Load Granularity Refinements

Draft Final Proposal

March 24, 2015

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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)

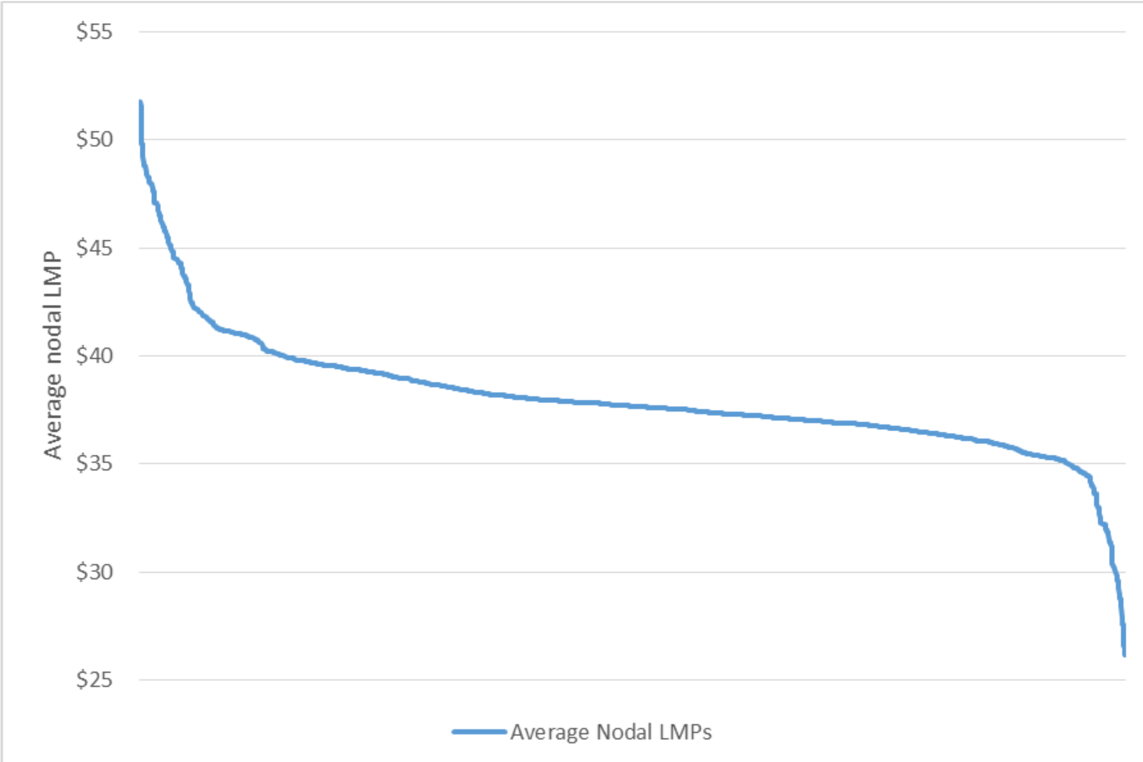
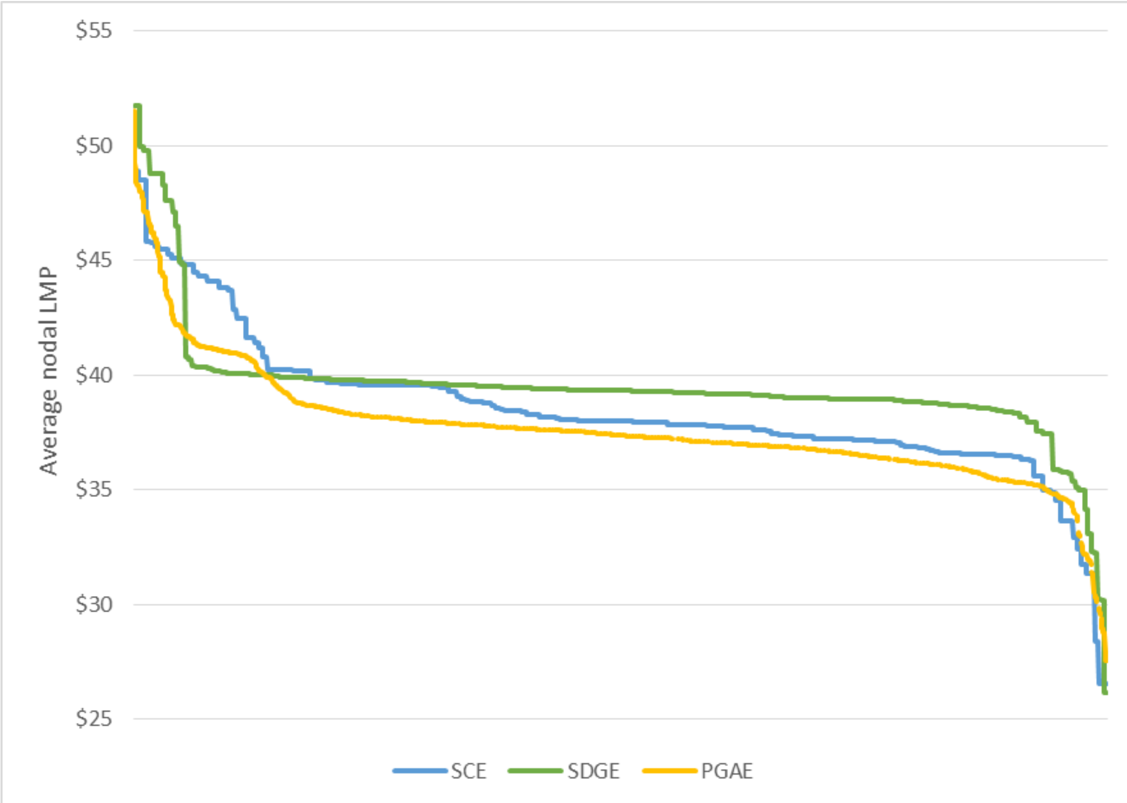


Figure 2 and Figure 3 below examine the average nodal prices geographically. Figure 2 uses the same average prices in Figure 1 but shows them by LAP. The three major DLAPs have similar price variations. This indicates that the load nodes with higher or lower average LMPs from Figure 1 are dispersed throughout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

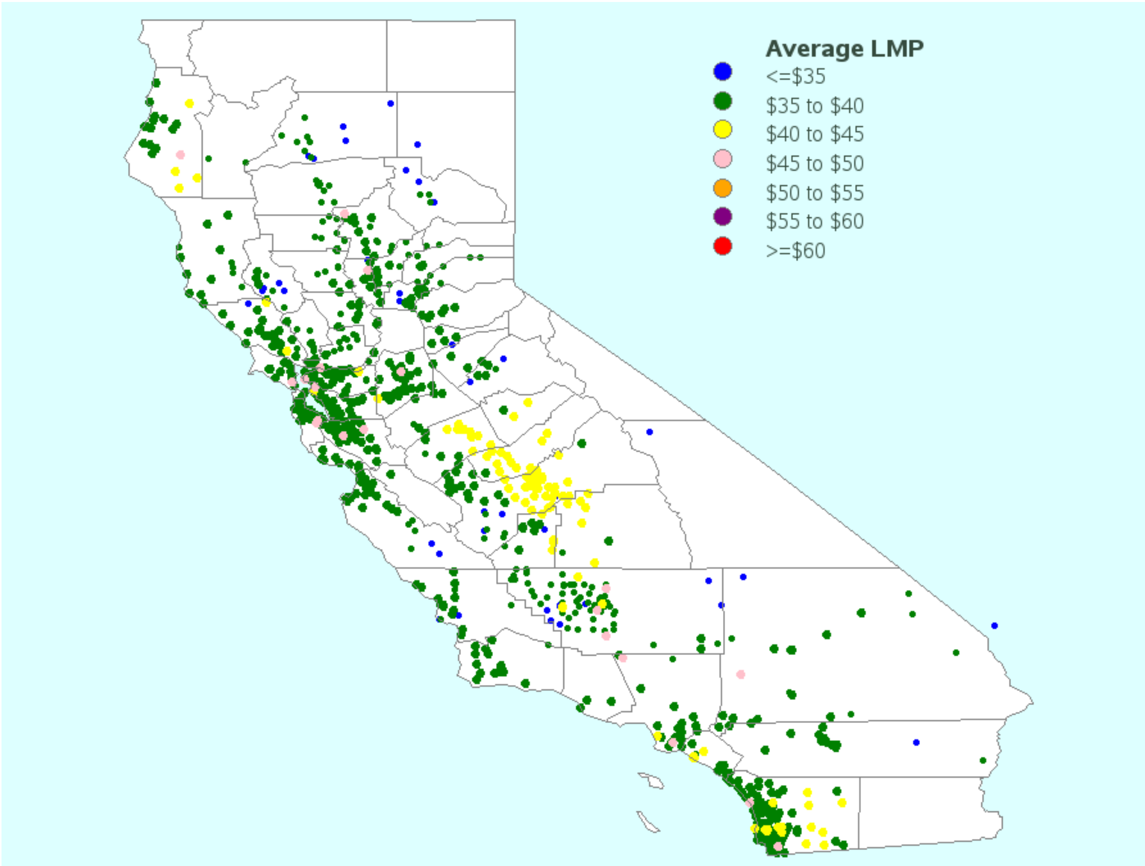
Figure 3 plots the average prices in Figure 1 and Figure 2 on a map of California to determine if there are regions within each LAP that have higher or lower average priced load nodes. The majority of load nodes have an average LMP in the $35-$40/MWh range (green). Load nodes with lower average prices (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.

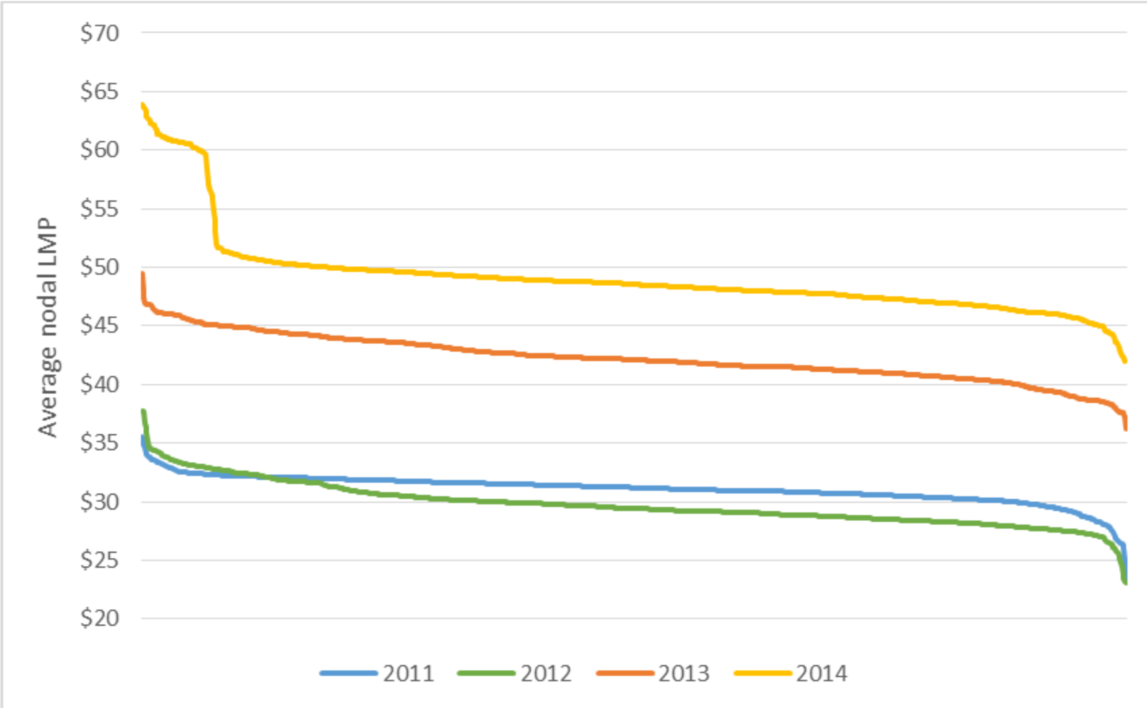
Figure 3 Simple average nodal LMPs heat map (2011-2014)



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)

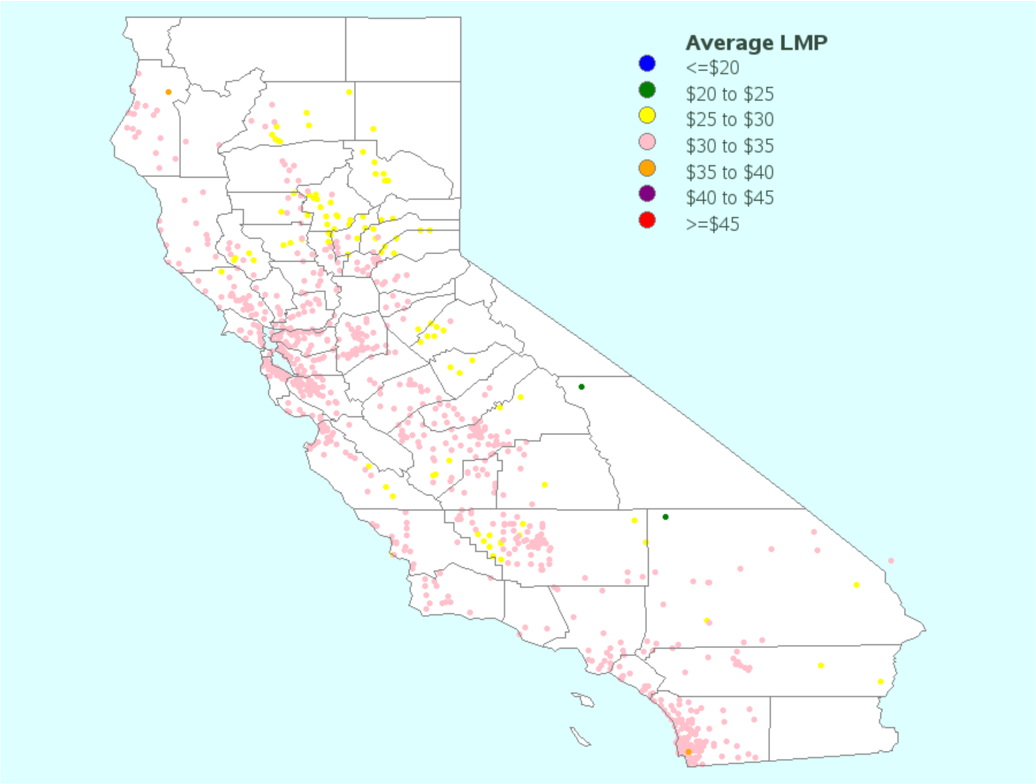
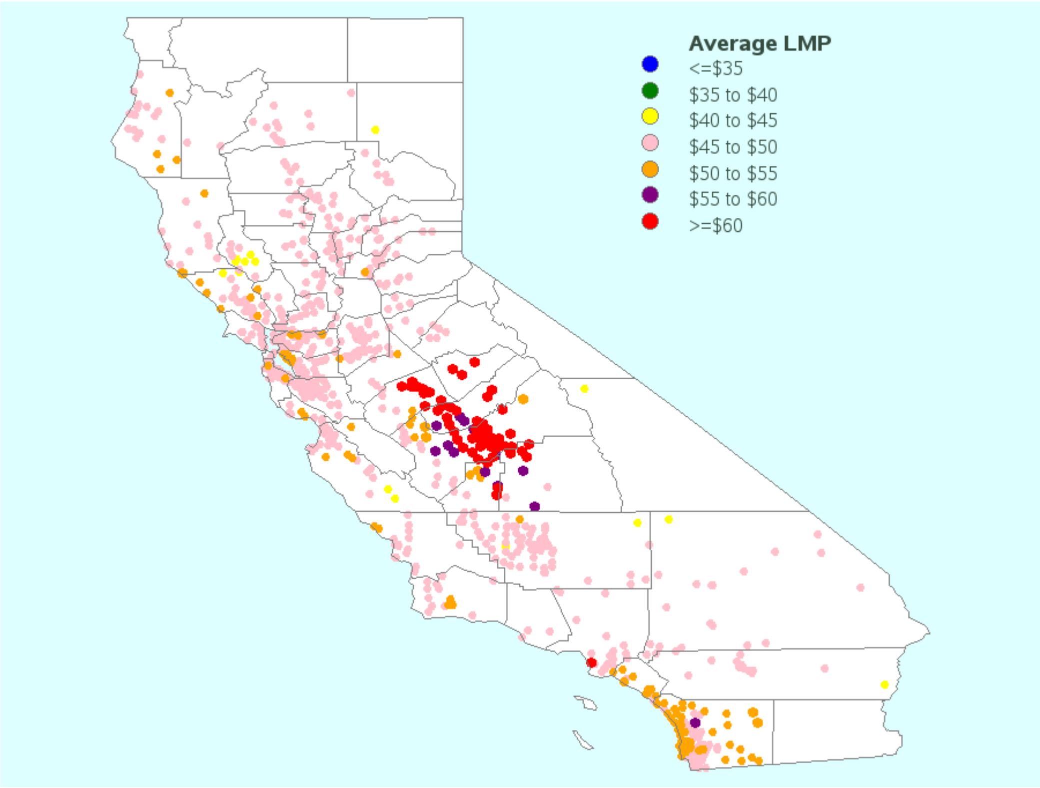


Figure 6 Simple average day-ahead nodal LMPs heat map (2014)



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

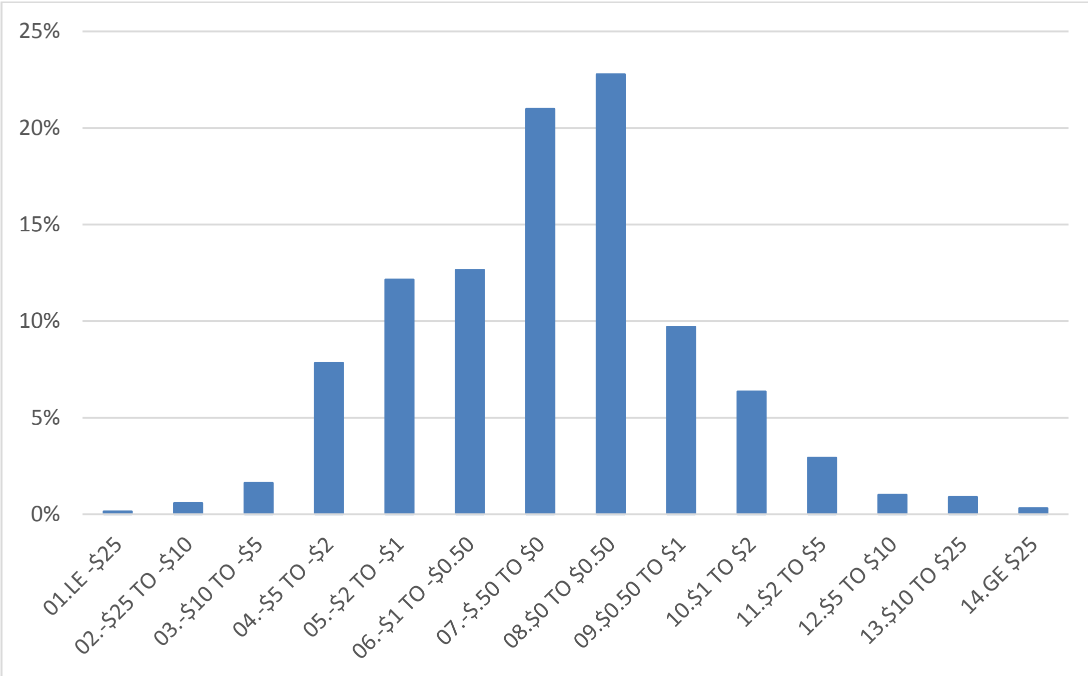
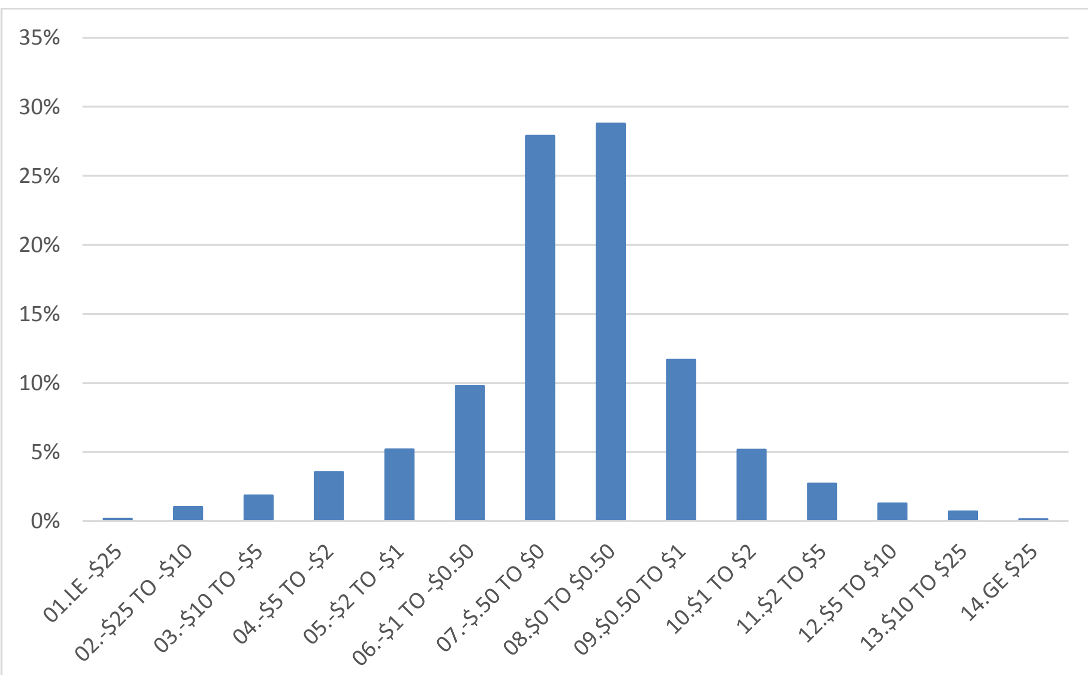


Figure 8 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – SCE



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

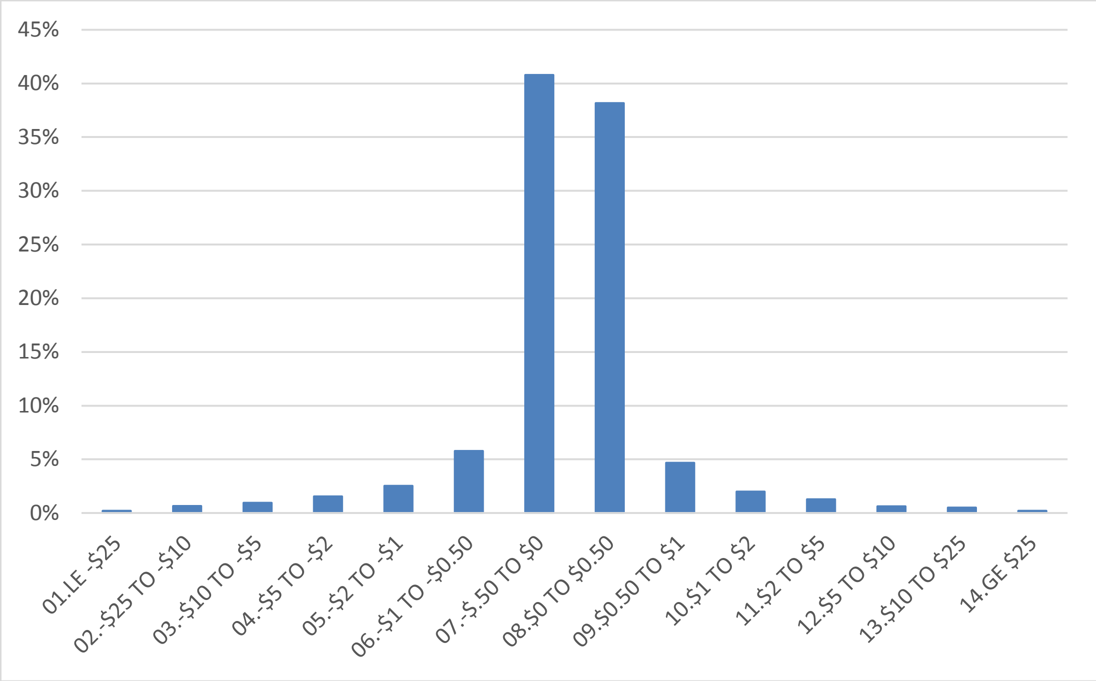


Figure 10 Percent of 2011-2014 load by difference of nodal LMP and DLAP LMP – VEA

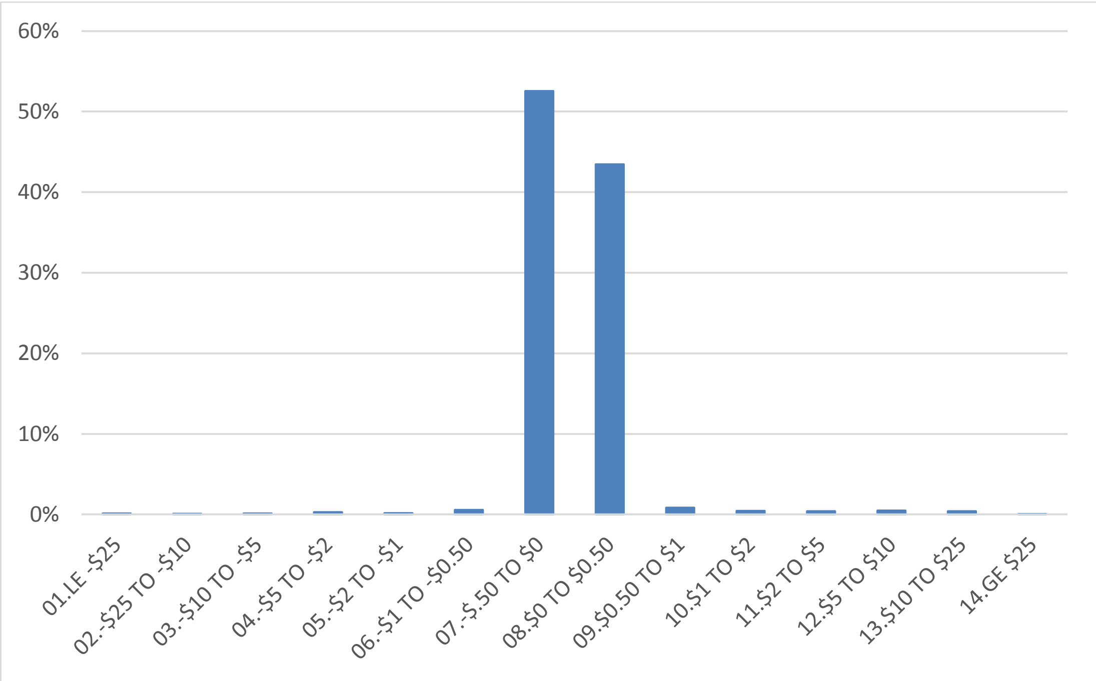


Table 1 below provides the percentages used to generate the previous four charts showing the percentage of DLAP load located at nodes with LMPs above/below the DLAP LMP by given thresholds.

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)

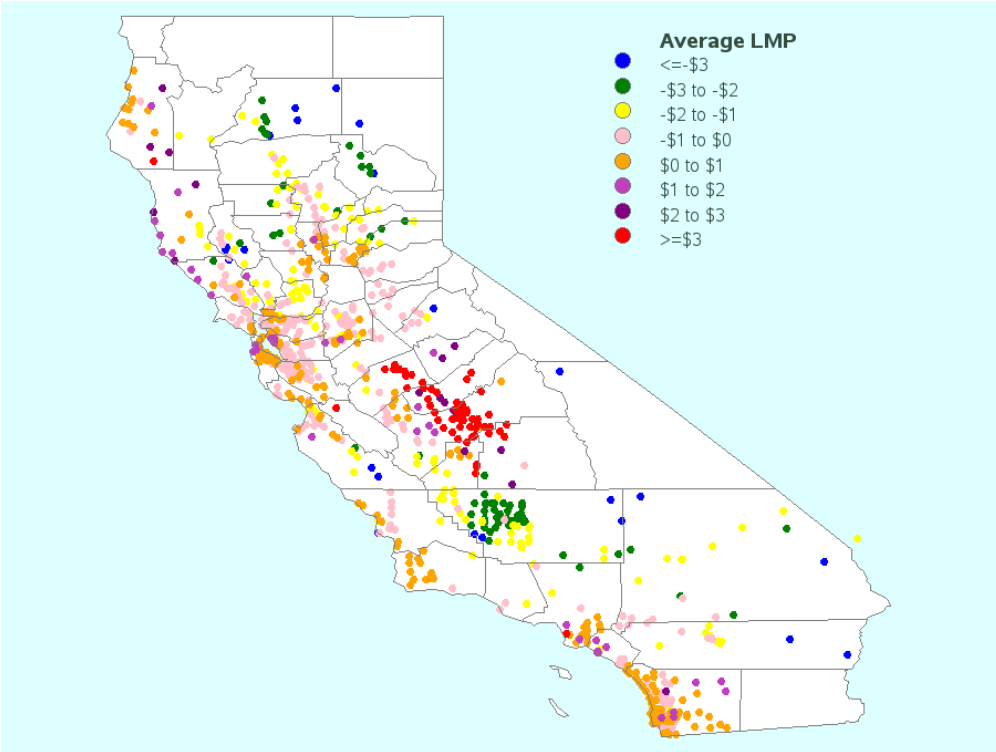
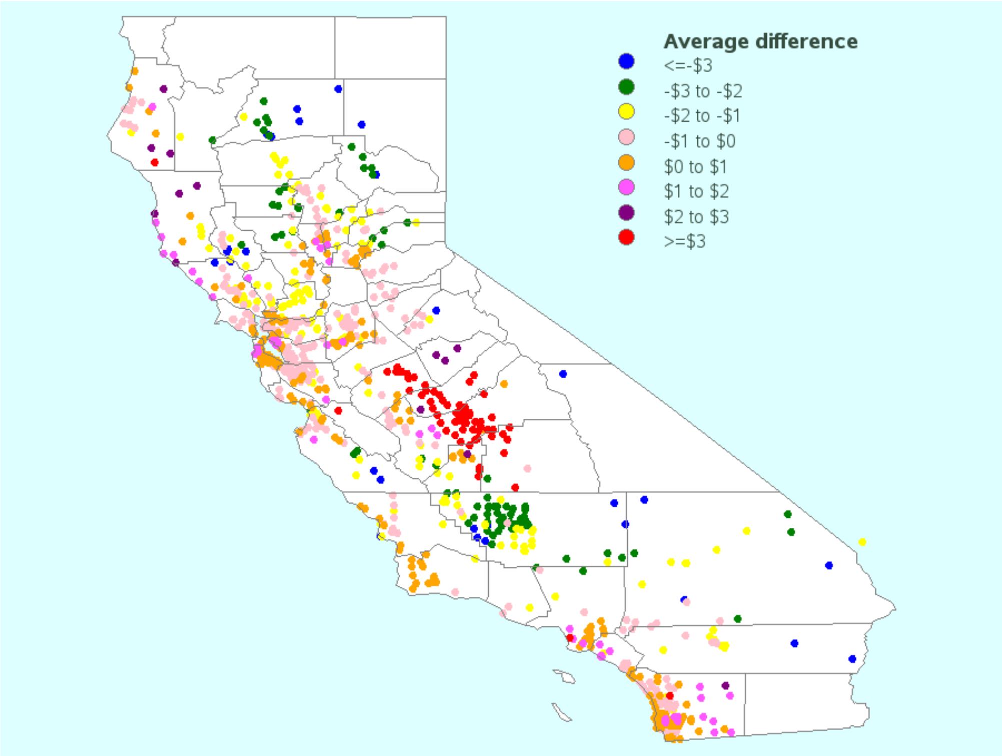


Figure 12 Load weighted average difference of nodal LMP to DLAP LMP heat map (2011-2014)



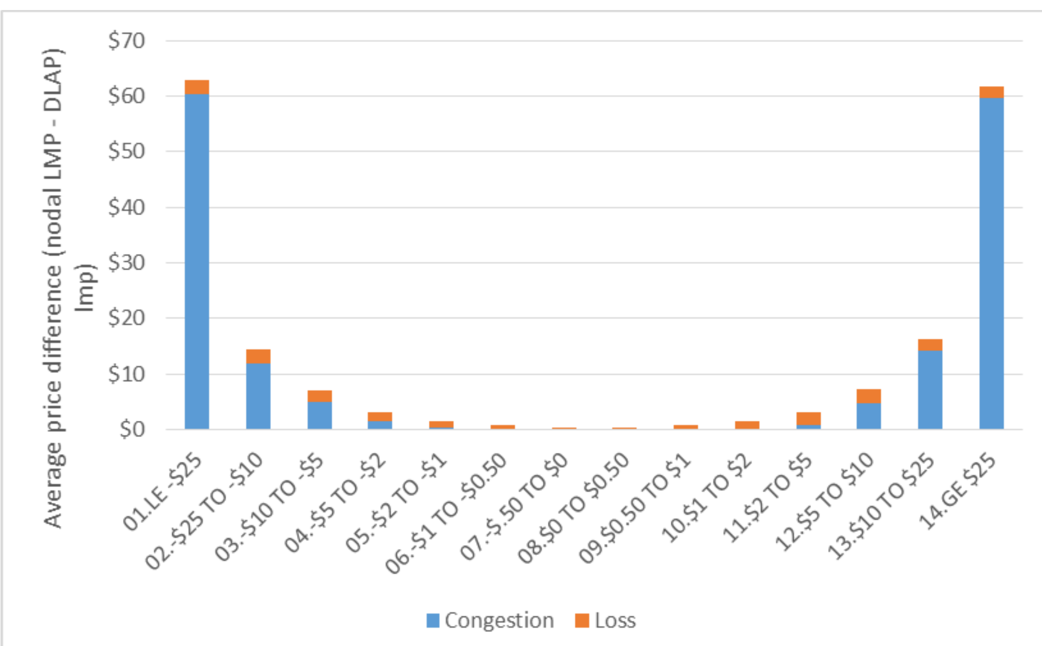
Any difference in a nodal LMP relative to the DLAP LMP is due to differences in the congestion components and/or loss components of the LMPs. The contribution each component has to the difference in each hour for each node was calculated. Then the average difference and average contributions were taken 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



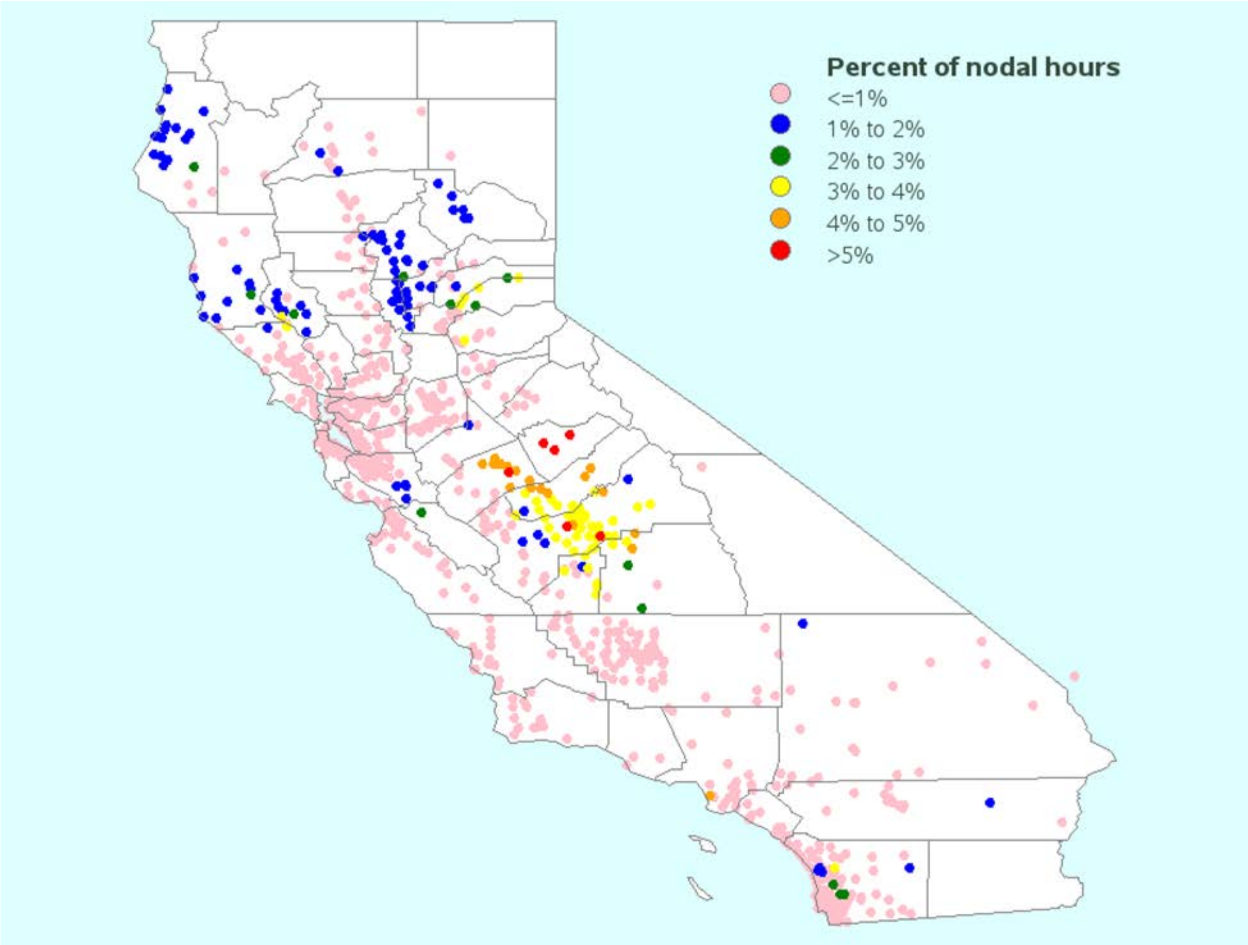
C. Nodal Price Volatility

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].

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[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

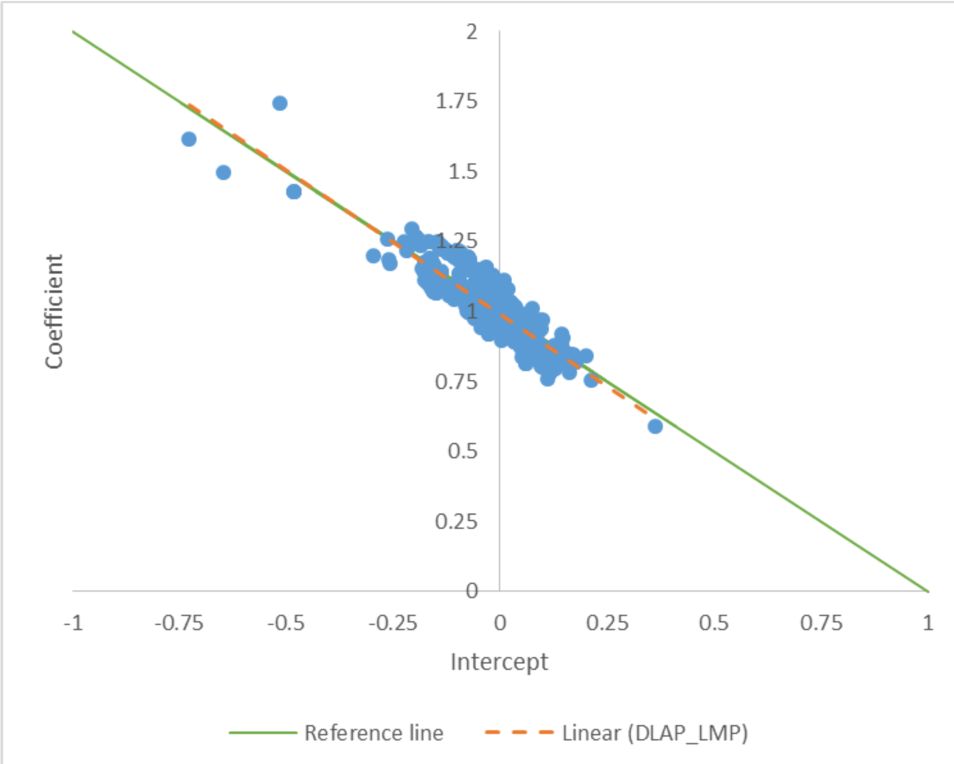


Figure 16 Regression results – SCE 2011-2014

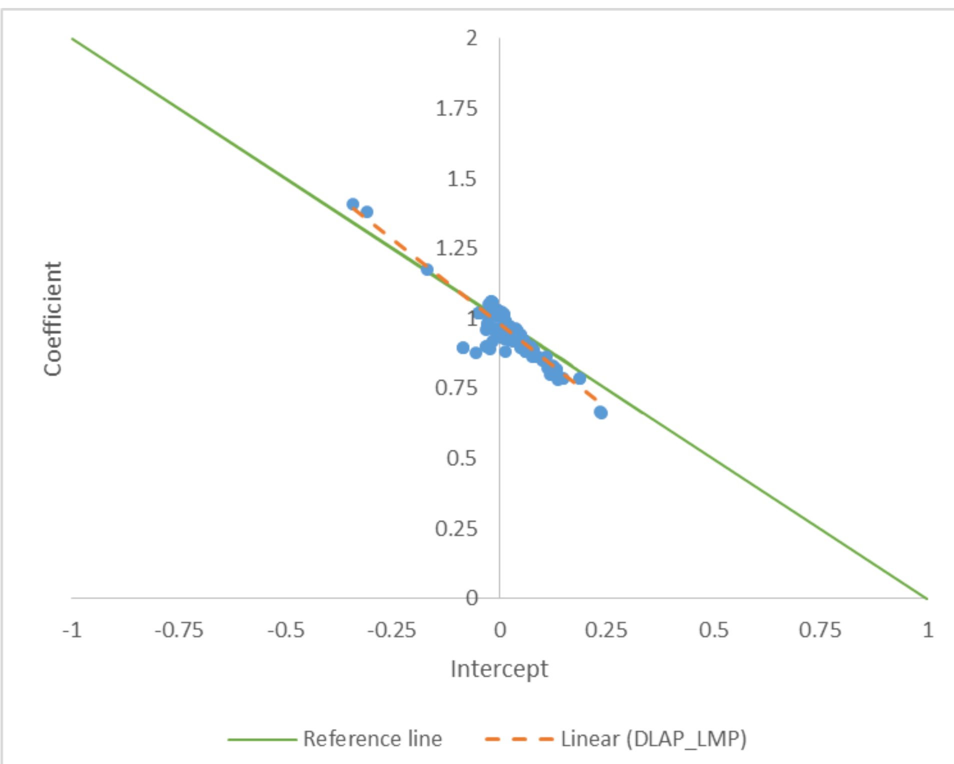


Figure 17 Regression results – SDGE 2011-2014

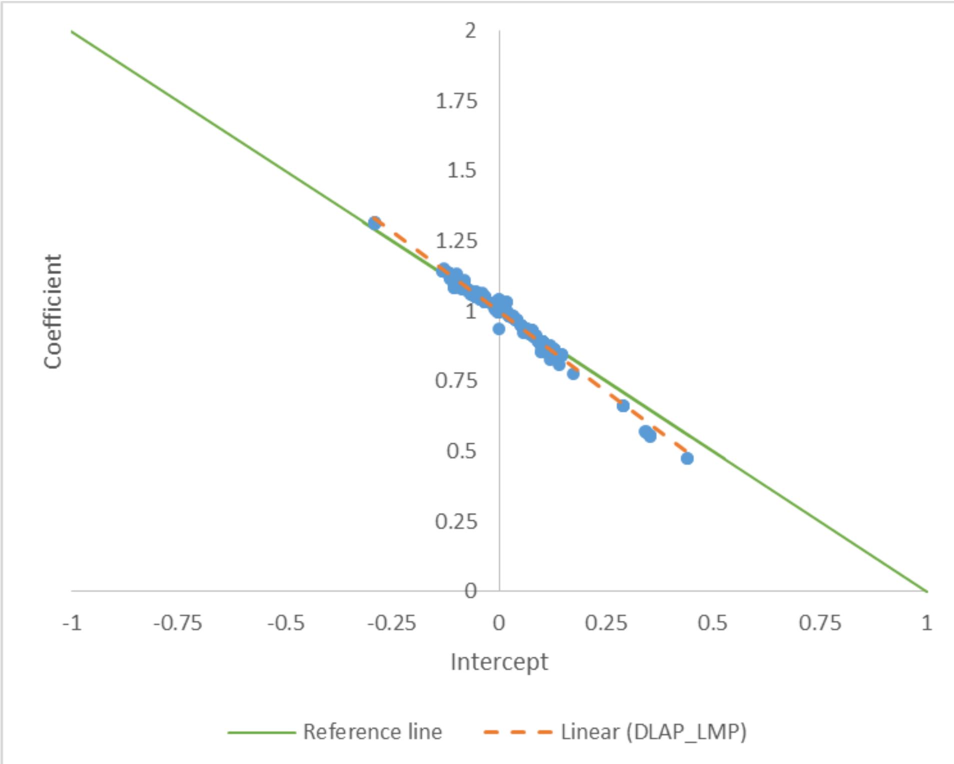
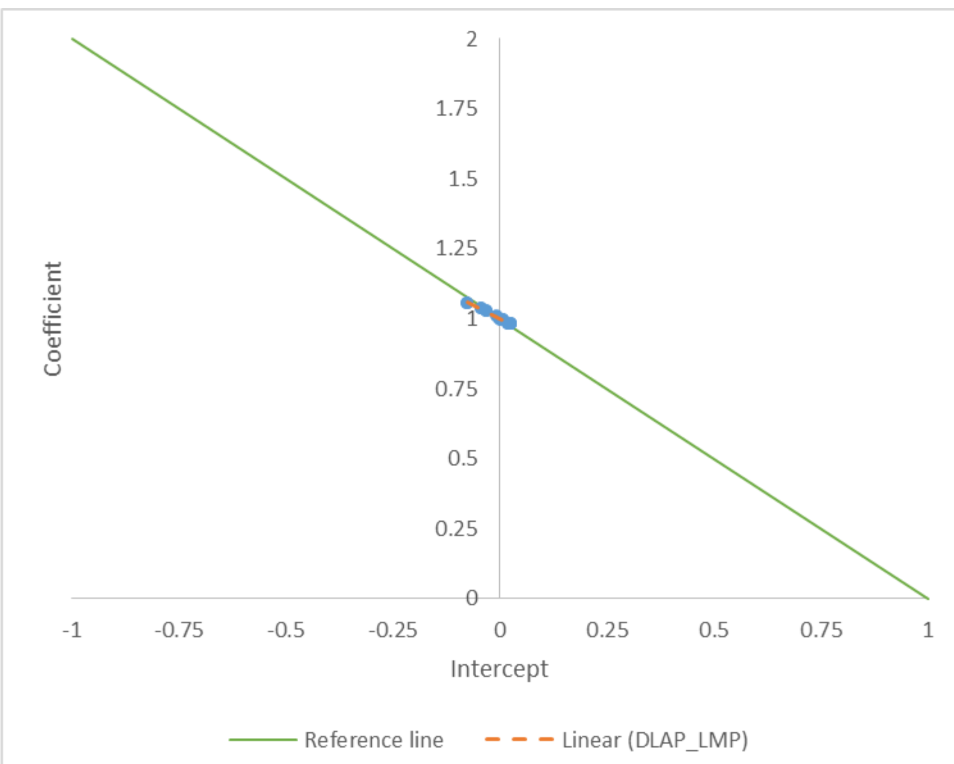


Figure 18 Regression results – VEA 2011-2014



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

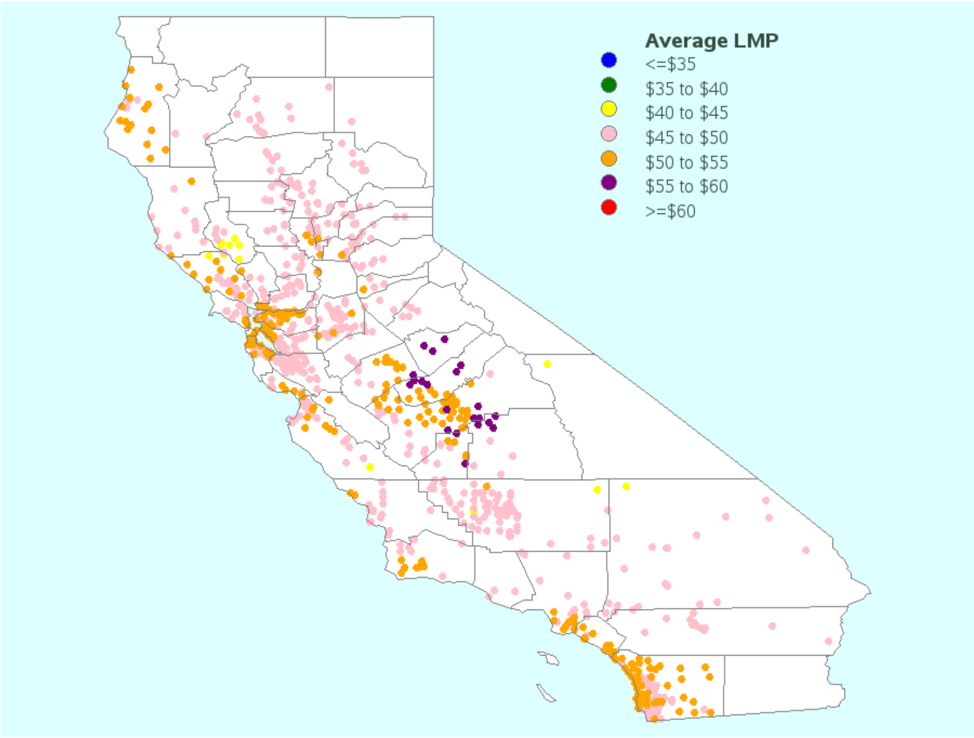
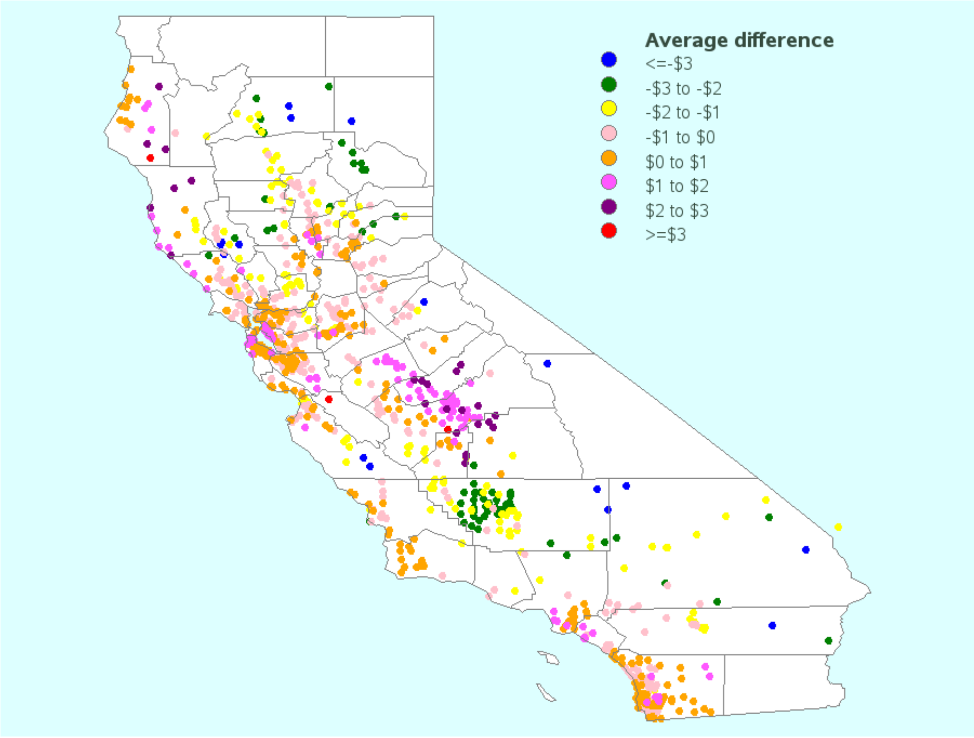


Figure 20 Average difference of nodal and DLAP LMP (2011-2014) excluding summer 2014



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.

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[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.