Primer on “Standard” Market Design Components: SCED, SCUC, RUC, Co-optimization and DAM

Wednesday, August 30, 2017

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Prepared for: Energy and Ancillary Services Working Group
41T

cc: 41T
Version: 41T

Classification: Select AESO Label
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1. Purpose

The purpose of this document is to serve as a primer to a number of market design elements that are used in other jurisdictions and will be considered and evaluated as part of the energy and ancillary services (EAS) market work stream within the Alberta capacity market design initiative. These elements were included in the Standard Market Design Components document shared with the Energy and Ancillary Services Working Group in session 2. The information in this document provides a high level description of the respective element, but does not include any assessment of the potential benefits and costs associated with the implementation of these elements in the Alberta electricity market.

2. Security Constrained Unit Commitment (SCUC)

SCUC is an optimization process that is used to determine unit commitments (i.e. the decision of exactly when to turn plants off and on) to serve demand at the optimal cost, based on cost information (often referred to as 3-part cost offers), resource operating constraints and transmission constraints.

The objective function of SCUC is to minimize the start-up, minimum load costs, and bid-in energy offer costs, subject to network and resource related constraints. If co-optimization of energy and ancillary services (AS) is used, then SCUC will include AS offer costs in the optimization algorithm. The output of SCUC is the commitment status and schedule for available resources in the electric system.

SCUC can be run in different time frames. Where a Day-Ahead Market (DAM) is used, it is usually run after the close of DAM over 1-hour or 15-minute increments the 24 hours of the next operating day (though longer timeframes are typically used in the optimization, only the 24 hours are used for settlement purposes in the day-ahead market). The output of SCUC is the next day resource schedule and hourly clearing prices.

SCUC can also be run at timeframes closer to real-time (i.e. intermediate or intraday runs), though at timeframes very close to delivery fewer resources are able to turn on/off (e.g., within 30 minutes, only quick-start CT units can be committed). It can be set up to run at certain pre-defined intervals (e.g. every hour, 15 minutes, or possibly every 5 minutes) or on-demand as needed, and is typically projecting over a 2-6 hour forward period. The intraday unit commitment re-assesses optimization and unit commitments over the next several intervals, using updated system information (such as updated transmission condition, generation outage status, variable generation forecast, etc.). The results of these look ahead period provide indicative, non-binding energy (and possibly AS) schedules to all resources over the next 2-6 hours, along with a projection of expected prices. These are not actual dispatches and are not binding price/schedule used for settlement purposes. However, the look-ahead period and multi-interval optimization can be used to pre-position the fleet to meet projected ramping needs and AS requirements over the coming dispatch intervals.
Input for SCUC

Typical inputs:

1. Generation energy offers including all three cost components:
   - Start-Up cost - start-up cost ($/start) can be dependent on the time passed since the unit was last shut-down
   - Minimum Load cost - minimum load cost ($/hr) expresses the unit operating costs at the minimum operating point. The minimum load cost is considered whenever a generating unit is online
   - Energy offer price – incremental offer price ($/MWh), which depends on the resource operating point over a series of offer price segments or based on a heat rate curve

2. Load demand bids – price responsive loads, dispatchable loads, and load procurement obligations, as applicable in the particular jurisdictions

3. Virtual transaction bids – offers/bids submitted to sell day-ahead and buy back in real time (or the opposite).

4. Ancillary service offers including regulating reserves, spinning reserves and non-spinning reserves. Cascading can be supported, i.e. a lower quality of AS can be substituted by a higher quality of AS. Note that when AS is co-optimized with energy, the opportunity cost across the two products is automatically incorporated into price-setting.

5. AS requirements: minimum regulating reserves, spinning reserves and non-spinning reserves, as per reliability standards.

Operating Constraints

SCUC takes into consideration operating constraints such as:

- 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. Minimum up time is the minimum amount of time that a unit must stay online between start-up and shut-down due to physical operating constraints.

- Minimum Down Time – is the minimum amount of time that a unit must stay offline after the start of shut-down.

- Start-Up Time – 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.

- Maximum Number of Daily Start-Ups

- Operational Ramp Rates – the operational ramp rate of the generating unit limits the energy schedule changes from one time period to the next in SCUC.

- Other operating constraints often depend on the capabilities of different software vendors and/or the customized requirements of the ISO. For example, some additional features are those applicable to energy limited resources such as pumped hydro and
storage facilities, distributed resources, demand response, detailed information gas CC plant operating modes, and variable ramp rates (i.e. ramp rates that depend on a plant's operating point)

Network Constraints

SCUC considers network, or transmission, constraints in the optimization process. To do so, it uses a network power flow model which performs AC power flow solutions. Transmission limits are modelled as MVA ratings including both the normal and emergency limits. Transmission outages are also reflected in the model usually through data transfer from an outage management tool.

SCUC performs contingency analysis simulating forced outages of network elements which may include line sections, transformers, switches, static Var compensators (SVC) as examples.

3. Security Constrained Economic Dispatch (SCED)

SCED is an optimization process that is used to run the real-time economic dispatch function to determine the optimal dispatch instructions.

It can be programmed to run at a pre-defined interval such as 5 or 15 minutes in alignment with the dispatch interval. The results of SCED are the real-time energy dispatches and prices.

Where co-optimization of energy and AS is used, SCED performs optimization that satisfies the energy requirements and AS requirements, while considering the system and operating constraints, and determines the least cost solution.

The SCED algorithm is very similar to that of SCUC except that costs and constraints associated with unit commitment decisions are excluded. Sometimes these two terminologies are used interchangeably. For example, in a FERC report to Congress, dated July 31, 2006, it speaks to SCED as being performed in two stages: a Unit Commitment stage (planning for tomorrow's dispatch), and a Unit Dispatch stage (dispatching the system in real time). In most markets that incorporate centralized unit commitment, the SCUC and/or SCED system is one integrated software package.

4. Reliability Unit Commitment (RUC)

RUC is used to commit resources to meet certain specific reliability requirements in the system or in a local area. RUC may be issued at a time before the DAM, at the time DAM or intra-day as needed, and for any duration period.

During the time when a RUC is running, the RUC resource is typically reflected and modeled in SCUC and SCED as a self-scheduled resource at the specific MW output. The optimization
formulation for RUC processes is the same as for SCUC, with the key difference being that it is not conducted at the same time as market settlements.

The payment and cost recovery for RUC is typically “out of market” based on terms and conditions of the contract or regulation. These out-of-market commitment instructions and associated uplift payments can introduce inefficient price suppression if not managed carefully to ensure that commitment costs are somehow adequately reflected in final market prices.

5. Co-optimization of Energy and Ancillary Services

There are two methods for scheduling energy and AS in order to satisfy the system requirements:

- Sequential optimization – where resources are first used to satisfy the ancillary services (typically the operating reserves) or the energy requirements, then the other.
- Co-optimization – where the bids and offers in the energy market and offers in the operating reserves market are evaluated at the same time, satisfying both the energy demand and the operating reserves requirements. The algorithm for a co-optimization model is set to achieve the overall least costs for the total products.

The co-optimization process, often included as a component in a market optimization software package, results in the scheduling of resources across the energy and operating reserve markets based on an “optimal solution”. The optimal solution is the one that maximizes the economic gain from trade across all markets. Maximizing the economic gain from trade requires that scheduling of the offered resources takes place in such a way that demand for energy and reserves can be satisfied at the lowest possible cost of production. The result of the process of trading off resources between the energy and operating reserve markets can be market clearing prices that do not correspond to any single offer submitted. The process of trading off resources can also result in market participant schedules that may not appear intuitive at first.

The following is a simplified example of co-optimization:

Assume:

- Dispatchable energy demand of 200 MW bid at $1,000/MW
- The requirement for OR is 100 MW
- There is only one class of OR

There are three generators offering both energy and operating reserve. It is assumed that all offers are for the maximum capacity of the unit. Their offers are as follows:

- Gen 1 offered 200 MW of energy at $25/MW and 100 MW of OR at $1/MW
- Gen 2 offered 200 MW of energy at $26/MW and 100 MW of OR at $4/MW
- Gen 3 offered 100 MW of energy at $40/MW and 100 MW of OR at $5/MW
If energy and AS are optimized sequentially and energy is cleared first before AS, the following will be the results:

And the total cost of production in this solution is:

\[
\text{Energy} \quad \text{OR} = 200 \text{ MW} \times 25 + 100 \text{ MW} \times 4 = 5400
\]

If co-optimization is used, i.e. energy and AS are cleared and optimized simultaneously, the following will be the results:

And the total cost of production in this solution is:

\[
\text{Energy} \quad \text{OR} = 100 \text{ MW} \times 25 + 100 \text{ MW} \times 26 + 100 \text{ MW} \times 1 = 5200
\]

This is lower than the $5,400 cost of production if the resources had been sequentially optimized because it takes advantage of the relative costs across both the energy and OR
markets. Therefore, this solution results in a greater economic gain from trade for the market at a whole.


6. Day-Ahead Market (DAM)

A Day-Ahead Market (DAM) is a forward market that allows resources to offer or bid for the next operating day. The objective of a DAM is to establish financially binding prices day ahead for delivery and consumption, leaving the real time market then for imbalances of supply and demand and associated imbalance pricing for those volumes.

Other variations of short-term forward markets could supplement the real-time (e.g. 1-minute or 5-minute) market with a forward market at 15-minutes, 1-hour, a few hours, or a few days ahead. We primarily discuss the mandatory day-ahead markets approach used in most of the U.S., and then briefly describe variations used in other jurisdictions.

In most U.S. markets day-ahead market participation is usually mandatory, meaning that capacity resources are typically required to participate in the DAM. Offer and bids, if cleared in DAM, are committed for the next day. The commitments are only financially binding but not physically binding. If a resource is unable to meet its commitment, it will have to pay for the cost of procuring the replacement energy in the real-time market (aka imbalance market or balancing market). Deviations from the Day-Ahead Market forecast load, supply and transmission conditions are reflected in the real-time market which is cleared at the real-time market prices.

As noted in section 2, SCUC is usually run after the close of DAM to determine the next day resource schedule and hourly price.

The DAM and real-time market are settled separately. The Day-ahead Market settlement is based on scheduled hourly quantities and on day-ahead hourly prices. The real-time market settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour.

The following figure illustrates the day-ahead market activities and the real-time market activities. Note that a SCUC run is performed after the day-ahead market close, an “intermediate” SCUC (RTC) runs every 15 minutes, and a SCED (RTD) function runs every 5 minutes in alignment of the dispatch interval:
A wide range of variations of the day-ahead and/or short term forward market are also implemented in various jurisdictions around the world. As a few examples:

- **Voluntary Day-Ahead Market (e.g. ERCOT):** Operates very similarly to the mandatory market except that buy and sell bids are voluntary, meaning that the total quantity of supply and demand transacted day ahead is only a subset of the total.

- **Mandatory Short-term Markets:** Some markets have multiple settlement intervals for the mandatory short-term market. For example, even if final settlements in real time are implemented on a 5-minute basis, additional mandatory settlements windows can be implemented on a 15-minute ahead, 1-hour ahead, multi-hour ahead, and/or day-ahead basis.

- **Continuously-Traded Intraday Market (e.g. Europe):** Voluntary supply and demand trades within the market and across interties supported, allowing the market to adjust positions as new information emerges. Connecting trades to finalized intertie schedules can help enable intertie trading closer to real time.

• Voluntary Short-Term Forward Markets Up to 1 Week Ahead (e.g. proposed but not yet implemented in Australia): Voluntary forward trading for certain delivery blocks (e.g. hourly, multi-hourly, or daily, depending on the needs of market participants). Can help market participants with informed operating decisions, gas scheduling, demand response scheduling, and unit commitments, e.g. in the absence of centralized unit commitments.

7. References


