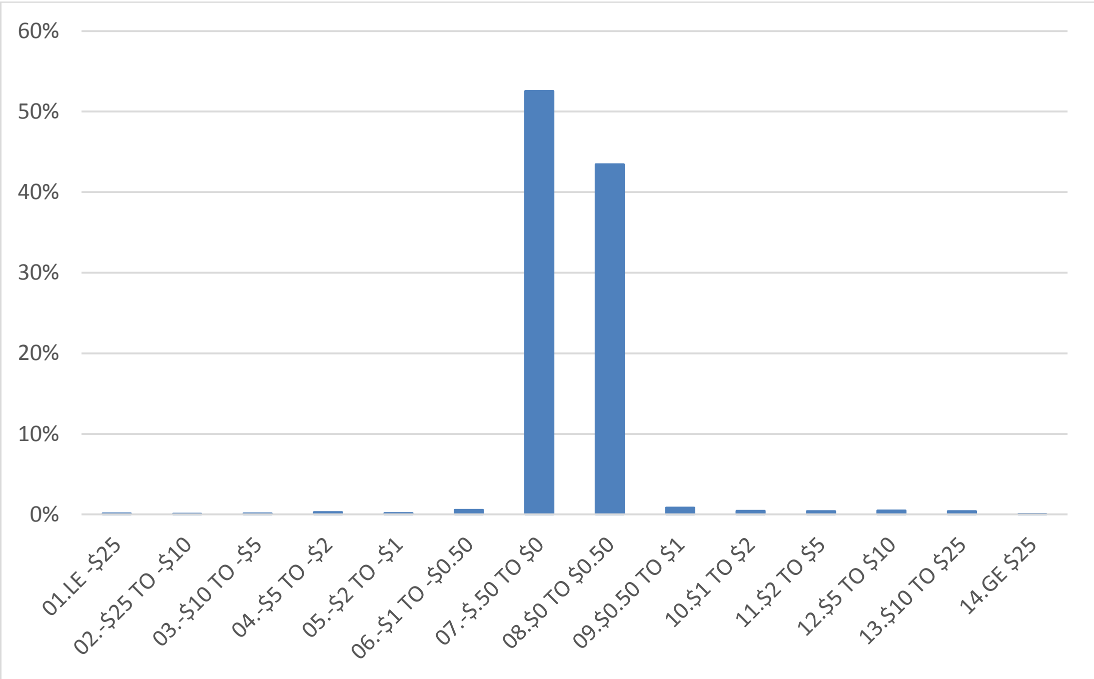


Table 1 below provides the percentages used to generate the previous four charts showing the percentage of DLAP load located at nodes with LMPs above/below the DLAP LMP by given thresholds.

Table 1 Percentage of 2011-2014 load by difference of nodal and DLAP LMP

Difference between nodal and DLAP LMP	Percentage of total DLAP load from 2011-2014			
	PGAE	SCE	SDGE	VEA
Less than -$25/MWh	0%	0%	0%	0%
Between -$25/MWh and -$10/MWh	1%	1%	1%	0%
Between -$10/MWh and -$5/MWh	2%	2%	1%	0%
Between -$5/MWh and-$2/MWh	8%	4%	2%	0%
Between -$2/MWh and -$1/MWh	12%	5%	3%	0%
Between -$1/MWh and-$0.50/MWh	13%	10%	6%	1%
Between -$.50/MWh and $0/MWh	21%	28%	41%	53%
Between $0/MWh and $0.50/MWh	23%	29%	38%	43%
Between $0.50/MWh and $1/MWh	10%	12%	5%	1%
Between $1/MWh and $2/MWh	6%	5%	2%	0%
Between $2/MWh and $5/MWh	3%	3%	1%	0%
Between $5/MWh and $10/MWh	1%	1%	1%	0%
Between $10/MWh and $25/MWh	1%	1%	1%	0%
Greater than $25/MWh	0%	0%	0%	0%

The average difference between the nodal LMP and DLAP LMP at each load node from 2011-2014 is shown geographically in Figure 11. The magnitude of the average differences are scattered throughout the ISO footprint except for the Greater Fresno area. Fresno and surrounding counties have nodal LMPs that are, on average, higher than the DLAP LMP by more than $3/MWh. As previously noted, this is due to congestion going into the Fresno area.

Figure 12 shows the average difference between nodal LMP and DLAP LMP weighted by load. This additional analysis was done in response to MSC input to determine if the material differences are correlated with higher load hours. There is no notable difference between the simple average and load weighted average; therefore, material differences between nodal and DLAP LMPs are not primarily during high load hours.

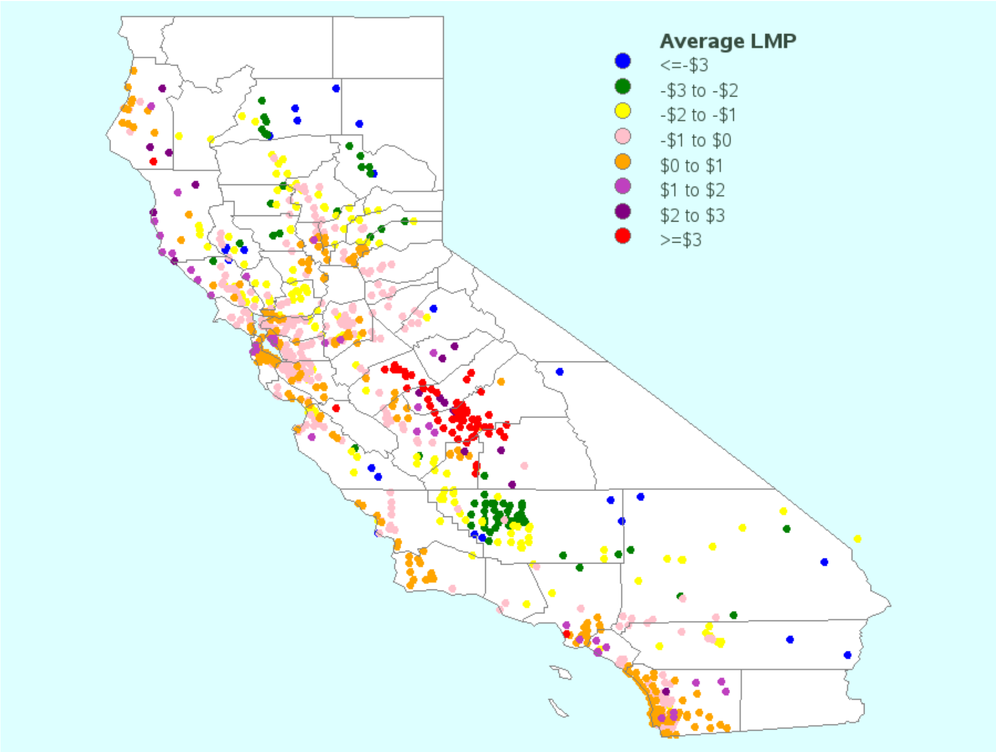


Figure 11 Average difference of nodal LMP to DLAP LMP heat map (2011-2014)

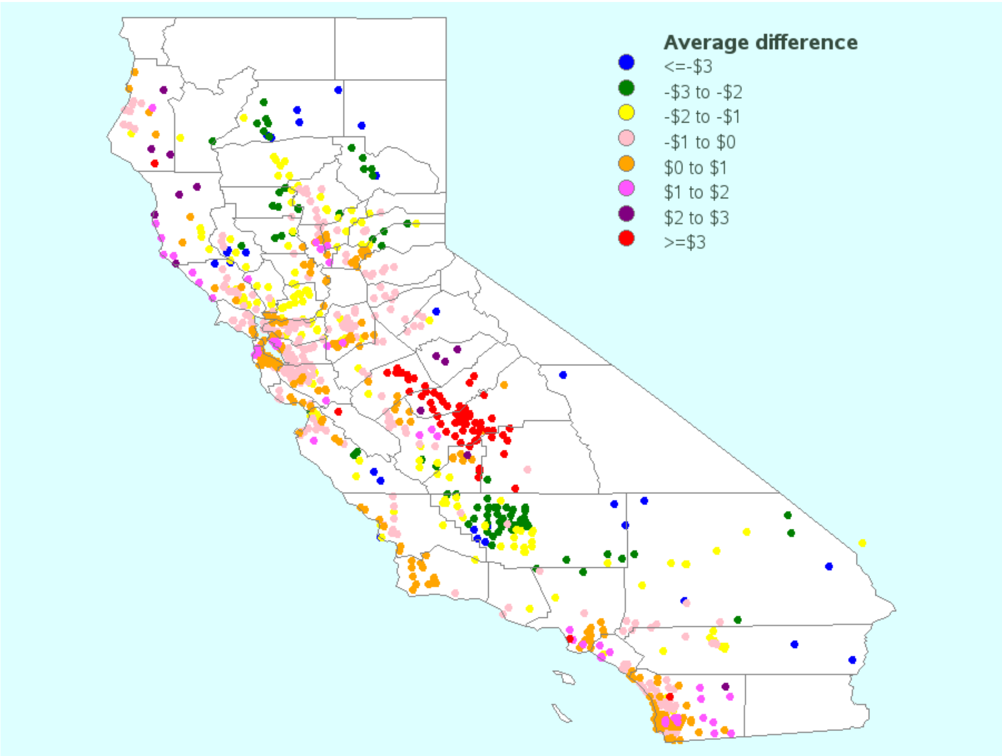


Figure 12 Load weighted average difference of nodal LMP to DLAP LMP heat map (2011-2014)

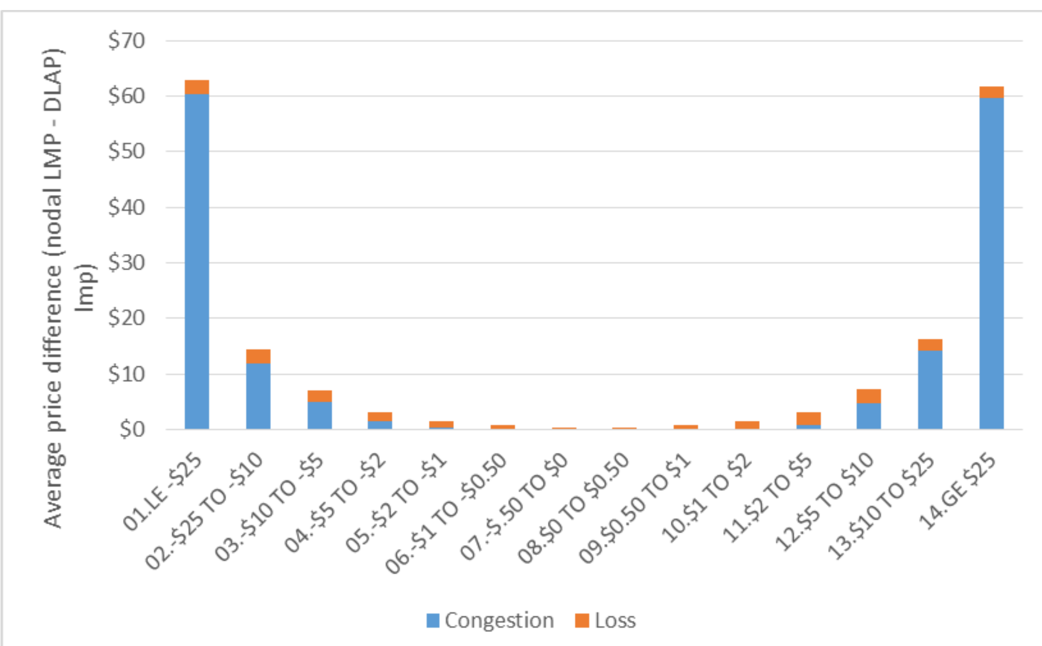
Any difference in a nodal LMP relative to the DLAP LMP is due to differences in the congestion components and/or loss components of the LMPs. The contribution each component has to the difference in each hour for each node was calculated. Then the average difference and average contributions were taken by the same pricing categories as Figures 7 – 10. Figure 12 below is for the PGAE LAP; all other LAPs show a similar pattern.

When the average price difference is large (tail ends of the chart), the majority of difference is due to congestion. As the difference decreases, i.e. gets closer to $0/MWh, loss becomes the main contributing factor. In general, congestion causes the highest difference between nodal LMPs and DLAP LMPs but occurs less frequently than losses. Losses are calculated every hour, therefore have a high frequency of occurrence but the difference they create between the nodal LMPs and DLAP LMPs is minimal.

This analysis was done to see how price differences may be minimized if load zones were based on loss factors or congestion conditions. The loss component of each node is based on the transmission voltage levels at that location. In the ISO footprint, there are high voltage lines right next to low voltage lines. Two nodes physically close to one another geographically can have significantly different loss components. Therefore creating contiguous zones based on similar loss components would be infeasible.

Creating zones based on congestion patterns would be difficult as well, because those patterns are not consistent. The ISO system is constantly evolving with new transmission, new resources, resources retiring, as well as unforeseen outages and de-rates. Therefore congestion is not consistent and oftentimes unpredictable. Creating load zones based on something that is constantly changing would require continuous re-evaluation and possibly re-defining zones.

Figure 13 Contributing factors to differences between nodal and DLAP LMPs – PGAE 2011-2014



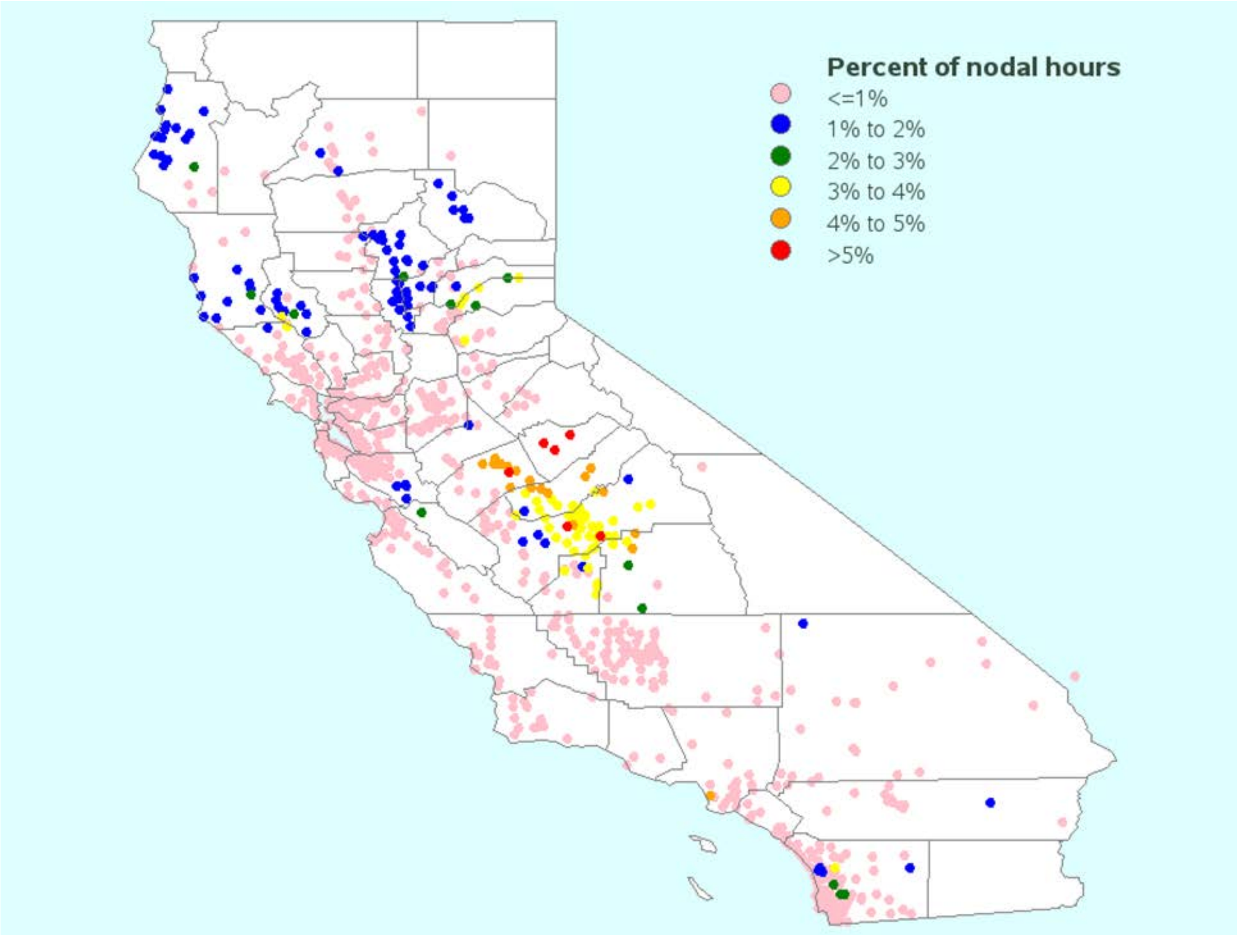
C. Nodal Price Volatility

In addition to analyzing the magnitude of price differences between the nodal LMP and DLAP LMP, the ISO analyzed the volatility of price divergence at each node. The frequency of price volatility at each node indicates the extent to which significant differences are concentrated to a few nodes or distributed amongst several nodes within the DLAP. The heat map below (Figure 13) shows all nodes in the ISO foot print that experienced a nodal LMP greater/lower than the DLAP LMP by at least $25/MWh in at least one hour[7]. Almost all nodes in each DLAP experienced a nodal LMP higher or lower than the DLAP LMP by at least $25/MWh once from 2011-2014, as indicated by the quantity of nodes represented in the map.

The volatility analysis shows that the price divergence from DLAP LMPs is not concentrated at a few nodes but scattered throughout the nodes in the LAP. There were very few nodes with at least one percent of hours where the nodal LMPs differed from the DLAP LMPs by more than $25/MWh (non-pink nodes) for three of the four DLAPs. VEA didn't have any nodes with at least one percent of hours from 2012-2014 with nodal LMPs that differed from the DLAP LMP by more than $25/MWh. Furthermore, the average load located at those nodes with the significant differences greater than one percent of total hours was relatively small. The PGAE DLAP had 18% of nodes with significant differences from the DLAP LMP but several of those nodes are located in the Greater Fresno area and experienced the divergence of prices during the summer of 2014.

[7] Only nodes that had data for at least one year were included in the analysis.

Figure 14 Volatility of nodal differences greater than $25/MWh 2011-2014



D. Regression Analysis

The ISO conducted a regression analysis similar to that done by the Market Surveillance Committee in 2011 to determine how nodal LMPs move relative to DLAP LMPs. The analysis regresses day-ahead nodal LMPs for load nodes on the DLAP LMPs using data from 2011-2014.

The regression results are presented in the following four figures, one for each current load zone. The variable on the horizontal axis is the intercept term from the regression results divided by the average DLAP LMP[8]. The variable on the vertical axis is the coefficient term of the regression results. The coefficient term indicates how well the two LMPs move together. A coefficient greater than 1 indicates the nodal LMP will have a larger movement relative to a movement in the DLAP LMP. A coefficient less than 1 indicates the nodal LMP will have a smaller movement relative to a movement in the DLAP LMP[9].

[8] The intercept was normalized so the intercept and coefficient terms can be interpreted together in a clean manner.

[9] For example, if the coefficient is .5 then a $1 increase/decrease in DLAP LMP will result in a $0.50 increase/decrease in nodal LMP. A coefficient equal to 1.5 means a $1 increase/decrease in DLAP LMP will result in

If the average nodal LMP is equal to the average DLAP LMP, then the point will fall on the green reference line. Points above the reference line have an average nodal LMP greater than the average DLAP LMP; points below the reference line have an average nodal LMP less than the average DLAP LMP. If all the nodes fall on the reference line, then the linear regression line (orange dashed line) will also fall on the reference line.

In all four LAPs, the majority of regression results are clustered on or near the reference line, and the linear regression line (orange dashed line) is close to the reference line as well. Furthermore, the cluster in each LAP is around (intercept, coefficient) equal to (0, 1). PGAE (Figure 15) and SCE (Figure 16) LAPs have a minimal amount of points away from the reference line and/or (0, 1). SDGE (Figure 17) regression results are mostly along the reference line with the exception of a few outliers. When the outliers are removed from the chart, the orange linear line follows the reference line more accurately. VEA (Figure 18) results all follow the green reference line. This analysis was also conducted by year. As would be expected, all results are similar to what is shown below with the exception of PGAE in 2014 due to the load nodes in Fresno and surrounding counties.

a $1.50 increase/decrease in nodal LMP. A negative coefficient means an increase/decrease of DLAP LMP will result in a decrease/increase of nodal LMP.

Figure 15 Regression results – PGAE 2011-2014

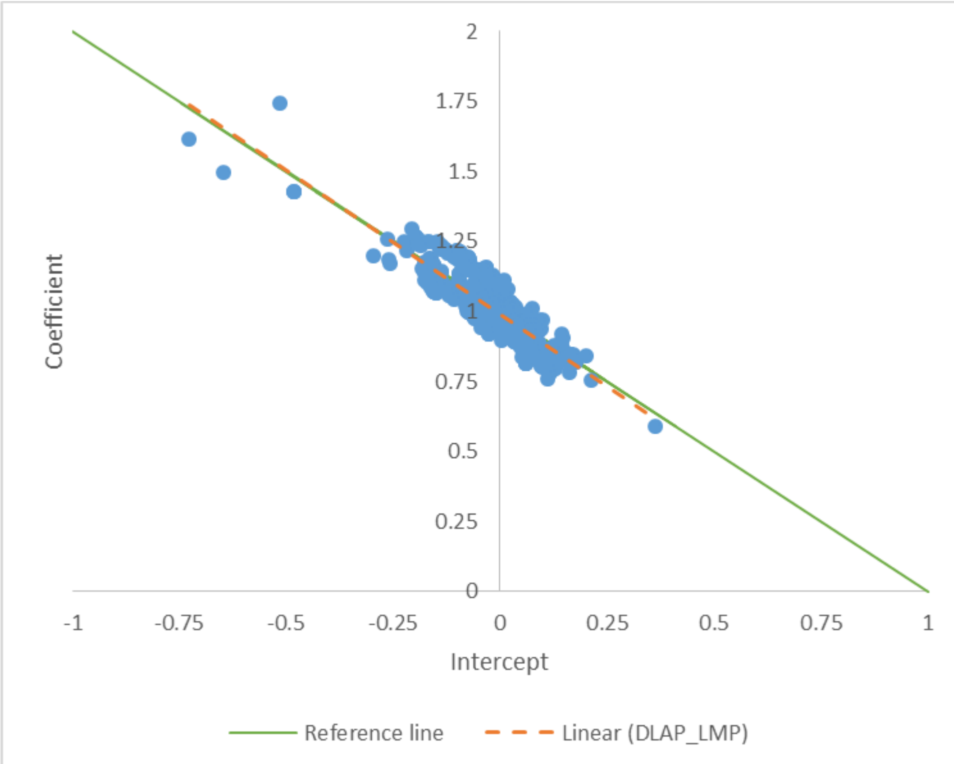


Figure 16 Regression results – SCE 2011-2014

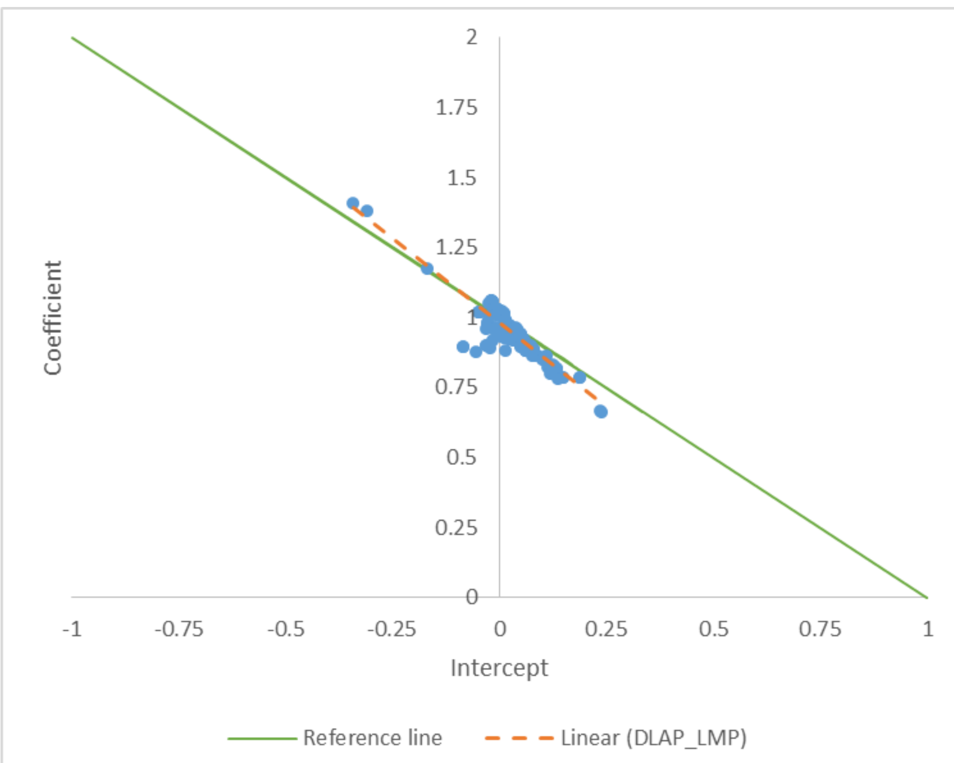


Figure 17 Regression results – SDGE 2011-2014

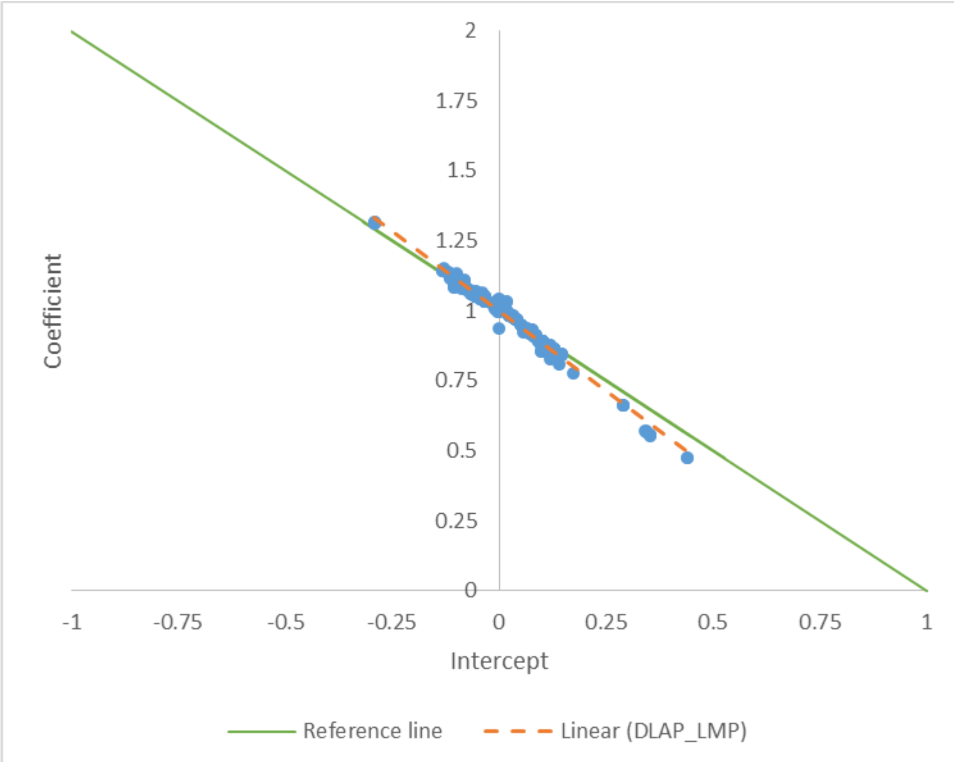
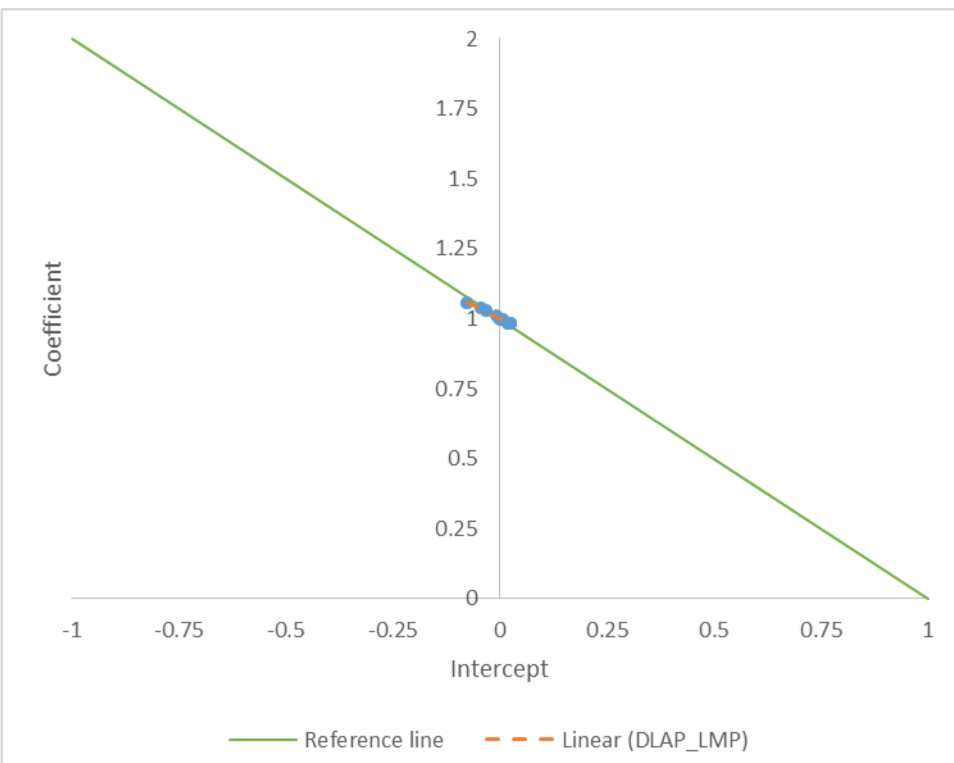


Figure 18 Regression results – VEA 2011-2014



In all four LAPs, the majority of regression results were clustered on or near the reference line, indicating that nodal LMPs move with DLAP LMPs such that the average nodal LMP is expected to be the average DLAP LMP. This analysis was also conducted by year. As expected, yearly results showed no significant differences except for PGAE in 2014 due to the load nodes in Fresno and surrounding counties.

E. The Greater Fresno area

The Fresno and surrounding counties have higher than average nodal LMPs in 2014 relative to the other load nodes on the system. The difference between the nodal LMPs in those counties and the PGAE DLAP LMP is higher than the difference between other nodal LMPs and the corresponding DLAP LMP. Therefore, that area is one that might be aggregated into another DLAP if the pricing trend became consistent. However, the price dispersion in the Greater Fresno area was isolated to July and August of 2014 due to congestion. Within the area, there are several hydro units, which under normal conditions generate during the day to serve high summer load in Fresno area. Due to the drought, the hydro generation was significantly lower. Therefore load was being served through the 230kV line, which resulted in congestion into the Fresno area during peak hours. The Helms unit was frequently being dispatched by the market to help serve load in Fresno and alleviate congestion. In turn, Helms had to replenish its water supply, and would pump during off peak hours. When Helms pumps, it adds to Fresno load, which would then lead to congestion during off peak hours. Therefore the market saw consistent congestion into the Greater Fresno area during July and August 2014.

Given that the congestion was caused by extreme hydro conditions, and will likely return to historical congestion levels when hydrological conditions improve, the ISO does not believe high congestion and nodal LMPs in the Greater Fresno area will continue to exist. Transmission projects have already been identified and approved to address concerns in the area. The 2012-2013 Transmission Plan[10] identified reliability-driven transmission projects to address potential overload and voltage concerns in the Greater Fresno area, such as the Gates-Gregg 230 kV Line. The 2012-2013 Transmission Planning Process (TPP) reliability assessment resulted in potential overload conditions in 2014, 2017, and 2022, which led to identifying transmission projects in the area.

During the economic assessment phase of the TPP, the base case models reliability driven projects as in-service. The 2012-2013 Transmission Planning Process economic assessment modeled the Gates-Gregg 230kV line as in service, resulting in minimal congestion. The TPP board approved report states that "[w]ith the reliability network upgrades identified in Section 3.3 (Central California Study) in the Greater Fresno Area (GFA), there is no significant congestion in this study area." Therefore, the congestion in that area should be mitigated with the expansion of the transmission system, and the current price divergence will likely dissipate. Creating a new DLAP based on congestion patterns that will likely become negligible is not conducive to the current ISO markets.

[10] Please refer to the 2012-2013 Board Approved Transmission Plan for more details on projects identified to address concerns in the Greater Fresno area. http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx

One way to assess the impact the approved transmission projects and upgrades may have on congestion in the Greater Fresno area is to analyze pricing trends excluding months with significant congestion in the area. As previously noted, the Greater Fresno area experienced unusual congestion during the summer of 2014. Excluding July through September 2014 from the analysis produced the results presented in the following two figures. The average nodal LMPs for 2014 (Figure 19) shows the nodal prices in the Greater Fresno area decreased from being greater than $60/MWh (Figure 6) to being primarily in the $50-$55/MWh range with some nodes in the $55-$60/MWh range. Furthermore, the average difference between the nodal LMPs and DLAP LMPs (Figure 19) decreased from being more than $3/MWh greater (Figure 11) to between $1/MWh and $3/MWh greater.

Figure 19 Average nodal LMPs 2014 excluding summer

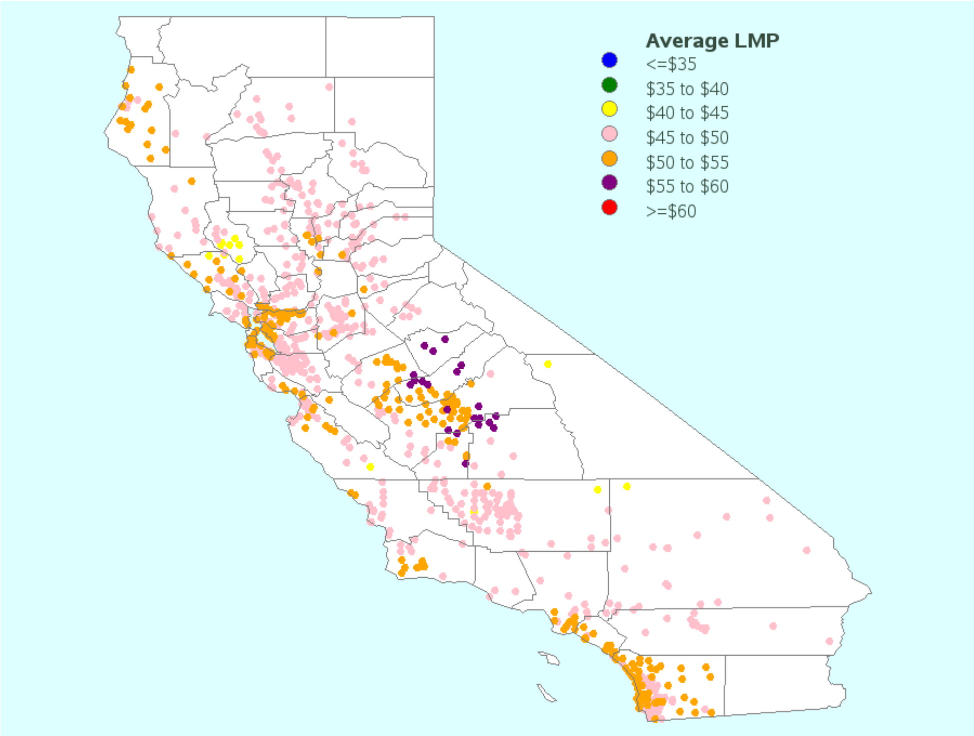
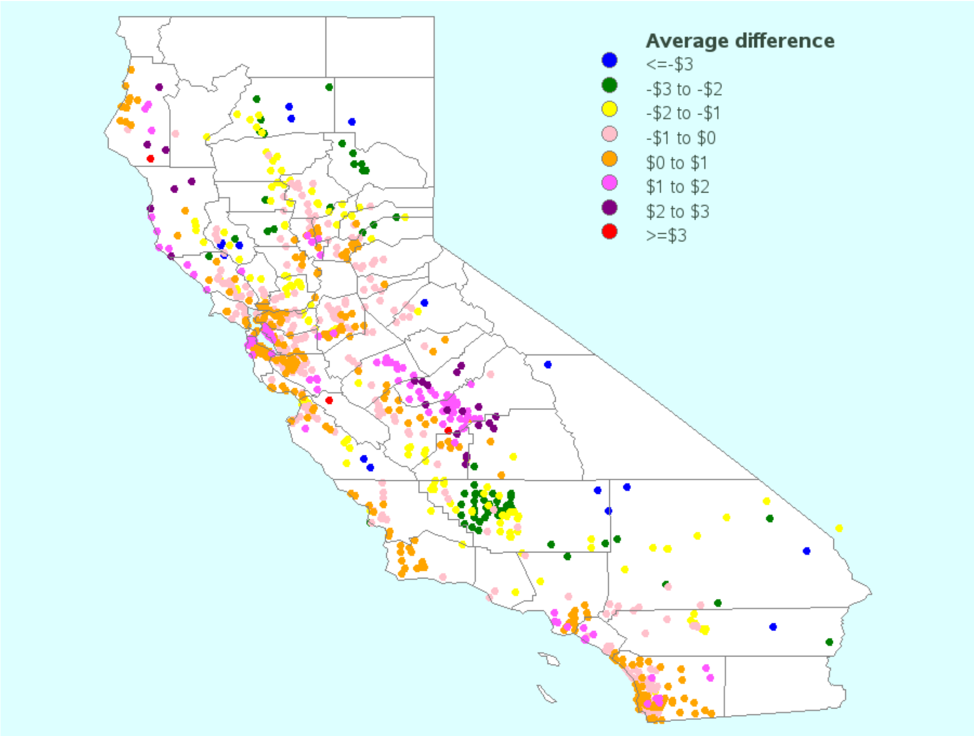


Figure 20 Average difference of nodal and DLAP LMP (2011-2014) excluding summer 2014



F. Impact of major market changes

The pricing study uses day-ahead nodal energy LMPs from 2011 through 2014, during which there were several major market changes. New products or market changes can impact pricing trends seen in the markets. During the analysis, the ISO accounted for changes in pricing trends that were correlated with the introduction of new products or major market changes. Below is a list of day-ahead market changes and products that occurred during the study period and the implementation date.

- Convergence bidding – February 2011
- Local market power mitigation enhancements, Phase 1 – April 2012
- Greenhouse gas compliance cost – January 2013
- Order 764 market changes – May 2014

During the four year period, the only major market change that had a consistent and material impact on pricing trends was the introduction of greenhouse gas compliance cost. This is most notably reflected in the average nodal LMPs by year (Figure 4) which shows an upward shift in all average nodal LMPs in 2013; the higher average nodal LMPs persisted in 2014. There was no other material change in pricing trends that was also correlated to, and resulted from, changes in the market.

VI. Estimated Implementation Costs

In the recent FERC order which granted the ISO one additional year to either disaggregate or seek further relief from disaggregating, FERC stated that the ISO must provide properly documented implementation cost estimates. On October 28th, the ISO issued an information request asking stakeholders to provide implementation cost estimates. The cost estimates were for nine categories (as described in Table 2 below) and four levels of disaggregation: slight disaggregation, load aggregation to minimize error (assume 23 LAPs), customized LSE specific LAPs, and fully nodal.

Table 2 Estimated implementation cost categories

Cost category	Description
Load Forecasting	Load research, additional data collection and storage, developing new systems
Metering and telemetry	Infrastructure to provide meter reads, mapping of customers meters, telemetry
Price forecasting	New systems
Bidding and scheduling	Day-ahead bid submission, additional portfolio analysis
Settlements and billing	Interface with ISO, internal calculations
Demand response	Forecasting and settlements
CRR procurement and settlement	Forecasting and settlements
Data integration and storage	Increased storage, data integration and mapping
Other business costs	Project management, contingency, allocated funds used during construction, testing, training

Stakeholders were asked to indicate which costs would be a one-time implementation cost, capital costs, and which would be on-going annual expenses. One-time costs are those that will not be incurred after implementation and include items such as project management, updating processes to align with changes in the markets, etc. Capital costs may include costs for systems, increased data storage, etc. Entities have stated that these costs are not expected to be a one-time cost and may be incurred every five to ten years as needed. Annual costs are expected to be incurred every year and include costs for items such as bid submission, settlements, forecasting, etc.

Eight stakeholders provided cost estimates, representing approximately 80% of scheduled day-ahead load. The ISO also developed cost estimates. Total implementation costs for the stakeholders and the ISO are provided for each level of disaggregation broken out by one-time, capital, and annual costs. Table 3 below summarizes the estimated implementation costs by the nine categories for the four levels of disaggregation.

The ISO provided stakeholders guidance on assumptions to make when generating the estimates such that all sets of estimates are based on the same set of premises. The following assumptions were made:

- Only costs that would be incurred if the ISO were to disaggregate are included
- Retail costs, such as retail billing costs, are excluded
- Assume full meter settlements with the ISO

On the low end, i.e. slight disaggregation, it is estimated to cost seven[11] stakeholders and the ISO a combined total of $3.15 million in one-time costs, $18.6 million in capital costs, and $2.5 million in annual expenses. If the ISO went fully nodal, it is estimated to cost stakeholders and the ISO a combined total $14.6 million in one-time costs, $132.6 million in capital costs, and $12.6 million each year. Other Business Integration Costs are a significant portion of the estimated costs. Costs in this category are project management, contingency, and Allowance for Funds used during Construction (AFUDC). Besides the other cost category, the majority of costs are for load forecasting and metering/telemetry. Actual implementation costs for all market participants are expected to be higher because 1) these estimates only represent eight entities, and 2) stakeholders have indicated capital costs are costs incurred periodically, therefore not a one-time cost.

Following the initial review of the estimated implementation costs, the ISO reached out to those entities which provided estimates for additional clarification. The ISO wanted to better understand what assumptions were made, costs included, and methods used by the entities to generate the costs. As discussed at the stakeholder meeting on March 3rd, the estimated costs only included costs that would be incurred if the ISO disaggregated the DLAPs such as system upgrades, increased data storage, and additional metering.

[11] Eight stakeholders provided estimates for LAPS to minimize error and Fully Nodal. Seven stakeholders provided estimates for Slight Disaggregation and Custom LSE specific LAPs.

Table 3 Estimated implementation costs

	Slight Disaggregation			LAPs to minimize error			Custom LSE Specific LAPs			Fully Nodal		
	One Time costs	**Capital Costs**	**Yearly Costs**	**One Time**	**Capital Costs**	**Yearly Costs**	**One time**	**Capital Costs**	**Yearly Costs**	**One time**	**Capital Costs**	**Yearly Costs**
Load Forecasting	$ 310,776	$ 3,600,000	$ 456,492	$ 1,138,646	$ 6,750,000	$ 692,492	$ 473,422	$ 3,300,000	$ 249,820	$ 2,174,052	$ 10,850,000	$ 1,249,820
Metering and Telemetry	$ 734,776	$ 4,400,000	$ 821,164	$ 1,909,646	$ 20,150,000	$ 2,349,164	$ 1,340,422	$ 10,800,000	$ 932,328	$ 2,340,052	$ 45,600,000	$ 3,420,328
Price Forecasting	$ 129,000	$ 520,000	$ 110,000	$ 339,000	$ 1,410,000	$ 473,000	$ 94,000	$ 650,000	$ 85,000	$ 489,000	$ 1,850,000	$ 523,000
Bidding and Scheduling	$ 182,500	$ 550,000	$ 85,164	$ 421,000	$ 1,532,000	$ 230,746	$ 337,000	$ 650,000	$ 171,328	$ 911,000	$ 2,575,000	$ 1,028,910
Settlements and Billing	$ 294,776	$ 1,050,000	$ 155,576	$ 715,646	$ 4,420,000	$ 275,582	$ 615,422	$ 1,500,000	$ 231,164	$ 1,254,052	$ 5,942,000	$ 406,164
Demand Response	$ 20,000	$ 100,000	$ 150,000	$ 220,000	$ 1,100,000	$ 300,000	$ 50,000	$ 500,000	$ 50,000	$ 440,000	$ 2,200,000	$ 575,000
CRR Procurement/Settlement	$ 159,000	$ 110,000	$ 91,740	$ 267,810	$ 110,000	$ 126,746	$ 160,810	$ 100,000	$ 82,328	$ 654,900	$ 120,000	$ 282,328
Data Integration and Storage	$ 233,000	$ 700,000	$ 112,000	$ 977,000	$ 2,400,000	$ 307,000	$ 442,000	$ 950,000	$ 132,000	$ 1,283,000	$ 6,200,000	$ 1,506,000
Other Business Integration Costs	$ 1,088,800	$ 7,566,120	$ 486,000	$ 3,185,900	$ 24,729,380	$ 1,582,200	$ 1,189,750	$ 7,296,500	$ 111,600	$ 5,061,150	$ 57,258,940	$ 3,630,700
Total	**$ 3,152,628**	**$ 18,596,120**	**$ 2,468,136**	**$ 9,174,648**	**$ 62,601,380**	**$ 6,336,930**	**$ 4,702,826**	**$ 25,746,500**	**$ 2,045,568**	**$ 14,607,206**	**$ 132,595,940**	**$ 12,622,250**

VII. Benefits

Conceptually, moving away from the current aggregation of load zones and average prices could provide benefits to the wholesale market, market participants, and other parties. However, being able to quantify these benefits in any accurate manner that would allow a direct comparison to costs is challenging. The main difficulty is constructing a plausible counter-factual to the current system. Constructing this counterfactual would require the ISO to make assumptions regarding, among other things, the price elasticity for energy, the probability of changes on the regulatory side, what the regulatory changes might be, how market participants will bid in demand, and if the current LDFs reflect how the market participants will bid in demand. There would be an inherent uncertainty in whatever outcome the ISO assumes on each of these items that would be difficult to justify as compared to reasonable alternate assumptions. Alternatively, the ISO could run a benefit estimate based on all potential combinations of reasonable assumptions. Doing so, however, would significantly increase the complexity of the benefit estimate exercise. In addition, estimated benefits would not align with all the levels of disaggregation of the cost estimations. Therefore a direct comparison of implementation costs to benefits for most of the levels of disaggregation would not be feasible.

There are other factors that also influence the size of the benefits. Retail electricity rates in California are established by the California Public Utilities Commission, along with other Local Regulatory Authorities. These retail rates do not reflect locational price differences between regions within the existing DLAPs, and changes to load pricing on the wholesale side may not be transferred to the retail side.

The ISO recognizes the importance of assessing the potential benefits of load disaggregation in this stakeholder process, and therefore has provided estimates of load disaggregation in the areas. Current ISO market structure, products, and processes capture some of the benefits load disaggregation would provide. Below is a list of existing products and processes and a brief description of the benefit provided. Therefore, benefit estimates provided by the ISO only include benefits that are in addition to those listed below which can already be realized.

Table 4 Potential benefits and existing ISO processes providing the benefits

Benefit	Benefit sub-category	Existing process
Incent investment	Transmission	The Transmission Planning Process (TPP) at the ISO does economic assessments of transmission projects using nodal pricing information.
	Generation	Nodal LMPs are currently posted on OASIS and can be utilized in economic assessments of potential generation investment decisions.
	Participating load	Participating load can create

		custom LAPS to schedule and settle day-ahead load at nodal prices.
Congestion revenue rights		LSEs can be allocated additional congestion revenue rights sinked at sub-LAPs starting in Tier 2 of the annual allocation process. They can also participate in the auctions to obtain more granular CRRs.
More efficient day-ahead market		Virtual supply bids can be submitted in the day-ahead market can provide the market optimization with a more efficient way to solve constraints.

As advocated by stakeholders, and supported by the ISO, any benefit assessment should

1. Focus on wholesale side benefits that may be realized without regulatory changes,
2. Be incremental to benefits that can already be realized through existing products and processes and,
3. Account for increased costs and risks of using existing products and processes to achieve same benefits

To assess potential benefits of further load disaggregation, the ISO estimated incremental benefits in three areas: investment incentive due to accurate price signals, efficient market outcomes, and congestion revenue rights. Following is a discussion of each potential benefit, existing products and processes that can achieve the same benefit, what incremental benefit may be realized, and an estimation of the potential incremental benefit.

A. Accurate Price Signals

There is some heterogeneity of prices within the DLAPs, but wholesale load settles at an average of those prices. More accurate geographic price signals might increase investment in transmission, generation, and participation in demand response by load where it is needed most. The potential benefits that could be realized because of more accurate price signals are directly related to the extent of heterogeneity of prices. The pricing study results have shown that price dispersion within the existing DLAPs, though it exists, is minimal. Therefore potential benefits gained from more accurate price signals would also be minimal.

Transmission investment

Investment in transmission projects have the potential to relieve congestion and lower price dispersion between nodes and DLAPs. Accurate prices can signal to potential investors where transmission is needed most. However, the ISO Transmission Planning Process already utilizes nodal LMPs when doing economic assessments of proposed transmission projects and upgrades. Therefore the accurate price signals are already available and being used to incent investment in those projects which are needed most. This can be further supported by the transmission projects in the Greater Fresno area identified to help address potential overload and voltage concerns, which did materialized during the summer of 2014. Therefore the estimated incremental benefit of accurate price signals to incent transmission investment is zero.

Generation investment

Accurate price signals also have the potential to incent investment in generation projects, which can potentially relieve congestion and lower price dispersion. The ISO already posts nodal LMPs on OASIS for potential investors to utilize when making investment decisions. Therefore the estimated incremental benefit of more accurate prices signals to incent investment in generation is zero.

Participation of demand response

Participating load (PL) and proxy demand response (PDR) resources have an existing incentive to locate at higher priced nodes, to maximize the value of their demand response. Therefore accurate price signals are essential when determining if, and where, demand response resources should locate. Again, the nodal LMPs are already posted on OASIS for potential demand response providers to utilize in any economic assessment. Participating load resources can schedule and settle at a more granular level in the current market by using Custom Load Aggregation Points (CLAPs). CLAPs can be comprised of a single node to several nodes, and a participating load is scheduled and settle at the CLAP LMP. However, the nodes in a CLAP must be within a defined sub-LAP. Sub-LAPs were defined based on reliability must run (RMR) study areas and transmission interfaces that reflected congestion reflected congestion in the early stages of the market. RMR areas are no longer significant in the markets and transmission projects have since changed congestion patterns. Therefore restricting the CLAPs by outdated sub-LAP definitions warrants re-evaluation. Currently, the ISO intends to re-evaluate the sub-LAP definitions such that CLAPs created in the future may have more flexibility in what nodes are used to create the CLAP. Given that nodal LMPs are publically posted and demand response resources can already utilize CLAPs to schedule and settle, the estimated incremental benefit of accurate price signals for demand response is also zero.

B. Improved congestion hedging

Increased allocated CRRs

A few important benefits are anticipated from the disaggregation of the default LAPs regarding congestion hedging. First, disaggregating the larger DLAPs could potentially allow for the release of more CRRs in the tier 1 of the annual allocation process with better alignment of LSEs' CRR awards with the congestion exposure of the load they serve. Load serving entities (LSEs) nominate CRRs sinked at one of the three DLAPs. The optimization software (the "simultaneous feasibility test" or SFT) then applies fixed load distribution factors (LDFs) to the nominated CRRs, which distributes the megawatts to the individual nodes within the DLAP. The software then models the source megawatts as injections and the distributed sinked megawatts as withdrawals to create flows. The quantity of CRRs allocated in Tier 1 are determined by the resulting flows and enforced constraints. When a constraint binds in the

CRR model, the total amount of allocated CRRs in the DLAP of the binding constraint is limited by the quantity that can physically flow on the system.

Table 5 below illustrates how the allocated CRRs are limited when a constraint is binding under the current CRR process. Assume 100MWs of CRRs are nominated to be sinked at DLAP A by only one LSE. Four nodes are within the DLAP with the corresponding LDFs shown below. The CRR model applies the LDFs to the nominated CRRs to get the modeled withdrawals at each node. When the CRR model is run, constraint C binds which impacts the feasible withdrawal at node 2 and only allows 20MWs as opposed to the nominated 30MWs. The CRR model then limits the total allocated CRRs in DLAP A such that only 20MWs are modeled to be withdrawn at node 2. This would cause 67MWs (67 = 20MWs/.3 LDF at node A) of allocated CRRs in DLAP A rather than the nominated 100MWs.

Table 5 Example of current CRR Model allocation process

Node	**Load Distribution Factor to DLAP A**	**CRR modeled withdrawals**	**Feasible withdrawals**	**Modeled withdrawals after limiting allocated CRRs.**
1	.2	20	20	13.4
2	.3	30	**20**	**20**
3	.4	40	40	26.8
4	.1	10	10	6.7
			Total allocated CRRs	**67**

The potential benefit would be if LSEs were able to nominate the CRRs sinked at individual nodes rather than the DLAPs, the CRR model would less likely limit all allocated CRRs in the DLAP when a constraint is binding. Table 6 uses the same assumptions from the previous example but has the CRRs nominated at the nodal level. Only the node at which the binding constraint limits the feasible withdrawal is limited; all other nominated CRRs are allocated the quantity nominated. This would result in 90MWs of CRRs being allocated as opposed to 67MWs of CRRs when the CRRs were nominated at the DLAP.

Table 6 Example of potential CRR Model allocation process

Node	**Nominated CRRs by LSE**	**CRR modeled withdrawals**	**Feasible withdrawals**	**Modeled withdrawals after limiting allocated CRRs.**
1	.2	20	20	20
2	.3	30	**20**	**20**
3	.4	40	40	40
4	.1	10	10	10
			Total allocated CRRs	**90**

Allocating CRRs only using DLAPs would cause LSEs to forego the hedge against congestion on the CRRs they are not allocated. Determining the expected congestion they are exposed to by not having all the CRRs they nominate is one way to estimate the benefit associated with increased allocated CRRs. It would have to be assumed that 1) all the nominated CRRs would be allocated to LSEs and 2) the source locations would remain the same. This is a conservative assumption that would over-estimate the benefit because not all CRRs nominated at nodes which are limited by a binding constraint would be allocated. There are three prices one could use to value the foregone congestion hedge:

1. Use the average CRR monthly auction price for each season and time of use,
2. Use the average CRR monthly auction price for each season and time of use, excluding negatively priced congestion revenue rights, and
3. Use the hourly day-ahead marginal congestion components of the source and sink nodes

The estimated benefit using the average monthly auction price results in $1.08 million per year. If the negatively priced CRRs are excluded from determining the average price, the estimated benefit is increased to $2.75 million per year. When using the day-ahead hourly marginal congestion components for the source and sink nodes, the estimated benefit is $2.73 million per year. Given the three methods of estimating the benefit of increased allocated CRRs, the ISO is estimating the benefit to be between $1.08 million and $2.75 million per year.

The estimated benefit of $1.08 - $2.75[12] million annually for increased allocated CRRs is an over-estimate for a few reasons explained below.

1. The methodology used to estimate the benefit assumed all nominated CRRs that were not allocated would have been allocated if allowed to be nominated at a nodal level. This would only occur if there were no binding constraints in the CRR model.
2. The current CRR allocation process already allows LSEs to nominate “sub-LAP” sinks starting in tier 2 of the annual process and in the monthly allocation process to enable a larger quantity of CRRs to be awarded. In addition, they can participate in the monthly auctions and acquire CRRs sinked at the nodal level.
3. The monthly auction prices also reflect the cost of risk other entities are willing to take on. Therefore, the monthly auction price over values the hedge for LSEs.
4. The benefit could be considered an income transfer from the entities that currently hold those CRRs to the LSEs which will be allocated the CRRs. LSEs may gain additional hedge against congestion, but at the cost of other entities losing the revenues associated with the CRRs they no longer hold.
5. Increasing the quantity of allocated CRRs may reduce the amount of CRRs awarded through the auctions, which could result in less auction revenues collected by the ISO to fund CRR payments.

[12] The estimated benefits reported are the average annual benefit for each methodology described using data from 2011-2014.

6. There is a potential cost of increased revenue inadequacy related to increasing allocated CRRs. This is discussed in more detail below along with an illustrative example.

Revenue inadequacy

Another potential benefit of disaggregation related to CRRs is the impact it may have on revenue inadequacy. Revenue inadequacy occurs when the congestion funds collected are insufficient to meet CRR settlements. IFM Congestion charges are calculated as the IFM marginal congestion component for all scheduled demand minus the IFM congestion component for all scheduled supply. Revenue inadequacy is mainly driven by the quantity of CRRs settled exceeding the quantity of scheduled demand in the IFM on which congestion funds are collected.

As previously discussed, the CRR model models CRR sources as injections and CRR sinks as withdrawals at nodes by applying LDFs to CRRs sourced or sinked at DLAPs. The model then constrains the resulting flows to being physically feasible on the system. The CRR model enforces transmission constraints, nomograms, branch groups, thermal limits, and contingencies when allocating and clearing the CRR market. Due to the time lag from when the CRR model is run and when the day-ahead market clears, there will be differences in modeled/enforced constraints. Unforeseen outages, derates, and newly created nomograms are just a few examples of what might cause the CRR model flows to be feasible when the CRR market is ran, but no longer feasible in the day-ahead market. When this occurs, the scheduled demand in the IFM may be less than what the CRR model indicated was feasible. Thus, the CRR model allocated/cleared more CRRs than what is being scheduled in the IFM, which results in reduced congestion funds collected to meet CRR settlements. Another modeling difference than may lead to revenue inadequacy is the extent to which day-ahead LDFs differ from the LDFs used in the CRR model. This could potentially result in a difference in congestion patterns between the CRR model, which limits allocated CRRs, and the day-ahead market, which settles CRRs.

Past instances of revenue inadequacy primarily have been driven by releasing too many CRRs due to differences in the CRR model and day-ahead market model. The CRR process has recently addressed inconsistencies between the day-ahead and CRR model. Starting in the 2015 annual process, the CRR model not only increased the enforced constraints and contingencies, but is also updating the list of constraints and contingencies based on more recent information. In addition, the break even analysis is now applied to internal paths rather than just interties. The break even analysis is where the CRR model determines the limit on constraints based on the quantity of CRRs it could have released and remained revenue neutral using data from the previous three years. Both of these enhancements have reduced the quantity of CRRs allocated and awarded and should therefore improve the ISO's CRR revenue adequacy.

The potential benefits gained by reducing revenue inadequacy with more granular load zones is likely to be minimal. Based on past experiences, revenue inadequacy is primarily driven by differences in the day-ahead model and CRR model. When constraints arise in the day-ahead market that were not enforced in the CRR model, the quantity of scheduled demand on which congestion funds are collected differ significantly from the quantity of CRRs which must be settled. Therefore the ISO is not collecting sufficient funds to cover the volume of CRRs allocated and awarded. Differences between the two models will not be improved as a result of disaggregation; however, note that the ISO has recently made changes to better align the two models as previously mentioned. Given the above discussion, the estimated incremental benefit to reducing revenue inadequacy as a result of disaggregation is zero.

Negative impacts of load disaggregation

The potential congestion revenue rights benefits gained with load disaggregation include increased allocated CRRs and improved revenue inadequacy. Despite the discussion above which explains why improved revenue inadequacy has negligible benefits, there is another interaction between the two benefits and load disaggregation that should be discussed. The first benefit of load disaggregation is increasing the amount of allocated CRRs if nominated at a nodal level rather than the DLAP level. The second benefit is the concept that revenue inadequacy could be reduced. However, history has shown that revenue inadequacy is primarily driven by allocating and awarding too many CRRs. Therefore, if the ISO were to disaggregate load and release more CRRs, it may actually increase revenue inadequacy rather than potentially decrease when constraints arise in the day-ahead model that were not enforced in the CRR model. Therefore revenue inadequacy could be considered an additional cost, as opposed to a potential benefit, of load disaggregation.

The interaction between increased allocated CRRs and revenue inadequacy is best explained through an example. Using the same DLAP and nodal structure from the CRR Allocation example above, assume

- 100MWs scheduled at the DLAP in the day-ahead market
- A $500 shadow price on a constraint that was not enforced in the CRR model
- Source nodes of the CRRs remain the same
- $0 congestion component at the source nodes
- LDFs are representative of where LSEs would schedule load on a nodal level
- LDFs are representative of where LSEs would sink nominated CRRs on a nodal level

The following two tables compare how the congestion funds and CRR payments are determined under a fully nodal regime and the current regime. The first table (Table 7) illustrates how they are collected and paid today. Congestion funds collected would be the product of the 100MWs of load at the DLAP and the marginal congestion component at the DLAP, resulting in $4,750 collected to fund the CRR payments. Using the allocated CRRs of 67, and the DLAP marginal congestion component of $47.50, CRR payments would total $3,183. Under the current regime, the CRR balancing account would have a surplus of $1,567.

Table 7 Example of revenue adequacy – DLAP scenario

Node	DA MWs	CRRs	Shift factor[13]	MCC	Congestion funds	CRR payments	Revenue Adequacy
DLAP A	100	67	.095	$47.50	$4,750	$3,183	$1,567

The second table (Table 8) is based on fully nodal disaggregation. Using the LDFs from the allocation example, the DA MWs column shows the megawatts that would be scheduled at each node under a nodal market. The nodal MCC column is the congestion component at the nodes, which is the product of the $500 shadow price and shift factor from the node to the constraint. The congestion funds collected through the day-ahead market would be collected at each node, and is the product of the nodal MCC and DA MWs, as shown in the Congestion Funds column. The CRR payments would be determined by the product of allocated CRRs and MCC at the nodal level, as shown in the CRR Payments column. Under a fully nodal regime, the ISO would collect $4,750 in congestion funds to pay $5,500 in CRR payments, resulting in $750 of revenue inadequacy.

Table 8 Example of revenue adequacy – nodal scenario

Node	DA MWs	CRRs	Shift factor	MCC	Congestion funds	CRR payments	Revenue adequacy
1	20	20	.3	$150	$3,000	$3,000	
2	30	20	-.15	($75)	($2,250)	($1,500)	
3	40	40	.2	$100	$4,000	$4,000	
4	10	10	0	$0	$0	$0	
Total	**100**	**90**			**$4,750**	**$5,500**	**($750)**

The amount of congestion funds collected did not differ between the two scenarios. However, due to the increase allocated CRRs, the CRR payments increased by $2,317. In this example, the market was revenue adequate under the DLAP scenario but then became revenue inadequate by $750 under a nodal scenario.

Disaggregation has the potential to *reduce* revenue adequacy in two manners. First, increasing the quantity of allocated CRRs, and thus payments, as previously illustrated. Second, as previously discussed, all allocated/awarded CRRs must create physically feasible flows on the CRR model. If more CRRs are allocated as a result of load disaggregation, then there may be a decrease in CRRs awarded in the auction process to maintain the physically feasible flows on the CRR model. Therefore the ISO may collect less auction revenues to help fund the CRR payments, further decreasing revenue adequacy. Both of these additional costs could fully, or more than, offset the estimated benefit of increased allocated CRRs. Therefore the ISO is acknowledging that the estimated benefit of $1.08 - $2.75 million annually may be further reduced due to increased revenue inadequacy.

[13] The DLAP marginal congestion component is determined by the sum of the product of the nodal LDFs and shift factors for each node in the DLAP. Using the shift factors from table 6, $47.50 = (.3*.2)+(-.15*.3)+(.2*.4)+(0*.1)

Moving to more granular load zones would also lead to a number of issues with the current CRR process. Many LSEs hold long-term CRRs that sink at a DLAP, which would no longer align accurately with load settlement once the increased granularity takes effect. There would have to be some sort of conversion from the old load zones to the new load zones in order for there to be any benefits to LSE's that hold long-term CRRs. Additionally, LSE CRR nominations in Tier 1 of the annual allocation process are restricted to those CRR source-sink combinations that were allocated to the LSE in the previous annual allocation. Without some modification to this rule, LSEs would be required to nominate DLAP CRRs in the priority nomination process for the initial CRR seasons when load settlement would be based on the new load zones.

C. More efficient day-ahead market outcomes

More granular load zones could improve the solution of the integrated forward market (IFM) optimization. Currently, in the day-ahead market, the optimization may have to adjust load to solve a constraint. When load is adjusted, it is adjusted at the DLAP Level. All nodes within the DLAP move up and down in lockstep according to their LDFs until the constraint is solved.

For example, the optimization may be forced to decrease load by 100MW at the DLAP level to get a 5MW change on a constraint within the DLAP. If the large DLAPs are disaggregated, the optimization may be able to adjust load at an individual node by a fraction of the amount to get the same 5MW change. This may allow the IFM optimization to reach a more precise solution within each individual load zone.

Currently, a market participant could submit a virtual supply bid at a node effective in solving the constraint. The day-ahead market could then use the virtual supply to potentially solve the constraint rather than adjusting load at the DLAP level. The extent to which virtual supply bids would be effective in providing the same benefit as disaggregated load depends on 1) the ability and willingness of market participants to submit virtual supply bids at the effective nodes and 2) the bid price of the virtual bid. Even if an effective virtual supply bid were submitted, depending on the bid price, it still may be less costly to adjust load at the DLAP to solve the constraint rather than the virtual supply bid at a node with a higher effectiveness factor.

In previous discussions, the ISO intended to conduct a case study to analyze the benefit of load disaggregation in reaching a more efficient market outcome during hours where this situation may have occurred. However, due to the implementation of the Fifteen Minute Market (FMM), the environment in which this case study could be conducted does not allow for cases prior to May 1, 2014 to be analyzed. Since May 1, 2014, there has not been an hour where the optimization adjusted load at a DLAP to solve a constraint. Therefore the ISO is unable to conduct the case study initially intended.

In place of the case study results, and in response to stakeholder feedback, the ISO can provide the frequency for which this has occurred. A couple factors were used to identify when the day-ahead market may benefit from being able to adjust load more granular. An hour was identified when 1) the DLAP bid was marginal, and 2) there was a high shadow price on the system. The high shadow price would indicate an inefficient adjustment to solve the constraint. This occurred in approximately 146 hours in 2014 with an average shadow price of $348.

Currently, a virtual supply bid could achieve the same benefit. Therefore one bookend estimate of potential benefit would be zero. The ISO recognizes there is inherent risk involved in submitting virtual supply bids to achieve the same benefit and market participants may not be willing to take on those risks and would rather gain the benefit through load disaggregation. Therefore, another estimate on the higher side could use the frequency of occurrence (146 hours) and apply an estimate of reduced costs due to solving the constraint by using nodal load. One would expect the shadow price on the constraint to be reduced with a more efficient market outcome, resulting in reduced congestion costs. However, given the hours of congestion in 2014, the average shadow price during hours the DLAP bid was marginal is less than the average shadow price during hours the DLAP bid was not marginal. This would indicate the benefit of reduced congestion due to a more efficient market outcome is zero. Therefore, the estimated incremental benefit of a more efficient market outcome is zero.

D. Summary of benefits

This section of the paper quantified the potential benefits of load disaggregation for three areas; accurate price signals to incent investment, congestion revenue rights, and more efficient market outcomes. Due to the complexity of conducting formal studies for each benefit, the ISO provided a range of estimated benefits where applicable. All estimates were on the higher side, determined incremental of any benefits that could currently be realized through other existing products and processes, and excluded retail side benefits. Table 9 below provides the total estimated benefits for each area discussed above. The total estimated benefit of $1.08 - $2.75 million annually covers approximately 15% of the estimated annual costs; that does not include covering any of the $14.6 million in one-time implementation costs or $132.6 million in capital costs.

Table 9 Summary of estimated benefits

Benefit	**Sub-category of benefits**	**Estimated annual benefit**
Accurate price signals to incent investment		
	Transmission investment	$0/year
	Generation investment	$0/year
	Demand response investment	$0/year
Congestion revenue rights		
	Increased allocated CRRs	$1.08 - $2.75 million/year
	Reduced revenue inadequacy	$0/year
Efficient market outcome		$0
Total		**$1.08 - $2.75/year***
***This is an over-estimated benefit as a result of assumptions made and potential costs due to revenue inadequacy not reflected in this table.**		

VIII. Proposal

The previous order issued by FERC which denied the ISO's request for a permanent waiver to complying with FERC's previous orders to disaggregate existing LAPs granted the ISO an additional year to seek further relief or disaggregate. FERC also provided guidance regarding what it would expect to see in any subsequent pricing study used to justify further relief from the compliance obligation to disaggregate. Through the current Load Granularity Refinements Initiative, the ISO has evaluated different levels of granularity for which load could bid, schedule, and settle in the day-ahead market. It includes a robust study on nodal day-ahead price dispersion to assess the potential benefits which could be realized if load was further disaggregated. In addition, estimated implementation costs and quantification of potential benefits are presented.

The pricing study results indicate that, short of nodal, there is no other logical level of disaggregation to analyze. The magnitude of benefits that could be gained through disaggregation is directly related to the magnitude of price dispersion. Nodal LMPs would theoretically provide the greatest benefits. The nodal analysis shows minimal price dispersion from 2011-2014; therefore, potential benefits will also be minimal. Furthermore, the material price dispersion that exists is sporadic and a result of unforeseen system conditions, and transmission projects have already been approved through the ISO's Transmission Planning Process to address overload conditions in that area.

The ISO acknowledges there are potential benefits of further disaggregating load. Benefits from sending more accurate price signals to end-use customers and in turn theoretically having load move around to lower priced areas can only be realized if changes are made to the current retail rate structure. At this time, the ISO foresees no changes to the retail rate structure. Therefore, the benefits in the assessment are limited to benefits on the wholesale side of the market. Since the nodal analysis shows minimal price dispersion, potential benefits are expected to be minimal. The ISO provided estimates of the potential benefits, which totaled $1.08 - $2.75 million annually.

The ISO requested cost estimate information from stakeholders. Eight stakeholders provided cost estimates for four levels of potential disaggregation ranging from slight disaggregation, i.e. two additional DLAPs, to fully nodal. Costs were provided in nine cost categories and indicated if they were one-time, capital, or annual costs. For the eight stakeholders and the ISO, estimated implementation costs for a fully nodal market are approximately $14.6 million in one-time costs, $132.6 million in capital costs, which may be re-incurred every five to ten years, and $12.6 million annually.

As informed by the pricing study results, minimal estimated benefits, and high estimated implementation costs, the ISO does not see justification for further disaggregating the current load aggregation points. The ISO intends to make a case to FERC by June 3, 2015 that the current load aggregation points are just and reasonable for the ISO market.

IX. Next Steps

The ISO will discuss this draft final proposal with stakeholders during a stakeholder call on March 31, 2015. Stakeholders should submit written comments by April 10, 2015 to initiativecomments@caiso.com. It would be helpful for stakeholders to discuss in their written comments whether they support the ISO's proposal, support the proposal with conditions, or do not support the proposal and why.

ATTACHMENT B

CAISO Market Surveillance Committee Opinion on Load Granularity Refinements

Opinion on
Load Granularity Refinements

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair

Members of the Market Surveillance Committee of the California ISO

Final
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I. Introduction

A lesson of the California crisis of 2000-2001—and of the history of power markets in general in the U.S.—is that in order to maximize the efficiency of market operations, avoid gaming, and provide incentives for appropriate resource siting, energy prices should reflect the cost of delivery, including the expense of location-specific congestion and losses. Transmission bottlenecks can significantly raise the marginal cost of delivery of wholesale power in load pockets compared to system-wide averages, while depressing prices in generation pockets. These cost differences vary greatly over time as system conditions change. Prices that reflect these costs provide needed incentives for resources to deliver supply or demand reductions where and when most needed. The CAISO's adoption of locational marginal pricing (LMP) under the 2009 Market Redesign and Technology Upgrade (MRTU) was a crucial step in providing these incentives in bulk power markets.

However, LMP is not applied to a large fraction of load in the CAISO markets, nor do most retail consumers in California face prices that reflect spatial variations in the marginal cost of service. Under the MRTU design, the bidding, scheduling and settlement of most of the ISO's internal load occurs at three large default load aggregation points (DLAPs). These DLAPs coincide with the service territories of the three California investor-owned utilities. The purpose of the DLAP design was to insulate wholesale load from locational cost impacts arising from the existing grid configuration. The justification for such insulation was that such load cannot respond to locational price signals because of the limited demand response products available when MRTU was implemented, and because CPUC retail rate-setting policies in California prevent CPUC jurisdiction retail customers from paying time-varying prices that reflect wholesale market conditions.[1]

[1] CAISO, *Load Granularity Refinements, Interim Proposal*, December 9, 2010, p. 2, www.caiso.com/Documents/LoadGranularityRefinementsInterimStrawProposal.pdf

The DLAP market design with three large DLAPs was part of the original MRTU proposal. This design feature was approved by FERC, but in their MRTU order they required the CAISO to disaggregate the three DLAPs by Release 2 of MRTU, scheduled for three years after the implementation of MRTU.[2] Subsequently, based upon analyses by the ISO and MSC as well as stakeholder input, the CAISO requested a deferral of the implementation date for the disaggregation of the three default LAPs until 2014.[3] In response, FERC approved that request.[4] In 2014, the ISO then asked FERC for a permanent waiver from the ISO's obligation to further disaggregate DLAPs by MRTU Release 2.[5] FERC denied that request, granting the ISO a one-year extension to either comply with, or seek further relief from, the ISO's obligation to disaggregate the DLAPs and requesting additional study of the issue by the ISO.[6] Since then, the ISO has undertaken a stakeholder process and additional analyses, and proposes to petition FERC to be relieved of its obligation to further disaggregate its DLAPs.[7]

In the *long run*, we believe that efficient investment and operations of supply, transmission and distribution, and demand-side resources require that settlements be based on prices that are differentiated over space and time, reflecting actual system congestion and loss conditions. In designing the ideal market, the long-run benefits and costs of full implementation of LMP for all market participants should be evaluated. If full LMP is justified by benefits that clearly exceed costs, then the question of the best transition path to a full LMP market should also be addressed at that time. However, at the request of FERC, the issues addressed by the ISO's study are the immediate questions of whether the DLAP design should be retained, modified, or discarded in the short-run, and what the benefits would be of a move *now* to more disaggregated DLAPs or even full LMP for wholesale load.

The MSC has discussed and studied the issue of increasing the spatial granularity of load on several occasions. During a public meeting of the MSC on October 8, 2010, the ISO's 2010 granularity studies and stakeholder process were summarized by ISO staff. Dr. Frank Wolak, then Chair of the MSC, followed with a presentation of an empirical analysis of the dispersion of LMPs under MRTU within DLAPs.[8] He listed several categories of potential benefits and costs to consumers and the market of introducing greater spatial granularity in pricing to loads.

[2] Paragraph 611 of FERC's September 21, 2006 *Order Conditionally Accepting the California Independent System Operator's Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade* (Docket No. ER06-615).

[3] CAISO, *Load Granularity Refinements, Interim Proposal*, op. cit.

[4] FERC, *Order Granting Extension of Time to Implement Default LAP Disaggregation* (Docket No. ER06-615), July 25, 2011.

[5] CAISO, *Motion of the CAISO for Waiver of Obligation to Disaggregate Default Load Aggregation Points*, Feb. 7, 2014.

[6] Order on Request for Waiver. Federal Energy Regulatory Commission. June 3, 2014. Docket Nos. ER06-615-000 ER02-1656-027 ER02-1656-029 ER02-1656-030 ER02-1656-031.

[7]CAISO, *Draft Final Proposal – Load Granularity Refinements*, www.caiso.com/Documents/DraftFinalProposal_LoadGranularityRefinements.pdf , March 24, 2015.

[8] F.A. Wolak, "Comments on Load Granularity," Oct. 8, 2010, www.caiso.com/Documents/ CommentsonLoadGranularity-MSCPresentation.pdf .

Among the benefits he listed included incentives for consumers to favor transmission investments that increase market efficiency and lower the need for local market power mitigation, incentives for efficient location of energy efficiency and demand response investments, and avoiding distortions arising from use of fixed load distribution factors. Among the cost categories identified by Dr. Wolak were changes in billing systems and the need to develop nodal-level load forecasting systems. He did not attempt to estimate the magnitudes of these benefits and costs, but he concluded that the costs would likely be small relative for all customers located in the State's population centers relative to the benefits to be derived from dynamic pricing and energy efficiency investments.[9] The MSC did not subsequently analyze the issue further, nor did it issue an opinion at that time on load granularity issues.

Since FERC's 2014 order requiring the ISO to address the issue with more analysis, the MSC has discussed the ISO's study at public meetings on Aug. 22 and Dec. 16, 2014, and Feb. 19, 2015. During the Dec. 16, 2014 meeting, MSC Member James Bushnell made a presentation on statistical approaches to analyzing price dispersion, and benefit-cost analysis approaches to quantifying the benefits of increased load granularity.[10] MSC members have also continued to provide informal advice to ISO staff on the design of LGR statistical and benefit studies.

In this opinion, we review the ISO's March 24, 2015 proposal,[11] including its study of price dispersion within DLAPs and the benefits analysis conducted to seek relief from FERC's requirement to disaggregate DLAPs. In the next section, we discuss the pricing study, as well as the ISO's estimation of costs of implementation. In Section III, we review the ISO's benefits study, and discuss the ISO's recommendation that DLAPs not be further disaggregated. Section IV summarizes our conclusions, which include the following. We find that the ISO's analysis supporting its recommendation for no further disaggregation is for the most part conservative, given its assumptions, in that it usually errs on the side of overestimation of the benefits of disaggregation of DLAPs. A very important assumption of the ISO's benefit assessment is that disaggregated prices would not be reflected in CPUC jurisdictional rates and that the lack of support for disaggregated prices from non-CPUC jurisdictional load serving entities would continue. Our major conclusion is that we support the ISO's recommendation against further disaggregation at this time because the likely benefits are small in the near future, and are likely to be well outweighed by the reported costs of implementation. This is because the CPUC has not made any efforts to date to modify retail rates based on locational wholesale prices, nor have they indicated that they will in the future. In addition, there is a lack of support for disaggregated prices from non-CPUC jurisdictional load serving entities. On the other hand, we do encourage reforms of retail ratemaking that would have those rates better reflect temporal and spatial variations in the cost of power to better enable price responsive consumers to adjust their consumption based on the cost of power.

[9] As summarized in F.A. Wolak, "Memorandum to ISO Board of Governors, MSC Activities from August 23, 2010 to October 15, 2010," Oct. 26, 2010, www.caiso.com/Documents/101215MarketSurveillanceCommitteeUpdate.pdf .

[10] J. Bushnell, *Load Granularity Price Dispersion Study Discussion – Measuring the Implications of LAP Aggregation*, Presentation, Dec. 16, 2014, www.caiso.com/Documents/LoadGranularityPriceDispersionStudyDiscussion-MSC_Presentation-Dec2014.pdf

[11] CAISO, *Draft Final Proposal*, op. cit.

II. The CAISO pricing study

In its June 3, 2014 order,[12] the FERC expressed dissatisfaction with the previous pricing study and identified five specific areas for CAISO to address in its current study. These are:

1. Detailed description of the underlying data used.
2. An analysis of a reasonable range of different alternative levels of disaggregation.
3. Focused discussion of areas exhibiting the largest price differences.
4. Properly supported estimates of implementation costs for different levels of disaggregation.
5. An analysis of the entire CAISO footprint, including SDG&E.

The FERC order also raised issue with the use of annual average nodal price differences as the primary statistic for justifying its proposals and noted the absence of discussion of the effects of disaggregation on congestion revenue rights.

In its current study the CAISO has addressed each of these points.[13] While the analysis still includes an evaluation of annual average price differences in the day-ahead market, the CAISO also analyzes correlations of day-ahead market nodal prices with DLAP prices and the frequency of large differences between nodal and DLAP prices. The data sources are well documented and we believe that the motivation and description of the analysis is clearly explained.

1. Assessment of Annual Average Price Differences

We note that annual average price differences in the day-ahead market are the most relevant statistics for assessing the incentive that more disaggregated pricing would provide for long-run responses to differences in power prices. Examples of such responses include the locational decisions of large power consumers, investments to reduce power consumption, and installations of behind-the-meter generation. Furthermore, if retail prices are based upon averages of hourly energy costs, as they currently are for CAISO retail customers that are subject to CPUC jurisdiction, then annual averages are also the relevant time frame for short-run responses, even if the CPUC-jurisdictional suppliers bought and sold power at hourly nodal LMPs, as they do today. This is because retail prices will only reflect average differences over much longer time frames until such time that the CPUC choses to change the prevailing retail pricing design. Thus, the CAISO study's primary focus on annual average price differences in the day-ahead market is reasonable.

The CAISO's pricing study shows that, between 2011 and 2014, the vast majority of load was located at nodes with average LMPs in the day-ahead market that fell within $2/MWh of

[12] FERC, Order on Request for Waiver, op. cit..

[13] The most recent version of the pricing study is contained in the CAISO's *Draft Final Proposal*, op. cit..

their DLAP price.[14] To put this finding into an economic context, we can compare this to the implied deadweight loss from such a price difference. Economists often utilize the concept of deadweight loss to quantify the inefficiency of market outcomes. The concept is illustrated in Figure 1, below.

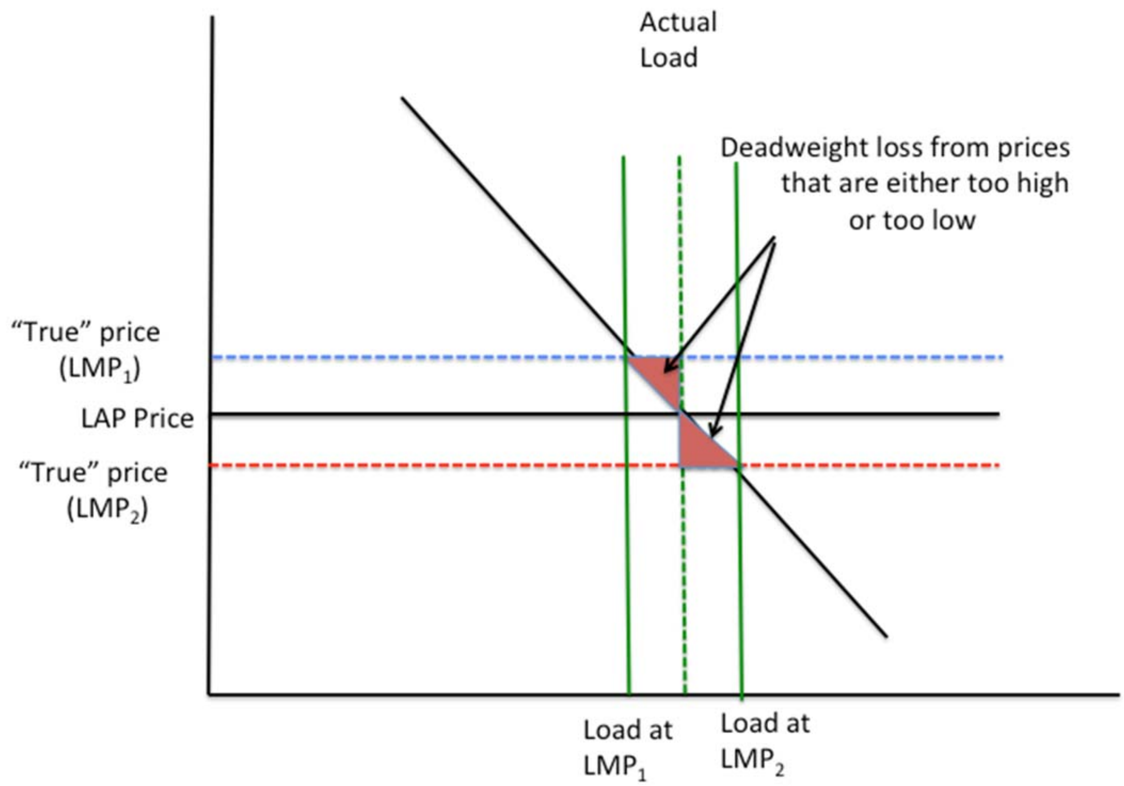

Figure 1. Deadweight loss from prices that are too high or low.

In the figure, the two triangles represent the deadweight loss. The upper triangle is the loss that occurs because the LAP price is too low relative to the local marginal cost of supply (LMP_1). As a result of too low a price, the actual load is higher than the efficient load (where the demand curve intersects LMP_1). The over-consumption results in a deadweight loss equal to the difference between the marginal cost of supplying power to that location and the marginal benefit of consumption (demand curve), which is the area of the upper triangle. In turn, the lower triangle is the social cost of under-consumption, where the ideal price is LMP_2, but local load pays the higher LAP price. The deadweight loss is the value of the consumption that should have taken place but didn't (the demand curve) minus the marginal cost of supply to that location (LMP_2).

As a very rough approximation to establish the relative magnitude of a deadweight loss from not reflecting such price differences in retail prices, we can apply the average 2013 CAISO day-ahead energy cost (excluding GMC) of \$44.14/MWh and the average 2013 CAISO load of

[14] For the PG&E, SCE, and SDG&E DLAPs, 85%, 89%, and 90% of load was at nodes with LMPs that averaged with \$2/MWh of their DLAP price, respectively (ibid., p. 14).

26,460 MW.[15] If we further assume a demand elasticity of -0.275 and assume a linear demand function, the implied slope of the average demand function would be about -0.00607 ($/MWh)/MW, or -165 MW/($/MWh).[16]

We can now obtain an estimate of the deadweight loss based on the elasticity, if we make the very conservative assumptions that 1) the average price difference is $2, and 2) that charging LMPs at the wholesale level would result in moving all retail load $2 closer to a price equal to marginal cost. Then the benefits in terms of reduced deadweight loss due to long-run changes in power demand in response to long-run differences in the cost of meeting load at locations within a common DLAP would be about $2.9 million/year.[17] This benefit estimate depends only on the elasticity, quantity of demand, prices, and dispersion of LMPs, and not on the whether the average retail prices are close to the LAP price or not.[18]

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[15] *Annual Report on Market Issues and Performance*. Department of Market Monitoring. California ISO. April 2014.

[16] Ito estimates a residential medium-run elasticity of -0.2 (K. Ito, "Do consumers respond to marginal or average price? Evidence from nonlinear electricity pricing," *American Economic Review*, forthcoming). As discussed in Borenstein et al. (S. Borenstein, J. Bushnell, F. Wolak, and M. Zaragoza-Watkins, "Report of the Market Simulation Group on Competitive Supply/Demand Balance in the California Allowance Market and the Potential for Market Manipulation," Report to the California Air Resources Board, June 2014), there are few estimates for commercial and industrial elasticities. The only published study from the last 20 years they find is D.R. Kamerschen and D.V. Porter's analysis ("The demand for residential, industrial and total electricity, 1973-1998," *Energy Economics*, 26(1), (2004): 87-100), which estimates a long-run industrial price elasticity of demand of -0.35 when controlling for heating and cooling degree-days. We arrive at -0.275 by assuming half of load is at the higher elasticity and half at the lower residential value. Under an assumption of linear demand, the deadweight loss estimate is scalable so that, for example, doubling the elasticity would double the DWL to roughly $6 million.

[17] Assuming a slope of 165 MW/$, the area of the deadweight loss triangle would be 2x2x165x1/2 per hour. Over the 8760 hours in the year, this implies $330 hour x 8760 hours = $2,891,000 in reduced deadweight loss per year from implementing more disaggregated pricing in the day-ahead market.

As implied by the previous footnote, this efficiency gain (reduction in loss) is proportional to the price elasticity. However, under the same linear assumption, the relationship of efficiency gain to the price changes themselves is nonlinear (more precisely, quadratic), so that, for example, if the range of prices doubles, then the deadweight loss quadruples. As a consequence, if LMPs vary only by a small amount (say a dollar or two) around the PLAP, then there is relatively little to be gained by increasing load granularity, but the benefits increase rapidly if the prices vary by much more (say by 5-10 $/MWh around the PLAP).

[18] For instance, assume that the LAP price is instead $30/MWh rather than $44.14, as assumed above, while the retail price is still $44.14. Assume further than LMP_1 = $32/MWh for one-half of the load, while for the other half LMP_2 = $28/MWh. If the retail prices for those respective groups of customers were changed to reflect the LMP differences ($46.14 and $42.14 per MWh, respectively), then the reduction in dead-weight loss would again be very roughly $2.9 million per year.

The calculation proceeds as follows. The change in consumption for customer group 1 would be -165 MW (which results from a -0.275 elasticity applied to a price change of +$2/$44.14 = +4.5% and a load of 13,23 = 26,460/2 MW), while group 2 would have a change of +165 MW. The change in the value of the two group's consumption (integral of the demand curves) would be -165 MW *($46.14+$44.14/MWh)/2 = -$7441/hr and +165 MW*($42.14+$44.14/MWh)/2 = + $7111/hr, respectively. The total change in cost would be -165 MW*32 $/MWh + 165 MW*28 $/MWh = -$659/hr.

As we discuss below, there are several reasons why it is uncertain whether more disaggregated wholesale pricing by the CAISO would be reflected in retail prices to the extent required to realize these benefits. Even so, the benefits from these long-term changes in consumption would be relatively small in terms of traditional economic loss, as they are just a fraction of the estimated implementation costs that were reported by load-serving entities in California in response to the CAISO's request for estimates of such costs. In their responses, stakeholders estimated their upfront investment costs to be on the order of $100 million, while on-going annual costs would be over $10 million/year. Even if those implementation costs were overestimated by, say, a factor of three, they were still well in excess of our estimate of the reduction of deadweight losses.

2. Focused Discussion on Locations and Sources of Price Differences

The CAISO pricing study concluded that it is difficult to identify obvious new pricing zones from the pattern of differences between LMP and DLAP prices that did arise during 2011-2014. In some cases, the CAISO found it difficult to group price differences into geographically contiguous areas, particularly when those differences were driven by losses.[19] In other cases, diverging LMPs were clustered but the CAISO concluded that the price differences are transient, being unlikely to persist because of transmission reinforcements or other reasons.

The one possible zone identified by CAISO's study is in the greater Fresno area. LMPs in the Fresno area were, on average, over $3 per megawatt hour higher than the PG&E DLAP price over the four year study period.[20] The CAISO analysis traces a primary cause of this divergence to peak hours during July and August of 2014, when drought conditions apparently created unusual congestion patterns for this area.

Furthermore, the CAISO proposal also states that transmission projects likely to reduce or eliminate this congestion have already been identified and approved. The CAISO argues that once these transmission projects are completed and normal hydrological conditions return, Fresno area LMPs will likely return to levels closer to other PG&E nodal LMPs. The CAISO pricing study concludes that there is no logical level of spatial disaggregation to analyze short of nodal.[21]

III. The CAISO Proposal and Analysis

The CAISO study <u>cites three areas</u> of potential benefits from further spatial disaggregation, discussed below, and finds that these benefits would be less than $3 million annually.[22] By con-

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Subtracting the change in cost from the sum of the value of consumption for the two groups results in a welfare gain (deadweight loss reduction) of $329/hr, or $2.9 million/year, as before. In sum, aligning retail price differences over space (or time, for that matter) with marginal cost differences is beneficial, even if prices differ systematically from marginal costs.

[19] See *Draft Final Proposal,* p. 19.

[20] Ibid., p. 26.

[21] Ibid., p. 14.

[22] Ibid., p. 41.

trast, the implementation costs identified by participants for a fully nodal implementation would include $14.6 million in implementation costs, $132.6 million in capital costs and $12.6 million in ongoing annual costs. Since the identified estimated benefits fall far short of the estimates of the costs of implementation, the CAISO concludes that the current level of price aggregation for load is just and reasonable and that no further disaggregation should be implemented at this time.[23]

In this section, we will comment briefly on the CAISO's analysis of the benefits of disaggregation and discuss the more difficult question of the proper context in which such an analysis should be performed. In short, we agree with the CAISO that given the apparent unwillingness of the CPUC to reflect locational price differences in the retail rates subject to its jurisdiction, [24] and the lack of interest in further price disaggregation by retail access load-serving entities,[25] by municipal utilities purchasing power at DLAP prices, [26] or by large power consumers, the benefits of further LAP disaggregation appear to be relatively small and would be outweighed by the apparent cost of implementation.

We also note that "just and reasonable" is not the same standard as "most long-run efficient." We support the view that fully nodal pricing or less aggregated zonal pricing would better support economic efficiency in the long-run, and would better enable price responsive load to reduce the need for incremental investment in generation and transmission, at least in the short-run. From a long-run economic efficiency perspective, the most attractive eventual paradigm for any electricity market would be one in which customers are exposed to -- and given the opportunity to adjust their power consumption in response to -- both the spatial and temporal variation in locational marginal prices, without the implementation costs and inflexibilities of "negawatt"-based demand response programs.

It is clear that those ideal conditions do not today exist in California today. A more difficult question is the degree to which ISOs, by adopting fully nodal pricing for loads, provide leadership that can influence state policies concerning retail pricing in one way or another. This is both a controversial and difficult to quantify concept.

A. Benefits Assessment

The CAISO study identifies and considers the quantification of three potential categories of benefits, including

[23] Ibid., p. 3.

[24] Comments of CPUC Staff, March 17, 2015

[25] See Comments of Alliance for Retail Energy markets, March 13, 2015, Comments of CLECA, April 3, 2015, Comments of Energy Users Forum and California Manufacturers and Technology Association, March 17, 2015, and Marin Clean Energy, March 3, 2015.

[26] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015.Comments on Behalf of California Municipal Utilities Association, April 13, 2015

1) Investment incentives,
2) Hedging of congestion costs, and
3) Efficiency of day-ahead market pricing.

The ISO's conclusions about each of those are reviewed in the subsections below.

In addition to those benefits, there are several other categories of potential benefits that might, in theory, be relevant, and we discuss several of those in Section III.B, below. We have already discussed one major category: the effect of local prices on the efficiency of electricity consumption, which would be the reductions in dead-weight loss we quantified in Section II. During the stakeholder process for this initiative, there was extensive discussion of both the qualitative and quantitative nature of any potential benefits with respect to end-use consumption. At issue was the extent to which any such benefits could be considered a result of CAISO wholesale pricing policies. For example the CPUC has concluded that "virtually all the benefits purportedly achievable from price disaggregation can be and/or are realized by existing market products, process and information."[27]

As a result of this stakeholder process, the CAISO proposal concluded that any benefits with respect to end-use consumer behavior fall under the rubric of retail pricing policies rather than wholesale market design. Thus they concluded that it would not be relevant to consider these types of benefits, such as the deadweight loss calculation we described in section II, as part of this process.

While we do not disagree with this conclusion, we note in addition that the magnitude of the deadweight loss appears to be relatively small compared to estimates of implementation costs. As noted above, assuming that all customers at all nodes had their rates adjusted according to their *annual average* nodal energy prices, rather than dynamically reflecting hourly DLAP prices, would imply a reduction in deadweight loss on the order of $3 million per year.

There are a few reasons why our very rough estimate of consumption-based inefficiency due to DLAP pricing could be understated. First, if a significant number of customers faced *hourly* nodal prices this number would most certainly increase. Second, if some customers had access to real-time nodal prices, then the larger price variations in real-time nodal prices imply more potential efficiency gains. Some large customers in California who can take advantage of retail access may presently face real-time prices on the margin from their providers. To the extent that this is the case, then the deadweight loss reductions may be somewhat higher than we have calculated.

1. *Investment incentives*

The CAISO proposal identifies a few areas where locational pricing signals provide value to the decision on whether to invest capital or make other long-run commitments with regards to energy production, consumption, or transmission. The CAISO concludes there are no material benefits to further disaggregation because spatial granularity is already provided for almost any

[27] California Public Utilities Commission, March 17, 2015 p. 3

relevant investment decision. [28] First, generation is already exposed to fully granular nodal pricing. Second, transmission investment is initiated through a planning process that already takes into account the underlying nodal energy prices for load, even though load is not paying those exact prices. Third, major end-use consumers that are able to respond to dispatch instructions have the option of becoming a participating load thus making them eligible for paying the nodal, rather than DLAP price. Similarly, end use customers able to provide demand response, can enroll as proxy demand resources and buy power at the nodal price. However, either option for consumers has high participation costs compared to the costs that would be faced if a power consumer instead had the option of being able to respond to real-time locational prices. Neither the participating load nor the proxy demand resource option would be available to power consumers who simply wish to be able to respond to nodal prices, but do not want to be dispatchable or provide demand response.[29]

The only remaining source of improved investment incentives relating to long-run locational price differences would therefore reside with durable goods purchases by end-use consumers who are not realistically able to become either participating loads or proxy demand resources. If retail pricing policies were to be changed so that all consumers faced retail prices whose differences over space reflected annual average differences in LMPs, then as we speculated in Section II, there might be an additional $2.9 million or so per year of benefits. However, there is no prospect at this time of such a policy change, so it is not reasonable to add this figure to the benefits calculated in the ISO's study.

2. *Congestion Revenue Rights*

The FERC order also identified congestion revenue rights as an area of potential benefits from increased granularity in wholesale pricing. The CAISO analysis also discusses this category of potential benefits in detail. The CAISO suggests that these benefits can arise because the simultaneous feasibility test used to allocate CRRs is artificially constrained by the DLAP paradigm. This is because all CRRs in the Tier 1 annual allocation process are treated in the CRR model as sinking at demand nodes within a LAP according to a fixed load distribution factor (LDF). In order to maintain feasibility when allocating CRRs, the process is forced to curtail these sinks proportionally to the LDFs. The CAISO identifies a concern that if desired distribution of CRRs was not proportional to these LDFs, this limitation to the feasibility test can restrict the amount of CRRs that are allocated, even though the desired group of CRRs may in fact be feasible for the actual network.

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[28] *Draft Final Proposal,* op. cit., pp. 32-33.

[29] See for example, California ISO, *Load Granularity Refinements, Draft Final Proposal*, September 18, 2013, www.caiso.com/Documents/DraftFinalProposal-LoadGranularityRefinementSep18_2013.pdf, p. 11. We have been informed by ISO staff that participating demand response loads have to have a minimum curtailable load of 100 kW, unless the load also wants to provide ancillary services, in which case the minimum load is 500 kW. Proxy demand response is only available to a load-serving entity that is both procuring the wholesale energy and, at the same time, is acting as the demand response provider and selling that energy back to the ISO.

The CAISO analysis estimates an upper bound on the benefits that could be created by awarding additional CRRs by nominating them as sinking at nodes rather than DLAPs. The resulting bound upon possible benefits ranges between $1.08 to $2.75 million per year based on CRRs nominated in Tier 1 but not awarded because of infeasibility. These values are derived from the monthly auction price.[30] The proposal characterizes this estimate as an upper bound for several reasons, including the fact that some of the CRRs unallocated in the annual process can be freed up in a subsequent distribution that allows for nominations at the sub-LAP level. Moreover, CRRs sinking at individual nodes can be obtained in the CRR auctions, so the DLAP aggregation does not prevent feasible individual CRRs from being acquired by load serving entities and used to hedge congestion costs in the day-ahead market.

Another reason that the CAISO estimate is an upper bound is that the hedging value of a CRR is at most a fraction of its auction value. The only efficiency loss from a potential shortfall of available CRRs would be related to any inefficient level of risk that potential CRR purchasers are required to take on when they are not able to acquire CRRs that would hedge congestion costs to the actual location of their load. This is the concept of *certainty equivalent*, where risk-averse firms are willing to pay a premium above the expected value of a revenue or cost stream in order to lock in that value with certainty. A rough estimate of this certainty equivalent could be gleaned from their willingness to pay for CRRs relative to the expected value of the congestion revenue stream. The hedging value would be measured by the risk premium in the CRR auction price relative to the expected payout. The expected payout is not observed, however, and the variability of actual payouts makes it difficult to infer the risk premium component of particular CRRs from the limited data on actual outcomes that is available.[31]

The CAISO's upper bound estimates do not measure the hedging value of the incremental CRRs, but instead use the *full* auction price (a close proxy for willingness to pay) applied to the CRRs requested in Tier 1 that were infeasible. This is in effect assuming that the associated revenues with the CRRs are worth nothing to their purchasers and that the entire bid price reflects the risk premium component. This is almost certainly a very conservative assumption in favor of finding large benefits.

There is, however, a slightly different hedging issue which is intrinsic to DLAPs. This arises for consumers whose load is not located at the DLAP. In that case, requiring them to hedge their load as if it is located at the DLAP, when it is in fact not, can cause CRR feasibility problems. In particular, CRRs that would hedge these loads by sinking at the DLAP at the margin could be infeasible by the CAISO simultaneous feasibility test, even though CRRs sinking at

[30] CAISO Draft Proposal, March 24, 2015, op. cit., p. 35.

[31] We understand that the prices for financial transmission rights in PJM and MISO often show significant risk premia. One analysis of data on prices and payoffs for congestion revenue rights in the NYISO (which are called TCCs in that market) claims to have found insignificant risk premia in the portion of the state outside NY City and Long Island, and large profits (excess of expected payoffs over CRR prices) in the latter region (S. Adamson, T. Noeb, and G. Parker, "Efficiency of financial transmission rights markets in centrally coordinated periodic auctions," *Energy Economics*, 32(4), 2010, 771–778). However, the prices and payoffs for TCCs sinking in the major congested load centers show a substantial long run average premium of the TCC price over the average payout.

the location of their actual load would be feasible. This would be a potential concern for municipal utilities and retail access customers.

One could place an upper bound on the benefits from greater DLAP disaggregation in terms of CRR hedging using the value of the CRRs nominated in any tier that were infeasible. But this would overstate the actual benefits because, first, not all of those CRRs might be feasible if they sank at the location of the actual load and, second, as noted above, the hedging value of a CRR is at most a fraction of its auction value. In any case, none of the municipal utilities or retail access customers or suppliers that might be impacted by this outcome expressed a desire for further disaggregation in DLAPs, so they do not appear to expect material benefits in terms of lower hedging costs or better hedging ability from locational price disaggregation.[32]

3. Day-ahead market pricing efficiency

Another potential benefit to increased granularity in the pricing of load that evaluated by the CAISO would be the ability to perform the day-ahead market optimization with more flexibility in adjusting load at different locations. The CAISO's day-ahead optimization, like the annual CRR allocation process, must clear load at all nodes in proportion to the load distribution factors used to define the DLAP in the day-ahead market and therefore can reduce transmission overloads through load adjustments only by reducing *all* nodal loads within a LAP in proportion to the load distribution factors. For example in order to use load to reduce overloads on paths into the San Francisco Bay Area, the optimization must reduce the amount of load that clears in the PG&E service territory , rather than hypothetically reducing the amount of load the clears only in Bay Area. The CAISO's analysis then observes that the extent to which DLAP load bids do not clear because of congestion within the DLAPs reduces the ability of LSEs to hedge in the day-ahead market. The analysis seeks to assess the magnitude of the inefficiency by reviewing the frequency with which DLAP bids are on the margin in the day-ahead market.[33]

In evaluating this issue one needs to keep in mind that we are not assessing a situation in which load cannot be met within part of the DLAP because of congestion, but simply the need to dispatch generation out of merit within part of the DLAP to manage congestion. Hence, when a DLAP load bid does not clear, it is because it is bid at a price level that is too low to allow some higher cost generation in the constrained region to clear, because that would boost the overall DLAP price above the price of the demand bid. The underlying problem is that submitting demand price bids for regions as large as some of the California DLAPs requires that load serving entities assess two quantities: first, at what price level to submit demand bids to avoid paying unduly high prices for power over the LAPs, while accounting for the level of variability and unpredictability in the general price level, and second at what price level to submit demand bids to avoid buying power at unduly high prices due to factors inflating the price of power within a

[32] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015; Comments on Behalf of California Municipal Utilities Association, April 13, 2015. This lack of benefits may reflect the use of the MSS load following option by municipal utilities that would have been most adversely impacted by settling their load at the DLAP.

[33] See *Draft Final Proposal*, March 24, 2015, op. cit., p. 39.

part of the DLAP. Large DLAPs with price differences within them require load serving entities to trade off the two objectives, choosing between paying too much in subregions when something distorts the price of power in the day-ahead market and selecting bid levels for the LAP that do not clear because of normal variability in market conditions, leaving the load serving entity exposed to real-time price volatility. It is undoubtedly hard for load serving entities to accurately project the competitive level of day-ahead market prices in any case and this difficulty is exacerbated by having to make this assessment over such a broad region. If there were transmission constraints within the DLAPs that frequently bind with high shadow prices, the use of these DLAPs would make it very difficult for load serving entities to submit rational downward sloping load bids.

Load serving entities do not necessarily need to submit price capped load bids, and the issues identified by the CAISO do not arise if load serving entities instead submit price taking bids. However, submitting price taking load bids can make a load serving entity more vulnerable to high prices that can arise for several reasons. These include: the exercise of market power in the day-ahead market; distortions in day-ahead market prices due to virtual bids motivated by other financial positions that cause day-ahead market prices to exceed expected real-time prices; mistaken load weights used by the CAISO in its day-ahead market model; and physical or virtual bids by other market participants that are driven by mistaken expectations. These considerations may not be particularly large in the CAISO because of the presence of extensive market power mitigation rules and rules preventing the use of virtual bids to benefit CRR positions. Nonetheless, the use of DLAPs increases the exposure of load serving entities to such distortions in day-ahead market prices to an extent that would not exist with more disaggregated pricing. Perhaps for this reason, it appears from the CAISO comments that load serving entities in California find it prudent to submit price capped load bids to limit their exposure to day-ahead market prices that are inconsistent with the real-time prices the entities expect.

As the California ISO notes, load serving entities can achieve essentially the same protection against clearing load bids at anomalously high day-ahead market prices by submitting virtual supply bids. [34] We do not have a sufficiently precise understanding of the constraints the CPUC has placed on virtual bidding by jurisdictional load serving entities but it could allow them to submit virtual supply bids in this manner, and other load serving entities certainly could do so. Indeed, load serving entities are submitting virtual supply bids today and some might be motivated by these considerations.[35] However, the ability to achieve the same outcome with nodal virtual supply bids as with price capped load bids does not mean that the benefits from more disaggregated bidding would be zero as asserted by the California ISO. Rather, it means that the benefits would be capped by the cost of using virtual supply bids for this purpose.[36]

[34] Ibid., p. 40.

[35] California ISO, Department of Market Monitoring*, 2013 Annual Report on Market Issues & Performance*, p. 118, Table 4.1 It is possible and perhaps likely that these virtual supply bids are in fact motivated by other considerations, such as supply resources under contract to the utility that do not bid into the day-ahead market. However, we do not have access to the data needed to assess the motivation for these bids.

[36] The CAISO figures regarding the frequency with which DLAP bids are marginal are not informative as to the magnitude of the benefits. This is because there can be losses from the inability to submit

Hence the benefits for the large investor owned utilities that serve load throughout the DLAPs would be capped by the costs they would incur if they submitted virtual supply bids to compensate for the inability to submit more disaggregated load bids. This would include the fee on virtual bids plus the uplift costs allocated to virtual supply bids, which was around 46 cents per megawatt hour in 2013.[37] The costs of using such a bidding strategy based on virtual bids would be much higher for non-jurisdictional load serving entities, such as municipal utilities and retail access suppliers. This is because they would also need to evaluate the expected real-time price at all the locations where they have no load but the investor owned utilities do serve load, instead of just needing to evaluate the expected real-time price at the location where they serve physical load,

However, as noted above, none of the municipal utilities nor retail access suppliers support more disaggregation of load pricing, so they must not believe these costs from being unable to submit more effective price capped bids to be material.[38] Similarly, none of the CPUC jurisdictional investor owned utilities supports more disaggregation of load pricing so they also presumably do not believe these costs are material.[39] This lack of interest in disaggregation may reflect their perception of a relative lack of congestion in the day-ahead market that would cause material dispersion in day-ahead market prices within the DLAPs.

It is difficult to quantify this effect, in part because of the difficulty in imagining what the counter-factual bidding of demand at individual nodes would be under a fully nodal regime. The amount of data available for such an analysis was also severely constrained by changes to the CAISO software that coincided with the implementation of its fifteen minute market.

B. Other Possible Sources of Benefits

In addition, there were other benefits that were not considered by the CAISO. These include the benefits of power consumers being able to respond to locational differences in real-time prices, reductions in CRR congestion rent shortfalls due to differences in within-DLAP load weights between the CRR allocation process and the day-ahead market, and consistent pricing

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downward sloping load bids at a more disaggregate level not only when the bids do not clear at the DLAP level but also when the DLAP bids *do* clear only because they were required to be submitted as aggregated across nodes, and more disaggregate bids would *not* have cleared.

[37] California ISO, Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, pp. 118 and 120.

[38] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015; Comments on Behalf of California Municipal Utilities Association, April 13, 2015; Comments of Alliance for Retail Energy Markets, March 13, 2015, Comments of CLECA, April 3, 2015, Comments of Energy Users Forum and California Manufacturers and Technology Association, March 17, 2015, and Marin Clean Energy, March 3, 2015.

[39] See Comments of Pacific Gas & Electric, March 13, 2015, and Southern California Edison Stakeholder Comments April 20, 2015.

for behind-the-meter generation. We define each of the categories below, and although in theory they could be important, we conclude that none is likely to be significant in the near term.

1. *Response to real-time prices*

The CAISO's analysis of price differences within the DLAPS was limited to day-ahead market prices. There is considerable volatility in real-time prices and there could be value in retail power consumers being able to adjust their consumption in response to large differences in real-time power prices within the LAP. In addition to reducing the cost of meeting load in real-time, such a real-time locational price signal for price responsive load might reduce the need for transmission and generation in the long run by enabling the CAISO to reliably meet load with fewer resources. Although we are unaware of whether there are presently significant numbers of direct access customers in the CAISO footprint who face real-time prices on the margin, this can and, we hope, will change in the future.

This functionality could also be provided by proxy demand resources, CPUC jurisdictional demand response and participating loads. But these are relatively high cost mechanisms as illustrated by the lack of any proxy demand resources, the very small number of participating loads resources, and the lack of real-time price response from CPUC jurisdictional demand response programs.

However, given the reluctance to date of the CPUC to embrace price responsive load among its jurisdictional customers and the lack of support from municipal utilities, retail access suppliers or large power consumers for greater locational price disaggregation, there is no evidence that there could be significant benefits of this type in the near term.

2. *Day-ahead market congestion rent shortfalls*

The CAISO analysis also considers the effect that more granular pricing could have on CRR revenue adequacy presently caused by the use of large DLAPs. At present the CAISO uses a single set of load weights to evaluate the feasibility of CRRs in the allocation and auction process and then different sets of load weights in the day-ahead market for each day. The large DLAPs inevitably lead to some infeasibility when awarded CRRs are subsequently infeasible when day-ahead market load weights are used. There would also be some offsetting surpluses when additional CRRs would be feasible with day-ahead market load weights.[40] The CAISO discussion argues that revenue inadequacy is primarily driven by differences between the day-ahead model and CRR model that are unrelated to LAP aggregation, and therefore sees no quantifiable benefit from disaggregation with regards to revenue adequacy.

However, there is a potential for CRR auction participants to magnify the shortfalls and create cost shifts by buying portfolios of nodal CRRs and LAP CRRs that have low constraint impacts at auction weights but potentially larger constraint impacts at day-ahead market weights. Shifting to less aggregated DLAPs would reduce the potential for these shortfalls and strategies.

[40] *Draft Final Proposal*, March 24, 2015, op. cit., p. 37.

These wealth transfers could also be avoided while continuing to settle load at the DLAPs by using the auction load weights to settle CRRs in the day-ahead market. Hence, the magnitude of the benefits from reducing these wealth transfers by implementing smaller DLAPs would be capped by the cost of shifting to using auction load weights to settle CRRs in the day-ahead market.

The CAISO analysis also discusses additional ways in which granular pricing might negatively impact CRR revenue adequacy. For instance, as noted in Section III.A.2 of the draft final proposal,[41] further disaggregation could result in an increase of allocated CRRs in the Tier 1 annual allocation process, which have the potential to displace feasible CRRs that are currently awarded through the auction process. Therefore, there could be a decrease in CRR auction revenues, which are included in the CRR balancing account, thus decreasing revenue adequacy.

3. Behind-the-meter generation

The current proposed design for accommodating behind-the-meter generation in the CAISO market provides for such generation that participates in the CPUC resource adequacy design to settle at nodal prices.[42] Retention of the DLAPs will create an incentive for behind-the-meter generation at locations with high prices to participate in the resource adequacy process and sell their power at the nodal price, and for resources at low priced locations to remain behind the meter and in effect sell their output at the DLAP price. This incentive will be small as long as price differences within the DLAP are small but it will be large at any locations with large price differences.

IV. Conclusion

While there are a number of potential benefits from increased disaggregation in load pricing, neither market participants nor the CPUC expect these benefits to be sufficient to make such a change cost-effective. The CAISO has compiled data showing that differences between nodal and DLAP prices in the day-ahead market have generally been small, particularly in the earlier years. These historical congestion patterns may of course not persist in coming years and congestion may increase. Alternatively, changes in the resource mix may cause day-ahead market congestion to become even smaller.

Thus, we support the ISO's proposal to maintain the status quo and not pursue further disaggregation of the existing DLAPs at this time. We support the long term vision of retail prices that reflect system conditions that vary over space and time so as to promote efficient coordination of resources in both wholesale and retail markets. However, in the absence of retail rate reform that would allow most customers to face such prices on the margin, there is little benefit to providing more spatial price granularity for load at this time, which would be greatly outweighed by the reported cost of implementation. On the other hand, we do encourage reforms of retail

[41] Ibid., p. 38.

[42] California ISO, *Reliability Services, Addendum to the Draft Final Proposal*, February 27, 2015, Section 4.3.1 describes requirements to be a participating generator or system resource.

ratemaking that would have those rates better reflect temporal and spatial variations in the cost of power to better enable price responsive consumers to adjust their consumption based on the cost of power.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above-referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 3rd day of June 2015.

/s/ Anna Pascuzzo
Anna Pascuzzo