California
Independent
System Operator

Manual

2009 Local Capacity Reliability Requirements Study

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California Independent System Operator

2009 LCR Study Manual
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Introduction

Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk 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 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. For instance, one category could require that the grid operator not only ensure 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.

The need for Local Generation arose from the restructuring of the California electric system in 1998. At that time, and consistent with the national trend toward restructuring and to foster a competitive generation market, the State directed the vertically integrated investor-owned utilities to turn operational control of their transmission assets to an independent system operator (the CAISO) and to divest a portion of their generation assets (so as to prevent the exercise of generation market power by the incumbent utilities). As a consequence of this restructuring, what was once an *integrated* system where the utilities made conscious trade-offs between investing in transmission and generation assets became a disaggregated system where the CAISO planned the transmission system and load-serving entities primarily relied on the market (merchant or third-party investment in generation) to satisfy new demand. As a result, where in the past the vertically integrated utility could use a mix of resources (transmission and generation) to both meet demand and operate the system reliably, the CAISO did not have generation resources readily available to meet local area reliability needs; that is, to ensure that the bulk electrical system was operated within the Applicable Reliability Criteria.

Furthermore, when the vertically integrated utilities sold their thermal generating units at the commencement of electric industry restructuring, they sold the units needed to meet local area reliability needs. Therefore, prior to CAISO start-up, it was determined that the CAISO needed to have these resources available to meet local reliability needs, and thus was born Reliability Must-Run or "RMR" Generation. The RMR Contract is intended to allow the CAISO to maintain reliability and to curb the market power of units needed to maintain local area reliability by giving the CAISO the ability to call on these units in real-time at cost-based prices. In addition, RMR units are able to collect a fixed option payment, to be negotiated between the RMR unit owner, the applicable Participating Transmission Owner, and the CAISO, the purpose of which is to cover a portion of the unit's going-forward fixed costs.

[1] Pub. Utilities Code § 345

It become more and more apparent that CAISO should only be engaged in a rather small number of contracts in order to maintain the reliability of the grid and that the vast majority of the units needed to reliably serve local area load should be procured through Load Serving Entities (LSE) as part of their Resource Adequacy Requirements.

The Locational Capacity study comes up with the minimum capacity needed in each one of the local areas, so that LSE can go out and pursue long or short-term contracts that met the need.

The study process includes a number of opportunities for stakeholder input. This input is incorporated into the next phase of studies.

Study Objectives

Similar to previous years, 2006, 2007 and 2008 LCR Studies, the purpose of the 2009 LCR Study is to identify specific areas within the CAISO Controlled Grid that have local reliability problems and to determine the minimum generation capacity (MW) that would be required to mitigate these local reliability problems.

LCR Area Assessment and Required Capacity Summary

Preface

The technical analysis the CAISO performed for the 2008 calendar year to determine the local reliability requirements evaluated ten local areas within the CAISO Controlled Grid where operational history has shown that local reliability issues exist. Seven of these areas (Humboldt, North Coast/North Bay, Greater Bay, Sierra, Stockton, Fresno and Kern) are in PG&E's service area; two (LA Basin and Big Creek/Ventura) are in SCE service area and one (San Diego) in SDG&E service area. A number of these areas are further subdivided as needed into sub-areas. A map of the areas is shown in Figure 1 below.

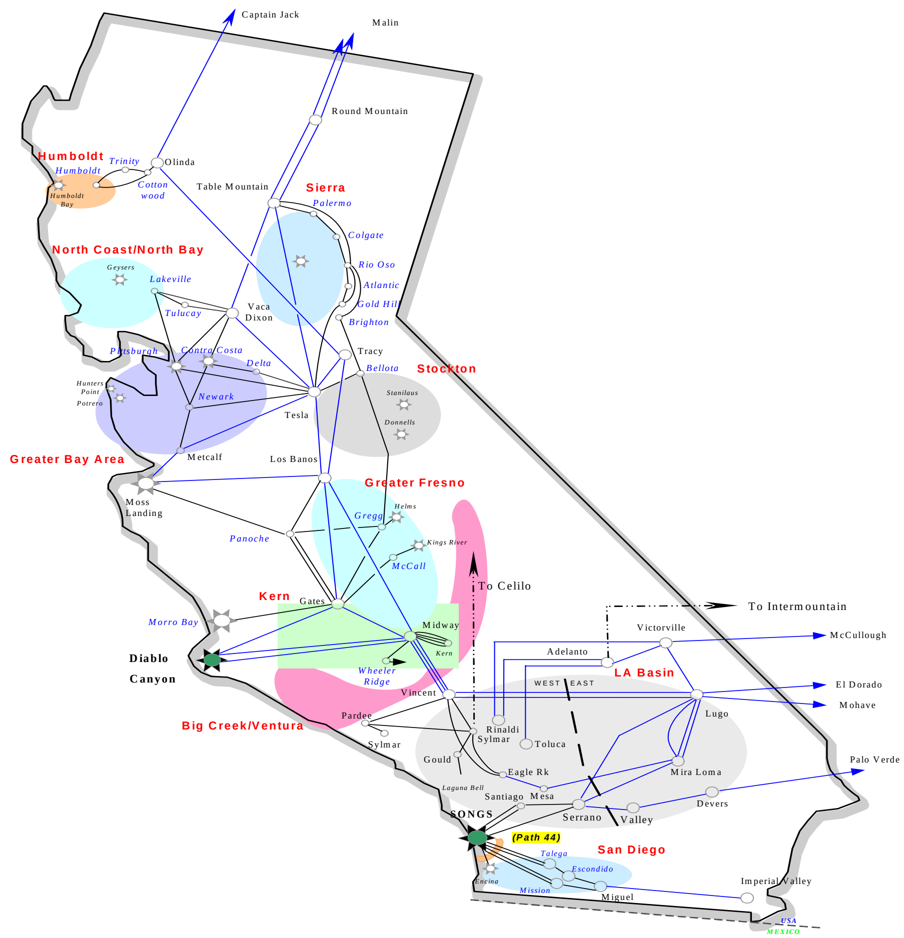

Figure 1 – LCR Area Map

Base Case Input Assumptions

Transmission System Configuration:

The existing transmission system shall be modeled, including all projects operational on or before June 1, 2009 and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.

Review:

The majority of local areas peak in the summer time. In order to be consistent with past practices as well as the base cases development guidelines the CAISO will model all transmission projects operational on or before June 1; with risks described bellow. Exemption: Humboldt area peaks in the winter as such only projects up to January 1, 2009 should be included.

Risks:

Certain system modifications may have the impact of reducing LCR requirements. If so, the possibility exists that prior to the time the system modification is implemented, the CAISO will be required to augment the quantity of capacity needed in a certain Local Area to account for the greater LCR that would otherwise exist in the absence of the assumed modification.

Generation Modeled:

All existing generation resources shall be modeled (less announced retirements) and shall also include all new generation projects that will be on-line and commercial on or before June 1, 2009.

Review:

The majority of local areas peak in the summer time. In order to be consistent with past practices as well as the base cases development guidelines the CAISO will model all generation projects operational on or before June 1; with risks described bellow. Exemption: Humboldt area peaks in the winter as such only new generation up to January 1, 2009 should be included.

Risks:

If the new generation resources will account for a significant amount in meeting the LCR requirements then there is a chance that the CAISO can not manage the transmission system in the first few moths of the year without additional (existing) generation (beyond the minimum contracted amount – required after June 1) being made available to the CAISO. As such the CAISO may be required to augment the quantity of capacity available in the first few months.

Load Forecast:

A 1-in-10 year summer peak load forecast shall be used.

Review:

An overwhelming majority of stakeholders and the CAISO have indicated that this study needs to be fully integrated into the annual transmission planning process in order to make a correct determination between solutions (transmission, generation or demand side) needed in order to solve the most stringent constraints into the local areas. The transmission planning process uses the 1-in-10 year summer peak forecast for local areas (See CAISO Planning Standards at: http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf). This requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. The 1-in-10 load forecast standard for local areas helps minimize the potential for interruption of end-use customers. In order to have non-discriminatory results (between transmission, generation and demand side) all options should be validated against the same load forecast (1-in-10). Using a lower load forecast (1-in-2, 1-in-5) for LCR studies only would give preferential treatment to transmission alternatives (always approved on 1-in-10 local load forecast based) vs. generation or demand side.

Risks:

None. The annual transmission planning process should address the cost effectiveness because here all alternatives are presented and studied on the same level of local load forecast (1-in-10), each one based on it's own costs and merits.

Methodology

Maximize Import Capability into the Local Area:

Import capability into the load pocket shall be maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements. In other words after the applicable contingencies have been taken the limiting element should be loaded at 100% of it's applicable rating, or the voltage and/or reactive margin should be at their respective minimum allowable levels.

Review:

An overwhelming majority of stakeholders have indicated that this study needs to present the minimum number of MW required in local area in order to meet the criteria.

Risks:

It is possible that the LSEs will comply in purchasing the minimum capacity requirement from units that are less effective (or that do not solve all the area constraints). If this should happen the CAISO would be forced to use its backstop mechanism in order to assure that the criteria is meet. The CAISO will try to minimize this exposure by publishing data that could help LSEs make more informed decisions like: single or multiple effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket, sub-area constraints, etc.

Maintaining Path Flows:,

Path flows shall be 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 the 2009 LCR Study is the South of Lugo transfer path flowing into the LA Basin.

Review:

All established path ratings should be maintained below their maximum limits regardless of voltage level, as established by existing reliability criteria. (See page XI-123 in the Minimum Operating Criteria – part of the Planning Coordination Committee Handbook at: http://www.wecc.biz/documents/library/publications/PCC/PCC_Handbook_Complete.pdf)

Risks:

If insufficient resources are provided, the CAISO would need to use its back-stop mechanism, since load will need to be dropped under normal conditions (or immediately after a single contingency in some cases) in order to maintain path flows bellow their limits.

QF/Nuclear/State/Federal Units:

Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources shall be modeled on-line at net qualifying capacity or historical output values (if NQC not available) for purposes of the 2009 LCR Study.

Review:

These units have an assured revenue stream and as such they should make their capacity available during 2009 summer operations. This will allow the studies to get results closer to the needs that are met in real-time operations, since for the most part all these units will be available to serve load next summer.

Risks:

None.

Units Owned or Under Long-term Contracts with LSEs:

Units owned or under long-term contracts with LSEs shall be modeled on-line at net qualifying capacity or historical output values (if NQC not available) for purposes of the 2009 LCR Study. This information could be taken from LSE’s long term procurement plans.

Review:

These units have an assured revenue stream and as such they should make their capacity available during 2009 summer operations. This will allow the studies to get results closer to the needs that are met in real-time operations, since for the most part all these units will be available to serve load next summer.

Risks:

None.

Maintaining Deliverability of Generation as well as Import Allocations Relied upon by RA:

Generation and import allocations, relied upon in the RA program, deliverability status shall be maintained for all common mode contingencies (including all single contingencies as well as double circuit tower line and same right-of-way contingencies).

Review:

Import allocations have been demonstrated to be deliverable while assuming existing local capacity requirements have been met and have been allocated to all LSE's. Also all existing generators been demonstrated to be fully deliverable to the aggregate of load. As such, they are allowed to count towards RA requirements once they have signed a long-term contract with any willing LSE. During the LCR studies the imports as well as the existing deliverable generation is dispatched at their deliverable or import allocated number. These import allocations and generation deliverability need to be maintained (through LCR studies that correctly represent them) to avoid the need to reduce the import allocations and deliverability of certain generators. The last approach is to be avoided because, in addition to market participant equitability issues, for the most part there will be rather large decreases in import allocations and generation deliverability for rather small decreases in local area LCR requirements. After a single contingency during the "System Readjustment" all generating units as well as imports can be reduced (up to a limit – see system readjustment) in order to protect for the next most limiting contingency.

Risks:

It is imperative that a good coordination is achieved between generation and import deliverability relative to LCR studies because otherwise it is possible that not all contracts already deemed deliverable can be delivered during the study conditions. (summer peak).

Load Pocket Boundary:

The 2009 LCR Study shall be produced based on load pockets defined by a fixed boundary.

Review:

An overwhelming majority of stakeholders and the CAISO have indicated that the requirement for this study should be fairly stable over time to encourage longer-term contracting by LSEs. Transmission configurations as well as unit and load effectiveness factors change every year due to new transmission projects added to the grid. As such, the only way to have a stable area is to define it as a fix boundary based on past experience of known constraints into any one area. The area definition is subject to change only if new major transmission and/or generation projects significantly change the local area constraints.

Risks:

There may be some units or loads located outside the local area boundary that may help reduce one or more of the constraints within the local area, but nevertheless not a eligible to be a Local Capacity Area Resource. However, in the great majority of cases, units and load outside the defined local area are less valuable in that they either do not mitigate the binding constraint or do not may help reduce flows on the majority of other potential constraints resulting from other less severe contingencies as do those resources located within the local area. During the validation of local procurement, the CAISO will use all units procured by all LSEs, regardless of location, in order to see if any backstop procurement is needed.

CAISO Statutory Obligation Regarding Safe Operation:

The CAISO must 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 the CAISO must protect for all single contingencies and common mode double line outages. As a further example, after a single contingency, the CAISO must readjust the system in order to be able to support the loss of the next most stringent contingency.

Review:

Many stakeholders do not understand this concept and claim that a single contingency only happens with a small probability therefore we should not even look beyond that. The truth is that the CAISO needs to be prepared under normal conditions (100% of the time) in order to support all Category B and C5 contingencies. Furthermore after a single contingency has happened the CAISO must be able to readjust the system in order to prepare for the next worst contingency (Category C3).

Risks:

None.

Criteria

Local Capacity Criteria to be studied

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

Table 1: Criteria Comparison

Contingency Component(s)	*Grid Planning*	*Local Capacity*
A – No Contingencies	X	X
B – Loss of a single element		
1. Generator (G-1)	X[1]	X[1]
2. Transmission Circuit (L-1)	X[1]	X[1]
3. Transformer (T-1)	X[1]	X[1,2]
4. Single Pole (dc) Line	X[1]	X[1]
5. G-1 system readjusted L-1	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	X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X	X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X	X
3. G-1 system readjusted G-1	X	X
3. L-1 system readjusted L-1	X	X
3. T-1 system readjusted T-1	X	
4. Bipolar (dc) Line	X	X
5. Two circuits (Common Mode) L-2	X	X
6. SLG fault (stuck breaker or protection failure) for G-1	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	X	
WECC-S3. Two generators (Common Mode) G-2	X[3]	X
D – Extreme event – loss of two or more elements		
Any B1-4 system readjusted (Common Mode) L-2	X[4]	X[3]
All other extreme combinations D1-14.	X[4]	

[1] System must be able to readjust and support the loss of the next element within A/R.
[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.

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 1. 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:*

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
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
Overlapping [6, 7]	Applicable Rating	Applicable Rating

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Most severe generating unit out, system readjusted, followed by a line outage. This over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including all established path ratings.

[4] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

[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 operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

[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/RAS/Safety Nets 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.

2. *Post Transient 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 Selected [1]	Stability Criteria [2] 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 – ISO Grid Planning Criteria or facility owner criteria as appropriate.

Definition of Terms

Applicable Rating:

This represents 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.

Temperature-adjusted ratings shall not be used because this is a 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.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings 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.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a single contingency (Category B):

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
    a. Decrease generation (up to 1150 MW) – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4)
    b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a single contingency (Category B):

1. Load drop – based on the intent of the CAISO/WECC and NERC criteria for category B contingencies.

Review:

This is one of the most controversial aspects of the interpretation of the existing NERC criteria, because the footnote mentions that load drop can be done after a category B event in certain local areas in order to comply. However the main body of the criteria it spells out that NO load drop should be done following a single contingency. All stakeholders and the CAISO agree that no load drop should be done immediately after a single contingency. However there is a disparity in regards to enforcing load drop (or no load drop) as part of the system readjustment period – in order to protect for the next most limiting contingency. It is CAISO opinion, and consensus in the LSAG group has been achieved that after a single contingency the system is in a Category B condition and the system should be planned based on the body of the criteria with no load drop being done regardless that is done immediately or in 15-30 minute after. Category C conditions only arrive after the second contingency has happened; at that point in time load drop is allowed in a planned and controlled manner. A robust California system should be planed on the main body of the criteria not the footnote regarding Category B contingencies. Therefore if there are available resources in the area they should be used first (and included in the LCR requirement) before resorting to load drop. The footnote can be used as a last resort for criteria compliance issues only if there are no resources available in the area.

Risks:

This interpretation tends to guarantee that load drop is done only as a last resort for Category B conditions if other resource measures are available and it is in line with existing operating practices. Doing otherwise could institutionalize that load drop may be the preferred way of planning the future of our system under Category B conditions and as a consequence it can seriously change the way we operate the system increasing load outage expose (if we only plan for load drop will most likely only have load drop to get out from Category B conditions).

Time allowed for manual readjustment:

This 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 30 minutes, based on the CAISO Grid Planning criteria.

Review:

This is a somewhat controversial aspect of the interpretation of existing criteria. This item is very specific in the CAISO grid planning criteria, however some will argue that 30 minutes only allows generation re-dispatch and automated switching were remote control is possible. If remote capability does not exist a person needs to be dispatched in the field to do switching and 30 minutes far less then required. If approved an exemption from the existing time requirements may be given for small local areas with very limited exposure and impact, clearly described in operating procedures and only until remote controlled switching equipment can be installed.

Risks:

None, it complies with the existing interpretation of the CAISO Grid Planning standards.

Special Protection Schemes:

All known SPS shall all be used. New SPS needs to be verified and approved by the CAISO and needs to comply with the new SPS guideline described in the CAISO Grid Planning Standards.

Review:

Not a controversial issue.

Risks:

None.

Studies by Performance Level

Performance Level A – Normal conditions:

1. Set the base case based on the existing input assumptions.
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the level of allocated imports through the RA program plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the area for highest flows due to normal flow pattern. Find one or more elements (or approved path ratings) that could be normally overloaded if not enough generation is maintained in the area.
4. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first) in the following order until the equipment is at the 100% of normal rating:

a. QF/Nuclear/State/Federal units

b. Units under known existing long-term contracts with LSEs

c. Other market units without long-term contracts

6. Add the output of all units that reduce the flow. This is the Category A requirement. Keep this so that it can be compared with category B and C requirements. It will only be used if higher then Category B or C requirements.
7. Repeat this for any sub area if required.

Performance Level B – Single Contingency Conditions:

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category A study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the level of allocated imports through the RA program plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load. (If needed contact Robert Sparks.)
3. Screen the area for highest emergency flows due to single contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under single contingency conditions) if not enough generation is maintained in the area.
4. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable). (If needed contact Robert Spark or Paul Didsayabutra.)
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first) in the following order until the equipment is at the 100% of normal rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This is the Category B requirement. Keep this so that it can be compared with category A and C requirements. It will only be used if higher then Category A or C requirements.
7. Repeat this for any sub area if required.

Performance Level C5 – Double Circuit Tower Line and Two Line in the Same Right-of-Way Conditions:

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category A study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the level of allocated imports through the RA program plus any increase due to new allocations that

may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load. (If needed contact Robert Sparks.)

3. Screen the area for highest emergency flows due to C4, C5 and WECC-S3 double contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area.
4. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable). (If needed contact Robert Spark or Paul Didsayabutra.)
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first) in the following order until the equipment is at the 100% of normal rating:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This may be the Category C4, C5 and WECC-S3 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other category C requirements.
7. Repeat this for any sub area if required.

Performance Level C3 – Any Two Single contingencies with System Readjustment Conditions:

1. Start with the base cases set for category B study.
2. Screen the area for highest emergency flows due to any double contingency conditions (except for two transformer outages). Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area.
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst contingency:
    a. System configuration change – based on validated and approved operating procedures
    b. Decrease generation from units that aggravate the constraint only. Stop decreasing a certain generator when:
        i. Another known flow limit in the system has been reached.
        ii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4).

    c. Increase generation from units that help reduce the flow on the most stringent element – this generation will become part of the LCR need (read next bullet).

5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first) in the following order until the equipment is at the 100% of normal rating:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This may be the Category C3 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other Category C requirements.
7. Repeat this for any sub area if required.

Protect against voltage collapse for Performance Level B followed by C5 Conditions:

1. Start with the base cases set for category B study.
2. Screen the area for voltage collapse only based on any single contingencies followed by C5 (double circuit tower line outages or two lines in the same right-of-way) contingency conditions if not enough generation is maintained in the area.
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst C5 contingency:
    a. System configuration change – based on validated and approved operating procedures
    b. Decrease generation from units that aggravate the constraint only. Stop decreasing a certain generator when:
        i. Another known flow limit in the system has been reached.
        ii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4).
    c. Increase generation from units that help maintain voltage stability – this generation will become part of the LCR need (read next bullet).
5. Go back to the units within the area that help eliminate the voltage collapse situation. Turn on these units up to their NQC (most effective unit first) in the following order until the voltage collapse situation has been eliminated:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts

6. Add the output of all units that help maintain the voltage stability in the local area. This may be the Category B1 + C5 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other Category C requirements.
7. Repeat this for any sub area if required.

Total Area LCR Requirement:

For any given area or sub area compare the requirement for Category A, B and C. The most stringent one will dictate that area LCR requirement.

General helpful tips:

If the area of study has one or more sub areas, then start with the smallest and/or most easy (radial) sub areas. All the units absolutely required in order to meet the sub area requirements should be turned on and accounted as part of the bigger sub area or entire area requirements (if they help reduce the flow on the most stringent element.)

If these units (absolutely needed in a sub area) aggravate other sub area requirements then be very careful during system re-dispatch so that the decrease of this generation does not cause problems in the previous sub area.

Service Reliability

Meet performance Criteria B

This service reliability level reflects generation capacity that must be available to comply with reliability standards for NERC Category B given that load cannot be removed to meet this performance standard under Applicable Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the only means of meeting any Applicable 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 including load interruptions prior to the actual occurrence of the second contingency.[2]

Meet performance Criteria C

This 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 (involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers as the CAISO operators prepare for the second contingency. However, the customer load will be interrupted at some small time after the second contingency occurs.

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

As the grid operator, the CAISO recommends this last option as the service reliability standard. It identifies a potential service reliability that reflects generation capacity set forth in meeting performance criteria C above, adjusted for any feasible operating solution identified by a PTO prior to the study and approved by the CAISO. On a day-to-day basis the CAISO has traditionally operated the network based on the N-1-1 contingency, with operating solutions developed with the PTOs.