**Load Shift Working Group: Final Report Outline (DRAFT)**

**November 1, 2018**

1. **Intro**
	1. Load shift is the modification of the timing of energy consumption from hours of high net load to hours with surplus renewable generation.
	2. The CPUC recognized Load Shift as a new model of demand response in D. 17-07-017 and created the Load Shift Working Group to develop a proposal for foundational elements of new models of demand response.
	3. The Commission gave the Working Group the following five tasks:
		1. Defining and developing new products including load consumption and bi-directional products;
		2. Developing a proposal of whether and how to pay a capacity value for load consuming and bi-directional products to provide to the RA proceeding
		3. Developing a list of data access issues relevant to new models that should be addressed prior to launching new models
		4. Developing a proposal on how to better coordinate the efforts of CAISO and the Commission
		5. Identifying the value of new products to provide to the Resource Adequacy proceeding
		6. Considering an energy storage emission metric for any storage related proposal
	4. The Working Group:
		1. Was first convened in January 2018
		2. 11 in-person meetings between February and December 2018
		3. Includes # stakeholders representing # organizations. Collectively, these organizations comprehensively represent customers, providers of demand response services, utilities, and grid operators.
		4. Was facilitated and supported by Gridworks and the Commission’s Energy Division.
	5. This Report:
		1. Completes the five prescribed tasks.
		2. Accomplishes the Commission’s direction to “inform a new rulemaking for developing new models of demand response” and does not “resolve every issue thoroughly.”

[Reference D.17-07-017]

* + 1. Represents a collective expression of the Working Group rather than an account of every party’s position on every issue. Some parties disagree with some parts of the report, but agree the report provides a reasonable foundation.
		2. Initiates a new era of demand response and renewable integration that warrants the engagement of stakeholders in California and beyond.
		3. Recommends:
			1. The Commission should provide a long-term commitment to load shift, spurring additional focus and investment.
			2. The Commission begin with a period of experimentation that will ensure adequate and pro-active testing of policies, incentives and business models with a range of approaches tested. The Commission’s aim should be to support progressive growth of load shift beginning immediately and maturing by 2025.
			3. The Commission begin by inviting pilot proposals along the lines of the products envisioned here in early 2019.
1. **Why Shift Load?**
	1. Background:
		1. California has substantially increased its share of electricity consumption met by renewable energy. Today over 22,000 MW are operational, including over 11,000 MW of solar. SB100 sets a timeline of ….
		2. At current levels of renewable penetration, energy production can outpace demand during certain times of the day, throwing supply and demand off balance. Two challenges emerge from this supply-demad dynamic:
			1. An oversupply of renewable generation in the middle of the day during certain seasons
				1. Include here a chart showing current-day and projected curtailment, from CAISO reports and other reports. There was a chart presented in the April LSWG on this (from P.Alstone) and there have been estimates of future oversupply.
			2. Increased ramping needs – which are the demands on non-solar resources to respond to the beginning and end of solar power’s daily production cycle
		3. Solutions to these challenges include a wide-range of policy and market changes, including load shift.
	2. LBNL’s 2025 Demand Response Potential Study estimates:
		1. Shift resources are estimated to provide $200-600M ($2015) in cost-effective resource to the CAISO system in 2025, beginning modestly but increasing as more renewables are built to satisfy increasing Renewable Portfolio Standards requirements and the value from avoided curtailment increases.
			1. Costs savings are the result of shift:
				1. Reducing system ramping needs
				2. Avoiding renewable power overgeneration and curtailment.

[Reference Figure 1, LBNL “[Shift Demand Response: A Primer](https://gridworks.org/wp-content/uploads/2018/02/Shift-Demand-Response-Primer_Final_180227.pdf)”]

* + - 1. Additional value beyond LBNL’s assessment may accrue though positive impacts on the distribution system, air quality, and economic development.
		1. The California power system circa 2025 is expected to have 10-20 GWh of load that can participate cost-effectively in Shift DR. This constitutes 2-5% of total daily load.
		2. Sources of shift are at hand, including readily available and emerging technologies such as:
			1. Air conditioning
			2. Refrigerated warehouses,
			3. Batteries,
			4. Commercial and industrial batch processes, and
			5. Electric vehicle charging.

[Reference Figure 7, LBNL “[Shift Demand Response: A Primer](https://gridworks.org/wp-content/uploads/2018/02/Shift-Demand-Response-Primer_Final_180227.pdf)”]

* 1. Building on LBNL’s Potential Study, the Commission’s 2017 Integrated Resource Planning Modeling concludes:
		1. Load shift provides a valuable service to shift energy use yielding increasing savings to ratepayer at more stringent GHG targets.

[Reference Slide 16 of [E3 Presentation](https://gridworks.org/wp-content/uploads/2018/04/04.18.18-Load-Shift-Working-Group-workshop-3_final.pdf) to Working Group (April 2018)]

* + 1. At more stringent GHG targets, balancing challenges become significant enough to incent addition of flexible loads to the system; more frequent renewable curtailment creates more value to incent shifting of loads
			1. Conclusion amplified subsequent to 2017 IRP Modeling by codification of [SB 100](http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100).
	1. Modelling of LBNL and 2017 Integrated Resource Plan modelling are confirmed by trends in CAISO market negative prices, renewable curtailment, and accelerated duck curves, including:
		1. Prices below zero in over 110 hours in 2017, all during midday hours in the first two quarters with high levels of solar generation and high hydro conditions. In comparison, day-ahead system marginal energy prices were negative during only three hours during all of 2016

[Reference [CAISO 2017 Report on Market Issues & Performance](http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf), Figure 3.6]

* + 1. Curtailment of renewable generation continued an upward trend in 2018.

[Reference CAISO “[Historical Curtailment](http://www.caiso.com/Documents/HistoricalCurtailment.pdf)” Chart]

* + 1. CAISO contributions to the Working Group recognize ramping needs resulting from solar energy’s daily production cycle are growing more quickly than originally expected

[Reference [CAISO Presentation](https://gridworks.org/wp-content/uploads/2018/04/04.18.18-Load-Shift-Working-Group-workshop-3_final.pdf) to Working Group (April 2018)]

* + 1. CAISO contributions to the Working Group suggests additions to California renewable energy portfolio going forward will accelerate renewable curtailment and negative pricing trends.
		2. [Reference [CAISO Presentation](https://gridworks.org/wp-content/uploads/2018/04/04.18.18-Load-Shift-Working-Group-workshop-3_final.pdf) to Working Group (April 2018)]
	1. Additional benefits of Load Shift may include:
		1. Deferred investment in transmission and distribution systems
		2. Increased hosting capacity at the distribution level
		3. Improved local air quality
		4. Bill savings for participating customers

The Working Group recognizes the potential of these additional benefits but did not analyze them in detail.

1. **Evaluation Criteria: What does success look like?**
	1. The Working Group developed a comprehensive Evaluation Framework to ensure:
		1. Comparability of product proposals
		2. Consistent evaluation of product proposals using criteria representative of California’s priorities for the electricity system
	2. Key criteria ask:
		1. Is the product technology neutral?
		2. Is it intended to be directly dispatchable by CAISO (“market integrated”)? Or reasonably considered market integrated while being dispatched outside the market?
		3. What grid needs does the product aim to address?
		4. What is the anticipated ability of customers to respond to the product at the time and place needed?
		5. How would the product’s performance be evaluated?
		6. What are the potential ratepayer costs?
		7. What are the potential impacts on California’s greenhouse gas reduction targets?
		8. What additional regulatory steps would be needed for implementation?
	3. These criteria were chosen by the Working Group because they are:
		1. Reasonably reflective of California’s Goals and Principles for demand response

[Reference [D.16-09-056](http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF), p.45-46]

* + 1. Practically employed
		2. Diverse enough to recognize meaningful differences between product proposals
	1. Each product proposal was evaluated using these criteria, ensuring comparability between the products and consistency in evaluation.
1. **Products Proposals**

*Appendices A-X feature full length product proposal following the Working Group’s Evaluation Framework. What follows are high-level summaries of each proposal.*

* 1. **Load Shift Resource 2.0**
		1. ***Summary Description:*** LSR 2.0, relying on existing policy provisions for economically participating demand response through the CAISO’s proxy demand resource tariff, adds functionalities to the participation model allowing the resource to bid and be dispatched for both load consumption and load curtailment from behind the meter resources. The initial product will allow a PDR to access day-ahead and real-time energy markets for both load curtailment and load consumption capabilities through the use of two separate resource IDs. The proposal will facilitate the provision of “shift” services while maintaining a demand response policy principle that injection or export of BTM resources beyond the retail meter is not eligible for wholesale market compensation.
		2. ***Is the product technology neutral?*** Yes
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** Yes.
		4. ***What grid needs does the product aim to address?***
			1. Fuel and other marginal cost operational savings while balancing dispatchable generation with net load – raising the belly of the duck while avoiding renewable curtailment.
			2. Operates during periods of negative pricing/overgeneration
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** Ability is analogous to current PDR customer experiences in meeting participation requirements and dispatch instructions.
		6. ***How would the product’s performance be evaluated?*** Measured against approved baseline calculations to measure both consumption and curtailment.
		7. ***What are the potential ratepayer costs?*** Potential incentive costs if product provides services beyond wholesale energy (e.g., capacity, local air quality benefits).
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** Product is market integrated and operates during negative pricing intervals, meeting the Working Group’s standard for being considered unqualified “GHG reducing”.
		9. ***What additional regulatory steps would be needed for implementation?***
			1. Approval by CAISO and FERC following a subsequent stakeholder initiative considering how technological neutrality.
			2. Potentially CPUC consideration of additional incentives.
	2. **Critical Consumption Period**
		1. ***Summary Description:*** The Critical Consumption Product is a load increase demand response product; the incremental load increase is triggered directly by negative wholesale Day Ahead nodal market prices and paid at the real time nodal wholesale market prices (i.e., an average of real-time intervals in a 15-minute retail interval). The load increase (Critical Consumption) would occur during Critical Consumption Periods, which are intended to occur during periods of renewables curtailment due to low net load. The load increase would be incented by having the incremental load “pay” a negative real-time wholesale market nodal price for energy (and non-energy components of the retail rate), and possibly earn a monthly participation incentive.
		2. ***Is the product technology neutral?*** Yes.
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** No, considered to be indirectly market integrated because response is informed by the DA forecast and linked to the RT market as the RT price is passed to the customer.
		4. ***What grid needs does the product aim to address?***
			1. Fuel and other marginal cost operational savings raising the belly of the duck and avoiding renewable curtailment.
			2. Operates during periods of negative pricing/overgeneration.
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** LSEs to notify customers by 2 pm of a critical consumption period opportunity for the following day. It would be up to the customer to select their availability duration would be***.***
		6. ***How would the product’s performance be evaluated?*** Settlement is to be determined but based on the 10/10 baseline methodology.
		7. ***What are the potential ratepayer costs?*** If the wholesale energy price paid by customers is lower than the generation component of the retail rate being replaced, then the LSE would collect less revenue than forecasted. This difference would need to be collected from other customers. Potential incentive costs if product provides services beyond wholesale energy.
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** Product is market informed and is intended to operate during negative pricing intervals, meeting the Working Group’s standard for being considered unqualified “GHG reducing”.
		9. ***What additional regulatory steps would be needed for implementation?*** Possibility of necessary mitigation for an increase in a customer maximum non-coincident demand charge caused by increased load from a CCP event. Flexibility around CPUC-jurisdictional, generation-related coincident demand charge. Possible use of a monthly participation fee to incent participation (similar to the XSP). CCP could evolve from a pilot to either a new rate or a market integrated product.
	3. **MIDAS**
		1. ***Summary Description:*** Under MIDAS, loads from internet connected devices are automatically shifted into lower price or lower emission periods based on application program interface (API) inputs (market or grid state informed signals, customer preferences and other end-use operating constraints) that customer use when they subscribe with a provider. MIDAS bundles the signal/preferences/constraints which are processed by a set of decision algorithms and relayed (usually via WiFi) to a device or controller that is attached to the end-use load. Ultimately the signal is acted upon based on decision algorithms that incorporate customer preferences and end use operation constraints.  MIDAS could operate as a standalone product or be integrated into other demand response or load shift products. Giving customers the ability to optimize their electricity consumption for emissions or cost will increase engagement and potentially increase enrollment in market integrated-products that include MIDAS-like features.
		2. ***Is the product technology neutral?*** Yes
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** No, the product is considered to be indirectly market integrated because, at scale and due to automation, the responses of the end-uses subscribed under these programs are highly predictable and can be picked up by the LSE and CAISO short-term load forecasting models that are relied upon for market awards as well as longer-term forecasts that are used to determine RA obligations and for T&D infrastructure planning.
		4. ***What grid needs does the product aim to address***? Determined based on grid state inputs - reduced cost of service for energy, reduced renewable curtailment, reduced greenhouse gas, reduced peak capacity requirement, reduced flexible ramping capacity requirements.
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** First, the customer would link their wifi-enabled devices into the 3rd party’s portal.  Second the customer would tell the 3rd party how sensitive they are to price and/or carbon intensity.  Finally, the 3rd party would take actions on the customer’s behalf to optimize for the customer’s preferences.  The 3rd party entity could provide an anticipated price curve so the customer knew ahead of time what actions may be taken.  The 3rd party could also send a daily or weekly report summarizing the amount of cost or carbon saved for the day on the customer’s behalf. The automated load control would increase customer participation and increase the effectiveness of the program.
		6. ***How would the product’s performance be evaluated?*** Since this is a market informed but not a market integrated product there is no formal “settlement” process. The retail customer is compensated by either bill reduction or by emissions reductions. There could be additional sources of revenue available including revenues from CAISO markets if the product becomes market integrated at some point or revenues from Government Agencies distribution funding for emissions reductions such as EPA/CARB/Air Quality Districts or by NGOs that are focused on emissions reductions.
		7. ***What are the potential ratepayer costs?*** Program administrative costs.
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** Considered to be GHG reducing. Aligning consumption to actual grid carbon intensity is much more impactful than an accounting-based system of RECs.  This type of product could make demand truly flexible in a way that it follows price and carbon signals, since solar and wind are inflexible generation resources.
		9. ***What additional regulatory steps would be needed for implementation?***

No additional regulatory or technological steps are needed, but unlocking more granular data visibility from AMI (5 or 15 minute) would enable even further value creation.  Further, allowing real-time EDI access to 3rd parties so they can verify that the API actions they are pushing are actually shifting load in real-time would create additional value.

* 1. **Pay for Load Shape**
		1. ***Summary Description:*** Customers who are participating in the program would modify their loads based on a target load shape, either at the site-level or in aggregate, and be compensated for the response. The value of incentives could be related to the reductions in the cost of serving loads that meet or approach the target and could include contributions from energy market savings and reduced costs for capacity (generation, transmission, distribution) and other factors as appropriate. The geographic granularity of the load shapes, how frequently they are updated, and whether different targets are appropriate for different customers, are critical decisions for product design.
		2. ***Is the product technology neutral?*** Yes.
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** No, considered to be indirectly market integrated because the LSEs define the target load shape to meet grid needs.
		4. **What grid needs does the product aim to address?** Reduced cost of service for energy, reduced renewable curtailment, reduced greenhouse gas, reduced peak capacity requirement, reduced flexible ramping capacity requirements, avoided distribution system investment costs (with appropriate modifications based on need), avoided transmission system investment costs (with appropriate modifications based on need).
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** Many different customers could respond in different ways. Instructed load-shape, based on typical daily net load for 1-3 month planning period (hourly time steps, weekday-weekend day); may be augmented with more geographically granular information (e.g., local constraints).
		6. ***How would the product’s performance be evaluated?*** New performance measurement evaluations are required. The ability to estimate cost savings of customers adapting to a load shape and how those savings are allocated to participating customers would be an important focus in a pilot.
		7. ***What are the potential ratepayer costs?*** Utilities and LSE’s would need to establish methods for forecasting the cost and emissions related to serving customer loads and use these forecasts to develop target load shapes. There would need to be a settlement process developed and deployed to score customer responses compared to the target and allocate incentives and/or payments for performance.
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** The “anti-duck curve” is the proposed core driver for defining the target load shape (with possible contributions from marginal price and emissions forecasts). Because of the structure of the CAISO energy market with positive correlation between marginal prices, net load, and emissions, this fundamental approach would tend to reduce the average emissions. Avoided curtailment would further improve the GHG performance of the PLS product.
		9. ***What additional regulatory steps would be needed for implementation?*** New pilots supported to further refine PLS. Likely regulatory oversight of program rules/frameworks if the approach is operationalized.

**Some other PRODUCT (missing name)**

* + 1. ***Summary Description:*** Customers commit with an aggregator to provide load consumption capacity and/or load curtailment as dispatched by the distribution system operator. Consumption capacity would serve either wholesale market or distribution grid needs at the distribution service operator’s discretion, consistent with program rules. Enables resources that have no ability or requirements to provide peaking capacity an opportunity to addresses excess energy planning and operational needs.
		2. ***Is the product technology neutral?*** Yes.
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** Yes, distribution system operator bids load consumption capacity that is not being utilized for distribution operations within CAISO’s proposed PDR-LSR.
		4. ***What grid needs does the product aim to address?*** Aligns with CAISO’s excess energy planning needs with envisioned market integrated participation with PDR-LSR during the load consumption time domain. Load consumption coordination enables managing of reverse power flow resulting from distributed generation exports onto the grid, improved voltage management, enables more DERs to easily interconnect along the entire distribution feeder during normal and abnormal configurations.
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** When resources are dispatched, third party aggregators will telemeter dispatch to DERs per PDR-LSR rules.
		6. ***How would the product’s performance be evaluated***? PDR-LSR baseline where applicable within specified time domains. Aggregated device level with baseline solely for PDR-LSR performance; telemetered reporting per program rules with monthly invoicing including performance metrics based on aggregated metered response.
		7. ***What are the potential ratepayer costs?*** Program administrative costs.
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** Product is market integrated and is intended to operate during negative pricing intervals, meeting the Working Group’s standard for being considered unqualified “GHG reducing”. The product will expand the hosting capacity of the distribution and CAISO system to interconnect future GHG free sources during and enable multiple use applications for existing renewable resources.
1. ***What additional regulatory steps would be needed for implementation?*** The CPUC needs to expand RA beyond peak load and enable alignment with capacity planning needs within all time and grid domains. Following CPUC order, the IOUs would develop rider tariffs – an additional tariff the utility may offer customers to credit their account in exchange for services provided-- to enable resource alignment with planning needs and submit to the CPUC for approval.
	1. **Sunrun Market Informed**
		1. ***Summary Description:*** Customers commit to permanently/seasonally provide load consumption capacity and/or load curtailment within the defined period of excess energy need. Participants in this program will not directly bid capacity or respond to real time markets but operate in a specific programmatic manner based on California's excess energy planning needs. DERs are scheduled to deliver load consumption capacity during specified hours based on market informed planning needs.
		2. ***Is the product technology neutral?*** Yes.
		3. ***Is it intended to be directly dispatchable by CAISO (“market integrated”)?*** No, considered market informed as scheduled load shift capacity is dispatched based on bulk system planning needs with coordination with distribution system operator.
		4. ***What grid needs does the product aim to address***? Load consumption coordination enables managing of reverse power flow, improved voltage management, enables more DERs to easily interconnect along the entire distribution feeder during normal and abnormal configuration.
		5. ***What is the anticipated ability of customers to respond to the product at the time and place needed?*** DERs and end user load management resources are scheduled to deliver load consumption capacity and load curtailment capacity based on a permanent/seasonal schedule.
		6. ***How would the product’s performance be evaluated?*** Program rules can enable simplified meter verification approaches for rider tariff customers demonstrating continued compliance at the service meter following initial M&V compliance. Premises level verification with device level reporting without baseline, unless needed for resource type.
		7. ***What are the potential ratepayer costs?*** Program administrative costs.
		8. ***What are the potential impacts on California’s greenhouse gas reduction targets?*** This market Informed operational response aligns with excess energy and peak planning needs within distribution and bulk power systems. A positive GHG impact is assumed for the following reasons: program will expand the hosting capacity of the distribution and CAISO system to interconnect future GHG free sources during and enable multiple use applications for existing renewable resources.
		9. ***What additional regulatory steps would be needed for implementation?*** The CPUC would need to expand RA beyond peak load and enable alignment with capacity planning needs within all time and grid domains. Following CPUC order, the IOUs would develop rider tariffs to enable resource alignment with planning needs and submit to the CPUC for approval.
2. **Product Evaluation [Note: this content is preliminary, pending further review by the working group in its November 14 Meeting]**
	1. A comparison of the product proposal reveals key similarities and differences.
		1. Similarities include:
			1. All products are technologically neutral.
			2. No product is energy neutral – take and shed are distinct.
			3. Performance evaluation of all products are a “work in progress”
			4. All products anticipate the ability to provide load shift in the context of the Commission’s Multi-use Application framework. This means the load shift may serve a variety of customer, distribution-level, or wholesale level needs consistent with applicable requirements of each product.
			5. All products need further consideration of potential Ratepayer costs.
		2. Differences between the products are captured in the following table. Each column represents a prominent, differentiating criteria in the Evaluation Framework:

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
|   | **Dispatch Method** | **Dispatch Geo-Granularity** | **Negative Pricing?** | **Transaction Settles at...** | **Settlement & Performance Evaluation** | **Role of IOU** | **Role of Third-party Aggregators** |
| **PDR LSR** | Market | Sublap | Yes | Aggregated Resource | Metered + Typical-Use Adjustment | Program Administrator | Aggregate, Bid, Coordinate, Settle |
| **LSR 2.0** | Market | Sublap | Yes | Aggregated Resource | Baseline | Support Rule 24; LSE | Aggregate, Bid, Coordinate, Settle |
| **CCP** | Program Administrator Signal Based on Day-Ahead Market Price | Nodal | Partial | Premise | Baseline | Program Administrator | Aggregate, coordinate, settle |
| **MIDAS** | Program Administrator Signal Based on Market Price or Other Grid State Indicators | Scalable | Partial | Premise | MIDAS group to provide feedback | Program Administrator | Aggregate, Coordinate |
| **Sunrun Integrated** | Program Administrator Signal Based on Market Price or Grid Condition Price | Scalable | Partial | Device (solar vs storage) | Metered plus... | Active DSO | Aggregate, Coordinate |
| **Sunrun Informed** | Scheduled | Scalable | Partial | Device | Metered | Passive DSO | Aggregate, Coordinate |
| **P4LS** | Scheduled | Scalable | Partial | Premise or Aggregated | Participant pool vs. average (control group) | Determine Schedule | Aggregate, Coordinate |

* 1. **Identify relative product strengths compared to evaluation criteria**
		1. **TBD Pending further discussion**
1. **Considering Questions from the Ruling**
	1. **Resource Adequacy**
		1. The Working Group recognizes a capacity value for Load Shift and considered how fully the current Resource Adequacy (RA) construct recognizes this value. The Working Group concludes the current RA construct would capture some of the capacity value possible through load shift, but not all. Specifically:
			1. The current RA construct recognizes the capacity value of load shed performed consistent with current RA requirements (i.e., Must Offer Obligations).
			2. The current RA construct does **not** recognize the value of:
				1. Reducing the downward ramp,
				2. Raising minimum net load,
				3. Flexible RA provided without also providing System/Local RA.
		2. The Working Group considered recommendations for changing the RA construct that would help better capture the value of load shift, including:
			1. Unbundling Flexible and System/Local RA, allowing load shift to provide Flexible RA without the obligation to be available for the peak demand requirements of system/local RA. [Note: this does NOT imply the same resource may be marketed to different Load Serving Entities, just the ability to sell one Load Serving Entity flex without selling system/local],
			2. Recognizing a new value for downward ramp as a part of Flexible RA,
			3. Recognizing a new value for raising minimum load, thereby reducing the need for Flexible RA.
		3. The Working Group considered recommendations which would be exogeneous to changing the RA construct, including:
			1. Recognizing the value of avoiding renewable curtailment, which may be an offshoot of the Integrated Resource Plans or an avoided cost assumption including in a cost-benefit analysis, as is done for other demand side programs.
			2. Recognizing the value of allowing California customers to benefit from negative or low-price energy made resulting from periods of oversupply.
			3. Recognizing the positive, if indirect, impact load shift can have on energy market participants generally. For example, when load shift reduces negative energy prices power producing resources get paid a higher energy price for their service, which in turn improves their financial readiness to prove further service as needed.
			4. Recognize an opportunity to impact customer choices on how they use new assets when they are making the choice of whether to adopt those assets, rather than attempting to impact their choice at a later date. Put differently, while it may not be immediately cost-effective to ask customers to use new technologies (e.g., storage, pre-cooling) to provide load shift now, it likely will be in the foreseeable future: better to get them on the right track now than attempt to convince them later.
			5. Recognize value load shift can provide to some locations of the distribution system consistent with the findings and implementation of the Distribution Resource Plans/Integration of Distributed Energy Resources constructs.
		4. The Working Group considered the perspective of customers and DR service providers who forecast energy prices may not be enough to induce load shift behavior under foreseeable energy market conditions. If this forecast is correct, then recognition and monetization of some of the capacity values identified by the Working Group could be the difference between achieving load shift or not.
		5. The Working Group recognized that any determination of capacity value identified above may introduce performance requirements (e.g., telemetry, response time, response duration) on the providers of load shift. Those performance requirements may vary by the capacity service being provided
	2. **Data Access**
		1. The Working Group considered whether there may be data access issues which must be addressed to support the development of load shift.
		2. The Working Group agreed that Rule 24/32 and ongoing efforts under the Distribution Resource Planning proceeding (R.14-08-013) provide a foundation addressing most data access issues related to load shift.
		3. Additional data access consideration may be incremental, including:
			1. Potential sub-metering requirements for certain product proposals
			2. Other?
	3. **Greenhouse Gas Emissions**
		1. Per the direction of D.18-06-012, The Working Group considered emission metrics for each proposal.
		2. The Working Group drew two conclusions:
			1. If the proposal was market integrated and/or resulted in incremental consumption during periods of negative pricing, that proposal would not require additional emissions metrics due to the strong correlation between negative prices and GHG emissions in CAISO markets.
			2. If the proposal was not market integrated or was reasonably expected to result in consumption during periods of positive prices, that proposal would need to identify its proposed emission metric for further consideration by the Commission.
				1. Proposals falling in this category have made such identifications herein.
		3. The Working Group notes that the Commission’s consideration of GHG metrics and emission impacts of time of use rates is an ongoing topic of consideration in [A.17-12-011](https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1712011). Some of the proposals advanced here share characteristics with TOU rates and the conclusions derived by the Commission in its consideration of that application may be leveraged to support its consideration of appropriate metrics to assess the GHG impact of load shift.
		4. A first order analysis of the GHG impacts from load shift shows that…[here could show a basic analysis of the GHG implications for various plausible load shift strategies, based on 2017 marginal emissions.]
	4. **Coordination with CAISO**
		1. The Working Group completed the task of considering closer coordination with CAISO by:
			1. Developing a product proposal (LSR 2.0) which is fully CAISO market integrated and evaluating the advantages and disadvantages of that integration.
			2. Recognizing the impact of CAISO market prices on any product proposal which is “market informed” and evaluating the advantages and disadvantages of that integration.
		2. The CAISO proffered substantial contributions to all product proposals and anticipates ongoing collaboration with stakeholders and the Commission in the forthcoming rulemaking on new models of demand response.
2. **Recommendations**
	1. **Findings**
		1. Grid conditions are evolving dynamically and flexible load stands to be a big part of California’s zero-carbon economy.
			1. The future of load shift is a discussion of “how to,” not “whether.”
		2. There is overall agreement and convergence at a high-level with the LBNL definition of “load shift” is aligning shiftable load with renewable generation.
			1. There is overall agreement that energy neutral is not necessarily a defining characteristic, and that the “take” and “shed” portions may be asymmetric, more representative of grid needs, or market efficiency.
		3. There is overall agreement that the end-product(s) should be technologically neutral, while also acknowledging that some technologies may thrive while others don’t, similar to the existing DR model providing curtailment service today.
		4. There is overall agreement that the load shift products should reflect grid needs from the integration of renewables, while accounting for customer needs and capabilities.
		5. There is overall agreement that the Commission’s approach should not be “one-size fits all,” that different customer classes, technologies, business models and stakeholders have value to add through load shift.
	2. **Recommendations on further research and consideration**
		1. Based on these findings the Working Group recommends
			1. The Commission should provide a long-term commitment to load shift, spurring additional focus and investment.
			2. The Commission begin with a period of experimentation that will ensure adequate and pro-active testing of policies, incentives and business models. The Commission’s aim should be to support progressive maturation of load shift by 2025.
			3. The Commission begin by inviting pilot proposals along the lines of the products envisioned here in early 2019.