ERCOT Concept Paper for

Real-Time Co-Optimization of Energy and Ancillary Services

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Revision History

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| Date | Version | Description | Author |
| 06/28/2014 | 0.1 | Initial Working Draft | ERCOT Team |
| 07/18/2017 | 0.2 | Updated by ERCOT staff to incorporate market participant comments from SAWG (07/14/2017) and ERCOT clarification on the NPRR 626 pricing run under RTC | ERCOT Team |
| 09/07/2017 | 0.3 | Updated by ERCOT.  Section 2.1: Clarifications and added Option 4 for AS product set  Section 2.2: ASDC, moved examples of ASDC to new Appendix 2  Section 2.12: Issues List. Modified a) to include Option 4 on the proposed product set  Section 2.4 edited to clarify which resources are qualified for AS Imbalance and to change the 15 minute price calculation to weight by the awards for each product. | ERCOT Team |
| 09/29/2017 | 0.4 | Incorporated comments from market participant on AS participation in Real-Time co-optimization in section 2.12 (k)  Corrected typos in Appendix 1 – Math equations | ERCOT Team |

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# Executive Summary

ERCOT stakeholders have been tasked with studying the implications of adding Real-Time Co-optimization (RTC) to the wholesale market.

Since nodal go-live, the procurement of ancillary services (AS, or operating reserves) has been co-optimized with the procurement of energy in the day-ahead market (DAM). Capacity from resources selected in the DAM to provide Responsive Reserves, Regulating Reserves or Offline Non-Spinning Reserves is set aside and unavailable for economic energy dispatch in the real-time market (RTM) under normal operating conditions (Non-Spinning Reserves provided from capacity of online resources is available for economic dispatch in the RTM, subject to an energy offer floor of $75/MWh).

A market design change, which was implemented on June 1, 2014, represents an approximation of a Real-Time Co-optimization based on the Operating Reserve Demand Curve (ORDC). The existing ORDC approximates the shortage pricing of operating reserves that would be accomplished with RTC by applying a price “adder” outside of the execution of the Security Constrained Economic Dispatch (SCED) engine. However, ORDC does not distinguish between the type and quality of online operating reserves, and does not achieve the efficient coordination of the provision of energy and operating reserves by Resources.

While RTC is a common feature in other wholesale electricity markets, the provision of energy and reserves in the current ERCOT real-time market is left to the QSEs to operate its Resources at the lowest cost between providing energy and Ancillary Services. This leaves an opportunity for ERCOT to facilitate ERCOT wide co-optimization across all QSEs that participate in SCED to determine the lowest cost to provide needed energy and Ancillary Services reducing the overall cost to consumers.

Real-Time Co-optimization is the process of simultaneously procuring energy and Ancillary Services (AS) from available Resources, at the lowest production cost[[1]](#footnote-1) to meet the Real-Time system demand for energy and AS. This results in the optimal allocation of all Resources’ capacity between energy and AS. However, the current Real-Time (RT) market as administrated by ERCOT is unable to consider capacity reserved for AS (e.g., capacity above the Resource’s High Ancillary Services Limit, or HASL) even if the energy offer or bid for that capacity would be economical. Using Real-Time Co-optimization, the Real-Time Market clearing process would consider all available capacity to serve system demand for energy and procure AS capacity at the lowest possible cost1. Market clearing is designed to normally occur every 5 minutes. The process under consideration would be similar to the clearing process for energy and AS in the DAM. Accordingly, Real-Time Co-optimization can be thought of as “running the DAM every five minutes in Real-Time.” The objectives of Real-Time Co-optimization are to enable appropriate scarcity pricing through optimal use of a Resource’s capacity for energy and AS, and to enable market participants to adjust their energy and AS portfolios in Real-Time.

ERCOT Staff has developed this concept paper as a starting point for stakeholder consideration of these Real-Time Market improvements.

# RT energy and AS Co-optimization

Co-optimization is the process of simultaneously procuring energy and Ancillary Services (AS) at the lowest production cost [[2]](#footnote-2) while meeting system demand for energy and AS. The result is optimal allocation of all Resources’ capacity between energy and AS.

In other words, the energy and AS Co-optimization clearing process ensures that, while maintaining the lowest cost for procuring the required MWs, the pricing outcomes for energy and AS — Locational Marginal Prices, or LMPs, and AS Market Clearing Prices for AS Capacity, or MCPCs, are such that, the Resources are provided the best possible total revenue outcome from the energy and AS awards.

The objectives of Real-Time Co-optimization are to enable appropriate scarcity pricing through optimal use of Resource’s capacity for energy and AS, and to enable market participants to adjust their energy and AS portfolios in Real-Time.

## Ancillary Service Product Set

This concept document presents two options.

**Option 1:**

This option, keeps the current set of AS products — namely, Regulation Up (Reg-Up), Fast Responding Regulation Service-Up (FRRS-Up), Regulation Down (Reg-Down), Fast Responding Regulation Service-Down (FRRS-Down), Responsive Reserve Service (RRS) and Non-Spin.

The AS product set for Option 1 (no change from current AS product set) :

1. Reg-Up,
2. Reg-Down,
3. RRS,
4. Non-Spin (can be provided by qualified On-Line and Off-Line Resources)

These products are the same for both the Day-Ahead Market (DAM) and Real-Time Market. The implication of this is that there is a change from the current Real-Time Market where, currently, there is a different valuation between On-Line reserves (Valued by the On-Line Price Adder) and Off-Line reserves (30 minute Off-Line reserves valued by the Off-Line Price Adder). Both DAM and the Real-Time Market will have the same AS demand curves.

**Option 2:**

This option proposes a change from the current set of AS products. The change is to replace the Non-Spin AS product with two products – Spinning Operating Reserve (SOR) and Non-Spinning Operating Reserve (NSOR) **with different prices (MCPC)**. The other products (Regulation, Responsive Reserve) remain the same.

The AS product set for Option 2:

1. Reg-Up/FRRS-Up,
2. Reg-Down/FRRS-Down,
3. RRS,
4. Spinning Operating Reserve (SOR): provided by On-Line Resources that can convert capacity to energy in 30 minutes – same requirement as current Non-Spin
5. Non-Spin Operating Reserves (NSOR): provided by Off-Line Resources that can convert capacity to energy in 30 minutes – same requirement as current Non-Spin

Spinning Operating Reserve (SOR): This is the available On-Line headroom minus the Regulation Up and RRS awards/responsibility. The qualification criteria proposed are the same as what is currently in place for Resources to be eligible to receive the On-Line Reserve Price Adder. The MCPC for SOR is the sum of the shadow prices of the SOR and NSOR reserve capacity procurement constraint. This capacity can be converted to energy in 30 minutes (same requirements as current Non-Spin)

Should On-Line capacity that cannot be converted to energy in 30 minutes (some duct burner capacity and Resources with low ramp rates) be eligible for SOR? ERCOT Operations input required.

Non-Spinning Operating Reserve (NSOR): This is the available Off-Line capacity that can be converted to energy in 30 minutes. The qualification criteria proposed are the same as what is currently in place for Resources to be eligible to receive the Off-Line Reserve Price Adder. The MCPC for NSOR is the shadow price of only the NSOR reserve capacity procurement constraint.

These products are the same for both the Day-Ahead Market (DAM) and Real-Time Market. The SOR and NSOR products are a replacement for the current Real-Time Market valuation of On-Line reserves and Off-Line reserves respectively.

**Option 3:**

This option proposes a change from the current set of AS products. The change is to Non-Spinning Operating Reserve (NSOR) from Resources that are off-line until called by ERCOT. The other products (Regulation, Responsive Reserve) remain the same.

The AS product set for Option 3:

1. Reg-Up,
2. Reg-Down,
3. RRS,
4. Non-Spin Operating Reserves (NSOR): provided by Off-Line Resources that can convert capacity to energy in 30 minutes – same requirement as current Non-Spin. The difference is that Non-Spin can only be procured from “truly” Off-Line Resources qualified to provide Non-Spin.

**Option 4: (Hybrid of Option 1 and Option 2)**

DAM is voluntary, e.g. there is no Must-Offer rule for Resources. In the current implementation of DAM, there are no restrictions on virtual activity (DAM energy Only Offers and Bids). This allows for price convergence between the DAM and the Real-Time Market.

Under the Real-Time Co-Optimization construct, there is general consensus that there will be some form of demand curve for each of the AS products for which the price ($/MW capacity) will be coordinated with the System-Wide Offer Cap and the Power Balance Penalty Curve.

The current implementation of ORDC B+ in the Real-Time Market did not entail changes to the DAM. The expectation being that the nature of DAM (voluntary market with unlimited allowance for virtual activity) would allow for price convergence based on expectations of Real-Time Market outcomes.

The implementation of RTC could be approached the same way (i.e. closest parallel to current implementation) where RTC is implemented with the individual ASDC and with no changes to the DAM. The expectation being that the virtual activity in DAM and AS offers will allow for price convergence between the DAM and the Real-Time Market.

This will narrow the scope of system changes associated with the implementation of RTC and allow for potential cost savings.

Option 4 keeps the current set of AS products for DAM (Option 1) — namely,

1. Regulation Up (Reg-Up/FRRS-Up),
2. Regulation Down (Reg-Down/FRRS-Down),
3. Responsive Reserve Service (RRS) and
4. Non-Spin.

Like the current implementation of the ORDC, there is no change to the DAM implementation, e.g. current penalties for violating the AS procurement constraints remain the same – will not incorporate the AS demand curves setup for the Real-Time Market.

In addition, to facilitate convergence between DAM and Real-Time Market, the System wide offer cap for energy and AS in the DAM, will remain at $9,000/MWh

For the Real-Time Market however, this option (Option 4) proposes to replace the Non-Spin AS product with two products – Spinning Operating Reserve (SOR) and Non-Spinning Operating Reserve (NSOR) **with different prices (MCPC)**, (like Option 2). Note that for Real-Time the System Wide Offer Cap will be different than what is used in DAM and will have to be co-ordinated with the Power Balance Penalty Curve and the maximum price on the different ASDCs. For example, in Real-Time, set the SWOC at $2,000/MWh, Power Balance Penalty at $9,001/MWh and the maximum value on the ASDC at $7,000/MW.

The AS product set for the Real-Time Market will be:

1. Reg-Up/FRRS-Up, same as DAM
2. Reg-Down/FRRS-Down, same as DAM
3. RRS, same as DAM
4. Spinning Operating Reserve (SOR): provided by On-Line Resources that can convert capacity to energy in 30 minutes – same requirement as current Non-Spin
5. Non-Spin Operating Reserves (NSOR): provided by Off-Line Resources that can convert capacity to energy in 30 minutes – same requirement as current Non-Spin

Spinning Operating Reserve (SOR): This is the available On-Line headroom minus the Regulation Up and RRS awards/responsibility. The qualification criteria proposed are the same as what is currently in place for Resources to be eligible to receive the On-Line Reserve Price Adder. The MCPC for SOR is the sum of the shadow prices of the SOR and NSOR reserve capacity procurement constraint. This capacity can be converted to energy in 30 minutes (same requirements as current Non-Spin)

Non-Spinning Operating Reserve (NSOR): This is the available Off-Line capacity that can be converted to energy in 30 minutes. The qualification criteria proposed are the same as what is currently in place for Resources to be eligible to receive the Off-Line Reserve Price Adder. The MCPC for NSOR is the shadow price of only the NSOR reserve capacity procurement constraint.

The high level mathematical formulations for Option 2 is presented in the appendix. The mathematical formulation for Option 1 can be derived from these equations. The equations for Option 3 are not described.

The discussion in this concept paper does not contemplate changing the current AS offer structure where the offered AS capacity MW has slots for offer prices for each of the AS products. This AS offer structure allows the market clearing engine (DAM or Real-Time Co-Optimization) to determine the optimal allocation of the offered MW among the various AS products.

## Setup of AS Demand Curves (ASDC) under Real-Time Co-optimization

Under RT Co-optimization of energy and AS, the AS requirements for each type of AS (e.g. Reg-Up, Reg-Down, RRS, Non-Spin, SOR, NSOR) to be procured are modeled as a demand curve. The AS demand curves for AS serve the same purpose as the Power Balance Penalty Curve for energy, i.e. the AS demand curve will set the price (MCPC) under the respective AS shortage conditions.

Two approaches are currently being discussed. One approach is to develop a process to disaggregate the ORDC into the individual ASDCs. In this approach, any change to the ORDC (changing minimum contingency level, shifting of mean or standard deviation) will get reflected in the individual ASDC. Note that with this approach, aggregating the individual ASDCs will reproduce the relevant ORDC.

The second approach is not to use the ORDC as reference to develop a process to setup the individual ASDCs for Reg-Up, Reg-Down, and RRS. The ASDCs for Non-Spin (Option 1) or SOR and NSOR (Option 2) could be based on some portion of the ORDC.

Four examples of these approaches are presented in Appendix 2.

## Co-ordination of the Power Balance Penalty Curve, Maximum value of ORDC, and Value Of Lost Load (VOLL)

In scarcity conditions, the AS demand curves sets the AS MCPC, similar to how the Power Balance Penalty Curve sets LMPs in the energy market under scarcity conditions.

The design of a Real-Time energy and AS Co-optimization is such that the market clearing will ensure that serving the inelastic system demand for energy (GTBD) is given priority over reserving capacity for AS. This means that the relationship between the prices for energy (LMP) and AS (MCPC) are such that the awards (Base Points) to serve energy will be prioritized over awards for AS.

This will be achieved by setting the maximum value ($/MW/h) on the AS demand curves (one curve for each AS type) and coordinating these values with the maximum value of the Power Balance Penalty Curve for energy. AS demand curves will be based on the ORDC.

This co-ordination ensures that in the worst case scenario, the minimum excess revenue a supplier can receive from energy sales (LMP minus EOC) is greater than the maximum excess revenue the supplier could receive from the sale of AS (MCPC minus AS Offer).

Excess revenue per MWh of energy award, over and above the submitted EOC from the sale of energy, is (in $/MWh)

LMP – EOC

Excess revenue per MW of AS award, over and above the submitted AS Offer from the sale of AS, is (in $/MW/h)

MCPC – AS Offer

Thus, in a worst case scenario, a supplier’s minimum excess revenue per MWh of energy sales occurs when the Power Balance Penalty curve sets the energy price (LMP) and the supplier has submitted its EOC at System Wide Offer Cap or SWOC, as follows:

Minimum Excess Revenue per MWh of energy award =

Maximum value of Power Balance Penalty Curve minus SWOC =

VOLL+1 – SWOC

Similarly, in a worst case scenario, a supplier’s maximum excess revenue per MW/h of AS sales occurs when the AS demand curve sets the AS price (MCPC) and the supplier has submitted its AS Offer at 0 $/MW/h, as follows:

Maximum Excess Revenue per MW/h of AS award =

Maximum value of ORDC minus AS Offer of 0$/MW/h =

Maximum value of ORDC

Therefore, the design parameters should be such that the maximum excess revenue per MW/h of AS award is less than minimum excess revenue per MWh of energy award, as follows:

Maximum Value of ORDC < VOLL+1-SWOC

The table below shows five different examples of these values (VOLL, SWOC and maximum value on the PBPC), with Examples 1-4 meeting the coordination criteria, and Example 5 not being properly coordinated.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Example 1** | **Example 2** | **Example 3** | **Example 4** | **Example 5** |
| **VOLL** | $9,000 | $18,000 | $9,000 | $9,000 | $18,000 |
| **SWOC** | $9,000 | $9,000 | $2,000 | $4,500 | $9,000 |
| **PBPC** | $9,001 | $18,001 | $9,001 | $9,001 | $18,001 |
| **Max ASDC** | $0 | $9,000 | $7,000 | $4,500 | $18,000 |
| **Comments** | Coordinated  Unworkable because Max ASDC is $0/MWh and unable to effectively establish reserve shortage pricing. | Coordinated  Energy prices at $18,000/MWh can occur due to ramp rate exhaustion or when marginal energy offers are at SWOC.  More likely to achieve maximum shortage pricing in the range of $9,000 to $10,000 if marginal energy offers range from $0 to $1,000. | Coordinated  More likely than other examples to achieve energy prices close to VOLL during acute reserve shortage conditions.  SWOC of $2,000 is within the range of observed submitted maximum energy offers. | Coordinated  If marginal energy offers are $2,000/MWh or less, energy prices at VOLL will occur only on rare occasions of ramp rate exhaustion.  More likely to achieve maximum shortage prices for energy in the range of $4,500 to $6,500 than VOLL. | Not Coordinated  Unworkable because Ancillary Services are given higher priority than ensuring that supply is equal to demand. |

As shown in the table above, Example 1 includes a VOLL of $9,000/MWh and a SWOC of $9,000. Each of these is consistent with existing Commission rules and/or prior decisions. However, to meet the RTC coordination criteria, the maximum ASDC value for Example 1 is $0/MWh, which is unworkable because such a value is unable to effectively establish reserve shortage pricing. Example 2 addresses the flaw in Example 1 by raising the VOLL to $18,000/MWh, which allows the maximum ASDC value to rise to $9,000. However, this change presents the possibility of energy prices of $18,000/MWh. Example 3 and 4 maintain a VOLL of $9,000/MWh, but with the SWOC changed to $2,000 and $4,500/MWh, respectively. If marginal energy offers are $2,000/MWh or less, Example 3 is more likely than Example 4 to achieve energy prices close to VOLL during acute reserve shortage conditions. Finally, Example 5 is a case that is not properly coordinated, and therefore unworkable because Ancillary Services are given higher priority than ensuring that supply is equal to demand.

These examples show that to achieve a coordinated and workable result with the implementation of RTC, decisions related to the appropriate VOLL and/or SWOC are required by the Commission (*i.e.*, maintaining the current SWOC = VOLL = $9,000/MWh and proper coordination is unworkable, as shown in Example 1). Example 2 would involve a value of VOLL that is different than the value previously adopted by the Commission in Project No. 40000 in 2013. Example 3 and 4 (or another coordinated variation) would maintain a VOLL of $9,000, but would require a change to the offer caps in P.U.C. Subst. R. 25.505 (at least as applicable to the real-time market, and depending on whether the day-ahead market is modified to incorporate ASDCs with the implementation of RTC).

## Settlements

In general, the current approach described in the ERCOT Nodal Protocols for AS imbalance settlements for ORDC will be employed for the settlement of AS in Real-Time. The changes from the current approach will be that each AS type will have its own AS imbalance settlement. Each AS type will have a 15 minute MCPC that is computed as a time-weighted average of the individual RT Market (i.e., 5 minute) AS MCPCs.

There will be checks on comparing the 5 minute average of the integrated HSL with the sum of the energy Base Points and AS Awards to ensure that Resources are providing sufficient capacity between consecutive SCED executions.

The 15 minute Settlement Interval AS MCPC is calculated as:

RTASMCPC =  (WF *y* \* RTASSP *y*)

The AS imbalance settlement for a given AS type, for resources awarded in DAM or RT for that AS type, is calculated as:

ASImbalanceAmount ($) = 0.25\*(DAASAwd – RTASAvgAwd)\*RTASMCPC

Award weighted option:

RTASAvgAwd = (WF *y* \* RTASAwd *y*)

WF *y* = RTASAwd *y* / RTASAwd *y*

|  |  |  |
| --- | --- | --- |
| Variable | Unit | *Description* |
| RTASMCPC | $/MW per hour | *Real-Time AS Market Clearing Price for Capacity* The Real-Time AS MCPC for the 15-minute Settlement Interval. |
| RTASSP*y* | $/MW per hour | *Real-Time AS Shadow Price* The Real-Time AS constraint Shadow Price for the SCED interval *y*. |
| DAASAwd | MW per hour | *Day-Ahead AS MW Award* |
| RTASAvgAwd | MW | *Real-Time Time Weighted Average AS MW Award* The Real-Time Time Weighted Average MW AS Award for the 15-minute Settlement Interval. |
| RTASAwd | MW | *Real-Time AS MW Award* The Real-Time AS MW Award for the SCED interval y. |
| WF *y* | none | *Weighting Factor per interval*The time weight used for the portion of the SCED interval *y* within the Settlement Interval in calculating a given Settlement Interval AS MCPC. |
| TLMPy | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the Settlement Interval. |
| y | none | *A SCED interval in the 15-minute Settlement Interval.  The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.* |

### Are There any Make-Whole Payments to Resources?

There are no Make-Whole Payments to Resources that can be directly attributed to the conceptual market design changes presented here. Make-Whole provisions to Resources that exist in the current market design may still apply (e.g. Emergency Base Point Settlements).

### Is There Any Uplift Required?

No changes from current market.

Just as occurs in the current Real-Time AS Imbalance Settlement process, as implemented by NPRR 568, etc., any occurrence of uplift to load on a Load-Ratio-Share basis arises only when the Real-Time AS Imbalance Settlement process results in a net payment to Resources.

## RUC/SASM Changes (2017 SAWG):

Implementation of RTC would also include modifications to the RUC engine, such that the ability to coordinate the provision of energy and AS among resources in the RTM would be recognized in RUC

* Compared to the current market, offers the potential to reduce RUC activity, particularly in broader import-constrained areas.
* SASM activity would be reduced due to the coordinated access to the ERCOT portfolio of resources for the provision of energy and AS in RT

With RT co-optimization, Ancillary Services procurements are reassigned every 5 minutes (nominally).

* Thus, if for whatever reason a QSE’s Day-Ahead AS responsibility cannot be provided, and, there is sufficient capacity available, then RT co-optimization will economically procure the required AS in a seamless fashion
* Current thinking is that the SASM process will NOT be needed under RT-co-optimization
* The RUC process that ensures sufficient capacity to meet load forecast and Ancillary Service requirements will be used to meet the scenario where a QSE reports to ERCOT that it cannot meet its Day-Ahead AS responsibility for future hours
* RUC engine (DRUC,HRUC,WRUC) will be modified to include co-optimization.
  + RUC process will commit sufficient capacity to meet load forecast and AS for the RUC study horizon
  + Not protect HASL – allows for improved congestion management
  + Discussion needed on which Resources can provide AS in the RUC study

## Locational Reserves

Implementation of RTC with locational reserve requirement will need further stakeholder discussions. Is there a reliability requirement and other conceptual discussions. What are the locational reliability requirements for reserves? To what extent should mitigation of AS offer curves be considered if there is a concern about market power with the introduction of locational reserve requirements?

## AS Deliverability

Though not directly related to the implementation of RTC, the deliverability of AS is being brought up as an item for discussion. Further discussions involving ERCOT operations and stakeholders are required.

## High Level Description of the Clearing Process and Outputs

Under Co-optimization, the RT market clearing **procures** the following, nominally once every 5 minutes (for the current 5 minutes):

Please note that the descriptions in the sections below are applicable for both the options unless explicitly stated otherwise.

1. Energy, in the form of Base Points, to meet the system demand for energy as represented by Generation To be Dispatched (GTBD); and
2. Procure capacity sufficient to meet the AS demand. Each type of AS will have its own ‘bid-to-buy’ demand curve.

Put another way, every 5 minutes the market clearing would result in the following:

1. Base Points for energy to all Resources to meet the system demand for energy (GTBD). These Base points are valid for the next 5 minutes or until the next clearing of the RT market. This is the same as in the current RT Market.
2. LMPs at all required locations that are binding for the next 5 minutes or until the next clearing of the RT market. This is the same as in the current RT Market
3. Reg-Up and Reg-Down awards and associated Reg-Up and Reg-Down MCPCs. This capacity is procured as Regulation Reserve Service and will be utilized by the ERCOT Load Frequency Control (LFC) engine to send regulation signals every LFC cycle – 4 seconds for the next 5 minutes or until next clearing of the RT market
4. RRS awards and RRS MCPC. This procured capacity must be available to be converted into energy, if required, in the next 10 minutes (like a call option). This responsibility to deliver exists for the next 5 minutes or until the next clearing of the RT market
5. Option 1: Non-Spin awards and Non-Spin MCPC. This procured capacity (Online and/or Offline) must be available to be converted into energy, if required, within the next 30 minutes following an instruction and must also be able to sustain the energy deployment for a 1 hour period (like a call option). This responsibility to deliver exists for the next 5 minutes or until the next clearing of the Real-Time market. On-Line Non-Spin capacity must be available to SCED for dispatch.

Resources with Non-Spin awards in RT are **not** eligible for Make-Whole payments. This treatment is the same as in the current design.

In order to award an Offline Resource Non-spin, the following factors are considered

1. Is it qualified for Non-Spin?
2. Has the resource satisfied its minimum down time?
3. Can the Resource startup in 30 minutes and reach LSL (check the warmth state and the associated cold, intermediate and hot startup times)?
4. Does it have adequate ramping capability to meet the performance requirements associated with its award?

Option 2:

Spinning Operating Reserve (SOR): This capacity is On-Line and available to SCED for dispatch. This capacity is capable of being converted into energy, if required, through successive SCED dispatch or manual instruction over the next 30 minutes and must also be able to sustain the energy deployment for a 1 hour period (like a call option). This responsibility to deliver exists for the next 5 minutes or until the next clearing of the Real-Time market.

Non-Spinning Operating Reserve (NSOR): This capacity is Off-Line and can be converted to energy, if required, within the next 30 minutes following an instruction and must also be able to sustain the energy deployment for a 1 hour period (like a call option). This responsibility to deliver exists for the next 5 minutes or until the next clearing of the Real-Time market.

Resources with Non-Spinning Operating Reserve (NSOR) awards in RT are **not** eligible for Make-Whole payments.

In order to award an Off-Line Resource NSOR, the following factors are considered

1. Is it qualified for NSOR?
2. Has the resource satisfied its minimum down time?
3. Can the Resource startup in 30 minutes and reach LSL (check the warmth state and the associated cold, intermediate and hot startup times)?
4. Does it have adequate ramping capability to meet the performance requirements associated with its award?
5. Appropriate constraints are enforced to limit energy and AS awards based on the Resources’ telemetered ramp rates. This is to ensure that the awards for energy and AS are ramp feasible.
6. Stakeholder discussions will be required to develop methodology to share the ramp rates between energy and AS (similar to the ramp sharing between current Security Constrained Economic Dispatch or SCED and LFC).
   1. When to use Emergency Ramp Rates?
   2. Should Reg-Up awards be limited by Reg\_down ramp rate? This is to prevent Resources from being harmed by sequence of increasing Base Points over a period of time and then a reduction where due to ramp down limitations, they become price takers and simultaneously there is a Reg-Up shortage pricing.
7. AS MW awards and associated MCPCs are published simultaneously with energy Base Points and associated LMPs — i.e. after every RT market clearing (nominally every 5 minutes). QSEs will not be required to immediately incorporate these AS awards into their control systems; i.e., there is no hand shaking between ERCOT and the QSEs representing Resources with regard to receipt and acknowledgement of AS awards. Rather, this is intrinsically done via the AS offer that can be updated at any time by the QSE or a Real-Time mechanism to inform ERCOT systems that Resource is unwilling or unable to provide AS.
8. Market clearing can be re-initiated by ERCOT, prior to the normal 5-minutes, as with the current design.
9. Resources in Start Up or Shut Down mode are not considered as available for energy dispatch nor are they considered available to provide AS.
10. The key performance metric for the Resource is its ability to follow the energy Base Point. Like the current RT Market, the results of the proposed RT Market with energy and AS Co-optimization are effective immediately; i.e., the Base Points, LMPs, AS awards and AS MCPCs are binding upon RT Market clearing.

### Pricing Run Changes (modifications to NPRR 626)

A pricing run based on NPRR 626 (Reliability Deployment Price Adder) will be required to mitigate price reversals associated with the deployment of Load Resources and/or out-of-market reliability deployments that may otherwise reduce the total Real-Time price in times of scarcity. The objective of the pricing run will remain the same — that is, to determine the positive change to System Lambda when Load Resources or out-of-market reliability deployments occur. This positive change to System Lambda is added to all original energy prices (LMPs), and under RT Co-optimization the same positive change to System Lambda would be added to all the original MCPCs.

The pricing run module is run after RTC. This pricing run will not require the modification of dispatch limits (High Dispatch Limit or HDL, and Low Dispatch Limit or LDL) for “in-market” Resources because in RT Co-optimization, the concept of High Ancillary Service Limit or HASL does not exist. Rather, the Resource’s entire capacity (between its Low Sustained Limit or LSL and High Sustained Limit or HSL) is considered available for allocation between energy and AS. The implication is that HDL calculated for the pricing run is not limited to HASL but by HSL and the LDL calculated for pricing run is not floored at LASL

In addition, automatic UFR trip of Load Resources may need to be considered in the NPRR 626 pricing run if Load Resources providing RRS are not charged an AS imbalance payment for RRS under UFR trip.

## Telemetry Changes for Generation and Controllable Load Resources

Currently, the QSE representing the Generation Resources or Controllable Load Resource sends every 2 seconds, for each Resource, their respective AS Responsibility (Reg-Up, Reg-Down, RRS, Non-Spin) and corresponding applicable AS Schedule (RRS and Non-Spin).

Under RT Co-Optimization, the telemetry for AS responsibility and schedule are not required. The Resource specific AS Offers can be updated at any point in time (or a Real-Time mechanism for the QSE to inform ERCOT the inability of a specific Resource in providing specific AS type) and will represent the willingness of the QSE representing the Resource to sell capacity for AS in the upcoming next RT Market.

The proposed RT Market considers the following Resource specific data to optimally allocate the Resource’s capacity:

1. Telemetered HSL, LSL (for Controllable Load Resource or CLR it is the Maximum Power Consumption or MPC and Low Power Consumption or LPC) , and ramp-rates, every 2 seconds
2. Energy Offer Curve or EOC that is locked down by the end of the adjustment period (for CLR, this is the Real-Time Market Energy Bid)
3. AS Offer that can be modified at any point in time (or a Real-Time mechanism for the QSE to inform ERCOT the inability of a specific Resource in providing specific AS type)

Further discussion via the stakeholder process will be needed to determine the proper timeline for updating AS Offers and EOCs and the eligibility criteria. There may be a need for additional telemetry to be used in conjunction with the AS offer to provide QSEs more flexibility.

## Telemetry Changes for Load Resources with UFR

One key issue involved in integrating Load Resources armed with high-set Under Frequency Relays (UFRs) into RT Co-optimization will be the practicality and necessity of arming/disarming the UFRs based on RRS awards. If determined to be impractical or infeasible, then these Load Resources would be ineligible to actively participate in the RT Market; instead their AS responsibilities originating from DAM, Trades, etc. would not be re-cleared in the RT Market —and they would effectively become price takers in the RT Market. This requires further discussion by ERCOT staff and stakeholders.

Update based on SAWG discussions:

Load Resource (LR) with UFR carrying RRS Responsibility (blocky AS):

1. Upon deployment will be exempt from AS imbalance charge
2. In RT, LR with UFR carrying RRS responsibility will be considered to be price takers (i.e. RRS offer from these LR = 0$/MW). i.e. no reduction of RRS demand curve by the amount of RRS responsibility from Load Resources.
3. However, when deployed, LR will be considered to be still providing RRS till the 3 hour limit after recall.
4. Need to develop process to account and differentiate scenarios where RRS from LR is deployed versus failure to provide, etc. This has impact on the AS imbalance settlement
5. NPRR 626 enhancement to consider LR MW under UFR trip

Note 1: The above exemptions from AS Imbalance charges is a deviation from current practice with ORDC price adders

Note 2: Need to allow/account for non-frequency responsive capacity (NFRC) telemetered by Resource

Accounting for Resource providing "truly" Offline Non-Spin (Option 1) and NSOR (Option 2):

Should these Resources be exempt from AS Imbalance charges upon deployment? Note - We do not do that currently with the ORDC price adder settlements.

## AS Deployment Process

1. Regulation Up and Regulation Down:

No material change from current process. LFC will deploy Regulation using the latest Regulation awards from the Real-Time Co-optimization engine.

Change is that LFC, will get as input, after every RT market clearing (usually every 5 minutes), a new set of QSE level Reg-Up and Reg-Down Responsibilities based on the Resource specific Reg-Up and Reg-Down awards.

1. Responsive Reserve Service or RRS:
2. Self-Deployment of UFR-type Load Resources due to frequency deviation from a forced outage (Unit Trips):

No change

1. ERCOT release of RRS capacity to SCED:

Major change

Under RT Co-optimization, the current process of ERCOT reserving RRS capacity and releasing it under scarcity conditions would be discontinued and replaced with a “HASL-free” operation in which RRS is procured until the RRS supply and demand curves intersect — i.e., “RRS supply” = “RRS demand”. Under scarcity conditions, energy to be served is given priority and smaller amounts of RRS would be procured — effectively similar to the release of RRS to SCED in current market. This results in scarcity pricing through the ORDC.

The current ability for the operator to manually enter an offset to GTBD will be retained to allow ERCOT the ability to react to persistent frequency deviations.

1. ERCOT deployment of RRS from Load Resource with High Set Under Frequency Relay:

Even under a RT Co-optimization, similar mechanism as the current market design would be employed to deploy RRS from Load Resources with High Set Under Frequency Relay. ERCOT can, depending on the analysis of current and forecasted conditions, instruct deployment of RRS from Load Resources with RRS responsibility (at that time). The pricing run will mitigate price reversals due to this type of ERCOT deployment.

1. On-Line Non-Spin (Option 1) or Spinning Operating Reserve (SOR – Option 2):
   1. On-Line Non-Spin (including Quick Start Generation Resource with telemetered status of On-Line) or SOR:

Minor change. Offer floors on Non-Spin capacity will be removed(?). Currently the online Non-Spin capacity is always available to SCED. Under RT Co-optimization, the “HASL-free” operation described above would allow this capacity to be converted to energy, if required.

* 1. Off-Line Non-Spin (truly Off-Line) (Option 1) or Non-Spinning Operating Reserve (NSOR) that is truly Off-Line (Option 2)

Even under a RT Co-optimization, similar mechanism as the current market design would be employed to deploy truly Off-Line Non-Spin or truly Off-Line NSOR. ERCOT can, depending on the analysis of current and forecasted conditions, instruct Offline Resources with Non-Spin or NSOR responsibility (at that time) to come Online. These Resources have the responsibility to deliver for 1 hour after they come online in or are recalled whichever comes first.

Further ERCOT staff and stakeholder discussions will be required to revisit the current procedures for deploying truly Offline Non-Spin or NSOR to mitigate local congestion when no market solution is available.

Under RT Co-optimization, consistent with current practice, Resources with Non-Spin or NSOR Responsibility that are Offline and deployed for Non-Spin or NSOR are **not** made whole to their Energy Offer Curve, **nor** are they made whole on their Startup Costs and Minimum Energy Costs.

## Discussion Items:

1. AS products: Two options currently under discussion (Option 1, Option 2).

**Status:** Still under discussion. Option 2 seems to have more interest

Should On-Line capacity that cannot be converted to energy in 30 minutes (some duct burner capacity and Resources with low ramp rates) be eligible for SOR? ERCOT Operations input required.

Note: At the July 14, 2017 SAWG meeting, another option (Option 3) was proposed. This option proposes has the same AS product set as Option 1 (Reg-Up, Reg-Down, RRS, Non-Spin). The difference from Option 1 is to make Non-Spin procurement ONLY from Off-Line Resources.

Note: 9/7/2017: ERCOT has added Option 4 (hybrid of Option 1 and Option 2) for consideration.

1. AS demand curves: Three examples currently under discussion.

**Status:** Still under discussion.

1. Co-ordination of PBPC, VOLL, SWOC and max. value on ASDC

**Status:** Consensus at SAWG on the need for co-ordination. The values are still under discussion

1. Locational Reserves: Is there a reliability requirement and other conceptual discussions. Examine the implementation of local ASDC as part of real time co-optimization in other markets to understand the need. What are the requirements? To what extent should mitigation of AS offer curves be considered?

**Status:** not discussed yet

Questions submitted by market participant for SAWG meeting on July 14, 2017:

“How would differences in MCPC due to locational reserves be settled?

Would loads behind the constraint in question be charged the additional cost so that prices reflect cost causation? How would such cost allocations be managed by retailers?”

1. RUC/SASM changes: Are any changes required?

**Status:** ERCOT presented its opinion and there seemed to be general consensus that RUC process would need to be modified to consider RTC and that SASM would not be needed

1. Do we need to model Real-Time AS demand curves in the DAM?

**Status:** This issue is being revisited in 2017 SAWG discussions.

Update from 2015 SAWG discussions: AS Demand Curves will be used in DAM. The AS demand curves will be the same in DAM and Real-Time

1. If we model AS demand curves in the DAM, as the DAM is voluntary, are there any issues? Resources do not have to participate since it is not mandatory to submit Resource specific Offers for energy and AS.

**Status:** This issue is being revisited in 2017 SAWG discussions.

Update from 2015 SAWG discussions: Consensus that this is not an issue

1. If we model AS demand curves in the DAM, then what is the process of achieving required levels of AS procurement in the DAM when the DAM process does not procure enough? Is it Reliability Unit Commitment or RUC?

**Status:** This issue is being revisited in 2017 SAWG discussions.

Update from 2015 SAWG discussions: Prefer to go into Real-Time with AS insufficiency or need to develop procedure to deal with AS insufficiency in DAM if it is unacceptable to go into RT with AS insufficiency

1. AS Demand Curves: If AS demand curves are **not** modeled in the DAM, then AS procurement is effectively given higher priority than energy — that is, in DAM, all energy demand has a price and hence can be curtailed, whereas the AS penalty is extremely high. This ensures that the AS Plan MW Requirements are procured. However, in RT, AS demand curves are modeled. The amount of Non-Spin procured depends on the intersection of the Non-Spin demand curve and the offer stack for Non-Spin. Hence, the procured amounts of Non-Spin can exceed or be less than the AS Plan MW Requirement for Non-Spin. If there is more Non-Spin procurement than the AS Plan, then loads are charged this amount on a Load-Ratio-Share. This is the same as the current process of AS Imbalance Settlements.

**Status:** This issue is being revisited in 2017 SAWG discussions.

Update from 2015 SAWG: Consensus is to model AS demand curves in DAM. For AS demand curves with a “long tail” – e.g. Non-Spin (Option 1) or SOR/NSOR (Option 2, Option 3), ERCOT may procure more AS than required for reliability if it is economical. Please note that a QSE attempting to self-arrange 100 % of AS obligation for Non-Spin (Option 1) or SOR/NSOR (Option 2, Option 3) may still get charged if the procured amounts exceed the amounts required for reliability.

1. AS Participation rules in RTC: Must every Resource qualified to provide AS participate? Under what conditions can a Resource opt-out of AS participation in RTC?

**Status:** This issue is being revisited in 2017 SAWG discussions.

From 2015 SAWG discussions on AS Offer Submission rule changes to increase substitutability/liquidity and also promote price cascading of AS MCPC from higher quality AS to lower quality AS.

* 1. Rule 1: In the Day-Ahead Market, If MW capacity offered for Reg-Up, then the same MW capacity offer is also considered for Non-Spin (Option 1) or SOR (Option 2) at the same price as Reg-Up if the QSE did not enter an offer price for Non-Spin (Option 1) or SOR (Option 2)
  2. Rule 2: In the Day-Ahead Market, If MW capacity offered for RRS, then the same MW capacity offer is also considered for Non-Spin (Option 1) or SOR (Option 2) at the same price as RRS if the QSE did not enter an offer price for Non-Spin (Option 1) or SOR (Option 2)
  3. Rule 3: In Real-Time, all SCED dispatchable capacity (LSL to HSL) for On-Line Resources considered to be offering Non-Spin (Option 1) or SOR (Option 2) at zero $/MW, this includes QSGR telemetering a status of ON, i.e. in Real-Time, On-Line Resources have mandatory participation in Non-Spin (Option 1) or SOR (Option 2).
  4. Rule 4: Develop exception rules where Resources can inform ERCOT of their inability to provide MW capacity for a particular AS. Is withdrawal of AS Offers or reduction in offered AS MW capacity an acceptable solution? If so, delete this rule.

1. AS participation in RTC – timeline for informing ERCOT of changes to AS offers

**Status:** This issue is being revisited in 2017 SAWG discussions.

From SAWG discussions on need to develop requirements for timeline for updating AS Offers and Energy Offers. There may be a need for additional telemetry to be used in conjunction with the AS offer to provide QSEs more flexibility. Alternative would be to use telemetry for specific AS types from a Resource to indicate inability or unwillingness to provide AS.

Note: At the July 14, 2017 SAWG meeting co-optimization participation requirements were discussed but not resolved and are included here for completeness.

Participation Principles for discussion:

* 1. Physical Responsive Reserve used in managing scarcity actions by the ERCOT Operator must be within a tolerance of total reserves available for dispatch in RT Co-0ptimization
  2. Any Generation Resource offers made in the DAM must continue to be valid in Real Time unless the Generation Resource has failed equipment enabling AS participation
  3. Generation Resources who self-schedule AS in the DAM, must provide AS offers in Real Time
  4. For Generation Resources that do not have AS and Energy offers in Real Time valid up to and including the Resource’s HSL, ERCOT will create an offer curve for AS and Energy up to and include HSL at SWOC. Generation Resources without valid offers are subject to review by the IMM
  5. Load Resources awarded RRS in DAM may not participate in RT Co-optimization and must remain in service unless deployed by frequency deviation or Dispatch Instruction
     + 1. Load Resources providing any AS except RRS must also provide RT bid prices for energy
       2. RT Co-Optimization software systems will include special software that runs 15 minutes ahead of SCED to detect data and offer errors and alarm QSE and ERCOT operators of problems before SCED uses invalid data for dispatch

Offers can only be changed before the Operating Period so that RUC and other systems can use the same Offers that will be used in real time. Resources cannot be “unwilling” to provide AS except when mechanical problems occur and causes forced outages of equipment or such actions could be considered a violation of PUC rules. ERCOT must provide a status indicator with each Ancillary Service by Resource so that QSEs may notify ERCOT and appropriate software systems of such mechanical problems without removing the offers from the management systems,AS Offers, if changed, must be locked down by the end of the adjustment period. Changes to offers made in the DAM for AS must be consistent with offers made in RT except for equipment failures.

1. Load Resource Deployment for RRS: Need to develop process to account and differentiate scenarios where RRS from LR is deployed versus failure to provide, etc. This has impact on the AS imbalance settlement

**Status:** not discussed yet

1. Load Resource Deployment for RRS: AS imbalance charges

**Status:** Update from 2015 SAWG discussions:

Load Resource (LR) with UFR carrying RRS Responsibility (blocky AS):

1. Upon deployment will be exempt from AS imbalance charge – this is a change from current practice with ORDC price adders
2. In RT, LR with UFR carrying RRS responsibility will be considered to be price takers (i.e. RRS offer from these LR = 0$/MW). i.e. no reduction of RRS demand curve by the amount of RRS responsibility from Load Resources. Discussion required on changes to NPRR 626 pricing run for including RRS MW deployment from Load Resource due to UFR Trip.
3. However, when deployed, LR will be considered to be still providing RRS till the 3 hour limit after recall.

Note 1: The above exemptions from AS Imbalance charges is a deviation from current practice

In addition, automatic UFR trip of Load Resources may need to be considered in the NPRR 626 pricing run if Load Resources providing RRS are not charged an AS imbalance payment for RRS under UFR trip.

1. Offer Floors: Should Offer floors on Non-Spin (NSOR) be removed?

**Status:** not discussed yet

1. Non-Spin Reserve Calculation: For Non-Spin, should the statistical distribution of Online Reserves be used or Online+Offline Reserves or some combination? Note that the price on the Non-Spin demand curve will be lower if the statistical distribution of the Online+Offline Reserves is used.

**Status:** Update from 2015 SAWG discussions: Use the statistical distribution of Online+Offline Reserves to build the Non-Spin (Option 1) or NSOR (Option 2, Option 3) Demand Curve. For SOR (Option 2, Option 3) use the statistical distribution of Online Reserves to build the SOR Demand Curve

1. Reg Down Demand Curve: How should the demand curve for Reg-Down be determined? Is it the same as the Reg-Up demand curve?

**Status:** Update from 2015 SAWG discussions: Reg-Down Demand Curve will have the same shape as the Reg-Up Demand Curve. Reg-Down Demand Curve width (MW required for Reg-Down)) will be based on ERCOT operational requirements. The price points on the Reg-Down Demand Curve will be the same as the Reg-Up Demand Curve till the Reg-Down MW requirement.

1. Accounting Issues: Accounting for Resource providing "truly" Offline Non-Spin (Option 1) and NSOR (Option 2):

Should these Resources be exempt from AS Imbalance charges upon deployment?

Note - We do not do that currently with the ORDC price adder settlements.

**Status:** not discussed yet

1. What other metrics apart from following Base Points, GREDP are required?

**Status:** not discussed yet

1. Ramping Issues: Stakeholder discussions will be required to develop methodology to share the ramp rates between energy and AS (similar to the ramp sharing between current Security Constrained Economic Dispatch or SCED and LFC).

**Status:** not discussed yet

1. Emergency Ramp Rates: When should Emergency Ramp Rates be used? Only upon ERCOT notification?

**Status:** not discussed yet

1. Reg-Up award limits: Should Reg-Up awards be limited by Reg\_down ramp rate? This is to prevent Resources from being harmed by sequence of increasing Base Points over a period of time and then a reduction where due to ramp down limitations, they become price takers and simultaneously there is a Reg-Up shortage pricing.

**Status:** not discussed yet

1. Make Whole Issues: Should there beMake Whole payments if Resources financially harmed with respect to Day-Ahead positions due to RT energy+AS co-optimization.

**Status:** SAWG Discussion on 2/25/2015: SAWG consensus to NOT have make-whole payments for this type of scenario.

Under Real-Time co-optimization when a Resource buys out of its Day ahead AS responsibility, the QSE representing the Resource could get financially harmed by the Real-Time imbalance settlement for energy and AS if it had made sales for AS from that Resource in the Day-Ahead Market. There are specific conditions under which this can occur:

1. System conditions are such that there is shortage/scarcity in one AS but surplus of capacity for energy. i.e. scarcity pricing for AS is not reflected in the energy prices (LMPs)

2. Resource is ramp constrained (how much it can move in 5 minutes) and the awards are limited by this. For example, if a Resource is generating energy at HSL and the next RT co-optimization results in a very high price for RRS, then the Resource MW award for RRS is how much it can be ramped down in 5 minutes.

3. QSE has made a sale of AS on this Resource in the Day-Ahead Market

Note: if a Resource has not made a Day-Ahead Sale for AS, then this scenario does not apply.

1. Settlement Interval Changes: Should ERCOT move to a 5 minute settlement?

**Status:** Raised at SAWG in 2015

ERCOT Staff commented that currently the ORDC price adders for capacity is done on a 15 minute basis and Real-Time Co-optimization does not have to change the settlement interval as the AS Imbalance settlement can continue to use a 15 minute settlement interval for AS capacity.

Comments submitted by market participant for SAWG meeting on July 14, 2017 on proposed 15 minute AS imbalance charge or payment settlement equations in this paper:

“Although the weighting factor approach has been used in ERCOT since market open, a more accurate settlement would be to settle Generation Resources and selected retail loads on a 5 minute basis. The above calculations would be modified to use each SCED execution in a five minute period to set the MCPE and MCPC along with the metered energy and AS in a 5 minute period to determine amounts paid to Generation Resources. Loads may also elect to settle on the same 5 minute period provided appropriate energy metering is available or provided by the retail load. Allowing retail load to react in the same time frame as prices are calculated optimizes the opportunity loads have to respond correctly to pricing events and eliminates the existing problems when prices are averaged over a 15minute period.”

1. AS Deliverability: What are the AS deliverability concerns and how can it be mitigated?

**Status:** not discussed yet

1. AS Offer Submittal Structure: Change DAM and RTC AS Offer submittal structure and procurement constraints so that there is explicit MCPC price cascading. The MCPC price hierarchy from highest to lowest is Reg-Up followed by RRS and then followed by Non-Spin. Thus, additional Regulation Up can be purchased at a lower cost than Responsive Reserve and likewise Responsive Reserve could be procured at a lower overall cost than Non-Spin. With this, ERCOT could procure more Regulation Up or more Responsive Reserve rather than higher cost Non-Spin if offers for such products indicate additional cost savings. Similar changes would be made to DAM

**Status:** not discussed yet

1. ERCOT Operator ability to enter manual offset to GTBD (current functionality): Should ERCOT Operators be able to manually override GTBD?Are there other opportunities to execute an additional SCED run to update all Resources Base Points so that proper pricing can be calculated.

**Status:** not discussed yet

# Appendix 1: High Level Mathematical Formulation of energy and AS Co-Optimization for Option 2

The simplified formulation of the optimization problem (objective, constraints, pricing analysis) is presented below where energy and the various AS products are co-optimized in both Day-Ahead and Real-Time Markets.

Simplifications:

1. Transmission constraints in both Day-Ahead and Real-Time, PTPs, block offers and bids in Day-Ahead are not considered
2. Constraints on how much AS can be awarded to a single resource based on a % of HSL or ramp capability are not considered
3. are the submitted bids ($/MWh), energy offers ($/MWh), AS offers ($/MW) respectively. For simplicity, these bids and offers are considered to be constant for the entire MW bid or offered.
4. In the Day-Ahead Market, Resources must submit offers to sell energy and AS (all the types) in order to be awarded.

The equations below are describing Option 2. The equations for Option 3 are not described. If the reader is interested in the equations for the Option 1 approach in the concept paper, then in the equations below:

* 1. Consider SOR offers (spinning operating reserve) as Non-Spin (both On-Line and Off-Line)
  2. Replace the demand curve for SOR with Non-Spin demand curve.
  3. Remove terms with NSOR (non-spinning operating reserve) – Off-line non-spin is already included in (v) a. above.

**Day-Ahead Market Objective Function:**

**Real-Time Market Objective Function:**

**Subject to:**

Ignoring transmission constraints and focusing on power balance, AS procurement and the main Resource limit constraints, the set of constraints are given below:

**System wide constraints:**

1. Power Balance: (Shadow price = )

**Day-Ahead:**

**Real-Time:**

1. Reg-Up Procurement (including FRRS-Up): (Shadow price = )
2. FRRS-Up maximum procurement limit: (Shadow price = )
3. Reg-Down Procurement (including FRRS-Down): (Shadow price = )
4. FRRS-Down maximum procurement limit: (Shadow price = )
5. RRS Procurement: (Shadow price = )
6. RRS maximum procurement from “blocky” Load Resource: (Shadow price = )
7. SOR Procurement: (Shadow price = )
8. NSOR Procurement: (Shadow price = )

**Individual Energy Bid constraints:**

1. Energy Bid MW constraint for every energy bid : (Shadow price = respectively)

**Individual Resource constraints:**

Each Resource will have its own set of constraints to ensure awards are within bounds of its own upper (HSL/MPC) and low (LSL/LPC) limits.

1. LSL Constraint for every modeled Generation Resource : (Shadow price = )
2. HSL Constraint for every modeled Generation Resource : (Shadow price = )

On-Line:

Off-Line:

1. AS Offer MW constraint for every modeled Generation Resource : (Shadow price = respectively)

On-Line:

Off-Line:

1. MPC & LPC Constraint for every modeled “Blocky” Load Resource : (Shadow price = )

Note that a “blocky” Load Resource is awarded only one AS product.

or

1. AS Offer MW constraint for every modeled “Blocky” Load Resource : (Shadow price = )

or

1. MPC & LPC Constraint for every modeled Controllable Load Resource : (Shadow price = )
2. AS Offer MW constraint for every Controllable Load Resource : (Shadow price = respectively)
3. HSL & LSL Constraint for every “Quick/Fast” Resource qualified for FRRS-Up and FFR1 and partly modeled as Generation Resource : (Shadow price = )
4. AS Offer MW constraint for every “Quick/Fast” Resource qualified for FRRS-Up and FFR1 and partly modeled as Generation Resource : (Shadow price = )
5. MPC & LPC Constraint for every “Quick/Fast” Resource qualified for FRRS-Up, FRRS-Down and RRS and partly modeled as Controllable Load Resource : (Shadow price = )
6. AS Offer MW constraint for every “Quick/Fast” Resource qualified for FRRS-Up and FRRS-Down and partly modeled as Controllable Load Resource : (Shadow price = respectively)

**Lagrangian Function:**

The objective and constraints are combined to form the Lagrange function:

At optimal solution (optimality condition)

i.e. the partial derivative of with respect to each award

and the shadow prices will equate to zero at the optimal solution.

Taking the partial derivative of with respect to each award

and rearranging the terms by

we get:

1. **Day Ahead:** For each energy bid , the following equation holds true

If the energy bid *i* is marginal to the power balance constraint, then and the energy bid *i* sets the shadow price for the power balance constraint (System Lambda )

**Real-Time:** If the Power Balance Penalty Curve is marginal to energy, the following equation holds true and the Power Balance Penalty Curve sets the shadow price for the power balance constraint (System Lambda ):

1. For each energy offer from modeled Generation Resource , the following equation holds true

If the energy offer *i* is marginal to the power balance constraint, then, and the energy offer *i* sets the shadow price for the power balance constraint (System Lambda )

1. For each Reg-Up offer from modeled Generation Resource , the following equation holds true

If the Reg-Up offer *i* is marginal to the Reg-Up Procurement constraint, then in most cases, and the Reg-Up Offer *i* sets the shadow price for the Reg-Up Procurement constraint ( this is the Reg-Up MCPC )

1. For each Reg-Down offer from modeled Generation Resource , the following equation holds true

If the Reg-Down offer *i* is marginal to the Reg-Down Procurement constraint, then, in most cases, and the Reg-Down Offer *i* sets the shadow price for the Reg-Down Procurement constraint ( this is the Reg-Down MCPC )

1. For each RRS offer from modeled Generation Resource , the following equation holds true

If the RRS offer *i* is marginal to the RRS Procurement constraint, then, and the RRS Offer *i* sets the shadow price for the RRS Procurement constraint (this is the RRS MCPC )

1. For each SOR offer from modeled Generation Resource , the following equation holds true

If the SOR offer *i* is marginal to the SOR Procurement constraint, then, .

Please note that the MCPC for SOR is the sum of the shadow price for the SOR and NSOR () procurement constraints.

1. For each NSOR offer from modeled offline Generation Resource , the following equation holds true

If the NSOR offer *i* is marginal to the SNSOR Procurement constraint, then, .

Note that the MCPC for NSOR is the shadow price for the NSOR procurement constraint

1. For each RRS offer from modeled “blocky” Load Resource , the following equation holds true

If the RRS offer *i* is marginal to the RRS Procurement constraint, then, and the RRS Offer *i* sets the shadow price for the RRS Procurement constraint (this is the RRS MCPC )

Note that if the RRS offer MW is submitted as a **block**, then, this offer **cannot** set the MCPC

If the RRS maximum procurement constraint from “blocky” Load Resource is binding then . In this case the MCPC for RRS is still the shadow price of the RRS procurement constraint () and the RRS awards to “blocky” Load Resources will be paid this price

1. For each SOR offer from modeled “blocky” Load Resource , the following equation holds true

If the SOR offer *i* is marginal to the SOR Procurement constraint, then, and the SOR Offer *i* sets the shadow price for the SOR Procurement constraint (this is the SOR MCPC )

Note that if the SOR offer MW is submitted as a **block**, then, this offer **cannot** set the MCPC

1. For each Reg-Up offer from modeled Controllable Load Resource , the following equation holds true
2. For each Reg-Down offer from modeled Controllable Load Resource , the following equation holds true
3. For each RRS offer from modeled Controllable Load Resource , the following equation holds true
4. For each SOR offer from modeled Controllable Load Resource , the following equation holds true
5. For each FRRS-Up offer from “Quick/Fast” Resource partly modeled as Generation Resource , the following equation holds true

If the FRRS-Up offer *i* is marginal to the Reg-Up Procurement constraint, then, and the FRRS-Up Offer *i* sets the shadow price for the Reg-Up Procurement constraint (this is the Reg-Up MCPC )

If the FRRS-Up maximum procurement constraint from “Quick/Fast” Resource is binding then . In this case the MCPC for Reg-Up is still the shadow price of the Reg-Up procurement constraint () and the FRRS-Up awards to “Quick/Fast” Resources will be paid this price

1. For each FRRS-Up offer from “Quick/Fast” Resource partly modeled as Load Resource , the following equation holds true

If the FRRS-Up offer *i* is marginal to the Reg-Up Procurement constraint, then, and the FRRS-Up Offer *i* sets the shadow price for the Reg-Up Procurement constraint (this is the Reg-Up MCPC )

If the FRRS-Up maximum procurement constraint from “Quick/Fast” Resource is binding then . In this case the MCPC for Reg-Up is still the shadow price of the Reg-Up procurement constraint () and the FRRS-Up awards to “Quick/Fast” Resources will be paid this price

1. For each FRRS-Down offer from “Quick/Fast” Resource partly modeled as Load Resource , the following equation holds true

If the FRRS-Down offer *i* is marginal to the Reg-Down Procurement constraint, then, and the FRRS-Down Offer *i* sets the shadow price for the Reg-Down Procurement constraint (this is the Reg-Up MCPC )

If the FRRS-Down maximum procurement constraint from “Quick/Fast” Resource is binding then . In this case the MCPC for Reg-Down is still the shadow price of the Reg-Down procurement constraint () and the FRRS-Up awards to “Quick/Fast” Resources will be paid this price

Note: If there is scarcity in any of the AS (Reg-Up, Reg-Down, RRS, SOR and NSOR), then the demand curves prices at the last cleared MW AS demand on the respective demand curves will set the Shadow Prices of the applicable procurement constraints.

**MCPC formula (from shadow prices)**

|  |  |  |
| --- | --- | --- |
| AS Product | MCPC | Comments |
| Reg-Up |  | Shadow price of the Reg-Up procurement (including FRRS-Up) constraint |
| FRRS-Up |  | FRRS-Up is valued the same as Reg-Up |
| Reg-Down |  | Shadow price of the Reg-Down procurement (including FRRS-Down) constraint |
| FRRS-Down |  | FRRS-Down is valued the same as Reg-Down |
| RRS |  | Shadow Price of the RRS procurement constraint |
| SOR |  | Sum of the Shadow Prices of the SOR and NSOR procurement constraints |
| NSOR |  | Shadow Price of the NSOR procurement constraint |

# Appendix 2: Examples for AS Demand Curves

Two approaches are currently being discussed. One approach is to develop a process to disaggregate the ORDC into the individual ASDCs. In this approach, any change to the ORDC (changing minimum contingency level, shifting of mean or standard deviation) will get reflected in the individual ASDC. Note that with this approach, aggregating the individual ASDCs will reproduce the relevant ORDC.

The second approach is not to use the ORDC as reference to develop a process to setup the individual ASDCs for Reg-Up, Reg-Down, and RRS. The ASDCs for Non-Spin (Option 1) or SOR and NSOR (Option 2) could be based on some portion of the ORDC.

Four examples of these approaches are presented below.

**Based on NERC requirements for RRS and RUS/RDS and ORDC for SOR and NSOR**

but rather based on minimum NERC requirements for those services.

**Example 4: ASDC for Reg-Up, RRS, SOR and NSOR Demand Curves (Option 2) – Based on First Principles.**

ORDC was an over-simplification of the demand curves for AS - it was only one curve used to represent the value of various different kinds of AS whose functions and values to the grid are entirely different from one another. RTC, with ASDC for each AS, now allows us to value each AS appropriately based on First Principles. Since, according to consensus at SAWG, ERCOT will procure AS in DAM using the same ASDC as in RTC, it's important to ensure that the ASDC reflect ERCOT's willingness-to-pay fo that AS. E.g., dividing up the current ORDC to create ASDC for RRS and RUS may result in RRS demand curve that is only a few hundred dollars per MW for RRS when greater amounts of RRS is required according to ERCOT analysis. Is ERCOT and the market willing to not meet NERC requirments if the RRS offer prices is greater than say $400/MW/hr (based on ORDC curve with RUS of 400MW and RRS of 2808MW - the 2808MW of RRS is actually equivalent to 3370MW of PFR which results in ORDC as low as $70/MW/hr for RUS plus PFR)?

The objective of RRS is to ensure Frequency is arrested above the Under-frequency Load Shedding (UFLS) threshold of 59.30 Hz and to meet NERC Frequency Response Obligation (FRO) Standard (BAL-003-1). FRO for ERCOT is determined based on instantaneous loss of two largest nuclear units (2,750 MW). If frequency is not arrested within tight timeframes, the system is at risk of cascading trips of under-frequency relays on generation and load resulting in involuntary load shedding and unstable grid operation. Thus, it's vitally important to have sufficient Physical Responsive Capacity (PRC), even at the expense of cutailing load, in order to avoid cascading failure. Non-responsive capacity, no matter how much is available, is of no help in arresting frequency after a disturbance in a timely manner. Thus, the demand curve for RRS should not be based on LOLP that is calculated as total capacity being less than load, but rather on failure to arrest frequency within required timeframes regardless of how much non-responsive excess capacity is available to the grid. The other important fact to consider is that being short 1,000MW of PRC does not imply loss of additional 1,000MW of load in a severe disturbance but rather the potential loss of tens of thousands of MWs of load due to the cascading effect.

Take the example of ERCOT determining 2,800MW of RRS is required to meet NERC BAL-003-1 standard (loss of two largest units or 2,750MW). The probability of unanticipated loss of 2,750MW of supply and/or increase in load within any 10-minute interval is less than 1; however, not having any PRC is likely to put at risk the entire grid not just 2,750MW or 2,800MW of load. Thus the value of the first X MW (where X>2,300MW based on out-of-market and EEA1 PRC triggers) of RRS may actually be greater than or multiples of VOLL. The ASDC for RRS would be, with increasing amounts of RRS, the decrease in the amount of load lost in disturbances times VOLL times the probability of that disturbance. In order to keep energy prices within VOLL, the RRS demand curve may have to be capped below VOLL even though the value of the first X MW may be greater than VOLL. Also, since ERCOT takes out-of-market actions (deploying Off-line Non-Spin) at PRC<2,500MW, the ASDC for RRS should be near its cap for at least 2,500MW. Of course, there are non-zero probabilities of disturbances greater than 2,750MW and having a greater amount of RRS would protect against those disturbances. Thus, the RRS demand curve would extend beyond the ERCOT-determined minimum amount of RRS required to meet BAL-003-1. Of course, RRS capacity also prevents loss of load due to capacity shortage.

The power imbalance between each SCED interval causes frequency deviation that requires regulating reserve to compensate. Resources providing regulating reserve should be able to closely follow ERCOT Load Frequency Control (LFC) signal for regulating reserves to be effective. ERCOT on an annual basis determines the MW amounts of Regulation-Up Service (Reg-Up) and Regulation-Down Service (Reg-Down) required to provide adequate regulating service for the system. RUS/RDS may be considered as frequency response to higher probability, lower MW amount disturbances. The implications of not having enough RUS/RDS is that frequency would deviate to a much greater extent. Of course, RUS capacity also prevents loss of load due to capacity shortage. What is the cost of such frequency deviation? The cost of frequency deviation increases with the amount of deviation but the probability of greater deviation decreases. ERCOT currently determines the historical probabilities of various amounts of regulating capacity needs in setting the RUS/RDS requirements. Since the minimum RUS/RDS requirement currently being determined by ERCOT is, according to ERCOT, required to cover the 95th percentile of deployed regulation or net load variability in order to comply with CPS1 performance standard and since RUS is considered a higher value AS than RRS and Non-Spin, it's reasonable to set the RUS/RDS demand curve for this minimum amount of RUS/RDS at the ASDC cap. It's important to note that RUS capacity may not qualify as PRC and so cannot be treated the same as RRS. What about the RUS demand curve beyond this minimum amount? At some frequency deviation level, it's no longer RUS that's deployed but RRS deployment takes over. A simplifying assumption may be that RRS takes over beyond the minimum RUS requirement as implied by the current AS methodology. Then the demand curve for RUS/RDS would be rectangular at the ASDC cap for the minimum RUS/RDS requirements. However, if there is additional room between the minimum RUS amount and where RRS picks up, then the RUS demand curve could be extended based on some value for the cost of such frequency deviation multiplied by its probability. RDS demand curve can also be extended based on some value for the cost of such frequency deviation multiplied by its probability.

SOR and NSOR capacity provides contingency reserves to replenish deployed RRS and RUS and also prevents loss of load due to capacity shortage. For simplicity, SOR and NSOR demand curves may be determined only considering the LOLP multiplied by VOLL as in current ORDC implementation.

Thus, the ASDCs are (where V=VOLL and ASDCcap=AS demand curve cap to coordinate with Power Balance Penalty Curve):

RUS: DRUS(RRUS) = ASDCcap, RRUS < Minimum RUS

= Min(ASDCcap, LOLP30(RRUS+RRRS+RSOR)\*V + PFD(RRUS)\*CFD1(RRUS)),

RRUS > Minimum RUS (optional)

where LOLP30 = 30-minute Loss of Load Probability due to capacity shortage

PFD = Probability of Frequency Deviation (less than when RRS kicks in; 0 above that value)

CFD1 = Cost of Frequency Deviation (based more on equipment and societal costs rather than V)

RDS: DRDS(RRDS) = ASDCcap, RRDS < Minimum RDS

= Min(ASDCcap, PFD(RRDS)\*CFD1(RRDS)), RRDS> Minimum RDS (optional)

where PFD = Probability of Frequency Deviation

CFD1 = Cost of Frequency Deviation (based on equipment and societal costs)

RRS: DRRS(RRRS) = ASDCcap, RRRS < 2,300MW

= Min(ASDCcap, LOLP30(RRUS+RRRS+RSOR)\*V + PFD(RRRS)\*CFD2(RRRS)),

RRRS > Minimum RRS

where LOLP30 = 30-minute Loss of Load Probability due to capacity shortage

PFD = Probability of Frequency Deviation

CFD2 = Cost of Frequency Deviation (based on multiples of V with cascading load trips)

SOR: DSOR(RSOR) = Min(ASDCcap, LOLP30(RRUS+RRRS+RSOR)\*V)

where LOLP30 = 30-minute Loss of Load Probability due to capacity shortage

NSOR: DNSOR(RSOR) = Min(ASDCcap, LOLP60(RRUS+RRRS+RSOR+RNSOR)\*V)

where LOLP60 = 60-minute Loss of Load Probability due to capacity shortage

1. The term Production Costs refers to the use of submitted Energy Offer Curves, AS Offers, and Energy Bid Curves (if applicable) and any associated mitigation of the Energy Offer Curves due to transmission congestion. [↑](#footnote-ref-1)
2. The term Production Costs refers to the use of submitted Energy Offer Curves, AS Offers, and Energy Bid Curves (if applicable) and any associated mitigation of the Energy Offer Curves due to transmission congestion. [↑](#footnote-ref-2)