Security Constrained Economic Dispatch (SCED) Overview

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Abstract

SCED is a mathematical model to generate the most economic generation dispatch while considering key system operation constraints, such as power balance constraint, reserve requirement constraints, transmission security constraints, as well as generation limitations, such as ramp rates, minimum and maximum output levels.

SCED can be used in real-time, intra-day and day-ahead, to generate forward dispatch and price signals. The look ahead time varies in different markets, from 5 minutes to the whole day 24 hours depending on objectives and the characteristics of the fleet. The price signals out of SCED dispatch are often non-binding, called ex-ante prices, mainly used to incentivize units to follow dispatch or come online. In some markets, very similar SCED process, run right after the dispatch interval and based on actual unit output, is used to generate real-time prices, called ex-post prices.

When SCED co-optimizes energy and ramp products, besides energy dispatch and prices, it also provides ramp assignments and ramp prices. Generation dispatch is restricted by the ramp rates. When a cheaper unit is ramp constrained, a more expensive flexible unit sets a higher energy price. When the economic dispatch (aka merit order dispatch) produces more than enough ramping capability in the system to meet the ramping requirement, the ramp

price is set to zero. In such instances, the energy prices themselves are relied upon to provide resources the incentive to follow dispatch instructions. When the energy price increases, resources with a marginal cost lower than the energy price have the incentive to increase output in order to maximize their revenue. This effectively provides a price incentive for quick start units to respond. Conversely, when energy prices go down, resources producing energy at a marginal cost that is higher than the energy price have an incentive to decrease output. A non-zero ramp price results when there is insufficient ramping capability in the system to meet a defined ramping requirement. Ramp price can incentivize resources, both online and off line, to respond to system's ramp needs depending on the look ahead time.

Energy, ramp product, and Ancillary Services (AS) co-optimization generates energy dispatch, ramp and ancillary service assignments and associated prices, and effectively creates a ramp product for the constrained period. It ensures that generation is balanced with load, and system ramp/ancillary service requirements are met. Higher quality product can be used to meet the lower quality AS requirements. Therefore, the prices cascade as well. The price signals could encourage resources to provide AS for the future intervals.

Overall, SCED not only generates efficient future generation dispatch, it also provides associated price signals to encourage resources to follow dispatch and help address system reliability operation needs. The discussion in this paper assumes that only resources already committed and on-line are available to provide energy and ramping capability. Certainly these concepts could be expanded to design a ramp product that would be committed based on a longer look-ahead interval and therefore result in additional unit commitments to provide required ramping capability when necessary. Such a product could be designed similarly to the other PJM AS products where resources are committed ahead of the operating hour to provide those services.

This paper provides an overview of how SCED can work under different modes and scenarios, including energy only mode, energy and ramp product co-optimization mode, energy, ramp product and AS co-optimization mode. It also illustrates how SCED can be used for transmission congestion management. Multi-interval SCED solutions are also briefly discussed.

Introduction

SCED is the key algorithm for generation dispatch. It determines the most economic dispatch, i.e. the lowest overall system production cost, for all generators, to serve forecasted load, meet system reserve requirements, and other capacity requirements while satisfying all generation and transmission limitations.

The look-ahead time ranges from 5 minutes to the whole day 24 hours. SCED can be used in Day-Ahead Market (DAM), to determine whole-day 24 hours' generation dispatch. In DAM, the cleared MWs are financially binding; and the prices out of SCED are DAM clearing prices. SCED can also be used in look-ahead, to determine the future hours' generation dispatch, and forecast future prices. The look ahead time can vary from 1 hour to 4 hours in different systems/markets. In this case, the MW and prices for future intervals are usually non-binding, mainly for advisory purpose, such as for operational planning. In real time operation, SCED is often used to determine dispatch signals for the next time interval, which can vary from

5 minutes to 20 minutes. The prices out of SCED can be used for real time market clearing. For look-ahead and real time operation, SCED often runs every 5 minutes to capture latest system information and needs. In some markets, SCED runs less frequently, such as every 15 minutes.

To align with system operation and ensure operational feasible solutions, SCED needs to reflect the key operation constraints, as well as resource level limitations.

This paper is focused on SCED, therefore, Security Constrained Unit Commitment (SCUC) is out of the scope. SCUC is mainly used for generation scheduling, i.e. determining units' ON or OFF schedules. SCED determines the MW dispatch for all ONLINE resources, which can be online generators, or dispatchable demand.

Mathematical Optimization Model

SCED is modeled as a mathematical optimization problem. The objective is to minimize the total production cost, or maximize the total social welfare under market environment.

The general inputs are forecasted load, interchange schedule, reserve requirements, generation incremental cost, i.e. offers, generation parameters including minimum and maximum output, reserve limits and ramp rates, prescheduled generation output level, transmission topology, transmission parameters and transmission flow limitations.

The general outputs are megawatt output for each online generator, reserve assignment for each generator, Locational Marginal Prices (LMP), and reserve prices for each reserve categories.

The objective function is modeled by equation (1):

$$Min\ f(P_i, D_j, R_{t,i}, R_{t,j}) \qquad (1)$$

Where

$f\left(P_i, D_j, R_{t,i}, R_{t,j}\right)$ represents the total system production cost

$$f\left(P_i, D_j, R_{t,i}, R_{t,j}\right) = \sum_{i \in G}(c_i\, P_i + \sum_{t \in RC}(o_{t,i} \cdot R_{t,i})) + \sum_j(-b_j \cdot D_j + \sum_{t \in RC}(o_{t,j} \cdot R_{t,j})) \qquad (2)$$

C_i represents generator i's offer price

P_i represents generator i's MW output

$C_i P_i$represents generator i's energy production cost

$o_{t,i}$ repesents generator i's offer price for reserve category of t

$R_{t,i}$ represents generator i's reserve quantity for reserve category of t

$o_{t,i} R_{t,i}$ represents generator i's reserve offer cost

$c_i P_i + \sum_{t \in RC}(o_{t,i} \cdot R_{t,i})$ represents generator i's total cost of producing energy and providing each type of reserves

b_i represents price sensitive demand j's bid price

D_j represents price sensitive demand j's MW

$b_j D_j$ represents price sensitive demand j's surplus

$-b_j \cdot D_j + \sum_{t \in RC}(o_{t,j} \cdot R_{t,j})$ represents price sensitive demand j's total cost of reducing energy and providing each type of reserves

There are two main types of constraints: system wide operation related constraints and resource level constraints. System wide constraints include power balance constraint, reserve requirement constraints, and transmission security constraints.

Resource level constraints include capacity constraints, ramp up/down constraints, power generation limit constraints : minimum and maximum, and ramping capability constraints.

Power balance constraint is the key system operation constraint. Total power generation in the system needs to be matched with its total system load. Power balance constraint is expressed in equation (3).

$$(\lambda)\text{:}\ \sum_{i\in G} P_i = \sum_n L_n + \sum_j D_j + P_{loss} \qquad (3)$$

Where Interchanges are considered in the fixed demand, L_n in this case. To explicitly include external transactions, power balance constraint can also be expressed in equation (4).

$$(\lambda)\text{:}\ \sum_{i\in G} P_i = \sum_n L_n + NetExport - NetImport + \sum_j D_j + P_{loss} \qquad (4)$$

λ represents shadow price of power balance constraint.

System loss is linearized as shown in equation (5):

$$P_{loss} = \sum_i \left(\frac{\partial P_{loss}}{\partial P_i} \cdot P_i\right) + \sum_n \left(\frac{\partial P_{loss}}{\partial L_n} \cdot L_n\right) + \sum_j \left(\frac{\partial P_{loss}}{\partial D_j} \cdot D_j\right) + offset \qquad (5)$$

Where offset is the linearization error

To mitigate system operation risk of potential generation loss or load increase, or interchange fluctuation, system often reserves a certain amount capacity, which is called reserve. Each system has its own reserve requirement. These can be incorporated into SCED as well to achieve overall system efficiency. Reserve requirement constraints can be expressed by inequality constraints, shown in (6).

$$(\beta_s)\text{:}\ \sum_i \sum_t (\delta_{t,i}^s R_{t,i}) + \sum_j \sum_t (\delta_{t,j}^s R_{t,j}) \geq Q_s \qquad (6)$$

Where

β_s represents the shadow price of reserve requirement constraint for reserve type s;

Q_s represents the reserve requirement for reserve type s

$\delta_{t,i}^{s}$ or $\delta_{t,j}^{s}$ are binary values: 1 represents that reserve type t from generator i or price sensitive demand j belongs to the set *s,* i.e. can provide reserve type *s*

Transmission security constraints are used to capture transmission limitations, and can be expressed as following inequality constraints (7).

$$(\mu_k):\ flow_k \leq flow_k^{max} \qquad (7)$$

Where

μ_k represents the shadow prices of transmission security constraint k

$flow_k$ represents the real power flow over a transmission line or a transmisison corridor, for transmission security constraint k

$flow_k^{max}$ represents the flow limitation for transmission security constraint k

Based on linearization, transmission flow is represented by equation (8):

$$flow_k = \sum_i \left(\frac{\partial flow_k}{\partial P_i} \cdot P_i\right) + \sum_n \left(\frac{\partial flow_k}{\partial L_n} \cdot L_n\right) + \sum_j \left(\frac{\partial flow_k}{\partial D_j} \cdot D_j\right) + bias \qquad (8)$$

where

$\frac{\partial flow_k}{\partial P_i}$ represents the constraint sensitivy, generation i to flow k

$\frac{\partial flow_k}{\partial L_n}$ represents the constraint sensitivy, fix load n to flow k

$\frac{\partial flow_k}{\partial D_j}$ represents the constraint sensitivy, price sensitive demand j to flow k

$bias$ represents the linearization error.

Capacity constraints for units can be expressed by the inequality constraint (9), i.e. the energy output plus all reserve assignments cannot exceed the maximum output for each generator.

$$(\gamma_i):\ P_i + \sum_t R_{t,i} \leq P_i^{max} \tag{9}$$

Where

γ_i represents the shadow price of the capacity constraint for generator i

P_i^{max} represents the maximum output of generator i

The Ramp up/down constraints for units can be expressed in the inequality constraints (10, 11):

$$(\eta_i^{up}):\quad P_i \leq P_i^{SE} + RC_i^T \tag{10}$$
$$(\eta_i^{dn}):\quad P_i \geq P_i^{SE} - RC_i^T \tag{11}$$

Where

η_i^{up} represents the shadow price of the ramp up constraint for generator i

η_i^{dn} represents the shadow price of the ramp down constraint for generator i

P_i^{SE} represents the initial output of generator i, for real-time use, the initial output value often comes from State Estimation solution

RC_i^T represents the ramping capability of generator *i* within the next interval T

For the markets with specific 10-min ramp and 30-min ramp products, the following ramping capability constraints (12-15) also need to be included.

$$(\eta_i^{10}): \quad \sum_t(\delta_{t,i}^{10} \cdot R_{t,i}) \leq RC_i^{10} \qquad (12)$$

$$(\eta_j^{10}): \quad \sum_t(\delta_{t,j}^{10} \cdot R_{t,j}) \leq RC_j^{10} \qquad (13)$$

$$(\eta_i^{30}): \quad \sum_t(\delta_{t,i}^{30} \cdot R_{t,i}) \leq RC_i^{30} \qquad (14)$$

$$(\eta_j^{30}): \quad \sum_t(\delta_{t,j}^{30} \cdot R_{t,j}) \leq RC_j^{30} \qquad (15)$$

Where

η_i^{10} represents the shadow price of the 10-min ramping capability constraint for generator i

$\delta_{t,j}^{10}$ is the binary value: 1 represents the generation i can reserve type t , which belongs to 10-min ramp reserve category

$R_{t,i}$ represents the reserve MW of generation i for reserve type t

RC_i^{10} represents the 10-minute reserve capability for generator i

RC_j^{10} represents the 10-minute reserve capability for price sensitive demand j

RC_i^{30} represents the 30-minute reserve capability for generator i

RC_j^{30} represents the 30-minute reserve capability for price sensitive demand j

η_j^{10} represents the shadow price of the 10-min ramping capability constraint for price sensitive demand j

η_i^{30} represents the shadow price of the 30-min ramping capability constraint for generator i

η_j^{30} represents the shadow price of the 30-min ramping capability constraint for price sensitive demand j

For decision variables, the following Upper and Lower bounds (16-21) also apply.

$$(\eta_i^{min}):\ P_i \geq P_i^{min} \quad (16)$$
$$(\eta_i^{max}):\ P_i \leq P_i^{max} \quad (17)$$
$$(\eta_j^{min}):\ D_j \geq D_j^{min} \quad (18)$$
$$(\eta_j^{max}):\ D_j \leq D_j^{max} \quad (19)$$
$$(\check{\mathfrak{z}}_{t,i}^{min}): R_{t,i} \geq 0 \quad (20)$$
$$(\check{\mathfrak{z}}_{t,j}^{min}): R_{t,j} \geq 0 \quad (21)$$

η, $\check{\mathfrak{z}}$ are the corresponding shadow prices.

Based on the marginal pricing theory, the LMP for each bus n is defined by equation (22).

$$LMP_n = \lambda\left(1 + \frac{\partial P_{loss}}{\partial D_n}\right) - \sum_k (\mu_k \cdot \frac{\partial flow_k}{\partial D_k}) \quad (22)$$

The Reserve Clearing Price (RCP) is defined by equation (23)

$$RCP_{t,i} = \sum_s (\beta_s \cdot \delta_{t,i}^s) \quad (23)$$

When the capacity constraint binds, energy price LMP_n is coupled with reserve clearing price $RCP_{t,i}$.

Applications

Energy Only Model

Energy only model is the simplest SCED model. In this case, only power balance constraint is included. This model generates the dispatch signal for each generator, and also unified system marginal price (SMP), which is determined by the intersection of supply curve and demand curve. All supply units with prices lower or equal to the SMP are scheduled to produce.

The SCED model is then simplified as the following, assuming there is no price sensitive demand bid, and no marginal loss pricing. In this case, transmission topology, transmission parameters and transmission flow limitations are not needed.

Objective function: $f(P_i) = \sum_{i \in G}(c_i\, P_i)$

Constraints:

(λ): $\sum_{i \in G} P_i = \sum_n L_n$ =Load Forecast

(γ_i): $P_i \leq P_i^{max}$
(η_i^{up}): $P_i \leq P_i^{SE} + RC_i^T$
(η_i^{dn}): $P_i \geq P_i^{SE} - RC_i^T$

(η_i^{min}): $P_i \geq P_i^{min}$

The energy price will be the same for all system, and determined by λ, i.e.

$$SMP = \lambda$$

The following is a three-unit example, with the look-ahead time of 10 minutes. Table 1 shows the unit characteristics (e.g. Minimum and Maximum output levels, ramp rates) , offer prices, and the units' current output levels. All three generators are already self-committed initially. G1 is the cheapest unit, and generating at its maximum output level initially. G1 can be considered as a base load unit. G3 is the most expensive unit among all three, and stays at its minimum output level initially. G3 can be considered as a peaking unit. G2 is the unit initially generating between its minimum and maximum output. G2 has the highest ramp rate, therefore, it is the most flexible unit. The initial load level is 430 MW.

Table 1 Unit Characteristics for a Three-unit Example

Gen	Min (MW)	Max (MW)	Ramp Rate (MW/Min)	Offer Price ($/MWh)	Initial Output (MW)
G1	100	400	1	25	400
G2	10	150	4	30	20
G3	10	100	2	35	10
Total	**120**	**650**			**430**

Scenario 1: Non-ramp constrained

The load forecast for the next 10 minutes is 440 MW. In this case, Table 2 shows the SCED solution for the next 10 minutes' dispatch interval. To meet 10 MW of load increase, only G2 and G3 can move up. Between the two units, G2 is the cheaper one to move up, so it becomes the marginal unit for the dispatch interval, and sets the system energy price at $30/MWh.

Table 2 SCED Solution for Scenario 1

Gen	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)
G1	400	400	30
G2	20	**30**	30
G3	10	10	30
Total	**430**	**440**	

Scenario 2: Ramp constrained

The load forecast for the next 10 minutes is now 480 MW. The initial system condition is still the same as that in Table 1. Table 3 shows the SCED solution in this case. Since the ramp rate of G2 is 4 MW/min, G2 can only move up 40 MW at most in 10 minutes, even though it is cheaper than G3. The initial output of G2 is 20 MW. After moving up 40 MW, G2 will generate at 60 MW for the next dispatch interval. G2 is ramp constrained in this case. To meet 50 MW of load increase, G3 has to move up 10 MW. It becomes the marginal unit and sets the system energy price at $35/MWh for the dispatch interval.

Table 3 SCED Solution for Scenario 2

Gen	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)
G1	400	400	35
G2	20	60	35
G3	10	**20**	35
Total	**430**	**480**	

If load forecast stays flat for the next 10 minutes' dispatch interval, G2 will be able to move up 10 MW, and the relative expensive G3 will then back down 10 MW, to its minimum output. Table 4 shows the SCED Solution for the flat next dispatch interval. G2 becomes the marginal unit for the next dispatch interval, and sets the system energy price at $30/MWh.

Table 4 SCED Solution for the next Dispatch Interval of Scenario 2

Gen	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)
G1	400	400	30
G2	60	**70**	30
G3	20	10	30
Total	**480**	**480**	

Scenario 3: Capacity constrained

For this scenario, the ramp rate of G2 is increased from 4 MW/min to 15 MW/min, and the load forecast for the next 10 minutes is increased to 565 MW. The initial system condition is still the same as that in Table 1. Table 5 shows the SCED solution for this scenario. Load increases 135 MW for the 10 minutes dispatch interval. Based on its high ramp rate, G2 can ramp up 150 MW in 10 minutes. However, the maximum output of G2 is only 150 MW. So, at most the output of G2 can only increase 130 MW. G2 is capacity constrained in this scenario, i.e. hits its capacity limit. G3 has to ramp up 5 MW to meet the load increase. It is the marginal unit and sets the system energy price at $35/MWh for the dispatch interval.

Table 5 SCED Solution for Scenario 3

Gen	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)
G1	400	400	35
G2	20	150	35
G3	10	**15**	35
Total	**430**	**565**	

Regarding to generation cycling, since SCED does not do unit commitment, i.e. no ON/OFF decisions, it mainly involves loading level changes for flexible units and peaking units . For example, in the above scenarios, the MW output changes mainly happen to the flexible unit G2 and the peaking unit G3.

Co-optimization Model

Energy and Ramp Product Co-Optimization

Comparing to energy only model, the energy and ramp product co-optimization model also enforces system wide ramping requirement. System ramping requirement is determined based on system needs. It could be based on frequency control need, or based on net load variability caused by intermittent renewable resources or volatile interchanges. It could be constant for the whole day, or for certain periods, or it can be dynamic, i.e. changing throughout the day, different requirement for different intervals. Ramping requirement is to cover the system uncertainties, which can be in both directions. Depending on the system needs, ramping requirement can be enforced only in one direction. The following equations and examples include the ramping requirements for both directions to cover the general case.

This model generates the energy dispatch signal for each generator , ramp MW provided by each generator, unified system marginal price (SMP), and ramp product price if Lost of Opportunity Cost (LOC) occurs. All supply units with prices lower or equal to the SMP are scheduled to produce. All available ramp MW are paid ramp product price.

The SCED model then becomes the following.

Objective function: $f(P_i) = \sum_{i \in G}(c_i\, P_i)$

Constraints:

Power balance constraint: total generation = load forecast + net interchange

(λ): $\sum_{i \in G} P_i = \sum_n L_n$

Ramping requirement constraints: total available ramp has to be greater than or equal to the ramping requirement. The Up ramping requirement can be different than the Down ramping requirement, based on the system operation conditions and net load volatility.

(β_R^{Up}): $\sum_i(\delta_i^{Up} R_i^{Up}) \geq Q_R^{Up}$

(β_R^{Dn}): $\sum_i(\delta_i^{Dn} R_i^{Dn}) \geq Q_R^{Dn}$

Generation capacity constraints:

$$\left(\gamma_i^{Up}\right):\ P_i + R_i^{Up} \le P_i^{max}$$
$$\left(\gamma_i^{Dn}\right):\ P_i - R_i^{Dn} \ge P_i^{min}$$

Ramp up/down constraints:

$$(\eta_i^{up}):\quad P_i \le P_i^{SE} + RC_i^T$$
$$(\eta_i^{dn}):\quad P_i \ge P_i^{SE} - RC_i^T$$

Ramping capability constraints:

$$\left(\eta_i^{Rup}\right):\quad R_i^{Up} \le RC_i$$
$$\left(\eta_i^{RDn}\right):\quad R_i^{Dn} \le RC_i$$

Decision variable upper and lower bounds

$$\left(\eta_i^{min}\right):\ P_i \ge P_i^{min}$$
$$\left(\eta_i^{max}\right):\ P_i \le P_i^{max}$$
$$\left(ǯ_i^{minRup}\right):\ R_i^{Up} \ge 0$$
$$\left(ǯ_i^{minRDn}\right):\ R_i^{Dn} \ge 0$$

The energy price will still be the same for all system

$$SMP = \lambda$$

Ramp product prices are set by the shadow prices of ramping requirement constraints, i.e.

$$RCP^{Up} = \beta_R^{Up}$$

$$RCP^{Dn} = \beta_R^{Dn}$$

In this model, each generator is eligible to provide ramp MW based on its ramp rate and generation limits. If economic energy dispatch (aka merit order dispatch) produces more than enough system ramping capability to meet the ramping requirement, the ramping requirement constraint will not bind, and the corresponding ramp product price would be zero.

The following scenarios still uses the same three-unit example, described by Table 1, with the same look-ahead time of 10 minutes. Under energy and ramp product co-optimization model, there is also system 10-minute ramping requirements for both up and down directions.

<u>Scenario 4: Enough ramping capability in the system</u>

The initial system condition is the same as that described in Table 1, and the initial load is still 430 MW. The load forecast for the next 10 minutes is 440 MW. The system 10-minute ramping requirements for both up and down directions are 20 MW. Table 6 shows the SCED solution for this scenario. To meet 10 MW of load increase, G2 is the cheapest unit to move up, since G1 is already at its maximum output. G2 is the marginal unit, and sets the system energy price at $30/MWh for the dispatch interval. Since G1 is already at its maximum output, it cannot provide any up ramp MW, but it can provide 10 MW of down ramp based on its ramp rate. G2 is generating at 30 MW. Based on its ramp rate, it can provide 40 MW of up ramp, but it can only move down 20 MW due to the limitation of its minimum output level. G3 is generating at its minimum output level of 10 MW. So, it can provide 20 MW of up ramp based on its ramp rate, but it cannot provide any down ramp. Therefore, the total system up ramping capability is 60 MW, and down ramping capability is 30 MW. Both are greater than the requirement of 20 MW. There is enough ramping capability in the system in both up and down directions, i.e. the requirement constraints are not binding, which results in zero ramp product prices in both Up and Down directions.

Table 6 SCED Solution for Scenario 4

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)	Up Ramp MW	Dn Ramp MW	Up Ramp Price ($/MW)	Dn Ramp Price ($/MW)
G1	1	400	400	30	0	10	0	0
G2	4	20	**30**	30	40	20	0	0
G3	2	10	10	30	20	0	0	0
Total		**430**	**440**		**60**	**30**		

<u>Scenario 5: LOC occur while enforcing ramping requirements</u>

For this scenario, the load forecast for the next 10 minutes becomes 570 MW. The system 10-minute ramping requirements for both up and down directions increase to 30 MW. The unit characteristics and the initial system condition are described in Table 7.

Table 7 Unit Characteristics and Initial System Conditions for Scenario5

Gen	Min (MW)	Max (MW)	Ramp Rate (MW/Min)	Offer Price ($/MWh)	Initial Output (MW)
G1	100	400	1	25	400
G2	10	150	**15**	30	20
G3	10	100	2	35	10
Total	**120**	**650**			**430**

To cover 140 MW of load increase from the initial system condition, G2 is the cheapest unit to move first. Based on its ramp rate, it can move up to its maximum output of 150MW. G3 then needs to increase 10 MW to cover the rest of the load increase. G3 is the marginal unit, and sets the system energy price at $35/MWh. Table 8 shows the SCED solution without enforcing ramping requirements, i.e. energy only solution. G1 and G2 are generating at their maximum output levels. Therefore, they cannot provide any up ramp. G3 can provide 20 MW of up ramp based on its ramp rate. So, the total system up ramping capability is only 20 MW. G1 can provide 10 MW of down ramp based on its ramp rate. G2 can provide 140 MW of down ramp based on its ramp rate and its minimum output. G3 can provide 10 MW of down ramp based on its ramp rate and its minimum output level. So the total system down ramping capability is 160 MW.

Table 8 SCED Solution without Enforcing Ramping Requirement

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)	Up Ramp MW	Dn Ramp MW
G1	1	400	400	35	0	10
G2	15	20	150	35	0	140
G3	2	10	**20**	35	20	10
Total		**430**	**570**		**20**	**160**

There is enough ramping capability in the downward direction to meet the requirement. However, there is not enough up ramping capability to meet the 30 MW of up direction ramping requirement. Table 9 shows the SCED solution under energy and ramp product co-optimization. Relative cheaper generation, G2 has to back down 10 MW of energy production to provide 10 MW of up ramp. In this case, LOC occurs for G2, which sets the Up ramp product price at 5 $/MW. G1 can only provide 10 MW of down ramp based on its ramp rate. G2 now can provide 10 MW of up ramp, and 130 MW of down ramp. G3 can provide 20 MW ramp in both directions based on its ramp rate. With co-optimization, the total system up ramping capability is now 30 MW, and the total system down ramping capability is 160MW. G3 is the marginal unit for energy, and G2 is the marginal unit for up ramp product. The energy and ramp production co-optimization achieves overall low system production cost. The corresponding pricing mechanism encourages units follow dispatch. Financially, it is indifferent for G2 between providing energy and ramp product. If G2 provides 150 MW of energy only, it would gain $750 per hour, as described in Equation (24). If G2 provides 140 MW of energy and 10 MW of up ramp, it gains $750 per hour as well, as described in Equation (25)

Table 9 SCED Solution for Scenario 5

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)	Up Ramp MW	Dn Ramp MW	Up Ramp Price ($/MW)	Dn Ramp Price ($/MW)
G1	1	400	400	35	0	10	5	0
G2	15	20	**140**	35	10	130	5	0
G3	2	10	**30**	35	20	20	5	0
Total		**430**	**570**		**30**	**160**		

$$Financial\ Gain\ for\ energy\ only = 150 * (35 - 30) = 750 \quad (24)$$

$$Financial\ Gain\ for\ energy\ and\ ramp = 140 * (35 - 30) + 10 * 5 = 750 \quad (25)$$

Energy, Ramp Product and Ancillary Services Co-optimization

Comparing to the energy and ramp product co-optimization model, energy, ramp product and Ancillary Services co-optimization model add the system wide ancillary service requirement constraints. This model, generates the energy dispatch signal for each generator, ramp MW and ancillary service MW provided by each generator, unified system marginal price (SMP), ramp product prices, and ancillary service clearing prices. Similar to Energy and Ramp Product Co-optimization model, system ramping requirement is determined based on system needs, to cover the uncertainties. Ancillary service requirements are normally set to align with the system operation criteria/practices. All these requirements can be constant or dynamic.

Assuming that the ancillary service co-optimized with the energy and ramp product is the 30 minutes Operating Reserve, the SCED model then becomes the following.

Objective function: $f(P_i) = \sum_{i \in G}(c_i\, P_i)$

Constraints:

Power balance constraint: total generation = load forecast + net interchange

(λ): $\sum_{i \in G} P_i = \sum_n L_n$

Ramping requirement constraints:

(β_R^{Up}): $\sum_i(\delta_i^{Up} R_i^{Up}) \geq Q_R^{Up}$

(β_R^{Dn}): $\sum_i(\delta_i^{Dn} R_i^{Dn}) \geq Q_R^{Dn}$

30-minutes Operating Reserve (OR) requirement constraint:

(β_{OR}): $\sum_i \sum_t(\delta_{t,i}^{OR} R_{t,i}) \geq Q_{OR}$

Generation capacity constraints:

(γ_i): $P_i + \sum_t R_{t,i} \leq P_i^{max}$
(γ_i^{Dn}): $P_i - R_i^{Dn} \geq P_i^{min}$

Ramp up/down constraints:

(η_i^{up}): $P_i \leq P_i^{SE} + RC_i^T$
(η_i^{dn}): $P_i \geq P_i^{SE} - RC_i^T$

Ramping capability constraints:

(η_i^{Rup}): $R_i^{Up} \leq RC_i$
(η_i^{RDn}): $R_i^{Dn} \leq RC_i$

(η_i^{30}): $\sum_t(\delta_{t,i}^{30} \cdot R_{t,i}) \leq RC_i^{30}$

Decision variable upper and lower bounds

$$\left(\eta_i^{min}\right):\ P_i \geq P_i^{min}$$
$$\left(\eta_i^{max}\right):\ P_i \leq P_i^{max}$$
$$\left(\mathfrak{z}_i^{minRup}\right):\ R_i^{Up} \geq 0$$
$$\left(\check{\mathfrak{z}}_i^{minRDn}\right):\ R_i^{Dn} \geq 0$$
$$\left(\check{\mathfrak{z}}_{OR,i}^{min}\right): R_{OR,i} \geq 0$$

The energy price will still be the same for all system

$$SMP = \lambda$$

Ramp Prices are set by the shadow prices of ramping requirement constraints, i.e.

$$RCP^{Up} = \beta_R^{Up}$$

$$RCP^{Dn} = \beta_R^{Dn}$$

And the Reserve Clearing Price (RCP) for Operating Reserve is set by the shadow price of Operating Reserve requirement constraint.

$$RCP_{OR} = \beta_{OR}$$

The following scenarios still uses the same three-unit example described in Table 1, with the same look-ahead time of 10 minutes. Under energy, ramp product and Ancillary Service co-optimization model, there is system 10-minute ramping requirements for both up and down directions, and system 30 minute Operating Reserve requirement.

<u>Scenario 6: Enough 30- minute Operating Reserve</u>

The load forecast for the next 10 minutes is 440 MW. The system 10-minute ramping requirements for both up and down direction are 20 MW. The system 30-minute Operating Reserve requirement is 150 MW. The initial system condition is the same as that in Table 1. Table 10 shows the SCED solution in this case. To meet 10 MW of load increase, G2 is the cheapest unit to move first. It moves up 10 MW and generates at 30 MW. It is the marginal unit for energy, and sets the system energy price at $30/MWh. Since G1 is already at its maximum output level, G1 can only provide 10 MW of down ramp based on its ramp rate. G2 can provide 40 MW of up ramp based on its ramp rate, and 20 MW of down ramp due to its minimum output level. G2 can provide 120 MW of OR based on its ramp rate. G3 can provide 20 MW of up ramp based on its ramp rate, and cannot provide down ramp since it is already at its minimum. It can provide 60 MW of OR based on its ramp rate. The total up ramping capability is 60 MW, total down ramping capability is 30 MW, and the total OR is 180 MW. There is enough ramping capability in the system in both up and down directions. Therefore, both Up Ramp and Down ramp product prices are zeros. There is also enough 30-minute Operating Reserve in the system. So, the OR price is zero as well.

Table 10 SCED Solution for Scenario 6

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	SMP ($/MWh)	Up Ramp MW	Dn Ramp MW	Up Ramp Price ($/MW)	Dn Ramp Price ($/MW)	Total OR MW	OR Price ($/MW)
G1	1	400	400	30	0	10	0	0	0	0
G2	4	20	**30**	30	40	20	0	0	120	0
G3	2	10	10	30	20	0	0	0	60	0
Total		**430**	**440**		**60**	**30**			**180**	

Scenario 7: LOC occur while enforcing 30- minute Operating Reserve requirement

The load forecast for the next 10 minutes is still 440 MW. The system 10-minute ramping requirements for both up and down directions are still 20 MW. The system 30-minute Operating Reserve requirement is now increased to 190 MW. Without changing unit dispatch, 30-minute Operating Reserve requirement cannot be met. Table 11 shows the co-optimized SCED solution for this scenario. In order to meet the 30-minute Operating Reserve requirement,G1 has to back down 10 MW of energy production to provide 10 MW of OR. G3 has to increase 10 MW of energy production to cover load. It becomes the marginal unit for energy, and sets the system energy price at $35/MWh. G2 is capacity constrained in this scenario. There is enough ramping capability in the system in both up and down directions. Therefore, both Up Ramp and Down ramp product prices are zeros., Backing down cheaper generation G1 to provide OR incurs LOC. G1 then becomes the marginal unit and sets the 30-minutes operating reserve price. The Reserve Clearing Price for 30-minute Operating Reserve is $10/MW, determined by the LOC of G1. The co-optimization achieves overall low system production cost, and the corresponding pricing mechanism encourages units follow dispatch. Financially, it is indifferent for G1 between providing energy and Operating Reserve. If G1 provides 400 MW of energy only, it would gain $4000 per hour, as described in Equation (26). If G1 provides 390 MW of energy and 10 MW of OR, it gains $4000 per hour as well, as described in Equation (27)

Table 11 SCED Solution for Scenario 7

Gen	**Ramp Rate (MW/Min)**	**Initial Output (MW)**	**Energy Dispatch MW**	**SMP ($/MWh)**	**Up Ramp MW**	**Dn Ramp MW**	**Up Ramp Price ($/MW)**	**Dn Ramp Price ($/MW)**	**Total OR MW**	**OR Price ($/MW)**
G1	1	400	**390**	35	10	10	0	0	10	10
G2	4	20	30	35	40	20	0	0	120	10
G3	2	10	**20**	35	20	10	0	0	60	10
Total		**430**	**440**		**70**	**50**			**190**	

$$Financial\ Gain\ for\ energy\ only = 400 * (35 - 25) = 4000 \quad (26)$$

$$Financial\ Gain\ for\ energy\ and\ ramp = 390 * (35 - 25) + 10 * 10 = 4000 \quad (27)$$

Transmission Congestion Management

For the SCED model including transmission congestion management, system topology, transmission related parameters and transmission flow limits need to be included. In this case, the energy price may be different at different location due to transmission congestion, resulting Locational Marginal Price (LMP). To clearly illustrate the effect of transmission constraints, the following specific model does not include ramp or ancillary service requirements.

SCED model then becomes the following.

Objective function: $f(P_i) = \sum_{i \in G}(c_i P_i)$

Constraints:

Power balance constraint: total generation = load forecast + net interchange

(λ): $\sum_{i \in G} P_i = \sum_n L_n$

Transmission security constraints:

(μ_k): $flow_k \leq flow_k^{max}$

$$flow_k = \sum_i (\frac{\partial flow_k}{\partial P_i} \cdot P_i) + \sum_n (\frac{\partial flow_k}{\partial L_n} \cdot L_n) + bias$$

Capacity constraints:

(γ_i): $P_i \leq P_i^{max}$

The Ramp up/down constraints:

(η_i^{up}): $P_i \leq P_i^{SE} + RC_i^T$
(η_i^{dn}): $P_i \geq P_i^{SE} - RC_i^T$

Decision variable Upper and Lower bounds:

(η_i^{min}): $P_i \geq P_i^{min}$

The LMP for each bus n is then defined as following

$$LMP_n = \lambda - \sum_k (\mu_k \cdot \frac{\partial flow_k}{\partial D_k})$$

The following scenarios still use the same three-unit example, described in Table 7, with the same look-ahead time of 10 minutes. Two-bus transmission network model is used for illustration, as shown in Figure 1.

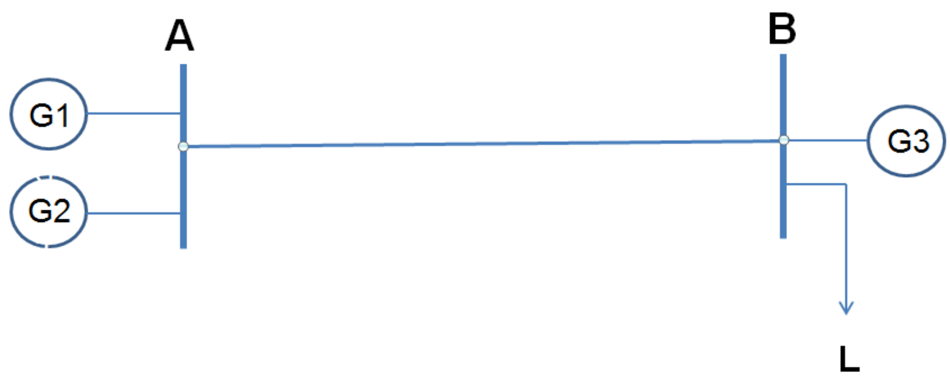

Figure 1 Two-bus System

Scenario 8: Unconstrained system, i.e. no transmission congestion

The load forecast for the next 10 minutes is 540 MW. The flow limit for the transmission line (A-B) is 600 MW. Table 12 shows the SCED solution in this case. Since the flow on the line AB is within its limit, there is no transmission congestion. G2 is the marginal unit, and sets the system energy price. The LMPs at both A and B location are the same, at $30/MWh.

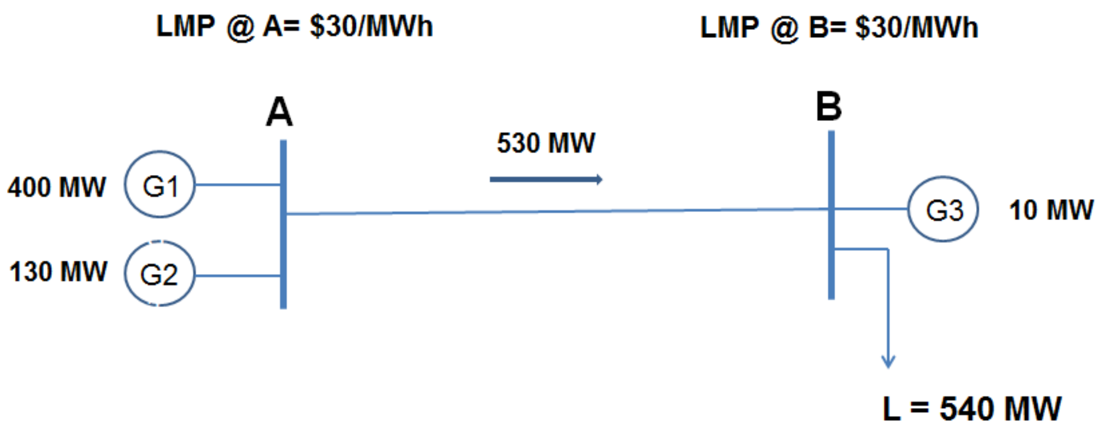

Figure 2 Two-bus System Illustration for Scenario 8

Table 12 SCED Solution for Scenario 8

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	LMP ($/MWh)
G1	1	400	400	30
G2	15	20	**130**	30
G3	2	10	10	30
Total		**430**	**540**	

<u>Scenario 9: Constrained system, i.e. with transmission congestion</u>

The load forecast for the next 10 minutes is still 540 MW. However, the flow limit for the transmission line (A-B) is reduced to 500 MW. Table 13 shows the SCED solution in this case. Due to the flow limitation, cheaper generation G2 has to be backed down, and expensive generator G3 is then used to serve the rest of the load. G2 is a marginal unit and set the price at location A at $30/MWh. G3 is also a marginal unit, and set the price at location B at $35/MWh. The LMP signals help to relieve the transmission congestion.

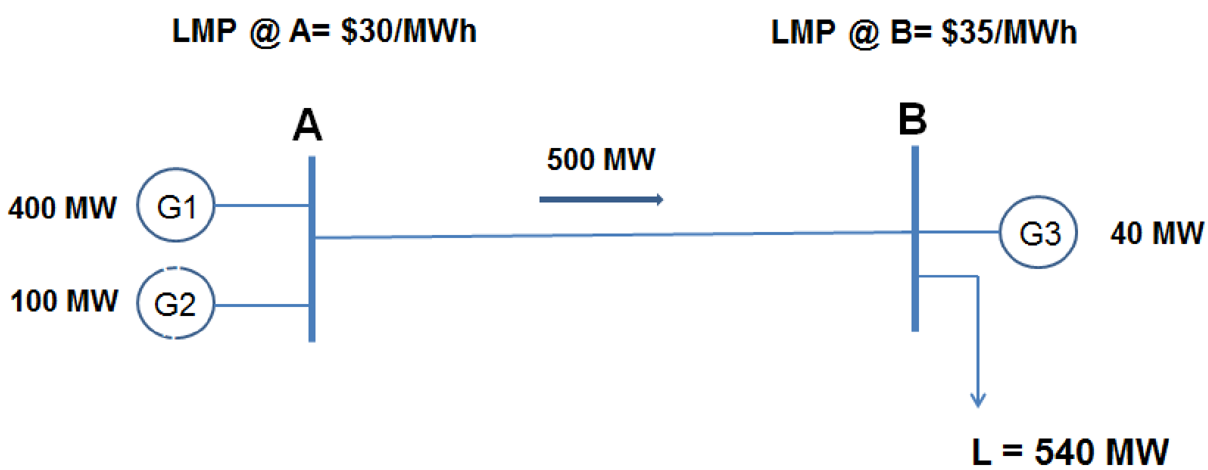

Figure 3 Two-bus System Illustration for Scenario 9

Table 13 SCED Solution for Scenario 9

Gen	Ramp Rate (MW/Min)	Initial Output (MW)	Energy Dispatch MW	LMP ($/MWh)
G1	1	400	400	30
G2	15	20	**100**	30
G3	2	10	**40**	35
Total		**430**	**540**	

Multi-Interval SCED

For the case of multiple intervals, the solution can be sequential, or time-coupled. Under sequential solution, the next time interval solution is solely based on the solution of the previous time interval, but cannot impact the previous time interval's solution. Under time-coupled solution, the future intervals can impact the first interval solution, resulting in lower over-all production cost.

Time-coupled SCED considers pre-ramp for future intervals, and achieves the lowest overall production cost . Table 14 shows a five-unit example to compare time-coupled SCED with sequential SCED solution, for four 5-minute future intervals.

Table 14 Five-unit Example

Gen	Offer Price ($/MWh)	Ramp Rate (MW/min)	Min (MW)	Max (MW)
G1	10	10	300	500
G2	12	5	20	150
G3	15	5	10	150
G4	100	100	50	400

The sequential SCED generates the following solutions for the four future intervals, as shown in Table 15. For each interval, the marginal unit's generation MW is bolded. For T1 interval, G1 is the marginal unit, and sets the SMP at $10/MWh. For T2 interval, G3 is the marginal unit and sets the SMP at $15/MWh. Relative cheap generators G2 and G3 are ramp limited for interval T3 and T4, so the expensive unit, G4 has to been dispatched to meet the load. G4 becomes the marginal unit, and set the SMP at $100/MWh.

Table 15 Sequential SCED Solution

Gen	T0	T1	T2	T3	T4
G1	400	**410**	460	500	500
G2	20	20	45	70	95
G3	10	10	**30**	55	80
G4	50	50	50	**155**	**125**
Demand	480	490	585	780	800

Time-coupled SCED generates different solutions for the four future intervals, as shown in Table 16. In this case, G2 and G3 are pre-ramped in the first interval, for the need of future demand in T3 and T4. In this case, G1 has to been dispatched down in the first interval. G1 is the marginal unit for the intervals of T1 and T2.

Table 16 Time-coupled SCED Solution

Gen	T0	T1	T2	T3	T4
G1	400	**360**	**405**	455	500
G2	20	45	70	95	120
G3	10	35	60	85	110
G4	50	50	50	**145**	**70**
Demand	480	490	585	780	800

Table 17 compares the total production cost between sequential SCED and Time-coupled SCED. As it shows, the time-coupled SCED results in lower total production cost, even though the production cost for the first two intervals are higher under time-coupled SCED.

Table 17 Total Production Cost Comparison

	T1	T2	T3	T4	Total Production Cost
Sequential SCED	9490	10590	22165	19840	62085
Time-Coupled SCED	9665	10790	21465	15090	57010

Besides more complicated model, the prices out of time-coupled SCED sometimes cannot easily justify the dispatch solution, especially for the first interval. How to pricing under time-coupled SCED is still a challenge today.

Since the last intervals impact the solution of the first interval, big load forecast error for the last intervals could contaminate the solution of time-coupled SCED.

Summary

SCED is an optimization method to generate dispatch signals to achieve the lowest total system production cost. It has the ability to incorporate variety of system operation constraints, such as system ramping requirement, ancillary service requirements, transmission security constraints. The associated pricing signals align with the dispatch solution, and encourage generators to follow dispatch, which in turn helps with efficient and reliable system operation.

The described ramp product design is similar to the regulation product in PJM markets. It could be expanded to be even more aligned with the design of the PJM Regulation product by employing a longer look-ahead time to allow for commitments of additional units to provide ramping capability when necessary. If Alberta wholesale electricity market moves forward with this product, PJM can provide assistance using the experiences from its Regulation Market, which procures regulation resources an hour ahead with real-time pricing based on system conditions, to ensure that system have enough ramping capability to handle uncertainty and provide the fine tuning needed for frequency control.

Appendix: Nomenclature

i	Index for all generators
j	Index for all price sensitive demand

t	Index for all reserve types, e.g. 10-min synchronized (or spinning) reserve, 10-min non-synchronized reserve, 30-min operating reserve, etc.
k	Index for all transmission constraint
s	Index for all reserve constraints
n	Index for all busses in the system
G	Set of generators
RC	Set of reserve category
min	Superscript that indicates the minimum value
max	Superscript that indicates the maximum value
SE	Superscript that indicates values obtained from State Estimator solution
10	Superscript that indicates values that can be achieved in 10 minutes
30	Superscript that indicate values that can be achieved in 30 minutes
up	Superscript that indicates the upper bound
dn	Superscript that indicates the lower bound
c	Offer price for generators
b	Bid price for price sensitive demand
o	Offer price for reserves
R	Reserve quantity
P	Generation output
D	Output of Price sensitive demand
L	Fixed demand
flow	Real power flow over a transmission line or a transmission corridor

Q Reserve requirement

P_{loss} System real power losses

$\delta_{t,i}^{x}\ or\ j$ Binary value: 1 represents that reserve type t from generator i or price sensitive demand j belongs to the set *x*

RC_i^T Ramping capability of generator *i* within the dispatch interval T

RC Ramping capability for generators or price sensitive demand

λ Shadow price of power balance constraint

μ Shadow prices of transmission security constraints

β Shadow prices of reserve requirement constraints

γ Shadow prices of capacity constraints

η Shadow prices of ramp constraints, or upper/lower bounds of generators and price sensitive demand

ξ Shadow prices of lower bounds for reserve quantity

Reference

Hong Chen, "Power Grid Operation in a Market Environment: Economic Efficiency and Risk Mitigation", *Wiley-IEEE Press, November 2016. ISBN: 978-1-118-98454-3.*