California ISO
Your Link to Power

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MARKET OPTIMIZATION DETAILS

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Market Optimization Details

Table of Contents

1 Market Optimization

This document describes the two mathematical engines Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) that are used to perform Unit Commitment and Economic Dispatch respectively in CAISO Day-Ahead (DAM) and Real-Time Markets (RTM). The usage of each engine is described first followed by a more detailed explanation of the algorithmic processes within each engine.

This document is intended to provide an explanation of the CAISO's use of the SCUC and SCED procedures in clearing its markets and serve as a guide. The actual terms, rates and conditions of service in the CAISO Balancing Authority Area and on the CAISO Controlled Grid are as provided in the CAISO Tariff as filed with the Federal Energy Regulatory Commission, as amended from time-to-time. Additional details regarding the ISO's market processes and procedures are also contained in the CAISO Business Practice Manuals.

2 Security Constrained Unit Commitment (SCUC)

CAISO uses SCUC to run the processes associated with the commitment of Generating Units in DAM and the Hour-Ahead Scheduling Process (HASP) and RTM. SCUC uses a multi-interval Time Horizon to commit and schedule resources and to meet the CAISO Forecast of CAISO Demand in the Market Power Mitigation – Reliability Requirement Determination (MPM-RRD), Residual Unit Commitment (RUC), HASP, Short-Term Unit Commitment (STUC) and RTUC, and the bid-in Demand in Integrated Forward Market (IFM).

In the Day-Ahead MPM-RRD, the IFM and RUC processes utilize SCUC which optimizes over the 24 hourly intervals of the next Trading Day. In RTUC, which runs every 15 minutes, SCUC optimizes over 4, 5, 7 and 18 15-minute intervals that span a portion of the current Trading Hour and one to four subsequent Trading Hours.

In the HASP run, i.e., the RTUC that runs once per hour just before the top of the hour, and the associated MPM-RRD process, SCUC optimizes over seven 15-minute intervals comprising the last 45 minutes of the next Trading Hour and the entire subsequent Trading Hour for which new RTM bids are submitted and HASP schedules are produced. The following run of RTUC represents the STUC optimization over 18 15-minute time intervals. The next two runs of RTUC have five and four 15-minute intervals, respectively, in their Time Horizon, which includes the entire subsequent Trading Hour.

2.1 SCUC Algorithm

The Day-Ahead Market Clearing problem includes next-day Generation and Demand Bids. The objective of the problem is to minimize Energy and Ancillary Services (AS) procurement costs subject to all submitted Energy and Ancillary Services submitted supply bids and transmission constraints. A similar formulation is used to solve the Real-Time Market Clearing problem as well as the Residual Unit Commitment problem. In all cases, SCUC accepts operational data and Bids from resources and power system operating requirements (e.g., Demand forecast, reserve requirements, security constraints, etc.).

In Real-Time, unit commitment is limited to medium- and fast-start units and the dispatch is initialized from the State Estimator solution or telemetry. The SCUC commits and dispatches resources based on minimum cost as reflected by Bid prices, subject to network constraints.

The SCUC adjusts generation, load, import and export schedules and clears Energy Supply and Demand Bids, and AS bids to meet AS requirements, while managing congestion by enforcing linearized transmission constraints, and generating unit inter-temporal constraints. The linearized transmission constraints are identified using AC-based power flow and contingency analysis algorithms based on a Full Network Model (FNM). The FNM includes all CAISO Balancing Authority Area transmission network buses and transmission constraints, and possibly a reduced network representation of the rest of the WECC system. Additionally the SCUC calculates Locational Marginal Prices (LMPs) for Energy, network constraint Shadow Prices and Ancillary Services Marginal Prices (ASMPs) consistent with the AC-based power flow model.

SCUC employs a Mixed Integer Programming (MIP) methodology that effectively addresses the numerous modeling requirements and constraints required in the CAISO Markets.

The use of the MIP methodology with its advanced features allows CAISO to deal effectively with a number of Market design elements including the co-optimization of Energy and Ancillary Services, a large number of transmission and other security constraints, dynamic Ramp Rates, Forbidden Operating Regions.

In general, the SCUC co-optimization engine is capable of clearing markets for Energy and Ancillary Services including the following modeling and functional capabilities:

- Simultaneous optimization of the following commodities:
  - Energy
  - Regulation Up and Down
  - Spinning and Non-Spinning Reserve
  - Reliability capacity
- Least-cost Market Clearing based on:
  - Three-part Generation Energy Bids
  - Single-part load Bids
  - Single-part Inter-Tie Energy Bids
  - Ancillary Services Bids
  - RUC Availability Bids
- Network Congestion Management
  - Full AC network model including transmission losses
  - Security analysis (contingency constraints)
  - Nomogram constraints
- Marginal Pricing
  - Energy, network loss and transmission congestion LMP components
  - Ancillary Service prices for each Ancillary Service Region and each Ancillary Service Bid
  - RUC Prices

2.2 SCUC Modeling Requirements

As markets evolve and mature, there is an increasing requirement for more accurate and complete modeling of the transmission system. This requires iterating between the Unit Commitment (UC) software and Network Applications (NA), resulting in the need to solve the UC problem multiple times to obtain optimal results consistent with the limitation in the transmission system.

For this purpose the SCUC engine employs a Full Network Model (FNM) that is comprised of a detailed model of the physical power system network along with an accurate model of commercial network arrangements. These arrangements reflect the commercial scheduling and operational practices to ensure that the resulting Locational Marginal Prices (LMPs) reflect both the physical system and the actual scheduling practices. The commercial content of the FNM includes the following:

- Load modeling considerations, such as load aggregation, Load Distribution Factors, custom load aggregation, custom Load Distribution Factors, and Trading Hubs
- Resource modeling considerations, such as Pumped-Storage Hydro Units, System Resources, Participating Load, Generating Units, and Generation Distribution Factors for Aggregate Generating Resources
- Commercial transmission considerations, such as ETCs/TORs, New PTOs, Dynamic Schedules and pseudo ties
- Grouping and zone definitions, such as UDCs, price Locations, MSSs, Integrated Balancing Authority Areas (IBAAs), AS Regions, and RUC zones
- Other scheduling elements, such as power system equipment schedules

This dual role of the FNM allows SCUC to efficiently clear the market by co-optimizing Energy and Ancillary Services while managing Congestion and Transmission Losses. The FNM essentially represents the transmission network for CAISO Controlled Grid and is comprised of the following network components:

- The CAISO Balancing Authority Area encompassing the networks of the Participating Transmission Owners (PTOs)
- Metered Subsystems (MSS) that are part of the CAISO Balancing Authority Area
- Non-CAISO Balancing Authority Areas that are embedded within the CAISO Balancing Authority Area
- Networks of New Participating Transmission Owners (New PTOs)

- Utilities (currently called UDCs)

The FNM includes an accurate reactive power (MVAR) model to ensure that reactive power related constraints are respected. The use of reactive power in power systems is an effective way for improving both Power transfer capability and voltage stability. An AC power flow with local controls is implemented in the Network Applications. The operational status or Schedules of the manually operated reactive power/voltage control equipment are accounted for in the FNM. Although the FNM is an AC model, SCUC is not pricing reactive power.

In addition to its physical and commercial components, several other model-related inputs are required in the optimization and processing of the FNM in the IFM Markets. These inputs are a) the Ancillary Services Regions and requirements, b) Constraint definitions and management, c) Branch Groups/Interfaces and Nomograms, and d) contingency definitions and management.

The power system transmission constraints in both the base case and contingency cases are included in SCUC optimization. The transmission power flows of the transmission system branches may be constrained in either direction. The set of transmission constraints selected to be included in the optimization are consistent according to specific constraint definition criteria. Any constraint loaded in base or contingency cases above a certain user adjustable percentage, e.g., 95%, of the transmission equipment loading is included in the optimization.

It should be noted that certain transmission constraints are monitored only (i.e., not enforced). These are monitored against the defined limits adjusted by certain percentages of the limit.

For analytical functions, e.g., “AC power flow” program, a number of slack bus options are provided, such as distributed load, distributed Generation, and single user selectable slack. The slack bus options affect the distribution of network loss deviation in the AC Power Flow solution, and thus the decomposition of the LMP between the System Marginal Energy and Marginal Loss Components.

The selection of the slack bus option is configurable for each Market Application. Currently, a distributed load slack is used in all Market Application except for the IFM where a distributed load slack is used except in the event that the IFM cannot clear with a distributed Load slack bus in which case it is ran with a distributed generation slack bus.

Lastly, there are two other very important NA functions that are used to produce network sensitivity information required to manage Transmission Losses and Congestion. These are:

- **Power Transfer Distribution Factor (PTDF) Calculations Function** – The PTDF calculations function produces the PTDFs. PTDFs are the sensitivities of injections at any location in the network with respect to flow on any transmission element (in a reference direction). PTDFs are used in the Congestion Management application and the calculation of the LMPs. They are calculated following each AC power flow run.

- **Loss Sensitivity Calculations Function** – The loss sensitivity calculations function calculates the marginal loss factors. These loss sensitivity factors are the sensitivities of Transmission Losses with respect to injection at any network node. Loss factors are calculated following each AC power flow run using the distributed load slack option. Loss factors are accurately calculated for both physical and commercial portions (resource aggregations) of the model. This function also calculates Transmission Losses after each AC power flow run. Transmission Losses are available on a total system basis as well as at each operating entity (e.g., company, MSS and UDC).

2.3 Objective Function

The SCUC engine determines optimally the commitment status and the Schedules of Generating Units as well as Participating Loads and Resource-Specific System Resources. The objective is to minimize the Start-Up and Minimum Load costs and bid in Energy costs and Ancillary Services, subject to network as well as resource related constraints over the entire Time Horizon, e.g., the Trading Day in the IFM. The time interval of the optimization is one hour in the DAM and 5 or 15 minutes in the RTM depending on the application.

In IFM the overall production (or Bid) cost is determined by the total of the Start-Up and Minimum Load Cost of CAISO-committed Generating Units, the Energy Bids of all scheduled Generating Units, and the Ancillary Service Bids of resources selected to provide Ancillary Services. This objective leads to a least-cost multi-product co-optimization methodology that maximizes economic efficiency, relieves network Congestion and considers physical constraints. The economic efficiency of the market operation can be achieved through a least-cost resource commitment and scheduling with co-optimization of Energy and Ancillary Services.

Mathematically, the objective function for the IFM is represented as follows:

$$\min \sum_{h=1}^{T} \sum_{i=1}^{N} \left[\begin{array}{l} SUC_i (1 - U_{i,h-1}) U_{i,h} + MLC_{i,h} U_{i,h} + \int_{P_{\min i}}^{P_{i,h}} C_{i,h}(P_{i,h})\, dP + \\ C_{i,h}^{RU} \cdot RU_{i,h} + C_{i,h}^{RD} \cdot RD_{i,h} + C_{i,h}^{SP} \cdot SP_{i,h} + C_{i,h}^{NS} \cdot NS_{i,h} \end{array} \right]$$

Where

h	Hour index
T	Total number of hours in the time horizon
i	Resource index
N	Total number of resources
$P_{i,h}$	Power output of resource *i* in hour *h*
$RU_{i,h}$	Regulation up provided by resource *i* in hour *h*
$RD_{i,h}$	Regulation down provided by resource *i* in hour *h*
$SP_{i,h}$	Spinning Reserve provided by resource *i* in hour *h*
$NS_{i,h}$	Non-spinning Reserve provided by resource *i* in hour *h*
$C_{i,h}(P_{i,h})$	Cost ($/hour) as a piece-wise linear function of output (MW) for resource i in hour h
$C_{i,h}^{RU}$	Bid cost ($/MW) of regulation up (MW) for resource *i* in hour *h*
$C_{i,h}^{RD}$	Bid cost ($/MW) of regulation down (MW) for resource *i* in hour *h*
$C_{i,h}^{SP}$	Bid cost ($/MW)of spinning reserve (MW) for resource *i* in hour *h*
$C_{i,h}^{NS}$	Bid cost ($/MW) of non-spinning reserve (MW) for resource *i* in hour *h*
SUC_i	Start-Up Cost ($/start) for resource *i*
$MLC_{i,h}$	Minimum Load Cost ($/hr) for resource *i* in hour *h*

$U_{i,h}$ Commitment status; = 0 if resource i is off-line, and = 1 if resource i is on-line, in hour h

Start-Up Cost is occurred whenever a start-up takes place and Minimum Load cost is occurred whenever the unit is online.

Scheduling Coordinators can submit three-part Energy Bids (the three parts are Start-Up Cost in $/start, Minimum Load Cost in $/hr, and Energy Bid Curve above Minimum Load in $/MWh) for Generating Units and Participating Loads. All online units provide Energy service. Some of them can be selected to provide Regulation Up/Down and Spinning Reserve services. Generators can provide Non-Spinning Reserves regardless of their commitment status in the DAM. Costs of Energy Self-Schedules and Self-Provided AS are represented by penalty costs in the objective function. Constraint violations are also represented by penalty costs in the objective function. These penalty terms are not shown in the equation above for simplicity.

Energy and Ancillary Service Bid Costs include integrated Energy Bid Curves. The Energy Bid Curves are stepwise functions of procured services, therefore Bid Costs are piecewise linear functions of service quantities. The minimum segment size is configurable with a default value of 0.01 MW in all cases.

The objective function in MPM is similar to the one in IFM; the submitted Energy Bids are used in both CCR and ACR, whereas the mitigated Energy Bids are used in IFM.

The objective function for the RUC optimization model includes the RUC Availability Bids instead of the Energy and Ancillary Services Bids. For partial RA units, a two segment RUC Availability Bid is acceptable, where the first segment of $0 represents the RA Capacity and the second segment with a bid-in non-zero $ value represents the remaining portion of the unit's capacity.

For RUC, the overall production cost is determined by the total of the Start-Up and Minimum Load Cost of CAISO-committed resources in addition to the ones committed in IFM and RUC Availability Bids of all Scheduled resources. Mathematically, the objective function for the RUC is represented as follows:

$$\min \sum_{h=1}^{T} \sum_{i=1}^{N} \left[SUC_i (1 - U_{i,h-1}) U_{i,h} + MLC_{i,h} U_{i,h} + C_{i,h}^{AV} RU_{i,h} \right]$$

Where:

$C_{i,h}^{AV}$ represents the RUC Availability Bids in ($/MW). Day-Ahead Schedules in RUC are considered as Self-Schedules (i.e., Price Takers) and are represented by penalty costs in the objective function. These penalty terms are not shown in the equation above for simplicity.

The objective function in RTUC is similar to the one in IFM, but the Real-Time Ancillary Services Bids and the mitigated Real-Time Energy bids are used instead. Day-Ahead Ancillary Services Awards are represented by penalty costs in the objective function. The objective function in RTED is similar to the one in RTUC, but without the Start-Up and Minimum Load Costs and without Ancillary Services Bids.

2.4 Input Bids for SCUC Engine

This section describes the various types of Bids that go into SCUC.

2.4.1 Generation Energy Bids

The Generation Energy Bids can include all three cost components:

- Start-Up Cost
- Minimum Load cost
- Energy Bid cost

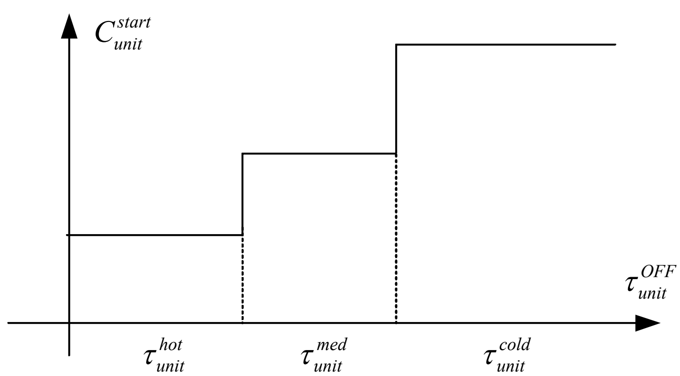
The Start-Up and Minimum Load costs are ignored when the Generating Unit self-commits by submitting Energy Self-Schedules and/or providing Submissions to Self-Provide AS, or when the Generating Unit must be online due to Reliability Must Run requirements or Day Ahead binding commitment and AS awards in RTM. In this case, only the single-part Energy Bid is considered.

The Generation Bids can be submitted in aggregated form associated with Generation Distribution Factors. The aggregated Generation Bids are optimized in aggregated form and resulting Generation Schedules are dis-aggregated to the individual Generating Units using Generation Distribution Factors to perform power flow calculations.

Start-Up Cost Curve:

The Start-Up Cost ($/start) can be dependent on the time passed since the unit was last Shut-Down. This function has a stepwise increasing form across three unit cooling states: hot,intermediate and cold. The typical Start-Up Cost function is illustrated in the following exhibit:

Exhibit A-1: Start-Up Cost Function



The down time is specified in minutes and rounded to the closest time interval in the IFM and to the next time interval in RTM to be a multiple of Market time intervals. The Start-Up Cost curve is treated as unlimited on the right hand side because cooling time is unlimited. Alternatively, the Start-Up Costs can be expressed as a single value not dependent on unit down time.

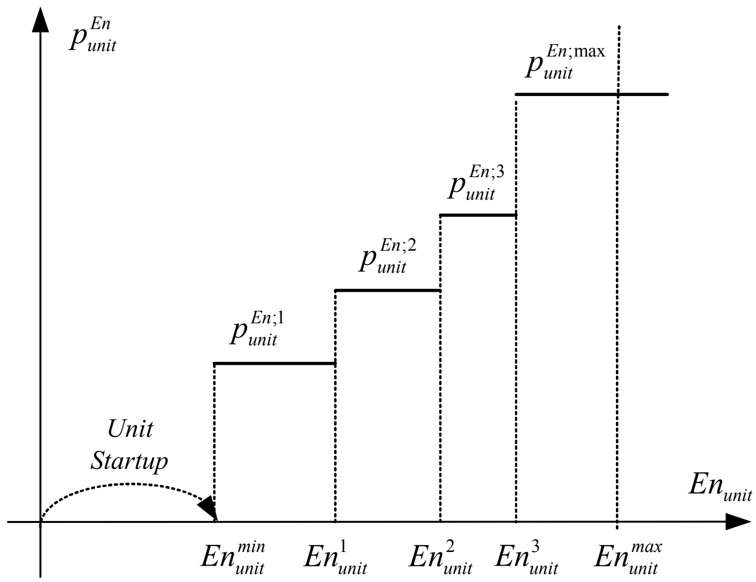
Minimum Load Cost:

The Minimum Load Cost ($/hr) expresses the unit operating costs at the minimum operating point. The Minimum Load Cost is considered whenever a Generating Unit is online.

Energy Bid Cost:

For each Trading Hour a separate Energy Bid Curve and/or Energy Self-Schedule can be submitted. A Generation Energy Bid Curve is a monotonically increasing stepwise function of incremental production cost ($/MWh) versus Energy Generation:

Exhibit A-2: Generation Energy Bid Curve



The integral of the Generation Energy Bid Curve from Minimum Load to the optimal schedule expresses the cost of produced Energy.

Energy Bid Limits:

The starting point of a submitted Generation Energy Bid is the lower economic limit (LEL) and endpoint is the upper economic limit (UEL). The LEL may not be less than the Minimum Load (Pmin) and the UEL may not be greater than the Maximum Capacity (Pmax). Furthermore, if the LEL is greater than Pmin, there must be submitted self-schedules that add up to the LEL.

2.4.2 Load Energy Bids

This section describes the types of load Bids.

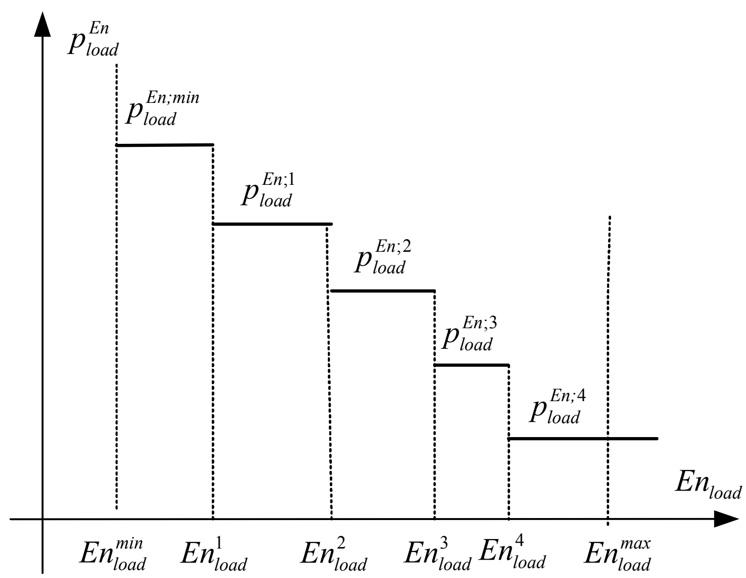
2.4.2.1 Non-Participating Load Bids

Load Single-Part Bid:

Non-Participating Load entities can submit aggregated single-part Energy Bids. These load resources are in online status and dispatched between LEL and UEL according to their Energy Bid Curves. The detailed modeling of the single-part load Bids is as follows.

The aggregated load Bid price curve is a monotonically decreasing stepwise function of incremental benefit ($/MWh) versus Energy consumption:

Exhibit A-3: Load Single-Part Bid



The integral of the load Energy Bid Curve from zero to the optimal schedule expresses the benefit of consumed Energy. This benefit is illustrated in the following exhibit:

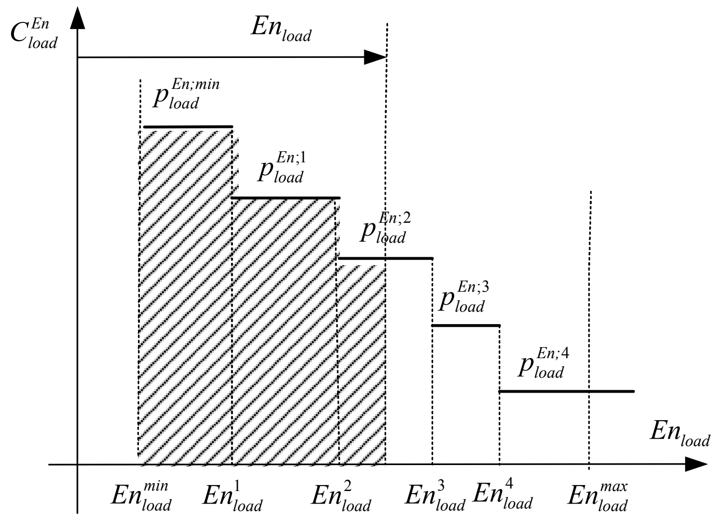


Exhibit A-4: Load Single-Part Bid Benefit

Note that minimum Load costs can be included as a constant part of Demand Bid costs because Non-Participating Load is treated always as online resource.

Load Inter-Temporal and Ramping Constraints:

The Non-Participant Load is considered to be online all the time and inter-temporal constraints are not applicable. Therefore, ramp rate constraints are not formulated for Non-Participating Load.

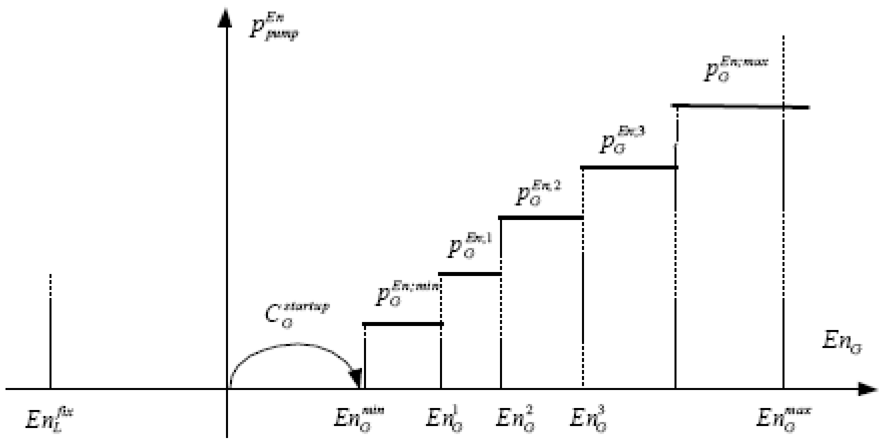
Load Bid Limits:

The starting point of a submitted load Energy Bid is the lower economic limit (LEL) and endpoint is the upper economic limit (UEL). If the LEL is greater than zero, there must be submitted self-schedules that add up to the LEL.

2.4.2.2 Pumped-Storage Hydro Unit Bids

The Pumped-Storage Hydro Units are modeled as a special case of Participating Load Resources. An explicit Pumped-Storage Hydro Unit model is used with three states (offline, pumping, generating) and a three-part bid as follows:

Exhibit A-4: Pumped-Storage Hydro Unit Bid



Where:

En_G	is the generation optimal schedule;
$En_G^{\min}$	is the Lower Economic Limit
En_G^i	for i=1,2,…,n; define the segments of the generator energy bid;
$p_G^{En;i}$	for i=1,2,…,n; are the prices of the generator energy bid segments;
En_L^{fix}	is the fixed Pumping Level;
$C_G^{startup}$	is the generator Start-Up Cost;
$C_G^{\min}$	is the generator Minimum Load Cost; and
$C_L^{\min}$	is the Pumping Cost (the cost/hr in pumping mode).

The model includes the ability to provide Non-Spinning Reserve in pumping mode. Inter-temporal constrains apply only to the generating mode, and they are similar to any Generating Resource.

2.4.2.3 Aggregated Participating Load Bids

Aggregated Participating Load is modeled as Aggregated Non-Participating Load in parallel with a pseudo-generating resource.

2.4.3 Ancillary Service Bids

Ancillary Service Costs:

For each Trading Hour separate Bids can be submitted for all Ancillary Services: Regulation Down, Regulation Up, Spinning Reserve and Non-Spinning Reserve. All these services can be provided from zero to Bid maximum MW range with a single service price value. The Ancillary Service costs are calculated using these single segment Bid price curves as follows:

$$C_{unit}^{RegUp;t}(RegUp_{unit}^{t}) = p_{unit}^{RegUp;t} \cdot RegUp_{unit}^{t}$$ - Generation unit Regulation Up cost

$$C_{unit}^{RegDn;t}(RegDn_{unit}^{t}) = p_{unit}^{RegDn;t} \cdot RegDn_{unit}^{t}$$ - Generation unit Regulation Down cost

$$C_{unit}^{Res;t}(Res_{unit}^{t}) = p_{unit}^{Res;t} \cdot Res_{unit}^{t}$$ - Generation unit Spinning Reserve cost

$$C_{unit}^{NRes;t}(NRes_{unit}^{t}) = p_{unit}^{NRes;t} \cdot NRes_{unit}^{t}$$ - Generation unit Non-Spinning Reserve cost

$$C_{load}^{NRes;t}(NRes_{load}^{t}) = p_{load}^{NRes;t} \cdot NRes_{load}^{t}$$ - Load Non-Spinning Reserve cost

Where:

$RegDn_{unit}^{t}$ is the Regulation Down Award

$RegUp_{unit}^{t}$ is the Regulation Up Award

Res_{unit}^{t} is the Spinning Reserve Award

$NRes_{unit}^{t}$ is the Non-Spinning Reserve Award

$p_{unit}^{RegDn;t}$ is the Regulation Down Bid price

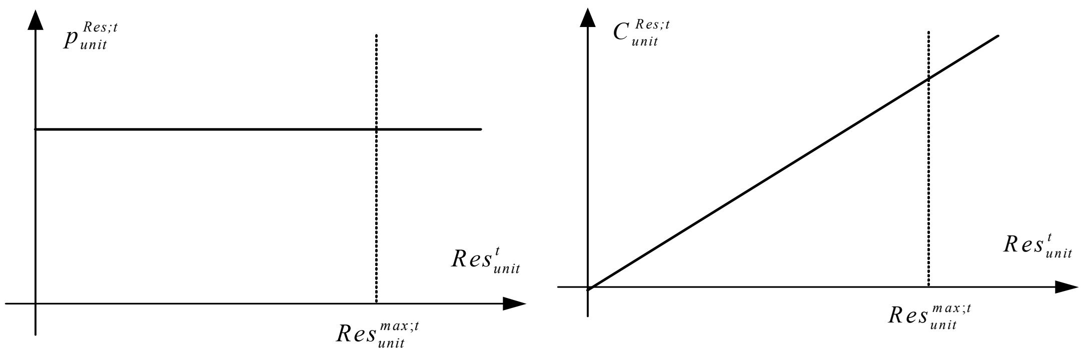
$p_{unit}^{RegUp;t}$ is the Regulation Up Bid price

$p_{unit}^{Res;t}$ is the Spinning Reserve Bid price

$p_{unit}^{NRes;t}$ is the Non-Spinning Reserve Bid price

These Ancillary Service Bid price and cost curves are illustrated on the following exhibits using Spinning Reserve as an example:

Exhibit A-5: Spinning Reserve Bid Price and Cost Curves



Note the cost curve is derived from the submitted single segment bid price.

Ancillary Service Limits:

Each Ancillary Service award is limited by the submitted maximum Bid Quantity (MW). Additionally, the resource ramping capability over the specified ramping time domain is considered as an Ancillary Service award limit. Separate Ramping Rates and ramping time domains can be specified for Regulation, Spinning and Non-Spinning Reserves. The most restrictive of these limits is applied as follows:

$$0 \le RegUp_{unit}^{t} \le \min\{RR_{unit}^{RegUp} \cdot T_{dom}^{Reg}\,;\,\overline{Reg}_{unit}^{Up;t}\};\quad unit \in G; t \in T$$
$$0 \le RegDn_{unit}^{t} \le \min\{RR_{unit}^{RegDn} \cdot T_{dom}^{Reg}\,;\,\overline{Reg}_{unit}^{Dn;t}\};\quad unit \in G; t \in T$$

$$0 \le Res_{unit}^{t} \le \min\{RR_{unit}^{Res} \cdot T_{dom}^{Res}\,;\,\overline{Res}_{unit}^{t}\};\quad unit \in G; t \in T$$

$$0 \le NRes^{t}_{unit} \le \min\{P^{\min}_{unit} + RR^{NRes}_{unit} \cdot \max\left(0, T^{NRes}_{dom} - SUT_{unit}\right), \overline{NRes}^{t}_{unit}\}; \quad unit \in G; t \in T$$

$$0 \le NRes^{t}_{load} \le \overline{NRes}^{t}_{load} \quad load \in L; t \in T\,.$$

Where:

RR^{RegUp}_{unit}	is the Regulating Up Ramp Rate
RR^{RegDn}_{unit}	is the Regulating Down Ramp Rate
RR^{Res}_{unit}	is the Spinning Reserve Ramp Rate
RR^{NRes}_{unit}	is the Non-Spinning Reserve Ramp Rate
T^{Reg}_{dom}	is the Regulation Time Domain
T^{ReS}_{dom}	is the Spinning Reserve Time Domain
T^{NRes}_{dom}	is the Non-Spinning Reserve Time Domain
$\overline{Reg}^{Up;t}_{unit}$	is the Regulation Up bid capacity
$\overline{Reg}^{Dn;t}_{unit}$	is the Regulation Down bid capacity
$\overline{Res}^{t}_{unit}$	is the Spinning Reserve bid capacity
$\overline{NRes}^{t}_{unit}$	is the Non-Spinning Reserve bid capacity
$\overline{NRes}^{t}_{load}$	Is the Non-Spinning bid capacity from a pump

Submissions to Self-Provide Ancillary Service:

Submissions to Self-Provide AS can be submitted in addition to or in place of Ancillary Service Bids. The Self-Provided AS are subject to qualification based on resource Ancillary Service ramping limits and regional requirements. A Qualified Ancillary Service Self-Provision may not be used to satisfy requirements for lower quality Ancillary Services.

2.4.4 Residual Unit Commitment (RUC) Bids

Reliability Capacity:

For each Trading Hour in the DAM, separate Bids can be submitted for RUC Capacity in excess of any submitted RA RUC Obligation as a single segment availability price curve. If a unit is Scheduled in IFM Market run, the RUC Capacity is additional capacity on top of Scheduled Energy in the IFM. If a unit is committed in RUC, the entire RUC Schedule constitutes RUC Capacity.

$$RCap_{unit}^{t} = \max\left(0;\ \Delta En_{unit}^{t}\right); \quad unit \in G; t \in T$$

Where:

Δ-values present quantities scheduled for reliability purposes as increments for generators and decrements (negative values) for participating loads to already Scheduled or self-provided quantities in IFM.

The portion of the RUC Capacity above the IFM Schedule that corresponds to a submitted RUC Availability Bid constitutes a RUC Award and is subject to payment at the relevant RUC LMP. If a resource is committed in RUC, the RUC Award does not include the Minimum Load; the Minimum Load is paid the relevant minimum load cost as part of the Bid Cost Recovery.

The RUC Capacity has a zero cost for the portion that corresponds to the RA RUC Obligation and the single price value is applied only to any additional RUC Capacity that corresponds to the RUC Availability Bid. The RUC Capacity costs are calculated using these single segment Bid price curves as follows:

$$C_{unit}^{RCap;t}(RCap_{unit}^{t}) = p_{unit}^{RCap;t} \cdot RCap_{unit}^{t} \qquad \text{- Generation unit cost}$$

Where:

$RCap_{unit}^{t}$ is the RUC Award

$p_{unit}^{RCap;t}$ is the RUC Availability Bid Price

The unit RUC Availability Bid price and cost curves are illustrated on the following exhibit:

Exhibit A-6: RUC Availability Bid Price and Cost Curves

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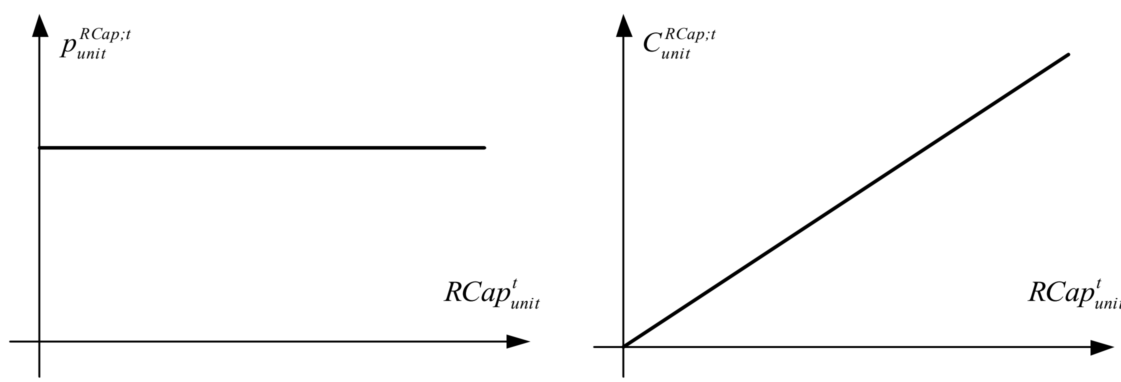


Note the cost curve is derived from the submitted single segment bid price

2.5 Constraints

This section describes the constraints that are enforced by the SCUC process. The constraints in the SCUC optimization include the power balance constraints, Ancillary Service capacity requirement constraints, network constraints under both base case condition and contingencies, and Generating Unit inter-temporal constraints.

2.5.1 Power Balance Constraint

The Power balance constraint states that the Generation in the system should balance out with the load plus the Transmission Losses. Only one market-wide power balance constraint is considered. The Energy balance is enforced by all Market Applications. Both Bid-in Generation and bid-in load (IFM only) or CAISO Forecast (Except IFM) participate in the power balance constraint including network Energy losses:

$$\sum_{unit \in G} En_{unit}^{t} - \sum_{load \in L} En_{load}^{t} = En_{req}^{t} + En_{loss}^{t} \;;\; t \in T$$

The Energy loss model is derived from the full AC network solution which is updated during the SCUC-NA iteration process. The network Energy losses are linearized using marginal loss factors α around the base operating point:

$$En_{loss}^{t} = En_{loss}^{base;t} + \Delta En_{loss}^{t} \,;\, t \in T$$

Where:

$$\Delta En_{loss}^{t} = \sum_{unit \in G} \alpha_{node}^{t} \cdot (En_{unit}^{t} - En_{unit}^{base;t}) - \sum_{load \in L} \alpha_{node}^{t} \cdot (En_{load}^{t} - En_{load}^{base;t}) \,;\, t \in T\,.$$

Depending on the Market Application, the Energy requirement can present the sum of fixed loads and Generations, system load forecast or actual Energy imbalance:

$$En_{req}^{t} = \begin{cases} En_{LF}^{t} - En_{loss}^{base;t} ; \; t \in T & Load \;\; Forecast \\ En_{SS}^{t} ; \; t \in T & Self - Schedules \\ En_{Imb}^{t} - En_{loss}^{base;t} ; \; t \in T & Energy \;\; Imbalance \end{cases}$$

Note that load forecast and imbalance requirement already include network Energy losses while Energy Self-Schedules present delivered load. The power balance can be expressed in terms of loss penalty factors:

$$\sum_{unit \in G} En_{unit}^{t} / pf_{unit}^{t} - \sum_{load \in L} En_{load}^{t} / pf_{load}^{t} = En_{req}^{t} + \Delta En_{req}^{t} ;\, t \in T$$

Where:

$$\Delta En_{req}^{t} = En_{loss}^{base;t} - \sum_{unit \in G} \alpha_{node}^{t} \cdot En_{unit}^{base;t} + \sum_{load \in L} \alpha_{node}^{t} \cdot En_{load}^{base;t} \;;\, t \in T$$

and loss penalty factors are calculated as follows:

$$pf_{unit}^{t} = 1/(1-\alpha_{node}^{t}) \text{ and } pf_{load}^{t} = 1/(1+\alpha_{node}^{t})$$

Where:

$En_{unit}^{base;t}$	is the Energy schedule of a unit from NA
$En_{unit}^{load;t}$	is the Energy schedule of load from NA
$En_{loss}^{base;t}$	is the Bass System losses from NA
α_{node}^{t}	is the Marginal loss rate at the node i.e. change in system losses due to a marginal injection at the node

2.5.2 Ancillary Services Constraints

The Ancillary Services Requirement can be set up on a global, system-wide basis, or on a more granular regional level. The CAISO Operator can specify the AS procurement requirements for each AS Region. These requirements are minimum and/or maximum bounds on AS procurement, both for the overall system and for pre-specified AS Regions. For each hour, the following AS requirement information is published:

- minimum requirements for Spinning Reserve, Non-Spinning Reserve, Regulation Up, and Regulation Down, by AS Region;
- maximum requirement for Regulation Down, by AS Region; and
- maximum requirements for the total of Spinning Reserve, Non-Spinning Reserve, and Regulation Up, by AS Region.

Both Ancillary Service Bids and Submissions to Self-Provide Ancillary Services can be submitted for each Ancillary Service. Additionally, Ancillary Service cascading is supported by the optimization, i.e., a lower quality of Ancillary Service can be substituted by a higher quality of Ancillary Service. Specifically:

- Regulation Up can be used as substitution for both Spinning and Non-Spinning Reserves

- Spinning Reserve can be used as substitution for Non-Spinning Reserve

All AS are procured based on a ramp time of 10 minutes. The cascading sequence is common for all Ancillary Service Regions and all time intervals. Selected Ancillary services Bids are paid the relevant Ancillary Service Marginal Price (ASMP). Qualified Ancillary Service Self-Provision reduces the relevant SC Ancillary Service Obligation for Ancillary Services Cost Allocation. The settlement for the allocation of Ancillary Services costs is system-wide. This means for example that a Load Serving Entity with load in the San Diego LAP can self-provide some or all of its AS Obligation from Generating Units in NP15 if the Self-Provided AS clears the IFM. Section 4.2.1 of Market Operations BPM provide more details about AS self-provision qualification process.

2.5.2.1 Regulation Up and Down Requirements

For each AS Region and each Trading Hour a minimum requirement for Regulation Up capacity and a minimum and maximum requirement for Regulation Down can be specified. Both Regulation Bids and Regulation self-provisions can participate in meeting these requirements. Only online generating units can be awarded Regulation service to meet the Regulation Up and Regulation Down requirements.

Separate minimum requirements for Regulation Up capacitiy can be specified for each Ancillary Service region

$$\underline{Reg}_{ASreq}^{Up;t} \leq \sum_{unit \in AS} Reg_{unit}^{Up;t} \ ; t \in T$$

Separate maximum and minimum requirements for Regulation Down capacities can be specified for each Ancillary Service region:

$$\underline{Reg}_{ASreq}^{Dn;t} \leq \sum_{unit \in AS} Reg_{unit}^{Dn;t} \leq \overline{Reg}_{ASreq}^{Dn;t} \ ; t \in T$$

<u>Reg Up Regional Requirements:</u>

$$\sum_{i=1}^{N} p_{i,t}^{\mathrm{Re}\,gUp} + RLXD_t^{\mathrm{Re}\,gUp} - RLXU_t^{\mathrm{Re}\,gUp} = p_t^{\mathrm{Re}\,gUp} ; P_t^{\mathrm{Re}\,gUp;req\min} \leq p_t^{\mathrm{Re}\,gUp} \leq P_t^{\mathrm{Re}\,gUp;req\max}, \quad \forall t$$

RLXD, RLXU – are nonnegative relaxation variables throughout to which the penalties for violation will apply.

Regional Reg UP Slack:

$$-SLCK_{\mathrm{t}}^{\mathrm{RegUp\_Spin}} - SLCK_{\mathrm{t}}^{\mathrm{RegUp\_Nspin}} + p_t^{\mathrm{Re}\,gUp} = P_t^{\mathrm{Re}\,gUp;reg\,\min}, \forall t$$

*SLCK^RegUp_Spin^, SLCK^Regup_Nspin^* – are the nonnegative amounts of Reg Up that can be cascaded down towards the regional Spin and Non-spin requirements.

2.5.2.2 Spinning Reserve Requirements

Separate Spinning Reserve minimum requirements can be specified for each AS Region and for each Trading Hour. Spinning Reserve requirements can be met by Spinning Reserve Bids and Spinning Reserve self-provisions as well as Regulation Up Bids. Only online Generating Units provide Spinning Reserve service. According to Ancillary Service cascading, Regulation Up can be used as Spinning Reserve after the Regulation Up requirement is met. The substitution of Regulation Up self-provisions for Spinning Reserve is not allowed.

$$\underline{Res}_{ASreq}^{t} + \underline{Reg}_{ASreq}^{Up;t} \leq \sum_{unit \in AS} Res_{unit}^{t} + \sum_{unit \in AS} Reg_{unit}^{Up;t} \; ; t \in T \quad .$$

Regional Spin Requirement:

$$SLCK_t^{\mathrm{Re}\,gUp\_Spin} + \sum_{i=1}^{N} p_{i,t}^{tmsr} + RLXD_t^{tmsr} - RLXU_t^{tmsr} = p_t^{tmsr}; \; P_t^{tmsr:req\,\min} \leq p_t^{tmsr} \leq P_t^{tmsr:req\,\max}, \forall t$$

- note that only the slack (the excess of Reg Up above the requirements) is counted towards the spin.

Regional Spin Slack:

$$-SLCK_t^{Spin\_NSpin} + p_t^{tmsr} = P_t^{tmsr:req\,\min}, \quad \forall t$$

2.5.2.3 Non-Spinning Reserve Requirements

Separate Non-Spinning Reserve minimum requirements can be specified for each AS Region for each Trading Hour. The Non-Spinning Reserve requirements can be met by Non-Spinning Reserve Bids and Non-Spinning Reserve self-provisions as well as Regulation Up and Spinning Reserve Bids. The cascading of Regulation Up and Spinning Reserve self-provisions is not allowed.

Regional Non-spin Requirements:

$$SLCK_t^{RegUp\_Nspin} + SLCK_t^{Spin\_Nspin} + \sum_{i=1}^{N} p_{i,t}^{tmns} + RLXD_t^{tmns} - RLXU_t^{tmns} = p_t^{tmns}; P_t^{tmns:req\min} \le p_t^{tmns} \le P_t^{tmns:req\max}, \forall t$$

2.5.2.4 Maximum Upward Capacity Constraint

The total amount of upward Ancillary Service capacity is limited for each AS Region. Specifically, the sum of Regulation Up, Spinning Reserve and Non-Spinning Reserve procured in each AS Region using Bids or self-provisions cannot exceed a limit maximum capacity at any time interval.

$$\sum_{unit \in AS} Reg_{unit}^{Up;t} + \sum_{unit \in AS} Res_{unit}^{t} + \sum_{unit \in AS} NRes_{unit}^{t} + \sum_{load \in AS} NRes_{load}^{t} \le \overline{UCap}_{ASreq}^{t} \; ; t \in T.$$

The Ancillary Service Self-Provisions are qualified if they satisfy the maximum upward regional capacity limit. Otherwise, qualified Ancillary Service Self-Provisions are determined according to the following rules:

- The total qualified Ancillary Service Self-Provisions are adjusted for each Ancillary Service region in order based on pre-specified priorities among these regions
- In each Ancillary Service region, the qualified Ancillary Service Self-Provisions are adjusted to meet regional maximum upward limit in reverse quality order (Non-Spinning Reserve first, followed by Spinning Reserve and then Regulation Up)
- For each Ancillary Service, Ancillary Service Self-Provisions are qualified pro rata to meet regional maximum upward limit

2.5.3 Network Constraints

Network constraints due to Energy Schedules are considered in the optimization for both the base case and contingency cases. The network Power Flow Model is based on a full AC power flow solution performed by Network Application (NA). However, SCUC/SCED models only MW (active) variables where MVAR (reactive) variables are not considered. Therefore in the NA-SCUC iteration process, the branch flow MVA limits are translated into MW limits in SCUC, assuming that MVAR branch flows and voltage magnitudes, as determined in NA, do not change significantly from one iteration to the next. In SCUC, the transmission line flows are expressed as linearized functions of the nodal power injections around the base operating state from NA using calculated PTDFs.

The set of critical transmission lines is selected according to the percentage of line MW loading. The lines loaded above the specified threshold are included in the optimization. To avoid oscillations in the SCUC-NA iteration process, lines are added into and never deleted from the critical set for a complete market process pass. The maximum number of enforced network constraints can be specified by the authorized user. The network constraints are ordered according to their percentage of loading. There are several types of network constraints as described next.

2.5.3.1 Network Branch Power Flow Limits

The network branch AC power flow limits are modeled as MVA ratings. They represent thermal limits of the transmission equipments. Normal and emergency ratings are specified for each branch for operation in normal and emergency conditions. Branch ratings can also be derated for each interval. The default branch rating is included with the EMS network model data imported into SCUC. Derated ratings are retrieved from CAISO Outage Management Tool (COMT) or entered manually by the CAISO Operator. The software selects the default ratings first, then overrides the default values with those from COMT, and finally overrides the COMT ratings with any user-entered values. Values can be adjusted using a percent bias adjustment.

2.5.3.2 Transmission Interface Limits

A transmission interface is a Branch Group or a path that consists of one or more branches. All interties and WECC paths are defined as transmission interfaces. A branch can be a member of multiple Branch Groups. The Branch Group definition is included with the EMS network model data maintained in the FNM, and that definition is also maintained in the Master File. The ratings for Branch Groups are referred to as Operating Transfer Capability (OTC), usually determined by AC power flow analysis, transient stability analysis, voltage stability analysis, and contingency analysis, performed by CAISO Operation Engineers and sometimes involving multiple neighboring Balancing Authority Areas. These ratings are specified in MW, are directional, and can change hourly. These ratings are provided to the Market Applications by Existing Transmission Contracts Calculator (ETCC). Branch Groups only have normal ratings and these ratings are enforced only in the Base case.

Usually these ratings already take into consideration the effects of significant contingencies. The intertie limits used in SCUC are affected by TOR and ETC transmission capacity reservations. CAISO determines the TOR and ETC rights on each transmission interface based on the applicable OTC, considering any Outages or derates, and related information provided by the responsible Participating Transmission Owner (PTO) or TOR party. The transmission interface limit for interties is then determined by reserving unused TOR and ETC capacity for TOR/ETC with applicable physical rights.

The CAISO market applications are capable of enforcing both Transmission Interface OTC and the associated individual branch limits; however because the Transmission Interface OTC is more restrictive, the associated individual branch limits are normally not enforced. The effect of a binding Transmission Interface constraint is to contribute a congestion component on the LMP at a given location equal to the product of the shadow price of that Transmission Interface and its aggregate shift factor at that location. This aggregate shift factor is calculated as the sum of the respective shift factors of the individual branches that compose the Transmission Interface. In the event that a Transmission Interface and one of its constituent branches are simultaneously binding (very unlikely), there are congestion contributions to the LMP from both the shadow price of the Transmission Interface and that of the constituent branch,

2.5.3.3 Intertie Scheduling Limit Energy-AS Constraints

Energy and Ancillary Service Bids compete for the use of inter-ties when their demands for transmission capacity are in the same direction. Ancillary Service imports compete with Energy Schedules on designated interties in the import direction. Moreover, Energy does not provide counter-flow for Ancillary Service when the demands for transmission capacity are in opposite directions, and Ancillary Service does not provide counter-flow for Energy when the demands for transmission capacity are in opposite directions. Finally, no netting is allowed among Ancillary Services. Only one of the intertie constraints may be binding in either direction at any given time.

Consequently, the intertie transmission constraints in the import direction are formulated as follows:

$$\max\left\{0, En_{Imp}^{t} - En_{Exp}^{t}\right\} + Reg_{Imp}^{Up;t} + Res_{Imp}^{t} + NRes_{Imp}^{t} \leq F_{Imp}^{OTC}; \quad t \in T$$

The intertie transmission constraints in the export direction are formulated in a similar way:

$$\max\left\{0, En_{Exp}^{t} - En_{Imp}^{t}\right\} + Reg_{Imp}^{Dn;t} \leq F_{Exp}^{OTC}; \quad t \in T$$

2.5.3.4 Nomograms

A Nomogram is a set of piece-wise linear inequality constraints relating Generating Unit output and transmission interface flows. Only constraints that relate AC branch MW flows and MW Generation having the standard format of single branch or interface constraints are considered in the SCUC. Resource statuses or Ancillary Services cannot be part of the Nomogram model. The Nomogram constraints must be piecewise linear constraints defining a convex set. Nomograms can consist of a family of piecewise linear constraints. The constraint curve is selected prior to the optimization. The following are examples of typical Nomogram variables:

- AC Interface MW Flow vs. AC Interface MW Flow
- AC Interface MW Flow vs. Area MW Generation

The Nomogram constraint presents a single piecewise linear curve relating two or more Nomogram variables.

2.5.3.5 Contingency Constraints

Contingencies are simulated forced Outages of network elements. SCUC performs contingency analysis using the FNM, to recognize network constraints in the commitment and Dispatch of Generating Units. NA provides a facility for definition and maintenance of contingencies.

A defined contingency may involve any modeled element: line sections, transformers, switches, circuit breakers, shunts, synchronous condensers, etc. Generator and load contingencies can also be defined (for monitoring purposes). Equipment Outages can be defined either by the element itself or its associated disconnect device. Contingency definitions can include actions beyond simply “opening” an element; thus, contingency definitions allow for several different possible actions/commands. For example, a single contingency may involve opening a transmission line, closing an alternate switch or line section (automatic load transfer, as in a “flip-flop” arrangement), and/or bypassing a series capacitor/reactor. The sequence of these events are pre-defined in contingencies.

While most contingencies are likely to involve only one or two elements, no single contingency includes more than 50 elements. The contingency application also categorize each contingency into one of several groups (a configurable number of categories). These categories allow any individual contingency to be applied in one or many Market environments (DAM, RTM).

The security constraints corresponding to contingencies (except monitor only contingencies) are enforced in a preventive control mode, i.e., the optimal Schedule is determined such that no security violations are expected to arise if any defined contingency occurs.

2.5.4 Inter-Temporal Constraints

In this Section we present the inter-temporal constraints in more details.

2.5.4.1 Minimum Up Time

Typically, a Generating Unit cannot change its commitment status at every time interval. It must stay online or offline for some minimum time period without changing its commitment status.

The Minimum Up Time (MUT) constraint, specified in minutes, is the minimum amount of time that a unit must stay online between Start-Up and Shut-Down due to physical operating constraints.

In other words, when a Generating Unit is started, it must stay online at least for T_{unit}^{ON} time intervals. Therefore, if a unit is started at time interval *t+1* the following condition is enforced:

$$u_{unit}^{t+1} + u_{unit}^{t+2} + \cdots + u_{unit}^{t+T_{\min}^{ON}} = T_{unit}^{ON}; \quad unit \in G; t \in T$$

2.5.4.2 Minimum Down Time

The Minimum Down Time (MDT) constraint, specified in minutes, is the minimum amount of time that a unit must stay offline after the start of Shut-Down, including Shut-Down time and Start-Up Time. SCUC can commit and decommit units based on economics and consistent with the units' MUT and MDT constraints.

It must stay offline at least for T_{unit}^{OFF} time intervals, and the following constraint is satisfied if a unit is Shut-Down at time interval *t+1*:

$$u_{unit}^{t+1} + u_{unit}^{t+2} + \cdots + u_{unit}^{t+T_{\min}^{OFF}} = 0; \quad unit \in G; t \in T\ .$$

Where:

u_{unit}^{t} is the status of the unit in time interval 't'

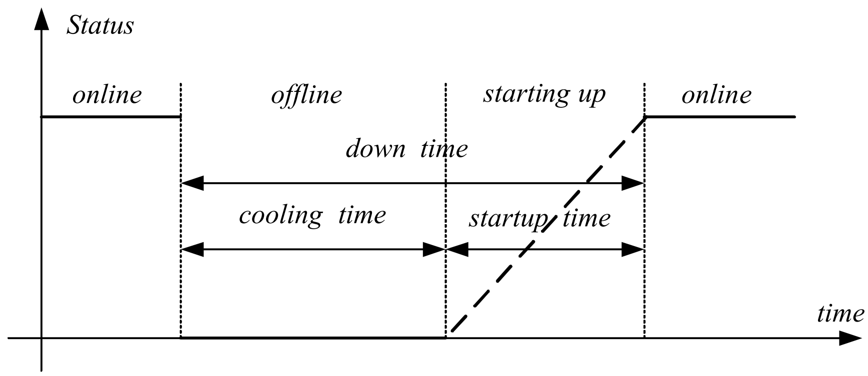
2.5.4.3 Start-Up Time

The Generating Unit Start-Up Time (SUT) is usually dependent on the cooling time, i.e., the time a unit needs to start up depends on how much time the unit has been offline. Therefore, the total down time consists of the cooling time and the Start-Up Time, which is dependent on the cooling time. The total down time is enforced to be no shorter than the MDT.

$$T_{min}^{cool} + T_{unit}^{SUT}(T_{unit}^{cool}) \geq T_{unit}^{OFF}; \quad unit \in G; t \in T\ .$$

The cooling, startup and down time relationship is illustrated on the following exhibit:

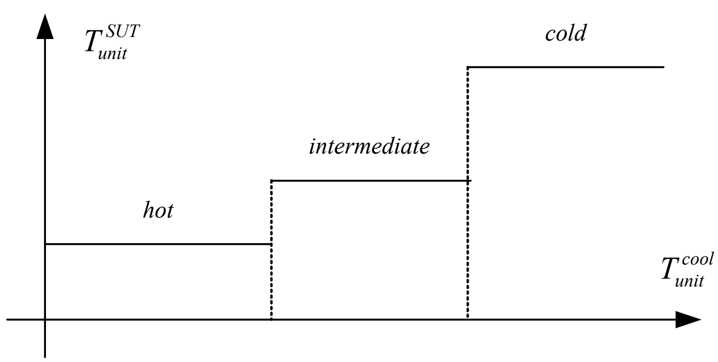
Exhibit A-7: Cooling, Startup, and Down Time



There are three cooling statuses: hot, intermediate and cold. These statuses are presented by separate segments of the Start-Up Time function. These segments are the same as segments of the Start-Up Cost function. The Start-Up Time function is a monotonically increasing staircase curve of Start-Up Cost versus cooling time.

This three-segment function is illustrated in the following exhibit:

Exhibit A-8: Startup Time Function



2.5.4.4 Maximum Number of Daily Start-Ups

Another Generating Unit constraint is related to the maximum number of daily Start-Ups. The total number of daily Start-Ups is limited by a specified number:

$$z_{unit}^{1} + z_{unit}^{2} + \cdots + z_{unit}^{T} \leq N_{unit}^{ON}; \quad unit \in G$$

2.5.4.5 Daily Energy Limits

Energy Limit constraints apply to a prescribed list of Generating Units that can generate limited amount of Energy for a given period of time. Energy-limited Generating Units must indicate an Energy Limit in their DAM Bids that applies to their Schedule and Dispatch throughout the Trading Day. The units are responsible for meeting their Energy Limit requirements for longer time periods, such as weekly, monthly or seasonal, subject to any applicable Resource Adequacy requirements. AS are not constrained by Energy Limits.

The total available Energy can be determined by long-term hydro or fuel scheduling. This limited Energy is optimally distributed over the scheduling period. Environmental limitations (e.g. air emissions etc) is also a reason for a generating unit being energy limited. Furthermore, there could be other non-economic factors as well leading to use-limitation of a resource.

The Energy limit constraint applies to the total energy scheduled or dispatched over the entire time period of each application as follows:

$$\underline{En}_{unit}^{T} \leq En_{unit}^{1} + En_{unit}^{2} + \cdots + En_{unit}^{t} + \cdots + En_{unit}^{T} \leq \overline{En}_{unit}^{T}; \quad unit \in G .$$

In the DAM, the maximum and minimum Energy Limits are obtained from the SIBR Clean Bids. The minimum Energy Limit is negative and applies only to Pump Storage Hydro units.

RTM enforces the Daily Energy Limits as a *dynamically adjusted rolling average* over the course of a Trading Day, providing room for optimal refinement of the DAM Schedules. Aside from the effect of other binding constraints that may conflict with the Energy Limit constraints, the methodology assures a feasible outcome, but only when Dispatch Instructions are followed accurately since the formulation involves only Instructed Imbalance Energy. Consequently, Energy Limits may be violated due to the regulating action of units on regulation and due to uninstructed deviations driving the Dispatch Instructions via the State Estimator feedback. The method would attempt to recover any Energy outside the rolling average limits over the course of a Trading Day; however, this may not be possible if uninstructed deviations persist.

Energy Limits are not enforced in the contingency Dispatch because the Time Horizon is extremely small (10') and the objective of the contingency Dispatch is to recover from a contingency as fast as possible without any regard to Energy limitations over the course of an entire Trading Day.

2.5.5 Ramping Processes

This section describes the effect of Ramping.

2.5.5.1 Operational/Regulating/Reserve Ramp Rate

The Operational Ramp Rate of Generating Units limits the Energy Schedule changes from one time period to the next in SCUC. The Operational Ramp Rate constraints for Energy Schedule changes from one time period to the next are determined by the Operational Ramp Rate function reduced by a configurable percentage of the relevant Regulation Awards in both consecutive intervals, multiplied by a configurable Ramping time domain. In DAM, the ramping time domain is 60min. The ramping time domain is halved at startup and shutdown.

The Operational Ramp Rate function is described by a staircase function of up to four segments (in addition to Ramp Rate segments inserted by SCUC for modeling Forbidden Operating Regions). The Operational Ramp Rate function is submitted with the Energy Schedule and Bid data. The Operational Ramp Rate function allows the SCs to declare the Ramp Rate at different operating levels. However, the submitted Ramp Rate function is fixed throughout the Time Horizon, for which they are submitted (either the 24 Trading Hours, for Day-Ahead, or single hour for the Hour-Ahead). In order to mitigate possible capacity withholding through submitting low Ramp Rates, SCUC uses the same Ramp Rates up as Ramp Rates down. The Ramp Rate changes as soon as the MW output ramps into a different operating level, (i.e., the Ramp Rate does not necessarily remain constant throughout a given range).

Similarly, Regulation Ramp Rate constraints for procurement of Regulation Up and Regulation Down are determined by the submitted Regulation Ramp Rate multiplied by a configurable time interval (currently 10 minutes). The Regulation Ramp Rate (for both Regulation Up and Regulation Down) is described by a single number. The Regulation Ramp Rate is also used to evaluate both Regulation Up and Regulation Down Bids and self-provisions.

Also, the Operating Reserve Ramp Rate constraints for procurement of the Spinning and Non-Spinning Reserves are determined by the submitted Operating Reserve Ramp Rate multiplied by a configurable time interval (currently 10 minutes). The Operating Reserve Ramp Rate (for both Spinning and Non-Spinning Reserves) is described by a single number. The Operating Reserve Ramp Rate is used to evaluate Spinning and Non-Spinning Reserve Bids and self-provisions.

Note that the total amount of upward Ancillary Services is limited by the Generating Unit Ramping capability over a specified time period (default is 10 minutes).

2.5.5.2 Ramping Constraints

The following ramping rules apply consistently for all market applications:

1) The resource's Operational Ramp Rate will always be used to constrain Energy schedules across time intervals irrespective of Regulation Awards. The Operational Ramp Rate may vary over the resource operating range and it incorporates any ramp rates over Forbidden Operating Regions. The fixed Regulating Ramp Rate would only be used to limit Regulation Awards.
2) Hourly intertie resources have infinite ramping capability and market applications follow the ramp capability as provided by the CAS Schedules for these resources.
3) The distinction between fast and slow resources would be eliminated.
4) The upward and downward ramp capability of on-line resources across time intervals would be limited to the duration of the time interval: 60min in DAM, 15min in RTUC, 5min in RTID and RTMD, and 10min in RTCD.
5) The upward and downward ramp capability of resources starting up or shutting down across time intervals (from or to the applicable Lower Operating Limit) would be limited to half the duration of the time interval: 30min in DAM, 7.5min in RTUC, and 2.5min in RTID and RTMD.
6) The upward ramp capability of resources starting up through Fast Unit Start-Up (from the applicable Lower Operating Limit) in RTCD would be limited to the difference between 10 minutes and their Start-Up Time.
7) The upward and downward ramp capability of resources across time intervals would not be limited by capacity limits (operating or regulating limits); in that respect, the upward

ramp capability would extend upwards to +∞ and the downward ramp capability would extend downwards to –∞ by extending the last and first segments of the Operational Ramp Rate curve beyond the resource Maximum Capacity and Minimum Load, respectively. Capacity limits would be enforced separately through the capacity constraints.

8) The upward ramp capability of resources across time intervals with Regulation Up Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

9) The downward ramp capability of resources across time intervals with Regulation Down Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor (same as Step 8).

10) By exception, the ramp capability of resources on regulation would not be limited in RTCD.

11) The configurable factor for the upward and downward resource ramp capability reduction would be application specific (DAM, RTUC, RTID and RTMD) because it would depend on the duration of the time interval.

These ramping rules result in a consistent unified treatment across all applications. Conditional ramp limits apply only to resources with Regulation Awards. No ramp capability reduction is required for Spinning or Non-Spinning Reserve Awards given that these awards are normally dispatched by RTCD where all ramp capability must be made available even at the expense of Regulation.

The ramp rate constraints under the simplified ramping approach are as follows:

Online operation: ($U_{t-1} = U_t = 1$)

$$RCD_T(EN_{t-1}) + \alpha_T \left(RD_{t-1} + RD_t\right) \leq EN_t - EN_{t-1} \leq RCU_T(EN_{t-1}) - \alpha_T \left(RU_{t-1} + RU_t\right) \quad \therefore t = 1,2,\ldots,N$$

Start-Up: ($U_{t-1} = 0 \wedge U_t = 1$, $EN_{t-1} = RD_{t-1} = RU_{t-1} = 0$)

$$EN_t \leq LOL_t + RCU_{T/2}(LOL_t) - \alpha_T\, RU_t \quad \therefore t = 1,2,\ldots,N$$

Shut-Down: ($U_{t-1} = 1 \wedge U_t = 0$, $EN_t = RD_t = RU_t = 0$)

$$EN_{t-1} \leq LOL_{t-1} + RCU_{T/2}(LOL_{t-1}) - \alpha_T \, RD_{t-1} \quad \therefore t = 1,2,\ldots,N$$

RTCD Start-Up:

$$EN \leq LOL + RCU_{(T-SUT)}(LOL)$$

With:

$$RCU_T(EN) \equiv \int_0^T ORR(EN)\,dt$$

$$RCD_T(EN) \equiv -\int_0^T ORR(EN)\,dt$$

Where:

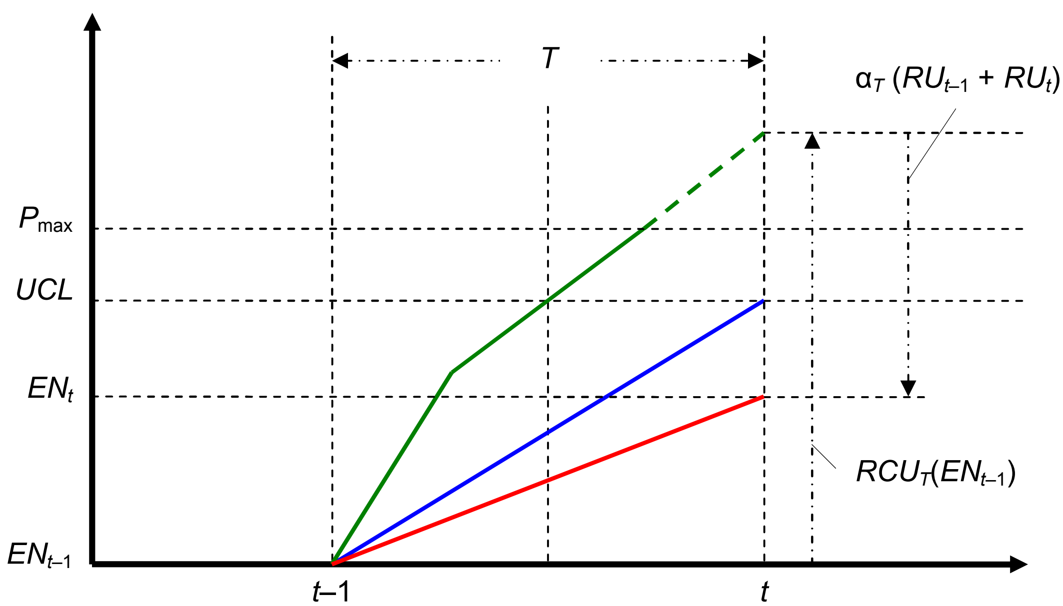
t	is the interval index (zero for initial condition);
N	is the number of intervals in the time horizon;
T	is applicable time domain (60 min in DAM, 15 min in RTUC, 5 min in RTID and RTMD, and 10 min in RTCD);
EN	is the Energy Schedule;
RU	is the Regulation Up Award;
RD	is the Regulation Down Award;
ORR	is the Operational Ramp Rate as a function of the Operating limit, extended below the Minimum Load and above the Maximum Capacity as needed;
RCU	is the upward ramp capability within the applicable time domain as a function of the Operating limit;
RCD	is the downward ramp capability within the applicable time domain as a function of the Operating limit;
LOL	is the applicable Lower Operating Limit
SUT	is the Start-Up Time; and

α is a configurable parameter for the applicable time domain ($0 \le \alpha$).

The default settings for the configurable parameter α are as follows:

DAM	α60' = 3
RTUC	α15' = 0.75
RTID RTMD	α5' = 0
RTCD	α10' = 0 (no ramp capability reduction in RTCD)

The following figure illustrates how the ramp constraints limit the energy schedule of an online resource across time intervals to reserve upward ramp capability for Regulation Up Awards over these intervals.



The green line is the upward unit trajectory at full ramp using the operational ramp rate curve and ignoring any capacity limits. UCL is upper capacity limit in interval t, in this case the lower of the Upper Operating Limit reflecting derates or the Upper Regulating Limit, minus the Regulation Up Award in interval t. Without any ramp capability reduction, the unit may be scheduled as high as the UCL (enforced by the capacity limit constraints). In this case, under the smooth cross-interval ramping requirement, the unit would ramp along the blue line.

However, considering the Regulation Up Awards, the simplified ramping constraints would bind the unit trajectory on the red line, thus reserving upward ramp capability for Regulation Up.

2.5.5.3 Ancillary Services Ramping Constraints

In addition to individual Ancillary Service ramping limits, the common Ancillary Service ramping constraint can be posted for each resource and each time interval. All upward Ancillary Services, i.e. Regulation Up, Spinning Reserve and Non-Spinning reserve can be limited by the resource ramping capability. The Ancillary Service ramping constraints are applicable for online generation units only. These constraints are expressed in time domain as follows:

$$\frac{Reg_{unit}^{Up;t}}{RR_{unit}^{Reg}} + \frac{Res_{unit}^{t}}{RR_{unit}^{Res}} + \frac{NRes_{unit}^{t}}{RR_{unit}^{NRes}} \leq T^{AS}; \quad unit \in G; t \in T$$

having meaning that the total ramping time can not exceed the specified Ancillary Service ramping time (default 10 minutes). These constraints include both Ancillary Service self-provisions and Ancillary Service Bids.

The Ancillary Service procurement can be constrained by resource Energy ramping of slow-ramping resources. These constraints are enforced by the following ramping rules:

- If Energy Schedule is ramping in upward direction more then 20 minutes (configurable) then the resource can not be awarded Regulation, Spinning Reserve or Non-Spinning Reserve) at both hours.
- If Energy Schedule is ramping in downward direction more than 20 minutes (configurable) then the resource can not be awarded Regulation Down at both hours.

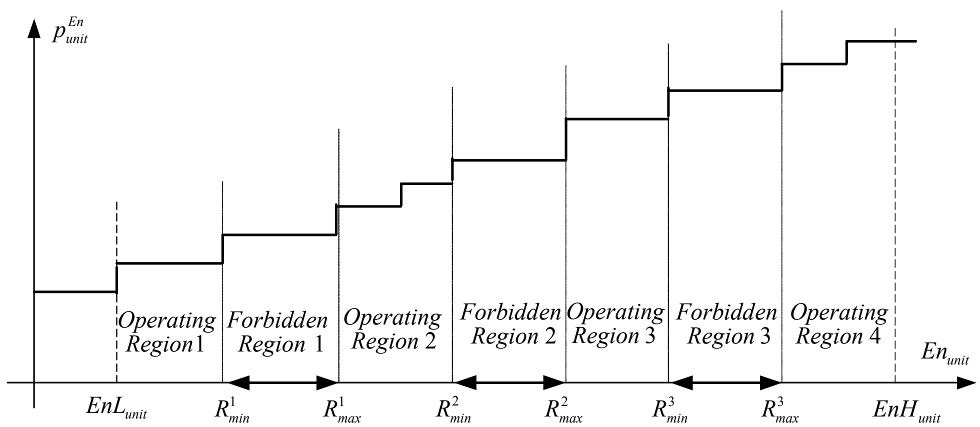
These constraints prevent Ancillary Services awards when the ramping capability of generating units is already fully used for Energy ramping.

2.5.6 Forbidden Operating Region Constraints

The Forbidden Operating Region is specified as a pair of low and high operating levels between which a Generating Unit may not operate in a stable manner. The Forbidden Operating Regions lie between the Generating Unit Minimum and Maximum Operating Limits and they do not overlap. There is a separate Ramp Rate segment for each Forbidden Operating Region, derived by dividing the Forbidden operating Region range with its crossing time. A Generating Unit can have up to four Forbidden Operating Regions.

The forbidden regions are illustrated on the following exhibit:

Exhibit A-9: Forbidden Operating Regions



There are certain rules that the SCUC engine enforces in the DA MPM and IFM while dealing with Forbidden Operating Regions. These rules are:

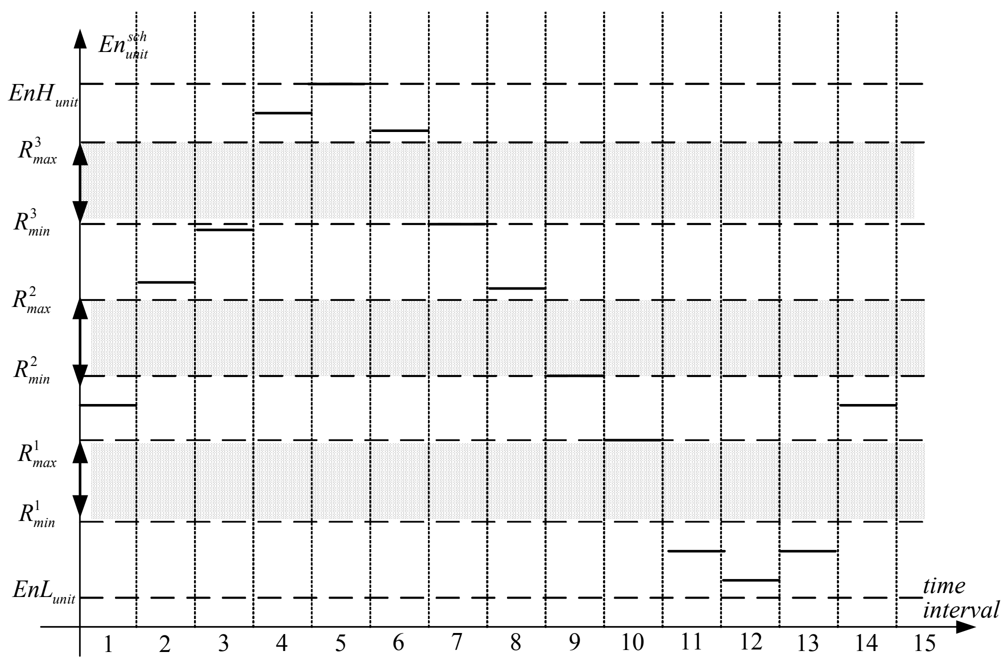
- If unit can cross the Forbidden Operating Region in less then one time interval then it is never scheduled to operate inside the Forbidden Operating Region.
- If a slow unit cannot cross Forbidden Operating Region without stepping inside it, the unit is scheduled to operate with full Ramp Rate inside a Forbidden Operating Region.
- The reversal of crossing direction is not allowed while the unit's Schedule is going through the Forbidden Operating Region. No hold time is modeled, i.e., once a unit crosses a Forbidden Operating Region, the unit is allowed in subsequent intervals to cross back the Forbidden Operating Region without requiring the unit to remain above or below the Forbidden Operating Region for a certain period of time.
- The unit cannot provide Ancillary Services within a Forbidden Operating Region, i.e. if unit is scheduled within Forbidden Operating Region then both downward and upward Ancillary Services are equal to zero.

- The unit cannot set the LMP within a Forbidden Operating Region.

- If a unit clears the Forbidden Operating Region in less than 20 minutes, then it is allowed to provide Ancillary Services.

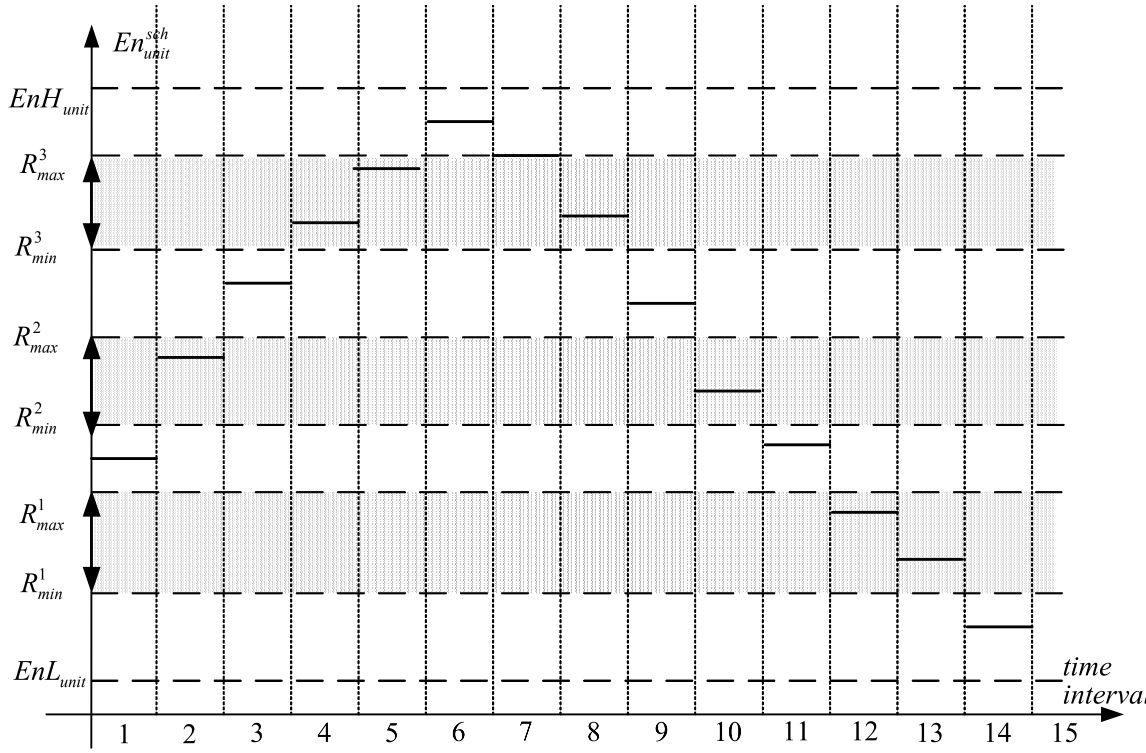
- If unit can cross the Forbidden Operating Region in less then one time interval then it is never scheduled to operate inside the Forbidden Operating Region. The Energy Schedule for this fast unit is illustrated on the following exhibit:

Exhibit A-10: A Fast Unit Energy Schedule



A slow unit can not cross a forbidden region without stepping inside it. In this case the unit is scheduled to operate with full Ramp Rate inside a forbidden region. The Energy Schedule for a slow unit that needs one time interval to cross the second forbidden region and two time intervals to cross the first and the third forbidden regions illustrated on the following exhibit:

Exhibit A-12: A Slow Unit Energy Schedule



2.6 Unit Commitment

This section describes the process for committing units.

2.6.1 Commitment Status

The commitment status for each unit is the On/Off state in each time period. A unit is Off when it is offline or in the process of starting up or shutting down. A unit is On when it is online and synchronized with the grid. An Off-On transition signifies a Start-Up and an On-Off transition signifies a shutdown. The SCUC software categorizes the reasons for which each Generating Unit is committed.

In IFM there are some simple rules that determine the commitment status of a unit. These are:

- If for any interval the unit is offline by SLIC, the unit's mode is set to “unavailable” (U) for that interval.

- If for any interval the unit is forced On by CAISO, the unit's mode is set to “Must Run” (M) for that interval.

- If for any interval the unit has a Self-Schedule, the unit’s mode is set to “Must Run” (M) for that interval.

- If for any interval the unit is forced Off by the CAISO Operator, the unit's mode is set to “Unavailable” (U).

- If a unit is manually scheduled as an RMR unit by the CAISO Operator, its mode is set to “Must Run” (M) in RUC.

- If the unit is determined by the MPM with an RMR requirement, its mode is set to “Must Run” (M) in RUC.

- In all other cases the unit is considered to have a “Cycling” (C) mode in the IFM and its commitment status in each time interval depends on economics and the self-commitment status of the unit.

Additional rules apply in Real-Time to determine the operating mode of the unit:

- If the unit has an Energy self-schedule, its operating mode is set to “Must Run” (M).

- If the unit has a Day-Ahead Regulation or Spinning Reserve Award, its operating mode is set to “Must Run” (M).

- If the unit has a Day-Ahead Non-Spinning Reserve Award and it is not a Fast Start Unit (FSU), its operating mode is set to “Must Run” (M).

- If an online unit has a Day-Ahead Non-Spinning Reserve Award and it is a Fast Start Unit (FSU) with MDT>0, its operating mode is set to “Must Run” (M) (because the non-spin would be unavailable if the unit is cycled off).

- If an online unit has a scheduled binding startup in the future (e.g., a DAM or STUC startup) and the time between the start of the time horizon and that scheduled startup is less than the MDT, its operating mode is set to “Must Run” (M) (because there is inadequate time for cycling off).

An SCUC commitment period is a time span of contiguous hours where a unit’s commitment status is “On” as considered by the SCUC application for the Time Horizon regardless of why the unit is committed. In other words, the SCUC commitment period includes the hours when the Generating Unit is “On” due to self-commitment, manual commitment by CAISO through CAISO Operator action (including certain RMR commitment), and optimal commitment by the SCUC application based on Bid information. The SCUC commitment period extends from a Start-Up to a Shut-Down and it is confined within one Trading Day.

A self-commitment period is a portion of the SCUC commitment period of a unit that has a non-empty Self-Schedule indicating its decision to self-commit the Generating Unit. The self-commitment period may include time periods where the unit does not have a Self-Schedule if it is determined that to meet the Self-Schedule the unit must be On due to MUT, MDT, and MDS constraints.

2.6.2 Boundary Conditions

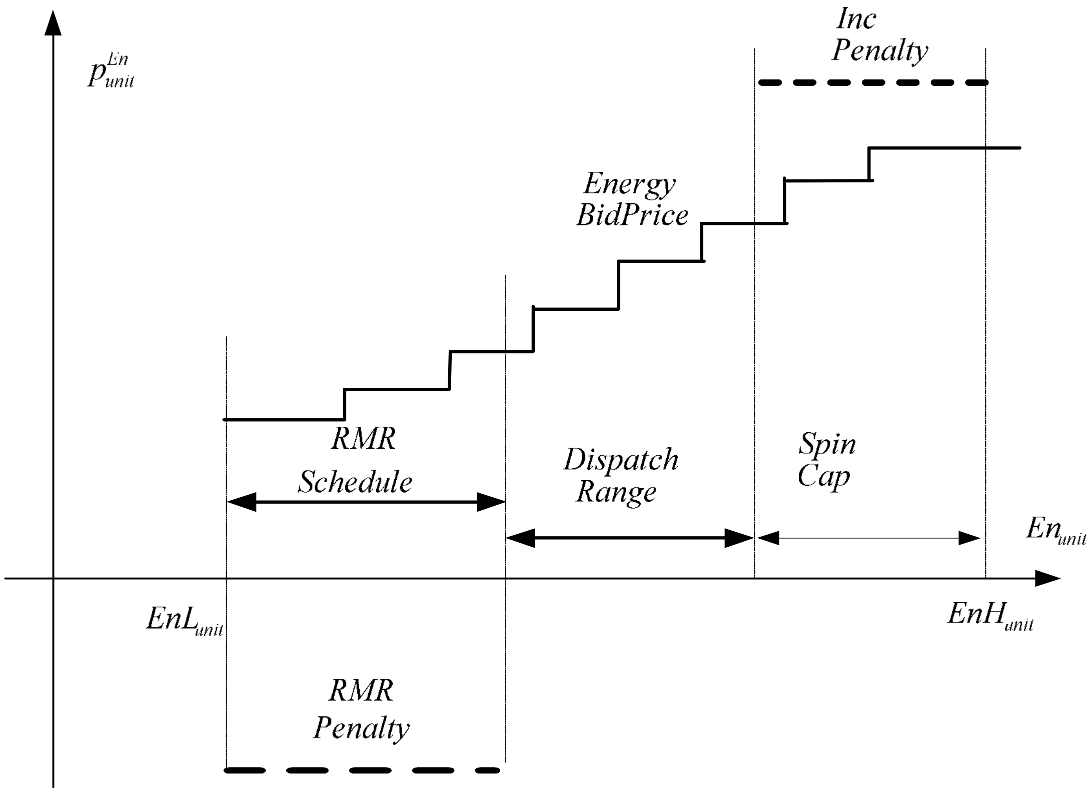
Each run in the IFM for a Trading Day needs to respect certain boundary conditions that result from the outcome of the IFM clearing of the previous day. For example, for a unit that was started up in the last hour of the previous Trading Day and has a Minimum Up Time of six hours, its operating mode is set to “Must Run” (M) for the first five hours of the following Trading Day. Similarly, for a unit that was shut down in the last hour of the previous Trading Day and has a Minimum Down Time of six hours, its operating mode is set to “Unavailable” (U) for the first five hours of the following Trading Day. For these reasons, and because the Start-Up Cost and Start-Up Time are a functions of the cooling time, boundary conditions track the time that a unit has been in a certain state (online or offline).

2.7 Penalty Prices

A Generating Unit may decide to self-commit by submitting a Self-Schedule. The total Self-Schedule of a unit is composed of several specific type of Self-Schedules associated with specific scheduling priorities such as RMR, TOR, ETC, and so on. These Self-Schedules need to be respected by the SCUC engine. One way to achieve this objective is to assign to each specific type of Self-Schedule a penalty price according to its scheduling priority.

The penalty prices express scheduling priorities and have high positive values for incremental adjustments (if applicable) and high negative values for decremental adjustments. If a generating resource has several Self-Schedules at the same time interval, then penalty prices and Self-Schedules are ordered so that the resulting Energy Bid price curve is monotonically increasing. An Energy Bid curve that includes penalty prices is illustrated on the following exhibit:

Exhibit A-11: Energy Bid Curve with Penalty Segments



Note that Inc Penalty covering spin capacity may not be a penalty if the spin is non-flagged as contingency only. If the spin is flagged as contingency only then the spin capacity is currently blocked from energy dispatch unless reserves are activated. If the reserves are activated because of a contingency, then the original bid is used. If the reserves are activated without contingency then the Inc Penalty is used.

In Exhibit A-13, the economic bid that was submitted was replaced with the RMR segment for an RMR requirement.

The SIBR validation process ensures that:

- The sum of all the Self-Schedules for a generating resource must be greater than or equal to the Minimum Load.

- The sum of all the Self-Schedules must be equal to the MW quantity of the first Energy Bid Curve point (if an Energy Bid is submitted) for all resources.

All Self-Schedules are protected from curtailment in the Congestion Management process, if there are other effective Economic Bids that can be used to relieve Congestion. If all effective Economic Bids are exhausted, the Self-Schedules between the Minimum Load and the Energy level of the first Energy Bid Curve point are subject to uneconomic adjustments based on the assigned penalty prices that reflect various scheduling priorities, such as RMR pre-Dispatch, TOR and ETC Schedules, Price Takers, etc. Imports and exports may be reduced to zero; load may be reduced to zero; Generation may be reduced to lower operating (or regulating) limit. Any Schedules below the Minimum Load level are treated as fixed Schedules and are not subject to uneconomic adjustments for Congestion Management.

Furthermore, the SCUC software provides the functionality to classify and prioritize constraints among themselves and the control scheduling priorities discussed earlier. A common system of priority levels is supported for both control and constraint priorities. The priority level for any control or constraint class is configurable. Control and constraint classes may share the same priority level. Currently, all constraints have higher priority (higher penalty prices) than all control priorities.

The scheduling and constraint priorities are presented in Section 6.6.5 of Market Operations BPM.

2.8 Pricing Runs

When the SCUC optimization engine converges, it produces schedules and LMPs for every time interval of the Time Horizon. However, in the event that Generating Units are optimally scheduled or dispatched in the penalty region due to “uneconomic adjustments” required for feasibility, marginal prices reflect the penalty prices of marginal Generating Units scheduled or dispatched in the penalty region. Similarly, if binding constraints are violated for feasibility, marginal prices reflect the penalty prices for these violations.

The solution to this problem requires another run, called the “pricing run,” to “filter” these penalty prices out of the dual solution (which produces the prices). Specifically, Generating Units scheduled or dispatched in the penalty region outside their Energy Bid (or their Schedule if there is no Energy Bid) is scheduled or dispatched optimally based on specified configurable priorities, but the appropriate Bid cap is used for pricing purposes.

- For Supply increase or Demand decrease in the penalty region the Energy Bid ceiling (Bid cap) is used.
- For Supply decrease or Demand increase in the penalty region the Energy Bid floor is used.

Also, Generating Units that are not allowed to set the LMP, as identified by a Master File flag (set according to rules stated in Tariff), are also filtered out in the pricing run. Specifically, in the pricing run these Schedules and dispatches are fixed and not re-optimized. The Energy Bid ceiling is used instead of any Bid price greater than the Energy Bid ceiling and the Energy Bid floor is used instead of any Bid price lower than the Energy Bid floor. The Bid caps are configurable and different for Energy and Ancillary Services.

- The Energy Bid ceiling and Energy Bid floor are set currently to $500/MWh and –$30/MWh, respectively.
- The Ancillary Services Bid ceiling and Ancillary Services Bid floor are set currently to $250/MW and $0/MW, respectively.

To maintain consistency between Generating Unit scheduling and commodity pricing, the optimal solution of the scheduling run is preserved in the pricing run to the extent possible. The Generating Unit commitment statuses from the scheduling run are locked in the pricing run, i.e. committed units are “must run” and uncommitted units are “unavailable”. All other constraints are considered in the pricing run.

The optimal Generating Unit Schedules are bounded in the pricing run around the optimal solution of the scheduling run if they are scheduled in the penalty region or at a Bid segment that violates the soft Bid cap (if soft Bid caps exist). These artificial bounds are relatively narrow possible, but large enough to allow a feasible region without creating degeneracy of the optimization model. All other Generating Units, except Constrained Output Generators (COGs), are bounded by their original Minimum and Maximum Operating Limits in the pricing run.

COGs, as identified by a Master File flag, are allowed to set the price in the pricing run if part of their Minimum Load Energy is required to meet Demand. The COGs are allowed to be scheduled continuously between zero MW and their Minimum Operating Limit in the pricing run so that they could set the price at their location if their optimal Schedule turns out to be above zero MW. The Ramping of COGs in the operating region between zero MW and their Minimum Operating Limit is not limited for all time periods of the Time Horizon.

2.9 Energy Pricing

2.9.1 System Marginal Energy Cost

The SCUC co-optimization engine calculates shadow prices as a byproduct of the optimization process. These shadow prices indicate the effect on the objective function of the various constraints. Shadow prices related to the system power balance represent the marginal Energy costs. These shadow prices are the Market Clearing Prices for Energy:

$$MCP^{En;t} = \lambda^{En;t} \ ; \quad t \in T$$

This is known as System Marginal Energy Cost.

2.9.2 Locational Marginal Prices

Load and Generating Unit contributions to the system power balance differ with respect to network Energy losses and eventual transmission congestion. Energy Market Clearing Prices are differentiated according to specific conditions of actual power injections and withdrawals at market participant locations. In general, Energy prices are different at each network node, i.e. they present Locational Marginal Prices. The Locational Marginal Prices for Energy are calculated respecting network losses and eventual transmission Congestion.

The components of Locational Marginal Prices are calculated:

$$LMP^{En;t}_{node} = MCP^{En;t}_{req}$$ - System Marginal Energy Cost

$$+ MCP^{En;t}_{req} \cdot (1 - pf^{t}_{node}) / pf^{t}_{node}$$ - Loss component

$$+ \sum_{line \in N} SF^{node}_{line} \cdot TSC^{t}_{line} \ ; \quad t \in T$$ - Congestion component

Where:

$LMP_{node}^{En;t}$ is Locational Marginal Price for energy at network *node* at time interval t

$MCP_{req}^{En;t}$ is market clearing price for energy requirement at time interval t

SF_{line}^{node} is shift factor for transmission line and network node

TSC_{line}^{t} is Transmission Shadow Cost for *line* constraint at time interval t

All three components of Locational Marginal Price are calculated for each pricing node and each time interval. In an event that a PNode becomes electrically disconnected from the market, LMP at an electrically close PNode is used as the LMP at that location.

This standard definition of Locational Marginal Prices is extended to reflect impact of nomogram constraints. The nomogram price component is calculated as follows:

$$LMP_{node}^{nom;t} = \sum_{line \in NOM} SF_{line}^{node} \cdot ISC_{line}^{t} \qquad \text{- Transmission corridor component}$$

Where ISC_{line}^{t} is Interface Shadow Cost for *line* (corridor) at time interval t

The Locational Marginal Prices are calculated for aggregated Generation and aggregated Custom Loads directly using aggregated loss penalty factors and aggregated shift factors. These Energy pieces are consistent with the optimal Energy schedules and can be used for settlement of aggregated resources.

2.9.3 Aggregated Energy Prices

To support the settlement process, the Aggregated Market Prices (AMP) are calculated for Aggregated Pricing Locations presenting Default Load Zones, Custom Load Zones and Trading Hubs. The AMPs are calculated in post optimization processing as a weighted sum of Energy Locational Marginal Prices at Pricing Locations belonging to an Aggregated Pricing Location:

$$AMP_{APnode}^{En;t} = \sum_{Pnode \in APnode} w_{Pnode}^{t} \cdot LMP_{Pnode}^{En;t}; \quad t \in T \ .$$

The weighted factors present contribution of individual Energy schedules at Pricing Locations relative to the total Energy schedule at an Aggregated Pricing Location:

$$w_{Pnode}^{t} = \frac{En_{Pnode}^{t}}{\sum\limits_{Pnode \in APnode} En_{Pnode}^{t}}; \quad t \in T \,.$$

2.9.4 Ancillary Service Marginal Pricing

The marginal cost approach is used for Ancillary Service pricing. According to regional Ancillary Service requirements, the Regional Ancillary Service Marginal Prices (RASMP) are calculated. Separate prices for Regulation Down, Regulation Up, Spinning Reserve and Non-Spinning Reserve are calculated.

The basis for ASMP calculation is shadow costs for minimal and maximal limits for posted Regional Ancillary Service requirements (RASMP). These shadow costs present marginal incremental costs that are calculated as a by-product of the optimization process for each Ancillary Service region. The Ancillary Service requirements are discussed in detail in section 2.5.2.

3 Security Constrained Economic Dispatch (SCED)

SCED is the optimization engine used to run the Real-Time Economic Dispatch (RTED) functions to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with Generating Unit and transmission constraints within the CAISO Balancing Authority Area. RTED runs every five minutes and utilizes a Time Horizon comprised of up to 13 five-minute intervals, but produces binding Dispatch Instructions only for the first five-minute interval of that Time Horizon. RTED produces LMPs at each PNode that are used for Settlement as described in Section 11.5 of the CAISO Tariff.

3.1 Security Constrained Economic Dispatch Description

The SCED optimization engine determines Energy Dispatch and prices. RTED executes regularly at a Dispatch time before each Dispatch Interval. There is a fixed time delay between each Dispatch time and the following Dispatch Interval. The time delay accounts for the RTED execution time, the Dispatch approval time, and the communication time for Dispatch

Instructions via ADS. The Time Delay is currently set to 5 minutes. The first Dispatch Interval of an hour starts at the start of that hour and the last Dispatch Interval ends at the end of that hour.

3.2 Security Constrained Economic Dispatch Target

The Dispatch Operating Target (DOT) is the optimal Dispatch calculated by RTED based on telemetry. The Dispatch Operating Point (DOP) is the expected trajectory of the dispatched Generating Unit as it responds to Dispatch Instructions taking into account its Ramp Rate capability. DOT is a single point on the DOP trajectory.

3.3 Security Constrained Economic Dispatch Functions

Specifically, RTED performs the following functions:

- Calculate the Imbalance MW requirement for the next Dispatch Operating Target (DOT), which is the middle of the next Dispatch Interval
- Calculate the Dispatch Operating Target for each Participating Generator as the optimal Dispatch for the next DOT to procure the required Imbalance Energy at least cost subject to Generating Unit and network constraints
- Perform a pricing run to determine the Locational Market Prices (LMPs) for the next Dispatch Interval; LMPs are calculated for each PNode and in an aggregate level at LAPs
- Calculate the Dispatch Operating Point (DOP) for each participating Generating Unit as a function of time as the expected trajectory of the Generating Unit operating point subject to Generating Unit capabilities
- Calculate the Ancillary Services capability of participating Generating Units at the start of the next Dispatch Interval based on Generating Unit capabilities, and Ancillary Services Schedules