# LADWP 2021
# LOCAL CAPACITY TECHNICAL ANALYSIS

## Phase 1: High-Load Case Scenario
## Phase 2: Mid-Load Case Scenario

## FINAL REPORT
## AND STUDY RESULTS

February 10, 2012
Redacted Version – November 2012

# Local Capacity Technical Study
# Overview and Results

## I. Executive Summary

This Report documents the results and recommendations of the 2021 Local Capacity Technical (LCT) Studies. The assumptions, processes, and criteria used for the Los Angeles Department of Water and Power's (LADWP) 2021 study mirrors those used in the California Independent System Operator's (CAISO) LCT Studies. LADWP and the CAISO criteria are discussed in the report. The Phase 1 Study (High Case) considers a high capacity need scenario where only LADWP's existing programs in energy conservation, demand-side-management (DSM), Demand Response (DR), and Distributed Generation (DG) are considered. Phase 2 Study (Low Case) considers a low capacity need scenario where aggressive programs in the above outlined items will be addressed.

The 2021 LCT study results are provided to the LADWP Board for their consideration and approval. These results will also be used by the LADWP for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any LADWP procurement of capacity needed to achieve the Reliability Criteria.

Below are LADWP's 2021 total LCR:

**Table 1a: 2021 Local Capacity Requirements - High-Load Case**

| | 2021 LCR Need Based on Category B [1] | | | 2021 LCR Need Based on Category C with operating procedure | | |
|---|---|---|---|---|---|---|
| **System Limiting Condition** | **Existing Capacity Needed** | **Deficiency in terms of Loadshed needed [2]** | **Total (MW)** | **Existing Capacity Needed** | **Deficiency in terms of Loadshed needed [3]** | **Total Generation Capacity + Loadshed (MW)** |
| Low PDCI | 2077 | 0 for 2hr | **2077** | 3386 | 150 | **3386 + 150** |
| High PDCI | 2777 | 0 for 2hr | **2777** | 3386 | 358 | **3386 + 358** |
| **Total** | **2777** | 0 for 2hr | **2777** | **3386** | **358** | **3386 + 358** |

**Table 1b: 2021 Local Capacity Requirements - Mid-Load Case**

| | 2021 LCR Need Based on Category B[1] | | | 2021 LCR Need Based on Category C with operating procedure | | |
|---|---|---|---|---|---|---|
| **PDCI Flow** | **Existing Capacity Needed** | **Deficiency[2]** | **Total (MW)** | **Existing Capacity Needed** | **Deficiency[3]** | **Total (MW)** |
| **High** | **2277** | **0 for 2hr** | **2277** | **3386** | **130** | **(3386 + 130) = 3516** |

The LADWP Basin LCR Area, which is defined in this analysis, includes all retail load in the Los Angeles basin served by the LADWP, with the exception of load at the Rinaldi Receiving Station which is outside the transmission choke points defining the LCR Area. The load and distributed generation of the municipal utilities of Glendale and Burbank are inside the LCR Area. (LADWP is not assessing the LCR issues for Burbank or Glendale because LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.) This draft study determined that the LCR needs of LADWP are 3,386 megawatt (MW) of generation capacity. This LCR is only 85 MW less than the currently installed LADWP in-basin thermal capacity. By 2021, assuming that all of the existing generation capacity is maintained, a

[1] A single contingency (i.e. Category B) means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[2] "0 for 2hrs" means that no loadshed is required immediately after the worst Category B contingency because no BES element is loaded in excess of its 2 hour (i.e. emergency) rating; however, loadshed is required after 2 hours to adjust the system so no BES element loaded in excess of its continuous rating.

[3] This deficiency is the loadshed needed after the second of two contingencies to meet the NERC requirement that no element exceed its emergency rating. After meeting this initial performance level by shedding load immediately after the Category C contingency, further loadshed would be needed in the subsequent two hours to restore the system to within normal ratings (rather than emergency ratings).

substantial amount of load shedding programs will be needed to meet the NERC reliability requirement. Short of adding more generation, for this High Case scenario other measures, such as high levels of DSM or DG programs may be needed to avoid load shedding and meet NERC reliability requirements.

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## II. Study Overview: Inputs, Outputs and Options

The LADWP incorporated into its 2021 LCT study the same criteria, input assumptions and methodology that were incorporated into CAISO's *2013-15 Local Capacity Technical Analysis: Final Report and Study Results*. December 2010. Instances where the LADWP used different criteria and assumptions are discussed in Section III.

The study assumes that LADWP will achieve the 33% renewable requirements in 2021 based on its 2011 Integrated Resource Plan. We note the LCT requirement is dependent on a variety of assumptions, and these may change over the next decade. For instance, changes to load requirements due to electric vehicle demand will modify the demand forecast, and certain renewable resource that are currently "firmed" may become variable in the future, potentially increasing LCT requirements

### A. Objectives

The intent of the 2021 LCT Study is to identify specific areas within the LADWP Balancing Authority Area that have limited import capability and to determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas

### B. Key Study Assumptions

#### 1. LADWP Inputs and Methodology

Two study scenarios are considered for the LCT study. The Phase 1 Study (High Case) considers a high capacity need scenario where only LADWP's existing (and planned) programs in energy conservation, demand-side-management (DSM), Demand Response (DR), and Distributed Generation (DG) are assumed to be in place in 2021. Phase 2 Study (Low Case) considers a lower capacity need scenario where aggressive programs in the above items are assumed to be implemented by 2021.

The following table sets forth a summary of the approved inputs and methodology that have been used in LADWP's 2021 LCT study:

**Table 2: Summary Table of Inputs and Methodology Used in this LCT Study**

| Issue: | How are they incorporated into this LCT study: |
|---|---|
| Input Assumptions: | |
| • Transmission System Configuration | The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by LADWP's system operations group. |
| • Generation Modeled | The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year |
| • Load Forecast | Uses a 1-in-10 year summer peak load forecast |
| Methodology: | |
| • Maximize Import Capability | Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements. |
| • QF/Nuclear/State/Federal Units | Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study. |
| • Maintaining Path Flows | Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the Victorville/Adelanto transfer path flowing into the LADWP Basin. |
| Performance Criteria: | |
| • Performance Level B & C, including incorporation of PTO operational solutions | This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the LADWP will incorporate all new projects that are in operation before June 1, of the study year and other feasible operational solutions brought forth by LADWP's system operations group. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study. |
| Load Pocket: | |
| • Fixed Boundary, including limited reference to published effectiveness factors | This LCT Study has been produced based on load pockets defined by a fixed boundary. The LADWP only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. |

Further details regarding the 2021 LCT Study methodology and assumptions are provided in Section III, below.

### 2. CAISO Assumption and Methodology Comparison

As agreed by the study team (California Energy Commission (CEC), CAISO, and LADWP), this LADWP Report uses the techniques developed and used by the CAISO to analyze the Local Capacity Requirements in its analysis, as detailed in the CAISO's "2013-2015 Local Capacity Technical Analysis: Final Report and Study Results, December 2010." By permission of the CAISO, this LADWP Report adopts the format and a substantial amount of language from the CAISO's report, with the intent of making the material easy to review by the California Air Resources Board (CARB) as it works to fairly allocate emission offsets among new or expanded generation units located in the South Coast Air Emission Management District.

LADWP has used the same planning standards as those use by the CAISO in determining the generation capacity requirement.[4] These standards are intended to apply to system planning studies and not system operating studies.[5] See below in Section "VI. Replies to Comments by CEC and CARB Staff" for a comparison of LADWP's planning and operation studies.

Instances where LADWP's criteria and assumptions differ from the CAISO's include:

- In this planning study, LADWP allows loadshed after two hours to restore the system to be within normal ratings (called N-1-adjusted by LADWP), but does not allow further loadshed to adjust for the next contingency (i.e. to prepare for N-1-1). In contrast, the CAISO does not allow any loadshed until the second contingency occurs.
- In this Phase 1 High Load case, LADWP modeled a trajectory case but did not model an environmentally constrained case, while the CAISO modeled both cases. The trajectory case is the currently approved plan while the

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[4] See below in this Report in Section III. Assumption Details: How the Study was Conducted, A. System Planning Criteria.

[5] Pg 38, California Environmental Protection Agency Air Resources Board's Report to the Governor and Legislature -- Interim (Phase 1) Report: AB 1318 South Coast Air Basin Electricity Needs Assessment and Permitting Recommendations, July 2010.

environmentally constrained case includes a high level of urban rooftop Photo voltaic Distributed Generation to reflect uncertainty of the severity of environmental constraints involved in building central plant renewable generation resources distant from load centers. Because LADWP has control of these constraints, the study team agreed that the environmentally constrained case did not need to be performed by LADWP.

- No Category C contingencies involving generation tripping were modeled by LADWP in the High case, while they were modeled in by the CAISO. This could cause LADWP's LCR to be underestimated, but not overestimated. The effect on LCR is assumed to be negligible.
- The 2021 CAISO base case was not available for use by LADWP due to time constraints in completing a Non-disclosure agreement. Instead of using the CAISO base case, LADWP used a base case developed in conjunction with the California Transmission Planning Group (CTPG), and the CAISO participated in the development of this base case. After LADWP obtained the CAISO base case, a sensitivity study was run which shows the result to be essentially identical. This is discussed below in the section "VI. Replies to Comments by CEC and CARB Staff".

Instances where LADWP's criteria and assumptions may differ from the CAISO's include:

- No firming of renewable resources by basin thermal generation are modeled in the Phase 1 High Load case. Firming resources would be added on top of LCR resources because the full MW output of the LCR units is needed to manage emergency transmission overloads.
- Cogeneration is assumed off-line in the Phase 1 High Load case in order to assure measurement of total demand by the system. This results in a system load increase of 337 MW in the 2021 model year. A sensitivity case with the cogeneration dispatched in the High-Load Case is described at the end of this document in the section "VIII. Sensitivity Case for

Cogeneration." (The cogeneration was dispatched in the Mid-Load Case by decreasing the load by 337 MW.) Cogeneration dispatch and location is described below in the section "VI. Replies to Comments by CEC and CARB Staff".

- The Mid-Load Case models decreased loads (due to additional EE, DM, and cogeneration) in the same manner as the CAISO. This is discussed below in Section V. "Description of Mid-Load Case".

### 3. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, actions by one Balancing Authority Area can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the NERC Planning Standards, the LADWP is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards. Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the LADWP.

The NERC Planning Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and the scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

### 4. Application of N-1, N-1-1, and N-2 Criteria

The LADWP will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions (N-0) the LADWP must protect for all single contingencies (N-1) and common mode (N-2) double line outages. Also, after a single contingency, the LADWP must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs. N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 (“category B contingency, manual system adjustment, followed by another category B contingency”). The N-2 represents NERC Category C5 (“any two circuits of a multiple circuit tower line”) as well as WECC-S2 (for 500 kV only) (“any two circuits in the same right-of-way”) with no manual system adjustment between the two contingencies.

### 5. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the LADWP also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

#### a. <u>Performance Criteria- Category B</u>

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that all thermal and voltage limits must be within their “Applicable Rating,” (A/R) which, in this case, are the emergency ratings of the lines. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met; however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

### b. Performance Criteria- Category C

The NERC Planning Standards require system operators to “look forward” to make sure they safely prepare for the “next” N-1 following the loss of the “first” N-1 (stay within Applicable Ratings after the “next” N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the “first” and “next” element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a “Special Protection Scheme” that would remove pre-identified load from service upon the loss of the “next “ element.[6] All Category C requirements in this report refer to situations when in real time

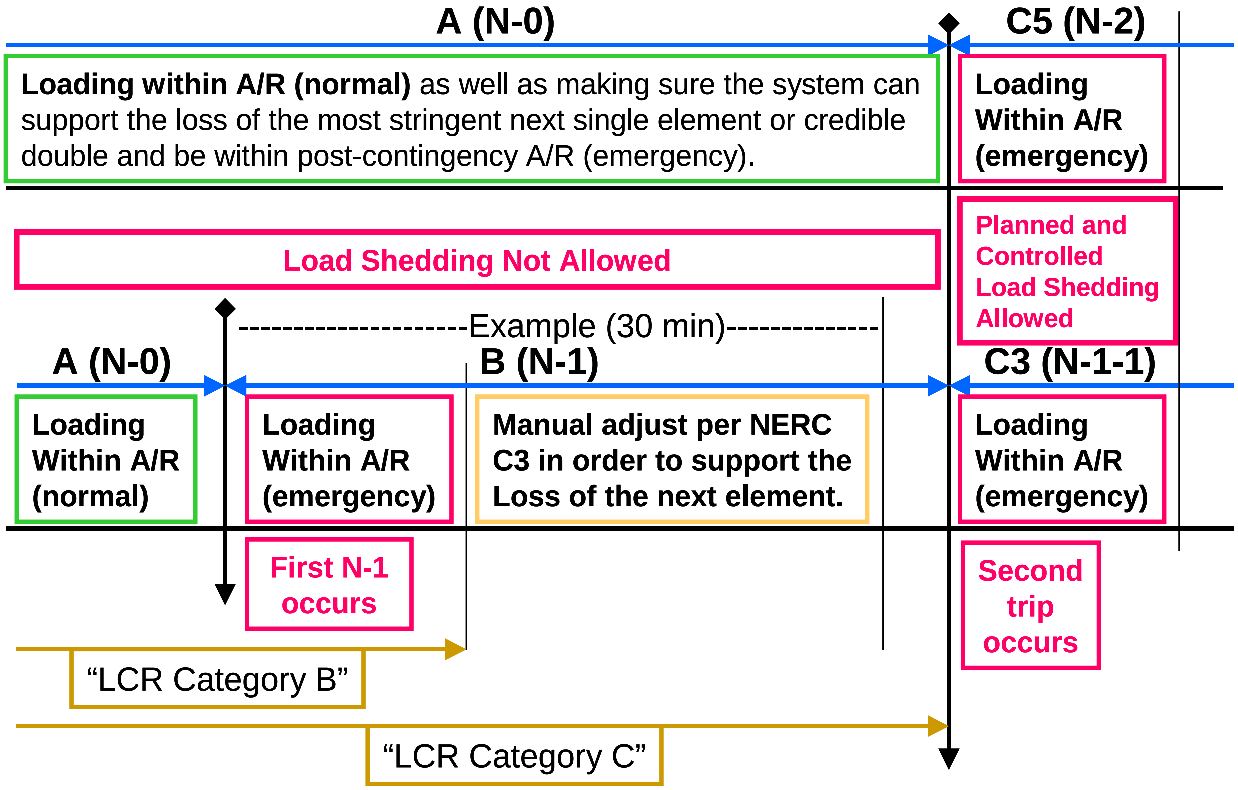
[6] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency.  In this time frame, load drop is not allowed per existing planning criteria.

Generally, Category C describes system performance that is expected following the loss of two or more system elements.  This loss of two elements is generally expected to happen simultaneously, referred to as N-2.  It should be noted that once the “next” element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C.  As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid “security.”

### c. LADWP Statutory Obligation Regarding Safe Operation

The LADWP will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions **A (N-0)** the LADWP must protect for all single contingencies **B (N-1)** and common mode **C5 (N-2)** double line outages.




Note: the above diagram is for the CAISO; LADWP allows loadshed two hours after a Category B contingency to restore the system to normal ratings.

The following definitions guide the LADWP's interpretation of the Reliability Criteria governing safe mode operation and are used in this LCT Study:

***Applicable Rating (A/R)*** the equipment rating that will be used under certain contingency conditions.

***Normal rating*** is to be used under normal conditions.

***Long-term emergency ratings***, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

***Short-term emergency ratings***, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

***<u>Temperature-adjusted ratings</u>*** shall not be used because this is a 10 year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

***<u>LADWP Equipment Rating Handbook</u>*** is the only official keeper of all existing ratings mentioned above.

***<u>Ratings for future projects</u>*** provided by LADWP's Transmission Planning.

***<u>Other short-term ratings</u>*** not included in the above categories may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

***<u>Path Ratings</u>*** need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

***<u>Controlled load drop</u>*** is achieved with the use of a Special Protection Scheme.

***<u>Planned load drop</u>*** is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

***<u>Special Protection Scheme (SPS):</u>*** all known SPS shall be assumed. New SPS must be verified and approved by the LADWP.

***<u>System Readjustment</u>*** represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

*<u>Actions that can be taken as system readjustment after a single contingency (Category B):</u>*

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
    a. Decrease generation
    b. Increase generation – this generation will become part of the LCR need
3. If the lost element cannot be restored, and generation re-dispatch is

insufficient, after two hours loadshed can be used to restore the system to normal ratings.

*<u>Actions, which shall not be taken as system readjustment after a single contingency (Category B):</u>*

1. Loadshed cannot be used (beyond that mentioned above in bullet 3 to restore the system to normal rating) to prepare for the next contingency.

This is one of the most controversial aspects of the interpretation of the existing NERC criteria because the NERC Planning Standards footnote mentions that load shedding can be done after a category B event in certain local areas in order to maintain compliance with performance criteria. However, the main body of the criteria spells out that no dropping of load should be done following a single contingency. All stakeholders and the LADWP agree that no involuntary interruption of load should be done immediately after a single contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. In this planning study, LADWP, in contrast to the CAISO, allows loadshed after two hours to restore the system to be within normal ratings (called N-1-adjusted by LADWP), but does not allow further loadshed to adjust for the next contingency (i.e. to prepare for N-1-1).

A robust transmission system should be, and under the LCT Study is being, planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the area, they are looked to meet reliability needs (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote may be applied for criteria compliance issues only where there are no resources available in the area.

***<u>Time allowed for manual readjustment</u>*** is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than two hours, based on existing LADWP Planning Standards.

### 6. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution "options" with varying ranges of potential service reliability consistent with LADWP's Reliability Criteria. The LADWP applies Option 2 for its purposes of identifying necessary local capacity needs and the corresponding potential scope of its backstop authority. Nevertheless, the LADWP continues to provide Option 1 as a point of reference for the CPUC and Local Regulatory Authorities in considering procurement targets for their jurisdictional LSEs.

- **Option 1- Meet Performance Criteria Category B**

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[7]

- **Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions**

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption)

7 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

developed and approved by the LADWP. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the LADWP operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.

As noted, Option 2 is the local capacity level that the LADWP requires to reliably operate the grid per NERC, WECC and LADWP standards. As such, the LADWP recommends adoption of this Option to guide resource adequacy procurement.

## III. Assumption Details: How the Study was Conducted

### A. System Planning Criteria

The following table provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

**Table 3: Criteria Comparison**

| Contingency Component(s) | NERC Planning Criteria | RMR Criteria | Local Capacity Criteria |
|---|---|---|---|
| **A – No Contingencies** | **X** | **X** | **X** |
| **B – Loss of a single element** | | | |
| 1. Generator (G-1) | **X** | **X** | **X**[1] |
| 2. Transmission Circuit (L-1) | **X** | **X** | **X**[1] |
| 3. Transformer (T-1) | **X** | **X** | **X**[1,2] |
| 4. Single Pole (dc) Line | **X** | **X** | **X**[1] |
| 5. G-1 system readjusted L-1 | **X** | **X** | **X** |
| **C – Loss of two or more elements** | | | |
| 1. Bus Section | **X** | | |
| 2. Breaker (failure or internal fault) | **X** | | |
| 3. L-1 system readjusted G-1 | **X** | | **(omitted 5)** |
| 3. G-1 system readjusted T-1 or T-1 system readjusted G-1 | **X** | | **(omitted 5)** |
| 3. L-1 system readjusted T-1 or T-1 system readjusted L-1 | **X** | | **X** |
| 3. G-1 system readjusted G-1 | **X** | | **(omitted 5)** |
| 3. L-1 system readjusted L-1 | **X** | | **X** |
| 3. T-1 system readjusted T-1 | **X** | | **X** |
| 4. Bipolar (dc) Line | **X** | | |
| 5. Two circuits (Common Mode) L-2 | **X** | | **X** |
| 6. SLG fault (stuck breaker or protection failure) for G-1 | **X** | | **X** |
| 7. SLG fault (stuck breaker or protection failure) for L-1 | **X** | | |
| 8. SLG fault (stuck breaker or protection failure) for T-1 | **X** | | |

| | | | |
|---|---|---|---|
| 9. SLG fault (stuck breaker or protection failure) for Bus section WECC-S3. Two generators (Common Mode) G-2 | X<br>X[3] | | X |
| **<u>D – Extreme event – loss of two or more elements</u>**<br>Any B1-4 system readjusted (Common Mode) L-2<br>All other extreme combinations D1-14. | X[4]<br>X[4] | | X[3] |

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.
5 CAISO tests these contingencies, but LADWP does not; by omitting these contingencies LADWP could underestimate but not overestimate the amount of LCR. The effect is expected to be negligible.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

### 1. Power Flow Assessment:

| <u>Contingencies</u> | <u>Thermal Criteria</u>[3] | <u>Voltage Criteria</u>[4] |
|---|---|---|
| Generating unit [1, 6] | Applicable Rating | Applicable Rating (Not used by LADWP [8]) |
| Transmission line [1, 6] | Applicable Rating | Applicable Rating |
| Transformer [1, 6] | Applicable Rating[5] | Applicable Rating[5] |
| (G-1)(L-1) [2, 6] | Applicable Rating | Applicable Rating (Not used by LADWP [8]) |
| Overlapping [6, 7] | Applicable Rating | Applicable Rating |

1 All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on local area systems.
2 Key generating unit out, system readjusted, followed by a line outage. This over-

lapping outage is considered a single contingency within the CAISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on LADWP Equipment Rating Handbook or facility upgrade plans including established WECC Path ratings.

[4] Applicable Rating – LADWP Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

[8] LADWP did not perform these contingencies. This could cause the LCR to be underestimated, but not overestimated. No effect on the amount or location is expected.

### 2. Post Transient Load Flow Assessment:

| Contingencies | Reactive Margin Criteria [2] |
|---|---|
| **Selected [1]** | **Applicable Rating** |

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

### 3. Stability Assessment:

| Contingencies | Stability Criteria [2] |
|---|---|
| **Selected [1]** | **Applicable Rating** |

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – LADWP Grid Planning Criteria or facility owner criteria as

appropriate.

## B. Load Forecast

### 1. System Forecast

For the purpose of conducting system studies, LADWP used its internally-derived the load forecast at the Balancing Authority (BA) levels for 2021, consistent with LADWP system planning assumptions. The CEC also has developed a load forecast for the LADWP balancing authority, which includes assumptions made by CEC regarding system demand and growth, which is not used in this study. The forecast is then distributed across the entire BA, down to the local area, division and substation level. LADWP (as well as CEC) uses an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

The LADWP 1:10 forecast of 6830 MW appears to be a close match to the CEC forecast of 6,784 MW.[8]

### 2. Base Case Load Development Method

LADWP used a base case developed in conjunction with the California Transmission Planning Group (CTPG) to model the 33% Renewable Portfolio Standard in 2012 across California. The CAISO participated in creating this base case as a member of CTPG.

#### i. Determination of system loads

The 1:10 system load forecast from LADWP's February 18, 2011 "2011 Retail

[8] The LADWP number includes AC and DC losses; it was not yet ascertained if the CEC forecast also includes AC and DC losses. Reference for CEC forecast:: "Table A-9: Peak Demand by Planning Area (MW), Updated High Forecast" in the CEC "Draft Staff Report, Updated California Energy Demand Forecast May 2011." http://www.energy.ca.gov/2011publications/CEC-200-2011-006/CEC-200-2011-006-SD.pdf

Electric Sales and Demand Forecast" was used for an aggregate load of the entire LADWP Balancing Authority area. In this Heavy Load case, the cogenerators located on the LADWP system are assumed off-line in order to assure measurement of total demand by the system. This results in a system load increase of 337 MW in the 2021 model year. Details of cogeneration dispatch and location, and an evaluation of its effect on the study results, are discussed elsewhere in this report.

#### ii. Allocation of system load to transmission bus level

The disaggregated (busbar load) is forecast based on the demand characteristics of individual Receiving Stations. This forecast shapes the busbar load to a LADWP Balancing Authority – wide coincidental peak. LADWP uses the annual disaggregated load forecast from LADWP's Distribution Planning group to allocate system load to load busses.

### C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for the LADWP system. Resource and transmission additions and changes are detailed in Section IV. For the rest of the WECC system the load was kept as in the base case which is based on one-in-five.

Electronic contingency files developed by LADWP were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. A LADWP created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies.

# IV. Local Capacity Requirement Study Results

## A. Summary of Study Results

LCR is defined as the amount of generating capacity that is needed within a Local Capacity Area to reliably serve the load located within this area. The results of the LADWP's analysis are summarized in the Executive Summary Tables.

**Table 4: 2021 Local Capacity Needs vs. Peak Load and Local Area Generation**

| Category C | 2021 Total LCR (MW) | LCR Area Peak Load (1 in 10) (MW) | High-Load LCR as % of LCR Area Peak Load | Total Dependable Local Area Generation (MW) | 2021 LCR as % of Total LCR Area Generation |
|---|---|---|---|---|---|
| Haynes | 1600 | 6227 | 26% | 3386 | 47% |
| Harbor | 466 | 6227 | 7% | 3386 | 14% |
| Scattergood | 810 | 6227 | 13% | 3386 | 24% |
| Valley | 510 | 6227 | 8% | 3386 | 15% |
| **Total** | **3386** | **--** | **54%** | **--** | **100%** |

Table 5 shows how much of the Local Capacity Area load is dependent on local generation and how much local generation must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria. These table also indicate where new transmission projects, new generation additions or demand side management programs may be most useful in order to reduce the dependency on existing, generally older and less efficient local area generation.

Two heavy summer system conditions were studied to capture the range of LCR needed in the LADWP LCR area.

- Minimum PDCI: 600 MW
- Maximum PDCI 3100 MW

## B. High-Load Case, Minimum PDCI System Limitation Condition

This condition is where the PDCI is minimum of about 600 MW while at the same time the LADWP import on Victorville/Adelanto to Los Angeles and the Castaic/Barren Ridge flow to the Los Angeles basin are the highest. The total resources needed in each the two timeline issues are:

**Table 5: High-Load Case, 2021 Local Capacity Requirements: Minimum PDCI System Limitation**

| Basin Thermal Generation | Capacity | Category B | Category C |
|---|---|---|---|
| Haynes | 1619 MW | 740 MW | 1600 MW |
| Harbor | 466 MW | 227 MW | 466 MW |
| Scattergood | 810 MW | 600 MW | 810 MW |
| Valley | 576 MW | 510 MW | 510 MW |
| **Total** | **3471 MW** | **2077 MW** | **3386 MW** |
| [redacted] | [redacted] | [redacted] | [redacted] |

### C. High-Load Case, Maximum PDCI System Limitation Condition

This condition is where the PDCI is maximum of 3100 MW while at the same time the LADWP import on Victorville/Adelanto to Los Angeles and the Castaic/Barren Ridge flow to the Los Angeles basin are the lowest. The total resources needed in each the two timeline issues are:

**Table 6a: High-Load Case, 2021 Local Capacity Requirements: Maximum PDCI System Limitation**

| Basin Thermal Generation | Capacity | Category B | Category C |
|---|---|---|---|
| Haynes | 1619 MW | 1440 MW | 1600 MW |
| Harbor | 466 MW | 227 MW | 466 MW |
| Scattergood | 810 MW | 600 MW | 810 MW |
| Valley | 576 MW | 510 MW | 510 MW |
| **Total** | **3471 MW** | **2777 MW** | **3386 MW** |
| [redacted] | [redacted] | [redacted] | [redacted] |

### D. Mid-Load Case, Maximum PDCI System Limitation Condition

This condition is same as above for the High-Load Case with Maximum PDCI. (No Minimum PDCI case was run for the Mid-Load Case.) The total resources needed in each the two timeline issues are:

[9] "0MW for 2hrs" means that no loadshed is required immediately after the worst Category B contingency because no BES element is loaded in excess of its 2 hour (i.e. emergency) rating; however, loadshed is required at 2 hours to adjust the system so no BES element loaded in excess of its continuous rating.

**Table 6b: Mid-Load Case, 2021 Local Capacity Requirements: Maximum PDCI System Limitation**

| Basin Thermal Generation | Capacity | Category B | Category C |
|---|---|---|---|
| Haynes | 1619 MW | 1440 MW | 1600 MW |
| Harbor | 466 MW | 227 MW | 466 MW |
| Scattergood | 810 MW | 600 MW | 810 MW |
| Valley | 576 MW | 510 MW | 510 MW |
| **Total** | **3471 MW** | **2777 MW** | **3386 MW** |
| [redacted] | [redacted] | [redacted] | [redacted] |

### E. Total System LCR Requirement (High-Load and Mid-Load Cases)

Total Local Capacity Requirement is determined by also achieving the requirements of each system limitation condition. Because these areas are a part of the interconnected electric system, the total system requirement is the maximum of all of the requirements.

**Table 7: High-Load Case and Mid-Load Case, 2021 Local Capacity Requirements: Meeting both Minimum and Maximum PDCI System Limitations**

| Basin Thermal Generation | Capacity | Category B | Category C |
|---|---|---|---|
| Haynes | 1619 MW | 1440 MW | 1600 MW |
| Harbor | 466 MW | 227 MW | 466 MW |
| Scattergood | 810 MW | 600 MW | 810 MW |
| Valley | 576 MW | 510 MW | 510 MW |
| **Total** | **3471 MW** | **2777 MW** | **3386 MW** |
| [redacted] | [redacted] | [redacted] | [redacted] |

Load shed for these LCR contingencies is location specific. In this report, load shed is only modeled at the busses immediately downstream[11] of the overloaded transmission line, however the effectiveness of LA Basin-wide demand reduction can be estimated by comparing the High-Load Case to the Mid-Load Case: for the most limiting contingencies, 2.7 MW load reduction spread across the LA Basin is equivalent to 1 MW of loadshed at the busses immediately downstream of the overloaded transmission

10 [redacted]

11 [redacted].

element.[12]

The efficacy of Demand Response to decrease the amount of loadshed is not well defined at this time due to the uncertainties regarding these programs, as discussed in the section for the Mid Load Case.

## V. Description of Mid-Load Case

The Mid Load case is created from the High Load Case by scaling down the LADWP loads by 626 MW. This represents (a) an decrease of load by 373 MW to represent increased Energy Efficiency plus (b) an decrease in load of 337 MW to represent cogeneration dispatched [13] plus (c) a 74 MW increase in load as a correction [14] to the forecast of rooftop urban Photo Voltaic distributed generation.

The 373 MW of increased Energy Efficiency is the "Advanced Program" which is part of a presentation to the LADWP Board from December 6, 2011; it represents an 8.6% increase from the baseline forecast by the year 2020. The allocation to individual load busses was done by using the distribution factors developed by the CEC and the San Diego Gas and Electric company: Residential 63%, Commercial 34% and Industrial 3%. (Assessing Impacts of Incremental Energy Efficiency Program Initiative on Local Capacity Requirements, CEC, November 4, 2011)

Increased Demand Response (DR) was not modeled in the Mid Load case because of uncertainty of the amount and effectiveness of DR. The mix of technologies in DR programs make it difficult to estimate their effectiveness and amount – i.e. it is hard to estimate how quickly customers can respond to signals to drop load, how often they would respond to requests to drop load, and how much customer acceptance can be

[12] Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 (=358-130) MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction.

[13] The cogeneration dispatch is described in section "VI. Replies to Comments by CEC and CARB Staff ".

[14] The 74 MW of urban rooftop Photo Voltaic distributed generation is 50% of the nameplate 148 MW target for the year 2020; it is scaled by 50% to model the 4:00 pm peak, where the 148 MW value is the maximum production at noon.

achieved.

Only existing cogeneration was modeled because (a) LADWP has seen no growth in cogeneration customers and (b) the State cogeneration initiative is still in-development. The State cogeneration initiative would help increase cogeneration by decreasing today's restrictions that limit the amount that cogeneration generation can exceed the customer's load.

These assumptions were agreed on with the study team. CEC staff communicated that the CAISO performed sensitivity studies to see if increased DR could off-set LCR needs in certain locations. LADWP has not performed any similar studies to see if loadshed could be off-set by increased DR.

## VI. Replies to Comments by CEC and CARB Staff

*Comments by CEC and CARB Staff on LADWP's October 31, 2011 draft LCR Report (in italic) (page references in Italic refer to the October 31 Draft)*

*<u>Oral Discussion Items from November 8</u>*

*"1. Page 2, please add to the text or create a footnote differentiating this planning study from the operating study submitted to SWRCB in Feb. 2011.*

> The values for "Category B" in Table 1 correspond to the LADWP operating study value for "minimum basin generation required for continuous security" in the LADWP 2010 Summer Assessment, provided to the State Water Board February 2011, with one caveat: Category B does not require generation be adjusted to restore loading and voltages to be within normal ratings. The 2010 Summer Assessment does require that adjustment; the resulting LCR value is called N-1-adjusted in the following discussion.
>
> The LCR values for "Category C" in Table 1 include N-1-adjusted. The LCR value for N-1-adjusted is determined during the simulation of the Category C contingency called N-1-1. N-1-1 means lose one line, adjust the system (resulting in the N-1-adjusted LCR value as in the Summer Assessment) and then lose another line, resulting in the N-1-1 LCR value. The required LCR and loadshed are calculated in two stages: first for N-1-adjusted, and subsequently for N-1-1.

[redacted]

| | | | |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

For N-1-adjusted, a single line is tripped-off, and LCR dispatch and loadshed is used to relieve overloads to restore the system to its *continuous* thermal ratings. This adjustment is not preparation for the next contingency, it is only to lower the line loading to meet continuous ratings instead of emergency ratings.

For N-1-1, the N-1-adjusted case has an additional line tripped-off, and loadshed is used to relieve overloads to restore the system to its *emergency* thermal ratings. For the N-1-1 contingencies, only loadshed could be used to relieve overloads because all LCR units were already dispatched in the N-1-adjusted calculation.

[redacted]

*"2. Page 7, incomplete sentence "In addition, the LADWP will incorporate all new projects that are in operation before June 1, of the study year and other feasible operational solutions brought forth by LADWP's system operations group or. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study." From the discussion on the conference call, it sounds like the report does not address the solutions that can reduce the need for procurement (or load shed). It sounded like LADWP may consider reconductoring where load shed is needed. Will this and any other possible solutions be added to the report?*

[redacted]

*"3. Page 8, please clarify the scope of this study as addressing emission offsets from new or expanded generators.*

We confirm that the scope of this study is limited to addressing the need for emission offsets from new or expanded generators.

*"4. Page 9, please clarify to what extent renewable firming resources (acknowledged to be additive to LCR needs) can be located outside of the geographic boundaries of the South Coast Air Basin, and thus do not require emission reduction credits or credits from SCAQMD's internal bank pursuant to Rule 1315.*

This has not been determined at this time.

*"5. Page 9, please augment the discussion of treating cogeneration as not dispatched and spreading the increase in load proportionally across all load busses and the consequences of this approach on the results obtained.*

The original DWP forecast had 337 MW of cogeneration, distributed to individual load banks. The High Load was made by scaling up load in the original forecast by 337 MW to model cogeneration as not dispatched. The Mid Load was made by reversing the scaling by 337 MW.

The effect of spreading the load increase (to create the High Load Case) proportionally across all load busses (rather than scaling down each bus according to its individual cogeneration components) is captured in the spread between the High Load Case and the Mid Load Case. The reason for this is (1) the Mid Load Case restores the individual cogeneration forecast by load bank and (2) both Cases require loadshed due to lack of generation located in the LADWP LA Basin LCR Area. There are no consequences of this approach that affect the results obtained: all LADWP generation in the Area is needed for LCR, regardless of how the cogeneration is modeled.

Simultaneous fine tuning of (a) forecasts for the 337 MW cogeneration to show gross cogeneration generator output rather than cogeneration load (which is 40 MW smaller than cogeneration generator output), and (b) forecasts for rooftop PV to account for lower output at the 4:00 pm system peak load, shows that using the value of 337 MW for cogeneration would cause the High Load Case load case to be 43 MW too high and the Mid Load Case load to be 74 MW too low. The 74 MW correction was made to the Mid-Load case, but no correction was made to the High-Load case. The consequences are estimated as 16 MW too high load shed in the High-Load case due to the extra 43 MW of load.[15] This is discussed further below in the response to question 11.

*"6. Page 24, please describe the rationale for the loads at Rinaldi to not be included in the defined area.*

The overloads requiring LCR generation are "downstream" of Rinaldi: power flows through the Rinaldi bus into the load pocket (toward Valley/Toluca or toward Tarzana). Because of this, the load level at Rinaldi does not influence LCR simulations, and loadshed at Rinaldi is not useful to mitigate LCR contingencies.

*"7. Page 26, please add to the discussion an explanation like that provided on the conference call that LADWP is required to dispatch resources to overcome the*

[15] Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction. Using this ratio, the High Load case has 16 MW too high loadshed.

*consequences on its system of other's usage of the PDCI.*

The difference between the High-PDCI case and the Low-PDCI case represents the burden on LADWP due to other's usage of the PDCI. In Table 5, this burden is an increase in loadshed of 208 MW (=358-150).

New Items Not Discussed November 8

*"1 Table 1 on page 3, are the deficiency numbers reversed? 318 MW of load shed corresponds to High PDCI according to Table 6 and 150 MW of load shed corresponds to Low PDCI according to Table 5.*

Yes. Table 1 is corrected.

*"2 Page 9, it may be helpful to highlight some of the key assumptions, such as load and OTC assumptions, between the CTPG and CAISO base case to verify that differences are minimal.*

The LADWP load and OTC assumptions are identical in the LADWP case and the CAISO case. Both cases have 6227 MW at the load buses in the Area. In both cases, all LA Basins thermal generating units (including all OTC units) were needed to mitigate overloads, and, in both cases, this amount of generation was insufficient, and load shed was needed.

Results for CAISO vs. CTPG comparison are:

- same LCR generation is needed in both cases
- 41 MW more loadshed is needed in the CAISO case (400 vs. 359)

This comparison is sufficient to show that the two cases provide essentially the same results. The comparison of these cases is discussed further above in the response to the first comment.

*"3. Page 16-17, please consider whether the discussion of the "option" to only pursue Category B is actually allowed by FERC/NERC/WECC standards.*

In the Operating Horizon, LADWP uses a Category B criteria with the caveat that the system is restored to within continuous rating in two hours. This is discussed above in the response in this section.

In the Operating Horizon, the CAISO requires that SCE use generation (instead of loadshed) to meet most contingencies in Category C.

It appears that LADWP would also move to match the CAISO's higher performance level (Category C) if LADWP was in the same Balancing Authority Area as the CAISO.

*"4. Page 19, what is the reference for footnote 8?*

LADWP did not simulate contingencies involving loss of a generator (Category B) or the loss of a transmission line and generator with the system adjusted between the loss of the two elements (Category C).

*"5. Page 20, the study references the CEC forecast, and it would be interesting to see how LADWP's forecast compares to the CEC forecast. Maybe a footnote with the comparison could be added.*

The LADWP 1:10 forecast of 6830 MW appears to be a close match to the CEC forecast of 6,784 MW. The LADWP number includes AC and DC losses; it was not yet ascertained if the CEC forecast also includes AC and DC losses.
Reference for CEC forecast: "Table A-9: Peak Demand by Planning Area (MW), Updated High Forecast" in the CEC "Draft Staff Report, Updated California Energy Demand Forecast May 2011."
http://www.energy.ca.gov/2011publications/CEC-200-2011-006/CEC-200-2011-006-SD.pdf

*"6. Page 21, it would be helpful to have a link to the "2011 Retail Electric Sales and Demand Forecast" assuming that this is available on the internet.*

Not available at this time.

*"7. Page 21, what is the method and where can results be found for allocation of system load to load busses.*

LADWP uses the annual disaggregated load forecast from LADWP's Distribution Planning group to allocate system load to load busses.

*"8. Page 22-23, please expand the discussion referencing these tables to address the finding that load shed is needed to satisfy contingencies, and clarify where that load shed ought to occur if any location is preferable compared to others. Please clarify whether this load shed can be accomplished through demand response programs or whether the immediacy of response requires that firm load be interrupted*

Load shed for these LCR contingencies is location specific. In this report, load shed is only modeled at the busses immediately downstream[16] of the overloaded transmission line, however the effectiveness of LA Basin-wide demand reduction can be assessed by comparing the High-Load Case to the Mid-Load Case: 2.7 MW load reduction spread across the LA Basin is equivalent to 1 MW of loadshed at the busses immediately downstream of the overloaded transmission element.[17]

---

16 [redacted].

17 Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction.

The efficacy of Demand Response to decrease the amount of loadshed is not well defined at this time due to the uncertainties regarding these programs, as discussed in the section for the Mid Load Case.

*"9. Page 24, can you elaborate on what it means to include Glendale and Burbank in the LADWP Basin Area definition, but not calculate their LCR?*

LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.

*"10. Page 24, please formalize the table at the bottom of the page and add a column providing the rationale for additions and subtractions to net peak load (NPL).*

Done

*"11. Page 25, please add the specific cogen unit capacities to this listing of resources. Shouldn't the capacities of Burbank and Glendale units assumed to be dispatched at 1:10 peak load conditions also be added?*

LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.

For Burbank and Glendale modeling in this study, the CTPG case has 22 MW more generation and 0.5 MW less load than the recently approved WECC case for Heavy Summer 2021 (21hs1a2, posted at WECC 5/11/2011.)

After close examination of the cogeneration forecast, it was found that the load in the High Load Case is 43 MW too high because of a mistake in interpretation of "cogen" in the forecast. The forecast cogen was interpreted as 337 MW of gross cogeneration generation output. However, the 337 MW value was composed of 189 MW of cogeneration load (instead of gross generation) plus (inadvertently) 148 MW of PV DG. The cogeneration forecast should be corrected downward to reflect only the 220 MW of dispatched cogeneration plus non-PV DG and no PV DG. Apart from the cogeneration, both the High-Load Case and the Mid-Load case should also have their load adjusted downward by 74 MW to correct the PV DG forecast to show 50% of the nameplate 148 MW of PV DC generating at 4:00 pm. (220+74=294; 337-294=43)

The cogeneration generator output at the system peak is 220 MW from the from the nameplate capacity of 296 MW. This 220 WM is composed of (a) 180 MW CHP serving cogeneration native load plus (b) 40 MW excess cogeneration and non-PV distributed generation.

| [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
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| [redacted] | [redacted] | [redacted] | |

[redacted]

*"12. Pages 29-30 need to be better integrated into the body of the report or clearly set aside as an attachment referred to in the body of the report.*

These pages were deleted because they did not add useful analysis to the report.

*Additional Questions from ARB Staff*

*"1. On the call you mentioned you expect more thermal generation may be needed to firm up renewables. From what we understand, this is generation above LCR requirements. As the trajectory case is based on currently approved plans and you know your RPS profile in 2020, can you estimate the MW and capacity factors needed for any firming generation that needs to be located in-basin?*

This has not been determined at this time.

*"2 PM2.5 is not covered by the SCAQMD Rule 1304 offset exemption for repowers. Is taking a 100 tpy PM2.5 emissions cap to avoid offsets expected to result in any significant operating constraints on existing units or projected capacity factors needed for repowered units? Based on installed MW, we expect this might only be an issue at the Haynes facility?*

No, taking a 100 tpy PM2.5 emissions cap is not expected to result in any significant operating constraints on existing units or on the projected capacity factors for the repowered units.

## VII. LCR for the LADWP Basin Area

***Area Definition***

[redacted]

These sub-stations form the boundary surrounding the LADWP Basin area:

[redacted]

The municipal utilities of Glendale and Burbank are included in this Area but their LCR requirement is not calculated. LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank

Load at the Rinaldi Receiving Station is not in this Area. The overloads requiring LCR generation are “downstream” of Rinaldi: power flows through the Rinaldi bus into the load pocket (toward Valley/Toluca or toward Tarzana). Because of this, the load level at Rinaldi does not influence LCR simulations, and loadshed at Rinaldi is not useful to mitigate LCR contingencies.

Total 2021 busload within the defined area for the High-Load Case is 6226 MW.

For the High-Load Case, cogeneration is assumed to not be dispatched.

| | |
|---|---|
| 1:10 NPL | 6830 |
| Cogen | 337 |
| 1:10 Gross | 7167 |

To get the load in the LA Basin at the bus-bars:

| | |
|---|---|
| 1:10 Gross | 7167 |

| | |
|---|---|
| transmission losses + Owens Valley load | 611 |
| LA Basin busbar load | 6556 |

To get the load in the LRA area:

| | |
|---|---|
| LA Basin busbar load | 6556 |
| Rinaldi load | 330* |
| LCR Area busbar load | 6226 |

* Rinaldi load is 343 prior to scaling down for cogen, and 330 after scaling down for cogen.

Total units and qualifying capacity available in the LA Basin area:

| Resource | Bus # | Bus Name | kV | NQC | Unit ID |
|---|---|---|---|---|---|
| Harbor 1 | [redacted] | HARB1G | [redacted] | 82 | [redacted] |
| Harbor 2 | [redacted] | HARB2G | [redacted] | 82 | [redacted] |
| Harbor 5 | [redacted] | HARB5G | [redacted] | 65 | [redacted] |
| Harbor 10 | [redacted] | HARBCT10 | [redacted] | 47.4 | [redacted] |
| Harbor 11 | [redacted] | HARBCT11 | [redacted] | 47.4 | [redacted] |
| Harbor 12 | [redacted] | HARBCT12 | [redacted] | 47.4 | [redacted] |
| Harbor 13 | [redacted] | HARBCT13 | [redacted] | 47.4 | [redacted] |
| Harbor 14 | [redacted] | HARBCT14 | [redacted] | 47.4 | [redacted] |
| Haynes 1 | [redacted] | HAYNES1G | [redacted] | 222 | [redacted] |
| Haynes 2 | [redacted] | HAYNES2G | [redacted] | 222 | [redacted] |
| Haynes 8 | [redacted] | HAYNES8G | [redacted] | 250 | [redacted] |
| Haynes 9 | [redacted] | HAYNES9G | [redacted] | 162.5 | [redacted] |
| Haynes 10 | [redacted] | HAYNS10G | [redacted] | 162.5 | [redacted] |
| Haynes 11 | [redacted] | HYN1112G | [redacted] | 100 | [redacted] |
| Haynes 12 | [redacted] | HYN1112G | [redacted] | 100 | [redacted] |
| Haynes 13 | [redacted] | HYN1314G | [redacted] | 100 | [redacted] |
| Haynes 14 | [redacted] | HYN1314G | [redacted] | 100 | [redacted] |
| Haynes 15 | [redacted] | HYN1516G | [redacted] | 100 | [redacted] |
| Haynes 16 | [redacted] | HYN1516G | [redacted] | 100 | [redacted] |
| Scattergood 1 | [redacted] | SCATT1G | [redacted] | 150 | [redacted] |
| Scattergood 2 | [redacted] | SCATT2G | [redacted] | 150 | [redacted] |
| Scattergood 4 | [redacted] | SCATT4ST | [redacted] | 210 | [redacted] |
| Scattergood 5 | [redacted] | SCATT5GT | [redacted] | 100 | [redacted] |
| Scattergood 6 | [redacted] | SCATT6GT | [redacted] | 100 | [redacted] |
| Scattergood 7 | [redacted] | SCATT7GT | [redacted] | 100 | [redacted] |
| Valley 5 | [redacted] | VALLEY5G | [redacted] | 47 | [redacted] |
| Valley 6 | [redacted] | VALLEY6G | [redacted] | 157 | [redacted] |
| Valley 7 | [redacted] | VALLEY7G | [redacted] | 157 | [redacted] |
| Valley 8 | [redacted] | VALLEY8G | [redacted] | 215 | [redacted] |

**Major new projects modeled:**

1. Repowering of several units in the LADWP Basin Local Capacity Area were modeled, but the change in MW capacity and location are essentially unchanged.
2. In the LADWP Basin Local Capacity Area, several upgrades were added

to relieve transmission bottlenecks (to meet Category C performance criteria) and to add to reliability (Category D loss of an entire Receiving Station):

[redacted]

3. In the LADWP Basin Local Capacity Area, wind and solar generation interconnections along with related transmission additions/upgrades were added:

[redacted]

***Critical Contingency Analysis Summary***

***LADWP Basin Area:***

There are two critical conditions for LCR analysis in the LADWP Basin; (1) high Pacific DC Intertie (PDCI) flows, and (2) low PDCI flows. This range of PDCI flows is required because (a) the PDCI is more than 50% owned by CAISO Participating Transmission Owners (SCE, Pasadena), and (b) FERC requires that LADWP must sell any LADWP-owned PDCI capacity on the LADWP OASIS unless the capacity is reserved (under strict rules) for the use of LADWP's native load customers. These constraints on LADWP's control over the PDCI means that LADWP cannot forecast the PDCI schedule because the overwhelming majority of PDCI schedule changes are driven hour-by-hour by others' market choices. The LCR requirement for the High PDCI case is overlapped with the Low PDCI case to provide the LADWP Basin overall LCR requirement.

The most critical contingencies for the LADWP Basin Area are:

[redacted]

[redacted]

[redacted]

[redacted]

**Effectiveness factors:**

All currently planned generation is included in the LCR total of [redacted], and several hundred MW of planned loadshed is still required. Because this deficit leave no options to pick between generation units to provide LCR capacity, no effectiveness factors are provided.

***LA Basin Overall Requirements:***

| **2021** | QF/Wind (MW) | Nuclear (MW) | LADWP (MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|
| Available generation | 0 | 0 | 3471 | 3471 |

| **High-Load Case 2021** | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW LCR Need (Generation + Loadshed) |
|---|---|---|---|
| Category B (Single)[18] | 2777 | **0 for 2 hr** | **2777 + 0** |
| Category C (Multiple)[19] | 3386 | **0 for 2 hr** | **3386 + 358** |

| **Mid-Load Case 2021** | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW LCR Need (Generation + Loadshed) |
|---|---|---|---|
| Category B (Single)[20] | Not calculated | | |
| Category C (Multiple)[21] | 3386 | **0 for 2 hr** | **3386 + 130** |

## VIII. Sensitivity Case for Cogeneration

Cogeneration is assumed off-line in the Phase 1 High Load case in order to assure measurement of total demand by the system. A sensitivity case is provided with the forecast 337 MW of cogneration modeled in-service (i.e. scaling down LADWP load by 337 MW.) This sensitivity case showed that at least 80 MW of loadshed would still be needed, in addition to all existing basin thermal units, to provide an acceptable level of system performance. [redacted]. This was not the worst contingence, so more than 80 MW of loadshed would likely be needed.

[18] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[19] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[20] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[21] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.