MANUAL 2

Ancillary Services Manual

~~May~~ ~~July~~ ~~August~~ November Draft 2006

Revision History Page

Revision	Date	Changes
3.6	~~9/30/06~~TBD	**Deleted Attachment B – AGC Functional Requirements** ▪ There were no references to the Attachment in version 3.5 of the manual **Inserted New Attachment A – VSS Qualifications Request Form** ▪ Inserted Qualification Request Form from TB 103 (TB 103 can be retired). Subsequent Attachments have been relabeled. **Inserted New Section 1.3** ▪ Inserted new section 1.3 "Payments and Charges for Ancillary Services" (from TB 121, TB 121 should be incorporated in the Accounting & Billing Manual before being retired) sections following 1.3 have been renumbered. **Inserted New Section 3.2** ▪ Inserted new section 3.2 Supplier Qualifications (from TB 091 and TB 103) sections following 3.2 have been renumbered. **Modified Section 3.6** **Changes to this section are in accordance with RT SCHD 2, Sect 1.1.** ▪ Changed title of heading to "Reactive Power Capability Demonstration" ▪ Second paragraph – inserted language on providing data during actual operation. ▪ Section 3.6 (old section 3.5) – Incorporated TB 091 (TB 091 can be retired) **Modified Section 3.6.1** ▪ Changed title of heading to "Frequency and Timing" ▪ First paragraph – inserted language stating each calendar year resources providing VSS must demonstrate both lagging and leading reactive capability. **Modified Section 3.6.2** ▪ First paragraph – inserted language on how measurements should be taken and how tests must be performed. **Modified Section 3.6.4** ▪ Changed title of heading to "Reporting Requirements" ▪ Replaced demonstration with "tests and/or demonstrations." ▪ Section 3.6.4 (old section 3.5.4) – Incorporated TB 126 (TB 126 must also be incorporated in ICAP manual then can be retired)

1. OVERVIEW

This section gives an overall description of the following Ancillary Services.

- Scheduling, System Control & Dispatch Service
- Voltage Support Service
- Regulation & Frequency Response Service
- Energy Imbalance Service
- Operating Reserve Service
- Black Start Capability Service

1.1 Purpose

The purpose of this Manual is to provide an overview of the Ancillary Services available in the New York market along with settlement process associated with each of the available ancillary services.

1.2 Summary of Services

~~Definition of Ancillary Services~~

Ancillary Services support the transmission of energy from resources to loads, while maintaining reliable operation of the New York State (NYS) Power System. Ancillary Services consist of physical equipment and human resources. The New York Independent System Operator (NYISO) is also responsible for directing the actions of Generation Resources and other facilities that provide Ancillary Services to the NYISO.

The NYISO coordinates the provision of all Ancillary Services and directly arranges for the supply of all Ancillary Services that are not self-supplied. Some Ancillary Services must be provided by the NYISO; others can either be provided by the NYISO or procured by the Transmission Customers and Suppliers themselves. Some Ancillary Services are provided at market-based prices, while others, due to the nature of the service, are provided at embedded cost-based prices. All Ancillary Service providers must be scheduled by the NYISO. Table 1.1 presents a summary of the NYISO Ancillary Services.

Table 1.1: Ancillary Services Summary

Ancillary Service~~s~~	Is the Service Location Dependent?	Who provides the Service – NYISO or Self-Supplied (SS)?	What is the Pricing method for the Ancillary Service?
Scheduling, System Control and Dispatch Service	No	NYISO	Embedded
Voltage Support Service	Yes	NYISO	Embedded
Regulation and Frequency Response Service	Yes	NYISO or (SS)	Market-based
Energy Imbalance Service	No	NYISO	Market-based
Operating Reserve Service	Yes	NYISO or (SS)	Market-based
Black Start Capability Service	Yes	NYISO	Embedded

1.3 Payments and Charges for Ancillary Services

Payments and charges for ancillary services are described in the ***NYISO Accounting and Billing Manual*** and set forth in the NYISO Open Access Transmission Tariff (OATT) and Services Tariff as noted in Table 1.2.

Table 1.2: Rate Schedules for Ancillary Services

Ancillary Service	OATT Rate Schedule	Services Tariff Rate Schedule
Scheduling, System Control and Dispatch Service	1	1
Voltage Support Service	2	2
Regulation and Frequency Response Service	3	3
Energy Imbalance Service	4	1
Operating Reserve Service	5	4 and 6
Black Start Capability Service	6	5

~~1.3~~1.4 Self-Supply of Ancillary Services

Transmission Customers and Suppliers are permitted to Self-Supply certain Ancillary Services, as identified in Table 1.1. In general, the following process must occur in order to Self-Supply Ancillary Services:

1. A Transmission Customer bids the resource required to provide the Ancillary Service into the Ancillary Services market.

2. The NYISO selects the successful bidders to provide each Ancillary Service. The selection of all Ancillary Service providers is subject to the same locational criteria.

3. Transmission Customers and Suppliers with resources selected by the NYISO use the revenues that they would otherwise have received for providing these services as an offset against charges they would otherwise need to pay the NYISO for the service.

- The LSEs identify in their application to NYISO the Ancillary Services that they plan to purchase through the NYISO.
- All suppliers of Ancillary Services using the self-supply option must place the facility under the operational control of the NYISO. All of these resources are subject to the same NYISO locational and performance criteria, and are subject to all payments and penalties as are defined for all other suppliers of the service.
- For more information, see the ***NYISO Accounting and Billing Manual***.

~~1.4~~1.5 Metering Requirements

- Ancillary Services Suppliers must ensure that adequate metering data is made available to the NYISO by direct transmission to the NYISO through existing Transmission Owner communication equipment.
- Additionally, for operational purposes, metered data provided to the NYISO must also simultaneously be provided to the Transmission Owner, which will handle such information consistent with the *OASIS* standards of conduct as specified in FERC Order No. 889.

3. Voltage Support Service

This section describes the voltage support service (VSS).

3.1 Description

In order to maintain transmission voltages on the NYS Transmission System within acceptable limits, generation facilities under the control of the NYISO are operated to produce (or absorb) ~~reactive power~~Reactive Power. Thus, Reactive Supply and Voltage Control Service ("Voltage Support Service") must be provided to support all Transactions on the NYS Transmission System. The amount of VSS that must be supplied will be determined based on the ~~reactive power~~Reactive Power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the NYISO.

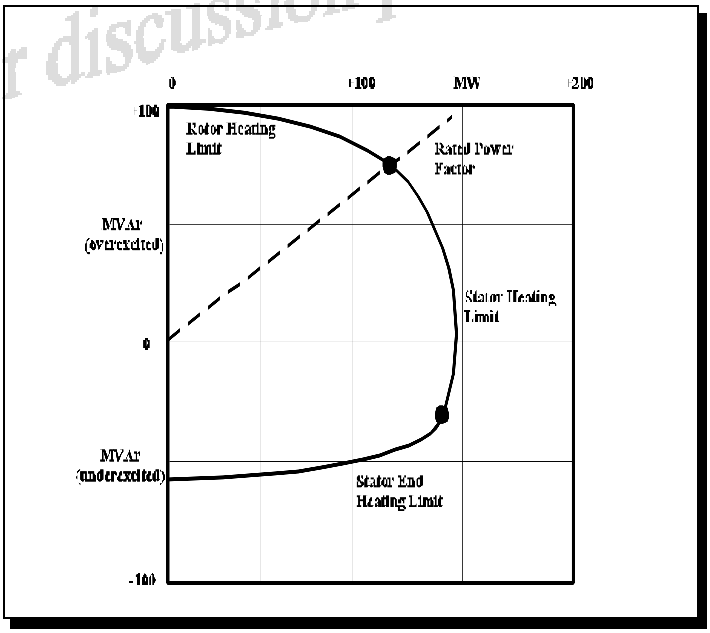

Figure 3.1: Generator MVAr versus MW Capability

The ability of a generator to produce or absorb ~~reactive power~~Reactive Power (MVAr) is limited by generator heating considerations. At full load, a generator is able to produce or absorb a relatively small amount of ~~reactive power~~Reactive Power. As the generator's production of real power decreases, its ability to produce or absorb ~~reactive power~~Reactive Power increases. Figure 3.1, called a reactive capability curve or a D-Curve, is representative of generators limiting characteristics at a particular temperature. Reactive capability decreases as the generator heats up and increases as the generator cools down. The reactive capability curve ~~can "shrink" with heating and "expand" with cooling of the machine. [**Note:** The generator's capability curve (D-curve) can~~therefore will "shrink" with heating and "expand" with cooling of the machine.~~]~~

3.2 Supplier Qualification

A VSS Supplier's Resource must be a Generator or a Synchronous Condenser. Suppliers of VSS must provide a Resource that has an Automatic Voltage Regulator (AVR) and has successfully performed a Reactive Power (MVAr) capability test in accordance with the NYISO Procedures described below. VSS suppliers must be able to produce or absorb Reactive Power within the Resource's tested reactive capability range and be able to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Resource's tested reactive capability.

In order to qualify to receive payments as a VSS Supplier the candidate Supplier, including previously disqualified VSS Suppliers that must re-qualify, must complete a VSS Qualification Form. That form is provided as of this manual. The Qualification Form must~~,~~ include a statement of intent to ~~participate in the~~provide Voltage Support Services ~~Market,~~ and attach~~:~~ ~~D~~documentation that the synchronous generator or synchronous condenser has an automatic voltage regulator (AVR). This documentation shall include the voltage regulator block diagram and associated data, the manufacturer's model number and specifications, and a generator reactive capability data sheet ("D-curve")~~; and~~.

~~Documentation that the synchronous generator or synchronous condenser has completed the reactive power~~Reactive Power ~~(MVAr) capability testing during the current calendar year.~~

The candidate VSS Supplier must complete and return the Voltage Support Service Suppliers Qualification Form, a copy of which is provided in Attachment A of this document, and supporting data to:

Manager, Auxiliary Market Operations~~Grid Accounting~~
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144

The original application form must be completed by a representative of the Supplier and signed by a Vice-President (or equivalent) of the corporation.

~~3.2~~3.3 Responsibilities for Service

The NYISO directs the Supplier's Resources to operate within their tested reactive capability limits. The scheduling of VSS is the responsibility of the NYISO.

- NYISO — The NYISO coordinates the NYS Power System voltages throughout the NYCA.
- Transmission Owners — Transmission Owners are responsible for the local control of the ~~reactive power~~Reactive Power resources that are connected to their network.
- Suppliers — ~~To qualify for payments,~~ Suppliers ~~of~~are expected to operate their Resources within demonstrated reactive capability limits. VSS ~~must provide a Resource that has an Automatic Voltage Regulator and has successfully performed Reactive Power (MVAr) capability testing in accordance with the NYISO Procedures and prevailing industry standards. Suppliers~~suppliers are also expected ~~to operate their Resources within these demonstrated reactive capability limits. VSS includes the ability to produce or absorb Reactive Power within the Resource's tested reactive capability range, and the ability~~ to

maintain a specific voltage level, as directed by the NYISO and the Transmission Owner System Operator, under both steady-state and post-contingency operating conditions subject to the limitations of the Resource's tested reactive capability.

~~3.3~~3.4 Payment for Service

This section describes the payments for VSS and covers the following:

- Method for determining payment
- Payments made to suppliers of VSS
- Payment for lost opportunity cost
- Payments made by transmission customers and LSEs

For more information, see ***NYISO Accounting & Billing Manual***.

~~3.3.1~~3.4.1 Method for Determining the Payments for Voltage Support Service

Payments to synchronous generators and synchronous condensers eligible for VSS are based upon a fixed dollar amount per MVAr as specified in the NYISO Market Services Tariff Rate Schedule 2 and the gross lagging MVAr capability as determined by annual capability testing performed by the generator and verified by the NYISO.

~~3.3.2~~3.4.2 Payments made to Suppliers for Voltage Support Service

The rate provided in Rate Schedule 2 shall be used to calculate payments to all eligible Suppliers providing VSS as applied on a Resource-specific basis. The NYISO shall calculate the payments on an annual basis, as the product of the compensation rate specified in Rate Schedule 2 and the gross lagging MVAr capability as demonstrated by actual test in the preceding calendar year. The NYISO shall, make payments to Suppliers on a monthly basis. Suppliers whose Resource(s) meet the requirements to supply Installed Capacity and are under contract to supply Installed Capacity receive one-twelfth the annual payment for VSS except as noted below for Non-Utility Generators. Suppliers whose Generators are not under contract to supply Installed Capacity and Suppliers with synchronous condensers receive one-twelfth the annual payment pro-rated by the number of hours that Generator or synchronous condenser operated in that month, as recorded by the NYISO.

For Non-Utility Generators that are operating under existing power purchase agreements, the entity that is purchasing Energy and/or Capacity under such agreement or providing Transmission Service under that agreement is contacted by the NYISO when the NYISO requires VSS from the contracted Resource.

~~3.3.3~~3.4.3 Payments for Voltage Support Service Provided by Non-Utility Generators with Existing Power Purchase Agreements

The NYISO pays each holder of a contract for a Non-Utility Generator operating under an existing power purchase agreement, which provides VSS.

- If that non-utility Generator provides installed capacity, the NYISO will pay it the product of: (1) one -twelfth of the annual $/MVAr rate for NYISO payments to Suppliers of VSS and (2) the lesser of the tested Reactive Power production capability (MVAr) of the Non-Utility Generator or the contract MVAr capability.
- If that non-utility Generator does not provide Installed Capacity, the NYISO will pay it the product of (1) and (2), as calculated above, multiplied by the number of hours in the month the Non-Utility Generator provided VSS divided by the number of hours in the month.

The NYISO calculates and makes payments on a monthly basis.

~~3.3.4~~3.4.4 Payments for Lost Opportunity Cost

A Supplier providing VSS from a Generator that is In-Service is entitled to receive Lost Opportunity Costs (LOCs) in the event the NYISO dispatches or directs the Generator to reduce its real power (MW) output in order to allow the unit to produce or absorb more ~~reactive power~~Reactive Power (MVAr).

The method for calculating LOC is based on the following:

- Real-Time LBMP
- Original dispatch point
- New dispatch point
- Bid curve of Generation supplying VSS

Figure 3.3.4 graphically portrays the calculation of the LOC for a Generator that reduced its MW output to allow it to produce or absorb more ~~reactive power~~Reactive Power (MVAr).

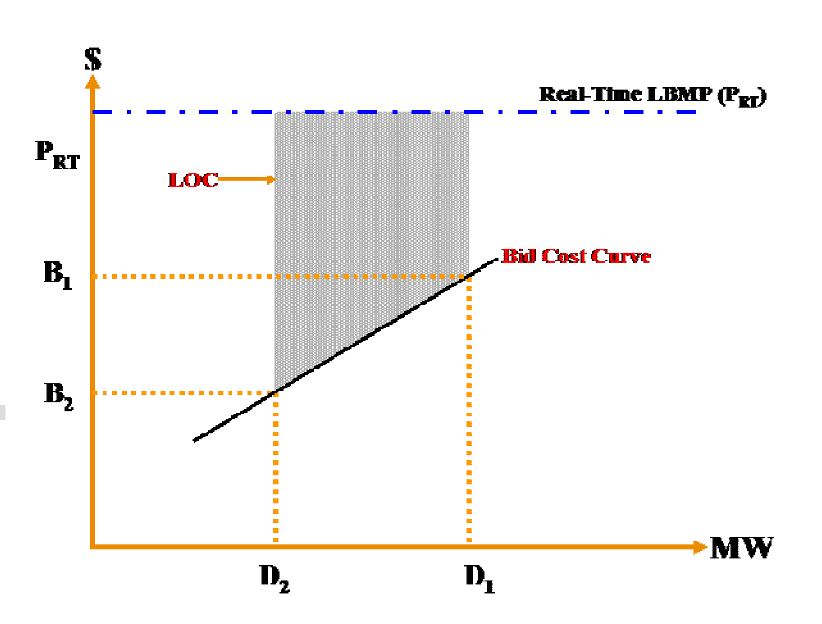

Figure 3.~~3~~4.4-1: Method for Calculating LOC

$$LOC = P_{RT}(D_1 - D_2) - \int_{D_2}^{D_1} Bid$$

Where: P_{RT} = Real Time LBMP
D_1 = Original Dispatch Point
D_2 = New Dispatch Point
Bid = Bid curve for generation supplying voltage support services

~~3.3.5~~3.4.5 Payments made by Transmission Customers and LSEs

Transmission Customers and Load Serving Entity (LSEs) taking service under the NYISO OATT pay the NYISO for VSS associated with energy withdrawals from the transmission system in accordance with Rate Schedule No. 2 of the OATT.

~~3.4~~3.5 Failure to Perform by Suppliers

A resource will have failed to provide voltage support if it:

1) fails at the end of 10 minutes to be within 5% (+/-) of the requested ~~reactive power~~Reactive Power (VArs) level of production or absorption as requested by the NYISO or applicable Transmission Owners for levels below the resource's demonstrated ~~reactive power~~Reactive Power capability at Dependable Maximum Net Capability (DMNC).

2) fails at the end of 10 minutes to be at 95% or greater of the resource's demonstrated ~~reactive power~~Reactive Power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the NYISO or applicable Transmission Owner.

3) fails to automatically respond, following a system contingency, to produce (or absorb) the ~~reactive power~~Reactive Power required in accordance with published NYISO (or Transmission Owner) system operating studies.

4) fails to maintain its automatic voltage regulator (AVR) in service and in automatic voltage control mode, or fails to commence timely repairs to the AVR.

Any resource that fails to provide voltage support when it is being paid to provide voltage support and is not otherwise excused pursuant to a forced outage, derate or maintenance outage as addressed in section 3.6.2 will be penalized in accordance as described below.

~~3.4.1~~3.5.1 Failure to Respond to NYISO's Request for Steady State Voltage Control

a) An installed capacity supplier of voltage support that fails to provide steady-state voltage support on a given day will forfeit 1/12th of the annual payment that resource would have received for providing voltage support, and must reimburse the NYISO for any lost opportunity costs paid to replacement sources of steady-state voltage support.

b) A non-installed capacity supplier of voltage support that fails to provide steady-state voltage support on a given day will forfeit the voltage support payment received by that resource in the last month in which that payment was positive (as a proxy for 1/12th of the annual payment that resource would have received for providing voltage support), and must reimburse the NYISO for any lost opportunity costs paid to replacement sources of steady-state voltage support.

c) A Resource will be disqualified as a supplier of voltage support after it fails to provide steady-state voltage support on three separate days within a 30-day period.

Reinstatement of Payments

The NYISO may reinstate payments once the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource must successfully perform a Reactive Power (MVAr) capability test, and
- the Resource must provide VSS for 30 consecutive days without any compliance failures. No payments for VSS or LOC are made to the Supplier during this period.

~~3.4.2~~3.5.2 Failure to Provide Voltage Support Service when a Contingency Occurs on the NYS Power System

a) An installed capacity supplier of voltage support that fails to provide voltage support following a contingency on a given day will forfeit 1/12th of the annual payment that resource would have received for providing voltage support on the first such occurrence, and 1/4th of the annual payment that resource would have received for providing voltage support on the second such occurrence. Generators that fail to provide voltage support following contingencies will not be charged lost opportunity costs for replacement sources of voltage support because there will not be enough time to arrange for replacement sources.

b) A non-installed capacity supplier of voltage support that fails to provide voltage support following a contingency on a given day will forfeit the voltage support payment received by that resource in the last month in which that payment was positive (as a proxy for 1/12th of the annual payment that resource would have received for providing voltage support) on the first occurrence. Additionally, it will forfeit the payment received by that resource in the last three months in which those payments were positive (as a proxy for 1/4th of the annual payment that resource would have received for providing voltage support) for the second failure.

c) A Resource will be disqualified as a supplier of voltage support after it fails to provide voltage support following a contingency on two separate occasions within a 30-day period.

Reinstatement of Payments

In addition, the Supplier that is in violation is prohibited from receiving VSS payments for the non-complying Resource until the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource successfully performs a Reactive Power (MVAr) capability test, and
- the Resource provides VSS for 30 consecutive days without any compliance failures. No payments for VSS or LOC are made to the Supplier during this period.

~~3.4.3~~3.5.3 Failure to Maintain Automatic Voltage Regulator in Service

a) A Resource will be disqualified as a supplier of voltage support after it fails to maintain the automatic voltage regulator in operation and fails to commence timely repairs following a failure of the automatic voltage regulator within a 30-day period.

Reinstatement of Payments

The Supplier will not receive Voltage Support Service payments for the disqualified Resource until the Supplier complies with the following conditions:

- the Supplier provides documentation to the NYISO of the completion of the repairs,
- the Supplier's Resource successfully performs a Reactive Power (MVAr) capability test, and
- the Resource provides Voltage Support Service for 30 consecutive days without any compliance failures. No payments for Voltage Support Service or LOC are made to the Supplier during this period.

~~3.5~~3.6 ~~Generator~~ Reactive Power Capability Testing or Demonstration

The purpose ~~for~~ of the Reactive Power capability testing or demonstration is to establish a uniform procedure of determining, confirming, and documenting the ~~reactive~~Reactive Power capability of ~~resources~~VSS Suppliers for real-time system voltage control~~, and provides the basis for compensation to suppliers of voltage support service. This procedure provides~~. The procedures set forth below provide the NYISO with accurate and timely information on the ~~reactive~~Reactive Power capability of the ~~generating units~~VSS Suppliers.

~~Units to be Tested~~

Each year~~All~~ resources that participate in ~~Voltage Support Service~~VSS must be tested to demonstrate both Lagging and Leading Reactive Power capability or must provide data collected during actual operation ~~in accordance with this procedure.~~~~each year~~ to demonstrate both Lagging and Leading Reactive Power capability. Tests may take the form of demonstration of Reactive Power capability based upon actual generator output data or tests conducted pursuant to the procedures set forth in this Manual. ~~All~~ T~~t~~ests ~~will~~must be coordinated with the NYISO and the Transmission Owner (TO) in whose service territory the unit is located. Test data reports must be submitted electronically by the VSS Supplier within five (5) business days of the test to the NYISO for review and~~, upon~~ acceptance ~~will be incorporated into the appropriate databases.~~. The demonstrated performance of the Lagging Reactive Power capability tests is the basis for compensation to Suppliers of VSS.

Definitions

Lagging MVAr — Reactive ~~power~~Power that is generated out of a generator and into the power system. By convention, lagging MVAr is a positive (+) number.

Leading MVAr — Reactive ~~power~~ Power that is absorbed by a generator out of the power system. By convention, leading MVAr is a negative (-) number.

~~3.5.1~~3.6.1 Frequency and Timing ~~of Testing~~

At least once each calendar year ~~E~~each ~~synchronous generator and synchronous condenser~~Resource providing ~~voltage~~ Voltage ~~support~~ Support ~~service~~ Service must test or ~~be tested at least once each calendar year to~~ demonstrate ~~maximum lagging and leading MVAr capability.~~both Lagging and Leading Reactive Capability. The demonstrated *Gross* Lagging MVAr capability will be the basis for compensation in the next compensation (calendar) year.

Both Lagging MVAr and Leading MVAr capability ~~testing~~ must be tested or ~~performed~~demonstrated ~~only~~ during the Summer capability period (May 1 through October 31, inclusive). Failure to test or ~~perform required testing~~demonstrate the resource's Reactive Power capability will result in the disqualification of the ~~unit(s)~~resource in the next compensation year.

Lagging MVAr capability testing will normally be performed during on-peak hours. ~~For generators, the lagging MVAr test must be performed at a net real power level of 90% (or greater) of its Dependable Maximum Net Capability (DMNC).~~ The VSS

Supplier must operate at maximum Lagging MVAr for at least one hour for the test to be acceptable.

The Leading MVAr testing will normally be performed during off-peak hours. ~~The leading MVAr test should be performed at the facility's minimum MW level (consistent with a real power level typical for off-peak or light load conditions).~~ The VSS Supplier must operate at maximum Leading MVAr for at least one hour for the test to be acceptable.

A VSS Supplier may schedule additional MVAr tests during the Summer capability period, however; only one test at a time may be scheduled. When scheduling an additional Reactive Capability Test, the VSS Supplier must again follow the test procedures given below. The VSS Supplier will be placed at the end of the queue for scheduling requests when requesting additional tests during a given capability period.

~~3.5.2~~3.6.2 Test Procedure for Generators

~~Each Supplier~~ Generator ~~has the responsibility to perform and report reactive capability testing on its respective units. The~~ Reactive Power capability tests are to be carried out under normal operating conditions. Extreme measures ~~are not to be taken to avoid overstating~~that might overstate a unit's ~~normally expected~~ reactive capability must be avoided. For example, measurements should be made with the unit operating with normal hydrogen pressure (or other normal coolant conditions). Both leading and lagging MVAr are to be measured at the generator terminal (gross) and, if metered data is available, at the point of interconnection (net). ~~Measurements should be made with the unit operating with normal hydrogen pressure (or other normal coolant conditions).~~ The lagging MVAr test must be performed at a net real power level of 90% (or greater) of the generator's Dependable Maximum Net Capability (DMNC). The leading MVAr test should be performed at the generator's minimum MW level (consistent with a real power level typical for off-peak or light load conditions).

The Transmission Owner ~~System Operator~~ is responsible for coordinating the test with the respective plant. Each Transmission Owner ~~System Operator notifies~~shall notify the NYISO at least one hour prior to the initiation of generator MVAr testing. The NYISO in turn notifies any other affected Transmission Owners. Test procedures are set forth below:

~~*Annual Tests*~~

~~It is the responsibility of the supplier to submit appropriate bids in the NYISO Day-Ahead Market such that the unit will be operating at the appropriate MW level for all tests. The Lagging MVAr test should be performed whenever practical during the on-peak period of the load cycle, and the Leading MVAr test should be performed whenever practical during the off-peak period of the load cycle.~~

~~To test maximum lagging MVAr capability, the unit being tested must be operated at, or above 90% of its Demonstrated Maximum Net MW Capability (DMNC). The unit is then moved to maximum lagging MVAr and held at this point for a minimum of one hour.~~

~~To test maximum leading MVAr capability, the unit being tested is operated at its normal MW low limit. The unit is moved to maximum leading MVAr and held at this point for a minimum of one hour.~~

~~For Nuclear units and units with normal MW low limits equal to normal MW operating capability, both leading and lagging MVAr capability are tested with the unit operating at its normal MW operating capability. Maximum lagging and leading MVAr test points are held for a minimum of one hour each.~~

~~*Test Results*~~

~~Attachment A shows the form that is used to document the test results that are submitted by the Supplier to the NYISO within ten (10) business days after the test. The test report shall include the supporting performance data, and must be submitted electronically. If the lagging and leading MVAr capability tests are performed on different dates, then the results can be submitted separately.~~

1. The VSS Supplier must notify the NYISO and the Transmission Owner (TO), at least five (5) business days prior to the day that the test is to be performed if the Supplier is a generator sized 100 MW or larger. Other VSS Suppliers must also notify the NYISO and TO of their plan to test, but a five-day notification is not required, though it is encouraged. The following information must be included in the notification of intent to perform a Reactive Capability test:
   - VSS Supplier name (as listed in the NYISO MIS)
   - VSS Supplier point identifier (PTID – a five digit number)
   - Net operating capability of the unit (MW)
   - VSS Supplier operator company name
   - Transmission Owner area
   - Test requested (lagging or leading)
   - Date and time of the test start
   - Name and telephone number of the person requesting the test

   A generator that is normally scheduled in the DAM and is operating within 100 MW of its normal operating capability may perform the MVAr test without the 5-day prior notification. If a generator's normal operating capability is less than 100 MW, the 5-day prior notification is also not required but is still recommended.

2. The NYISO will notify the VSS Supplier of the status of the request three (3) business days prior to the planned test date. It should be noted that test approvals are subject to a NYISO reliability review and the NYISO reserves the right to cancel or terminate the test at any time. The TO may also request that the NYISO cancel or terminate the test at any time should local reliability criteria be violated. The NYISO will document all approvals, cancellations, and terminations including the party ~~and reason~~ responsible and reason for implementing the cancellation or termination.

3. On the day prior to the scheduled date of the Reactive Capability Test, generators with a normal MW operating capability of 100 MW or greater must bid energy into the Day-Ahead Market (DAM). The bid must be structured to ensure that the generator is scheduled at the appropriate MW level for the hours requested to perform the Reactive Capability Test. The VSS Supplier must notify the NYISO (notify NYISO Generation Scheduling at (518) 356-6050) by hour 14:00 of the prior business day~~,~~ that the unit has been scheduled in the DAM, and that the test will be conducted as scheduled. If the generator is not scheduled, then the Reactive Capability Test is cancelled. If the generator has a net operating capability of less than 100 MW~~,~~ or if the generator is a quick start unit that can be committed by the Real-Time Commitment (RTC), a DAM bid is not required. The VSS Supplier must still notify the NYISO and the TO, by hour 14:00 of the prior business day, of the intent to perform a Reactive Capability Test.
4. On the day of the scheduled Reactive Capability Test, the VSS Supplier, through the TO, must request permission from the NYISO System Operator to perform the test at least three (3) hours prior to the test start time. The generator must also bid energy into the Hour-Ahead Market (if not previously committed in the DAM) to ensure that the generator is scheduled at the appropriate MW level for the hours requested to perform the Reactive Capability Test. The NYISO System Operator will approve or deny the request, through the TO, at least two (2) hours prior to the scheduled test, allowing time for any desired Hour-Ahead Market bid adjustments. The NYISO will document all approvals, cancellations and terminations of the tests. The log will include the name of the party and reason for implementing the cancellation or termination.
5. Upon beginning the test, the VSS Supplier must notify the NYISO System Operator, through the TO, that the Reactive Capability Test has started.
6. The NYISO will log that the VSS Supplier is performing a Reactive Capability Test.
7. Upon completion of the test, the VSS Supplier must notify the NYISO System Operator, through the TO, that the test is complete. The NYISO will log the completion time and the name of the generator plant personnel reporting the test.

~~3.5.3~~3.6.3 Test Procedure for Synchronous Condensers

Each synchronous condenser providing this service will be required to demonstrate the maximum leading and lagging MVAr capability it can maintain for one hour.

3.6.4 ~~Documentation of Test Results~~Reporting Requirements

Attachment B of this manual illustrates the spreadsheet that is to be used to document the results of Reactive Power capability tests and demonstrations. An electronic version of the ~~test~~ report spreadsheet is available on the NYISO's web site. Suppliers of VSS must complete the ~~test report~~ spreadsheet and submit the completed spreadsheet to the NYISO within ten (10) business days of the ~~test's~~ test or ~~completion~~demonstration. The ~~test~~ report spreadsheet must include supporting performance data including gross and net MW and MVAr output, terminal or station bus voltage, and unit auxiliary load MW and MVAr. These data must be sampled at the beginning and end of the test or demonstration ~~t~~ period and least once every five (5) minutes during the test or demonstration period. The ~~test~~ report spreadsheet must clearly indicate the start and end times of the test or demonstration period.

The completed test or report forms must be submitted electronically (by email) to the NYISO at the following email address: vss_test_results~~genplan~~@nyiso.com. If the lagging and leading MVAr capability tests or demonstrations are performed on different dates, then the results of the lagging and leading tests or demonstrations can be submitted separately.

The NYISO collects generator reactive capability data of VSS Suppliers. The NYISO provides these data to the operating division of the Generator's~~generator's~~ Transmission Owner (TO) within sixty (60) days of the end of the capability period. This allows sufficient time for the NYISO to assemble the data with due consideration to ~~g~~Generator owner reporting requirements.

~~3.5.4~~3.6.5 Allowance for Out-of-period Reactive Capability Testing

There are three (3) conditions where NYISO will provisionally accept testing for Voltage Support Service when that test is not conducted within the specified Summer Capability Period:

1. A new resource entering commercial operation, or
2. An existing provider's resource returning to service from an extended forced outage, or
3. An existing resource becoming eligible to qualify as a VSS supplier.

Initial Qualification of New Resource

For a new resource entering commercial service and requesting qualification as a Voltage Support Service supplier, the resource must complete the annual test requirements within thirty (30) days of entering service, and forward the completed test report, in electronic form, to NYISO within five (5) business days of the completion of that test. The resource shall also provide, in writing, the required documentation of the resource's reactive capability and automatic voltage regulator.

Existing Resource returning from Extended Forced Outage

An existing supplier's resource returning to service following an extended forced outage must complete the annual test requirements within thirty (30) days of returning to service, and forward the completed test report, in electronic form, to NYISO within five (5) business days of the completion of that test.

Existing Resource becoming eligible as a VSS Supplier

If, as the result of equipment upgrades or changes in qualification requirements, an existing supplier's resource becomes eligible, the Supplier must complete the annual test requirements within thirty (30) days of the effective date of the change in qualification requirement or equipment upgrade, and forward the completed test report, in electronic form, to NYISO within five (5) business days of the completion of that test.

Follow-up Testing Requirement

For any of the above conditions, the following conditions and requirements apply:

The NYISO will accept the demonstrated lagging MVAr capability as the basis for compensation on a provisional basis until the beginning of the next Summer Capability Period.

To continue qualification to receive VSS payments the resource is required to perform a complete annual test within thirty (30) days of the start of the Summer Capability Period, and forward the completed test report, in electronic form, to NYISO within five (5) business days of the completion of that test. This “in period” test will also qualify the resource for continued participation in the VSS in the next compensation year.

~~3.6~~3.7 Voltage Support

The following procedures apply to VSS.

~~3.6.1~~3.7.1 Request for Voltage Support Service

The NYISO may request corrective actions from voltage support facilities that are already in service and available. The procedures for Real-Time voltage control are covered in the ***NYISO Emergency Operations*** and ***Transmission & Dispatching Operations Manuals.***

~~3.6.2~~3.7.2 Voltage Support Availability

Supplier Actions:

The supplier is obligated to provide timely notification of any operational restrictions that may limit the voltage support capability.

The supplier must perform the following:

1) The Automatic Voltage Regulator (AVR) shall be maintained in service in automatic voltage regulation mode at all times, unless instructed otherwise by the NYISO or the Transmission Owner System Operator.

2) Provide immediate notification to the NYISO through the Transmission Owner System Operator whenever the AVR, or any other equipment necessary for maintaining the resource’s demonstrated ~~reactive~~ Reactive ~~power~~ Power capability (including, but not limited to, auxiliary cooling systems, exciters, etc.) is forced out of service or derated, and provided notice as required by the ***NYISO Outage Scheduling Manual*** prior to removal from service for scheduled maintenance.

Attachment A –
VSS Qualification Request Form

Voltage Support Services
Qualifications Request Form

- ________ Attached to this form is documentation that demonstrates that the resource(s) listed below have an Automatic Voltage Regulator (AVR).
- ________ Attached to this form is a completed NYISO Reactive Power Capability Test Report documenting that the resource(s) listed below have successfully performed Reactive Power capability testing during current calendar year.

The resource(s) listed below will participate in Voltage Support Ancillary Service under the direction of the NYISO and agree to comply with all applicable rules and procedures associated with NYISO voltage and ~~reactive power~~Reactive Power control.

Resource	***Type (Generator or Synchronous Condenser)***	***Location***	***NYISO ICAP Contract***	***NYISO MIS PTID***	***Generator MW Capability***

Market Participant Information:

____

Officer's Signature Date

New York ISO Approval:

____

Approved by Date

____

Manager, Grid Accounting and Settlements Date

~~Attachment B –~~
~~AGC Functional Requirements~~

~~AGC FUNCTIONAL REQUIREMENTS~~

~~In the AGC implementation, TOs will retransmit UDGs from the NYISO to individual generating units. The AGC function will calculate area control error and allocate this error to selected regulating units. AGC will determine the UDG for each unit by combining the unit's regulation requirement (if any) with its ramped basepoint derived from its RTD 5-minute basepoint. The NYISO computer system will send UDGs to TOs that will in turn retransmit the UDGs to generating units in their control area. Regulation penalties for all NYCA units will be assigned by the NYISO directly to individual generating units based on their monitored performance.~~

~~AGC GENERAL~~

~~Automatic Generation Control (AGC) shall provide supplementary control to automatically adjust the power outputs of generating units in the NYCA in response to changes in system net interchange and system frequency and that implements the unit basepoints calculated by NYISO's RTD function.~~

~~The AGC function shall execute periodically, with a user adjustable period initially set to six seconds.~~

- ~~AGC Preprocessing~~
- ~~Determination of AGC Control State, Area Control Error and Area Requirement~~
- ~~Select Specific Generating Units for Regulation~~
- ~~Unit Desired Generation~~
- ~~Monitor Conditions to Request Immediate SCD Execution~~
- ~~Unit Response Testing~~

~~AGC PROCESSING~~

~~The AGC function shall begin by preprocessing Real-Time inputs from the NYCA, including unit actual generation MW values, tie-line MW values, and system frequency. AGC shall also calculate the total Actual Net Interchange and Ramped Desired Net Interchange, and determine the ramped values of new unit basepoints calculated by Real-Time Dispatch (RTD).~~

~~AGC Real-Time Measurements, System Data, and Unit Data:~~

~~Real-time data will be scanned by the NYISO EMS computer system every six seconds and will be available in the NYISO mainframe database denoted as the In-Core Data Area (ICDA). The following Real-Time values will be provided to AGC in the ICDA:~~

- ~~Tie-line Values (MW)~~
- ~~Net Unit Actual Generation Values (MW)~~

- ~~Upper and Lower Operating Limits for each unit (MW)~~
- ~~Unit Operating Status Flags (On-Line, On-Dispatch, On-Control).~~

~~A telemetry status byte accompanying each data value will indicate whether or not the telemetered value is currently being updated by its source and whether or not it is considered to be valid. Automatic Generation Control shall use this status, along with a comparison of the value with individually user adjustable high and low reasonability limits, to create a data quality code for each value.~~

~~Confirmed invalid data shall generate an alarm message to the dispatcher and shall help determine whether or not AGC is suspended or tripped.~~

~~The following system data will be provided to AGC in the ICDA by other NYISO functions:~~

- ~~Desired Net Interchange, Start Time, and Ramp Interval~~
- ~~Inadvertent Payback Setter~~
- ~~Array of [(Tie Line MWh) - (Integral of Tie Line MW)] Values~~
- ~~Scheduled Frequency~~
- ~~Net Interchange Offset~~
- ~~Active Security Constraints.~~

~~The following unit data will be provided to AGC via the ICDA:~~

- ~~Normal Response Rates~~
- ~~Regulation Response Rates~~
- ~~Emergency Response Rates~~
- ~~Control Deadbands~~
- ~~RTD Basepoints~~
- ~~Matrix of Generator Shift Factors vs. Security Constraints~~
- ~~Reserve / Max Gen Pickup Flags~~
- ~~Step Change Factors.~~
- ~~Forbidden Region Limits~~
- ~~Governor Action Bias Factors.~~

~~In addition, certain values will be scanned once a second and the six most recent 1-second values will be saved in the ICDA. AGC shall utilize the six 1-second values to generate a smoothed 6-second value for further calculations. These 1-second values are:~~

- ~~(a) New Scotland frequency~~
- ~~(b) Tie-line MWs.~~

~~The existing EMS filters all Real-Time analog data (i.e., tie-line MWs, generation MWs, and frequency) using two filtering techniques:~~

- ~~A spike filter delays accepting significant step changes for one six-second scan, discarding the value if the change does not persist (significance limits adjustable for each type of variable)~~
- ~~A digital filter provides smoothing with the formula:~~

~~$x_i = 0.6*(\text{new input}) + 0.4*x_{i-1}$~~

~~where:~~

~~x_i = current filtered value of variable~~

~~x_{i-1} = previous value of filtered variable~~

~~The capability for additional input filtering, adjustable on an individual variable basis, shall be provided by AGC for future use should this prove necessary.~~

~~Frequency Measurement Processing~~

~~There are eleven redundant frequency values measured every six seconds throughout the NYCA. Any of these variables can be selected by the dispatcher for the system frequency used in AGC. The primary frequency measurement is the New Scotland 345 kV bus. Automatic Generation Control shall monitor all of the frequency measurements and provide diagnostic information to the dispatcher by generating alarm messages when they are flagged as bad by the EMS. Automatic Generation Control shall also generate an alarm when any of the frequencies are significantly different, implying an islanding condition.~~

~~Scheduled Frequency:~~

~~Automatic Generation Control shall obtain scheduled frequency from the NYISO Frequency Scheduling function via the ICDA. Whenever scheduled frequency changes, AGC shall use the new value in all subsequent calculations based upon the scheduled start time of the change.~~

~~Actual Net Interchange:~~

~~Automatic Generation Control shall calculate Actual Net Interchange (ANI) as the algebraic sum of all the tie-line MW values. There are no pseudo tie-lines representing generating units or loads located outside the contiguous NYCA. Automatic Generation Control shall also calculate a filtered Actual Net Interchange (ANI_f) for the Area Control Error.~~

~~Ramped Desired Net Interchange:~~

~~The Interchange Scheduler program determines the Desired Net Interchange (DNI) whenever there is a schedule change. In addition, the dispatcher may change the value of DNI at any time. The following DNI information packet is then provided to AGC in the Avanti database via point data exchange with the mainframe ICDA (previous DNI also available):~~

- ~~Desired Net Interchange~~
- ~~Ramp Start Time (explicit date and time or indication that start is immediate)~~

- ~~Optional percentage initial step change (see below).~~

~~Automatic Generation Control shall continuously monitor the DNI packet in Avanti. Whenever any of the above values change, AGC shall calculate a new ramped Desired Net Interchange that changes linearly to the new DNI value over the Ramp Interval beginning at the Ramp Start Time.~~

~~The starting point of the DNI ramp shall normally be either the ANI or the previous value of the ramped DNI, whichever is closer to the new DNI. However, if the current value of ANI is on the opposite side of the new DNI from the old DNI (greater than new DNI if DNI is increasing or less than the new DNI if DNI is decreasing), there will be no ramp. In this case, the value of the new DNI shall become effective immediately without a ramp at the DNI Start Time.~~

~~As a dispatcher option, a user adjustable percentage of the change to the new DNI may be taken at the beginning of the ramp, with the remainder of the change ramped linearly over the ramp interval.~~

~~Automatic Generation Control shall verify that the rate of change from the old DNI to the new DNI does not exceed a user adjustable rate (typically, 60 MW/min or 600 MWs over 10 minutes); that the start time is not past or too far in the future; that the ramp interval is not too long, nor the initial step too large. Automatic Generation Control shall generate an alarm message to the dispatcher if the new DNI fails these tests. Automatic Generation Control shall limit the change between the new DNI and the old DNI to 10 times the user defined rate.~~

~~Automatic Generation Control shall utilize the ramped value of DNI for all calculations involving DNI, including calculations when AGC is SUSPENDED or TRIPPED.~~

~~There is no requirement for dynamic interchange schedules that change dynamically in real time (as opposed to quarter-hourly or upon dispatcher entry).~~

~~During a system disturbance or when ACE becomes very large, the dispatcher may request that RTD-CAM operate in the Reserve Pickup or Maximum Generation Pickup mode. During a Reserve Pickup or Max Gen Pickup the DNI is held constant, this means AGC doesn't calculate the basepoints for the regulating units. In other words regulation is suspended during Reserve Pickup and Max Gen Pickup. Other RTD-CAM modes do not place a hold on changes to the DNI. Upon completion of the Reserve Pickup or Maximum Generation Pickup the value DNI is allowed to complete the interrupted ramp over the remaining portion of the original ramp interval. Similarly when AGC is TRIPPED or SUSPENDED, the DNI is also held constant.~~

~~When AGC is initially changed from OFF or TEST to any other control state, AGC shall set DNI to the final value of the Desired Net Interchange without any ramping.~~

~~Automatic Generation Control shall always observe a unit's Upper Operating Limit (UOL) and Lower Operating Limit (LOL) for both basepoint changes and regulation. Operating Limits shall not be exceeded unless the dispatcher manually overrides the limit value. If an Operating Limit is changed to a more restrictive value and the unit's actual generation is outside the new value, AGC shall immediately control the unit within the new limit. RTD generally observes limits more restrictive than the Operating Limits in determining unit RTD basepoints.~~

~~Unit Response Rates:~~

~~Each unit has up to three bid unit response rates:~~

- ~~NORMAL Response Rate (NRR) – the expected unit response rate for RTD basepoint changes (dispatchable units supplying energy). A unit may specify up to three NORMAL response rates. When multiple NORMAL response rates are defined, each is applied to a portion of the unit's operating range.~~
- ~~REGULATION Response Rate (RRR) – the expected unit response rate for regulation (units supplying regulation capability)~~
- ~~EMERGENCY Response Rate (ERR) – the expected unit response rate during Reserve Pickup and Maximum Generation Pickup modes (units supplying reserve capability for reserve pickup and all dispatchable units for max gen pickup)~~

~~For units supplying regulation, if RRR differs from the capacity-weighted NRRs, the total expected response rate is the maximum of the capacity-weighted NRRs and RRR. For units supplying reserve, ERR must be greater than or equal to the capacity-weighted NRRs.~~

~~Response rates are not calculated or based on unit test results but are specified by a unit's owner in the bidding process. They are assumed to be constant over the unit's entire operating range in both directions.~~

~~Ramped RTD Basepoints:~~

~~Under normal conditions RTD calculates new RTD basepoints for all MANUAL, BASE and REGULATE units in the NYCA 5 minutes and passes these values to AGC. RTD also sends the basepoints directly to these units to provide an advanced indication of expected unit loading.~~

~~Just prior to the start of each hour, the execution of RTD is deferred until 30 seconds after the hour. Real-Time Dispatch runs at that time to calculate proper new basepoints for all units that are scheduled hourly.~~

~~Automatic Generation Control shall have access to both the current and previous values of unit basepoints. Each set of basepoints includes a single time stamp to indicate when RTD calculated these values. Whenever AGC detects a change in the time stamp of the current basepoints, AGC shall calculate new Ramped RTD Basepoints (RBP) for all units.~~

~~The starting value for each basepoint ramp shall be determined differently for regulating units and non-regulating units:~~

~~calculated during the previous execution of RTD (modified if necessary for hydro units)~~

- ~~Non-Regulating Units – the starting value for the basepoint ramp shall be determined by the unit's actual generation in relation to the old basepoint calculated during the previous run of RTD and the new RTD basepoint, as follows:~~

~~If Actual Generation is below the old basepoint for a basepoint increase or above the old basepoint for a basepoint decrease, the Ramped RTD Basepoint shall begin the ramp from the old basepoint value and shall reach the new RTD basepoint value in exactly 5 minutes, with the value changing every AGC program execution~~

~~If Actual Generation is between the old and new basepoints, the Ramped RTD Basepoint shall begin from the value of the Actual Generation and reach the new RTD basepoint in exactly 5 minutes, with the value increasing every AGC program execution~~

~~If Actual Generation is above the new basepoint for a basepoint increase or below the new basepoint for a basepoint decrease, the Ramped RTD Basepoint shall be set immediately to the value of the new basepoint.~~

~~The value of the Ramped RTD Basepoint will be included in the determination of each unit's Unit Desired Generation (UDG).~~

~~Automatic Generation Control is not required to check whether or not the ramp rate to the new RTD basepoint for any unit exceeds the Normal or Emergency Response Rates for that unit. However, AGC shall ensure that the new basepoint observes the unit's Upper and Lower Operating Limits. AGC shall also restrict new basepoints to a user adjustable maximum basepoint change limit for each generator.~~

~~All units that are NOT "self-committed fixed" are expected to respond to a reserve pickup 10-minute basepoint at its emergency response rate as bid. If the unit exceeds the given basepoint established by RTD-CAM or Reserve Pickup is deactivated, whichever occurs first, it will be paid for the overgeneration. However, the unit must return to its RTD basepoint, which will be consistent with the LBMP, within three RTD intervals (15 min) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.~~

~~On Control with or without a reserve award:~~

~~An on-control unit providing 6 second AGC regulation is expected to respond to a reserve pickup 10-minute basepoint at its stated response rates bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its RTD/AGC basepoint, which will be consistent with the LBMP, within three RTD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the 3-RTD interval grace period.~~

~~Automatic Generation Control shall bias the ramped basepoints for regulating hydro units to allow them to stay close to their scheduled water release profile. For example, if during NYCA system morning load pickup, a regulating hydro unit regulates above its RTD basepoint much more often than below it, it will release too much water. Automatic Generation Control shall accumulate the net amount of regulation energy $\Sigma(UDG_i - RBP_i)$ every control cycle between midnight and midnight for each regulating hydro unit and, whenever the magnitude of regulation energy exceeds a user adjustable limit for each unit, bias the unit's RTD basepoint by an individually adjustable fixed offset in the direction to reduce the accumulated regulation energy. The regulation energy accumulation for a unit shall be reset to zero whenever the AGC control state or the unit control mode changes and at midnight.~~

~~Determination of AGC Control State, Area Control Error, and Area Requirement~~

~~The AGC function shall determine its Control State based upon conditions in the NYCA and upon dispatcher entry. The calculation of Area Control Error, filtered Area Control Error, and Area Requirement shall be the next steps in defining control requirements for generating units involved in regulation for the NYCA.~~

~~AGC Control States:~~

~~The AGC function shall operate in one of the following AGC Control States:~~

- ~~ACTIVE – All AGC functions operational~~
- ~~SUSPENDED – Inputs processed, desired net interchange (DNI) ramped, ACE calculated, and UDG calculations for regulating units temporarily changed to follow ramped RTD basepoints only (holding the last deviation from basepoint due to regulation)~~
- ~~TRIPPED – Functionally similar to SUSPENDED, AGC goes to TRIP state after being SUSPENDED for a user adjustable period of time or upon dispatcher command. In addition, the regulation component shall be gradually removed from the values of UDG for regulating units.~~
- ~~OFF – AGC not operational; all UDGs held constant.~~
- ~~TEST – AGC functions operational except UDGs are displayed and saved but not sent to units (OFF state telemetered to generating units).~~

~~Transition to/from TEST or to/from OFF and between ACTIVE and TRIPPED shall be under dispatcher control only; transitions between ACTIVE and SUSPENDED shall be automatic based upon the occurrence and duration of any of the conditions defined below.~~

~~The SUSPENDED state shall only be reached from the ACTIVE state. When the condition causing the SUSPENDED state is relieved within a user adjustable period, either on its own or by means of dispatcher manual override, transition back to ACTIVE shall occur automatically. When the SUSPENDED state is not relieved within this period, an automatic transition of AGC control state from SUSPENDED to TRIPPED shall occur. The dispatcher may also transfer AGC to TRIPPED at any time.~~

~~The AGC Control State shall be transmitted to all generating units and to the TOs either every 6 seconds or upon change.~~

~~AGC shall be automatically suspended upon occurrence of any of the following conditions that are sustained for longer than a user adjustable period of time:~~

- ~~Excessive ACE (separate limit in each direction)~~
- ~~Invalid frequency telemetry~~
- ~~Invalid telemetry from any significant tie-line (i.e., last valid value greater than a user adjustable limit per tie-line in each direction)~~
- ~~Invalid telemetry from any of a predefined set of significant generators.~~

~~Failure of input validity shall be determined when a value is outside its Reasonability Limits, when the status of the input is BAD, or the input telemetry is marked as FAILED in the system database. However, AGC shall not be suspended upon the occurrence of large frequency excursions.~~

~~Upon AGC suspension, the dispatcher shall be notified and the calculation of UDGs shall be modified as described below.~~

~~AGC Trip:~~

~~Automatic Generation Control shall be automatically tripped when AGC has been suspended for more than a user adjustable time period or upon dispatcher direction. Upon AGC trip, the dispatcher shall be notified and the calculation of UDG shall be modified as described below.~~

~~Sign Conventions:~~

~~The sign conventions for AGC shall be as follows:~~

- ~~Power Flow INTO the NYCA is POSITIVE (+)~~
- ~~Net Interchange (both Desired Net Interchange (DNI) and Actual Net Interchange (ANI)) INTO the NYCA is POSITIVE (+)~~
- ~~For Inadvertent Interchange, defined as (DNI – ANI), POSITIVE (+) indicates excess generation~~
- ~~Frequency Bias Coefficient is NEGATIVE (–)~~
- ~~POSITIVE (+) ACE indicates excess generation and requires generation to DECREASE.~~

~~ANI Filtering:~~

~~The AGC function shall provide a filter for total actual net interchange with user adjustable tuning coefficients. The result of this filter will be denoted ANI_f. The filter shall operate as follows:~~

~~$NI_I = * ANI + (\beta * NI_{i-1}$~~
~~Where $= ½ANI - NI_{i-1}½/K$~~
~~$\beta = 1 - \alpha$~~
~~κ = Filter Constant~~
~~Also, if $\alpha > 1$, $NI_i = ANI$.~~

~~purpose of NERC compliance calculations and filtered Area Control Error (ACE_f) in order to develop the control requirement to minimize NYCA deviation from the scheduled values of frequency and net interchange. The value of ACE shall be determined as follows:~~

$$ACE = [(DNI - IPS) - (ANI + NIO)] - [\beta_f * (F_A - F_S)]$$

~~The value of filtered area control error (ACE_f) shall be determined as follows:~~

$$ACE_f = [(DNI - IPS) - (ANI_f + NIO)] - [\beta_f * (F_A - F_S)]$$

~~Where:~~

- ~~ACE = Unfiltered Area Control Error~~
- ~~ACE_f = Filtered Area Control Error~~
- ~~DNI = Desired Net Interchange~~
- ~~ANI = Unfiltered Actual Net Interchange~~
- ~~ANI_f = Filtered Actual Net Interchange~~
- ~~IPS = Inadvertent Payback Setter (see below)~~
- ~~NIO = Net Interchange Offset (includes meter error correction) (see below)~~
- ~~βf = Frequency Bias Coefficient (currently -2880 MW/Hz)~~
- ~~FA = Actual Frequency~~
- ~~FS = Scheduled Frequency (default value = 60.0 Hz)~~

~~As a selectable alternative to the above calculation of ACE_f, the Actual Net Interchange shall not be filtered but instead the raw value of unfiltered ACE shall be filtered. This filtered raw ACE may be utilized instead of ACE_f.~~

~~In either case, filtering shall be provided such that load trends, interchange schedule changes, and frequency deviations are recognized, but fast, zero-mean, randomly varying changes in ACE are removed and unnecessary unit control is minimized. The filtering algorithm shall not delay AGC response to controllable ACE excursions nor respond to fast transient excursions. Nonlinear filtering techniques or statistical methods are acceptable.~~

~~Also in either case, the raw value of ACE, which includes the spike filtering and simple smoothing for each tie line input to exclude transient telemetering problems, shall only be used for NERC Performance Monitoring purposes.~~

~~ACE Calculation Modes:~~

~~Automatic Generation Control shall normally operate in Tie-Line Bias Control Mode using the above formula to calculate ACE_f. Operation in either Constant Net Interchange Mode [$ACE_f = (DNI - IPS) - (ANI_f + NIO)$] or Constant Frequency mode [$ACE_f = - \beta_f * (F_A - F_S)$] shall be selected by the dispatcher when necessary.~~

~~There is no requirement for special automatic inadvertent or time error correction modes. Inadvertent interchange corrections will be implemented by creating firm transactions that affect DNI. Time error correction will be implemented via dispatcher changes to the value of~~

~~default values without explicit numeric entry.~~

~~In the event of islanding of the NYCA, the dispatcher shall be able to select Constant Frequency mode and place AGC in the ACTIVE control state to control a single control area that includes those generators specified by RTD with electrical connectivity to the NYISO Control Center.~~

~~Inadvertent Payback Setter:~~

~~The Inadvertent Payback Setter (IPS) component of ACE is used to payback energy under the specific cases of NPCC shared activation of reserve or unilateral paybacks under NERC rules. IPS is set manually by the dispatcher.~~

~~Net Interchange Offset:~~

~~The Net Interchange Offset (NIO) component of ACE is used to correct for differences between MW and MWh metering. NIO is calculated by AGC every 6 seconds as the algebraic sum of an array of values in the ICDA that lists the difference between the hourly MWh meter reading and the integrated instantaneous MW value for each tie-line for the previous hour.~~

~~ACE Deadband:~~

~~When the magnitude of raw ACE falls within a user adjustable deadband, the calculated value of ACE_f shall be set to zero.~~

~~Area Requirement:~~

~~The Area Requirement (AR) shall be determined from ACE_f using a control scheme that incorporates both ACE_f and the integral of ACE_f. The integral term shall increase the Area Requirement when the magnitude of ACE_f is moderate and persists at nearly a constant value. The integral term shall be reset whenever:~~

- ~~ACE_f is changing more than a user adjustable amount per AGC cycle~~
- ~~ACE_f magnitude falls within its user adjustable deadband~~
- ~~ACE_f crosses zero~~
- ~~ACE_f magnitude exceeds a user adjustable limit~~
- ~~AGC control state changes~~
- ~~Change in dispatcher selection of either integral term or ACE biasing (defined below).~~

~~The integral term shall not result either in overshoot when regulating units are moving to correct a large ACEf or cause AR to windup when AGC is not ACTIVE. Optionally, AR shall also take into account the total anticipated unit response to previous control actions.~~

~~Note that the use of the term "Area Requirement" in this Specification differs from the traditional use of the term, where area requirement is equivalent to negative area control error.~~

~~not result in appropriate response to ACE_f. In this case, AR shall be determined from ACE_f using an ACE Biasing term instead of the integral of ACE_f. The ACE Biasing term shall add to or subtract from ACE_f a value whose magnitude increases linearly (up to a limit) when the magnitude of ACE_f remains outside a user adjustable limit for more than a user adjustable time period. The bias shall decrease at a user adjustable rate when the magnitude of ACE_f returns within another limit for more than a user adjustable time period. Setting AR equal to ACE_f plus the ACE Biasing term in lieu of ACE_f plus the integral of ACE_f, or setting AR equal to ACE_f, shall be selectable by the dispatcher.~~

~~Feedforward Control:~~

~~The AGC function shall reduce unnecessary control action at regulating units by compensating for unit response lag with feedforward control. The feedforward logic shall anticipate response to prior control actions and introduce appropriate compensation while waiting for regulating units to respond. Individual units need not be modeled separately but regulating units will be considered as a single lumped unit with a single lag.~~

~~The vendor shall recommend a feedforward control method that should consider AGC control outputs over (at least) the previous 5 control cycles and take into account the removal of control windup from Unit Desired Generation values.~~

~~Predictive Features:~~

~~The AGC algorithm is not required to incorporate predictive features for load or interchange. The RTD function incorporates a 5-minute load forecast, the anticipated change to DNI, and units starting up or shutting down in determining the basepoints for all units.~~

~~Select Specific Generating Units for Regulation~~

~~Although the bid Regulation Response Rates could be used to distribute the Area Requirement to all regulating units every AGC cycle, a more sophisticated selection of specific generating units for regulation shall be made to achieve a variety of objectives. These objectives include improvement in overall system responsiveness to AR, observing security constraints, keeping regulating units operating close to their (ramped) RTD basepoints, and reducing the frequency and amount of loading changes requested for each unit.~~

~~To achieve these objectives, units shall be selected for regulation with a 6-step process:~~

- ~~Establish unit control mode (e.g., OFFLINE, MANUAL, BASE, REGULATE or TEST).~~
- ~~Calculate the preliminary effective response rate actually available from each regulating unit taking into account its bid Regulation Response Rate, unit operating limits, and the direction of basepoint ramping relative to the direction to reduce AR.~~
- ~~Rank regulating units in order of preference for use this control cycle based upon security constraints, preliminary effective response rate, the magnitude of AR, the deviation of unit actual generation from its ramped RTD basepoint, direction of RTD ramp to reduce/increase AR, whether the unit is stopped or already moving in the direction to increase or decrease AR, and how often the unit has been selected previously for regulation.~~

~~units.~~

- ~~Determine the total amount of regulation required to reduce AR to zero in a reasonable period of time.~~
- ~~Select the specific regulating units in order of rank necessary to provide the total amount of regulation required.~~

~~Unit Control Modes:~~

~~Automatic Generation Control shall support generators in various unit control modes. AGC shall derive (as a minimum) the following unit control modes, which are derived from the three unit operating status flags received in Real-Time from TOs associated with each generating unit and from dispatcher entries:~~

- ~~UNAVAILABLE – Unit offline with the unit breaker tripped, unavailable for reserve contribution, and not considered by AGC (On-Line flag reset)~~
- ~~OFFLINE/AVAILABLE (OFFLINE) – Unit offline with the unit breaker tripped, available for reserve pick-up, but not considered by AGC (On-Line flag reset)~~
- ~~OFF-DISPATCH (MANUAL) – Unit breaker closed and unit manually controlled in the field by unit personnel based upon its RTD recommended basepoint sent every 5 minutes (includes hourly schedule changes and the periods during a unit's initial ramp up to minimum generation and final ramp down prior to shut down according to a ramping profile (On-Line flag set, On-Dispatch Flag reset)~~
- ~~ON-DISPATCH/NON-REGULATING (BASE) – Unit breaker closed and unit automatically controlled by AGC to its ramped RTD basepoint without contribution to regulation (On-Line & On-Dispatch flags set, On-Control flag reset)~~
- ~~ON-DISPATCH/REGULATING (REGULATE) – Unit breaker closed and unit automatically controlled by AGC to the combination of its ramped RTD basepoint and its regulation requirement (On-Line, On-Dispatch & On-Control flags set)~~
- ~~TEST – Unit breaker closed and unit automatically controlled using NYISO dispatcher-entered UDG (On-Line & On-Dispatch flags set plus dispatcher entry to override On-Control flag).~~

~~The dispatcher may change the derived unit control mode as follows:~~

- ~~REGULATE to BASE~~
- ~~REGULATE or BASE to MANUAL or TEST~~
- ~~TEST to/from MANUAL.~~

~~The unit control mode currently in effect shall be transmitted to each of the generating units either periodically or upon change.~~

~~The next step in selecting units for regulation during a particular AGC control cycle is the determination of their preliminary effective regulation response rates (PERRRs). PERRRs are the unit response rates actually available from regulating units. The term “preliminary” implies that subsequent adjustments will be made to these values.~~

~~PERRRs are transient and, every control cycle, may vary from the values of the Regulation Response Rates (RRRs) bid for those units. PERRR values depend upon whether the regulating units are already being ramped to new RTD basepoints that tend to increase or decrease AR and are also affected when units reach their operating limits.~~

~~For a regulating unit not at its operating limit and already ramping in a direction to decrease AR, its effective (additional) regulating response rate shall be the difference between its bid RRR and its ramp rate (ERRR = RRR-|BPR|). If its basepoint ramp rate exceeds RRR, there is no additional response rate available and ERRR shall be zero.~~

~~Alternatively, if a regulating unit is already ramping in a direction to increase AR, AGC shall have the option of stopping the basepoint ramp (PERRR = |BPR|) and, possibly, reversing the unit to move it at its RRR in the opposite direction (PERRR = RRR+|BPR|).~~

~~If there is no basepoint ramp, the PERRR shall equal its RRR.~~

~~When a regulating unit reaches an operating limit, its PERRR shall be determined in a similar fashion. However, when the limit blocks unit movement for regulation, ramping, or both, the value of PERRR is affected depending upon the relative direction of its basepoint ramp and its regulation requirement.~~

~~These conditions may be summarized as follows:~~

~~Unit Not At Limit~~

~~BPR & AR move unit in same direction: PERRR = RRR-|BPR| (or 0 if |BPR|>RRR)~~
~~BPR & AR move unit in opposite directions: PERRR = |BPR| (possibly RRR+|BPR|)~~
~~BPR = 0: PERRR = RRR~~

~~Unit At Limit~~

~~BPR & AR both move unit beyond limit: PERRR = 0 (no movement possible)~~
~~BPR & AR both move unit in from limit: PERRR = RRR-|BPR| (or 0 if |BPR|>RRR)~~
~~BPR moves unit beyond limit & AR opposite: PERRR = |BPR| (possibly RRR+|BPR|)~~
~~BPR moves unit in from limit & AR opposite: PERRR = |BPR| (stop ramp)~~

~~Composite Priority Factors:~~

~~When the magnitude of AR is small or moderate, AGC shall not distribute the control requirement to all the regulating units available but shall use units deemed best during that control cycle. In order to select the most appropriate regulating units for control, AGC shall rank each unit in order of preference based upon a Composite Priority Factor (CPF) determined, separately for each regulating unit, on the following priority factors:~~

- ~~Deviation of the units desired generation calculated last AGC cycle from the unit’s current ramped RTD basepoint~~

- ~~Whether or not the unit's actual generation is changing or the unit is stopped, and~~
- ~~How often the unit has recently been selected for regulation.~~

~~Each of these priority factors shall be calculated as a numeric value from 0 to 1.0 and then be weighted with a user adjustable priority factor coefficient common to all units. Each priority factor shall also be enabled or disabled based upon the magnitude of AR, compliance with the NERC Control Performance Standards, and/or at dispatcher option. The weighted and enabled factors shall be added together to generate the CPF for each regulating unit.~~

~~Automatic Generation Control shall be sufficiently flexible to permit the addition of other CPF priority factors.~~

~~Deviation from Ramped RTD Basepoint Priority Factor:~~

~~A regulating unit that is controlled away from its ramped RTD basepoint may eventually approach an operating limit. In order to maintain regulating margin in both the raise and lower directions, it is preferable to operate this unit close to its basepoint. Units that are farthest from their ramped basepoints and can be moved towards those basepoints in a direction to decrease AR shall have a higher priority factor than other units. The size of the CPF shall be inversely proportional to the Regulation Response Rate of the unit so that units that move quickly away from their basepoints will not be assumed to be abnormally far from their basepoints relative to units that move more slowly. This element shall also be normalized to keep the element in proportion to other elements in CPF. The Basepoint Deviation Priority factor shall be calculated as follows:~~

~~Deviation = ((UDG~~$_{t-1}$ ~~– RBP)*(SIGN(AR)) / (RRR/ΣRRR~~$_i$~~)~~
~~Normalized Deviation = (Deviation – Lowest Deviation) / (Highest Deviation – Lowest Deviation)~~
~~Weighted Deviation = Normalized Deviation *~~ C_D
~~Basepoint Deviation Priority Factor = Weighted Deviation * [Enable (1) or Disable (0)]~~

~~Where:~~

~~UDG~~t-1 ~~= Previous UDG~~
~~RBP = Ramped RTD Basepoint~~
~~AR = Area Requirement~~
~~RRR = Regulation Response Rate~~
~~ΣRRR~~$_i$ ~~= Sum of RRR for all REGULATE units~~
~~Lowest Deviation = Lowest algebraic value of Deviation (may be negative)~~
~~Highest Deviation = Highest algebraic value of Deviation~~
C_D ~~= Deviation coefficient (common for all units)~~

~~It may be desirable (and easier) to speed up units already ramping to a new RTD basepoint in the direction that decreases AR rather than to control units that are not ramping or that are ramping to a basepoint that increases AR. Units that are already ramping in a direction to increase AR may be more desirable to slow down or stop ramping than to control a unit not currently ramping. The Ramping Direction Priority Factor attempts to quantify these preferences. The Ramping Direction Priority factor shall be calculated as follows:~~

~~Ramp Index =~~

~~1.0 if basepoint ramp decreases AR~~
~~0.5 if basepoint ramp increases AR, or~~
~~if either ramp rate or AR is 0~~

~~Weighted Ramp Index = Ramp Index * C_R~~

~~Ramp Direction Priority Factor = Weighted Ramp Index * [Enable (1) or Disable (0)]~~

~~where:~~

~~C_R = Ramp Index coefficient (common for all units)~~

~~Unit Moving Priority Factor:~~

~~It may be desirable to utilize units already moving for regulation rather than units that are stopped. If so, the Unit Moving Priority Factor will raise the priority of moving units. The Unit Moving Priority factor shall be calculated as follows:~~

~~Moving Index =~~

~~1.0 if unit actual generation has changed by more than an individually user adjustable limit per unit over the past n control cycles~~
~~0.0 if unit actual generation has not changed~~

~~Weighted Moving Index = Ramp Index * C_M~~

~~Unit Moving Priority Factor = Weighted Moving Index * [Enable (1) or Disable (0)]~~

~~where:~~

~~C_M = Moving Index coefficient (common for all units)~~

~~Unit Usage Priority Factor:~~

~~It may not be desirable to use some regulating units often and others infrequently. The Unit Usage Priority Factor gives preference to units that have not been used for regulation recently. The Unit Usage Priority factor shall be calculated as follows:~~

~~Usage = Number of times a unit has been selected for regulation in the past m control cycles~~

~~Normalized Usage = (Highest Usage – Usage)/(Highest Usage – Lowest Usage)~~

~~Unit Usage Priority Factor = Weighted Usage Index * [Enable (1) or Disable (0)]~~

~~where:~~

~~C_U = Usage Index coefficient (common for all units)~~

~~Enable/Disable Priority Factors:~~

~~Each of the above priority factors shall be enabled or disabled based upon the magnitude of AR, whether or not the NYCA is operating in compliance with the NERC Control Performance Standards, and/or based on dispatcher entry.~~

~~Whenever the magnitude of AR exceeds a user adjustable limit for each category of priority factor, that priority factor shall be temporarily set to zero. Similarly, whenever the NYCA is not operating in compliance with the NERC Control Performance Standards as defined below, Calculate NERC Compliance Criteria, each of the priority factors may be disabled. Finally, the dispatcher shall be able to enable or disable any individual priority factor separately for each regulating unit.~~

~~Fast-Response Units:~~

~~Regulating units with very fast response rates shall be controlled back to their basepoints once they reach an operating limit as long as the magnitude of AR remains small. Fast-response units being controlled back to their basepoints shall have their composite priority factor set to zero to avoid being selected for regulation. Fast-response units shall be identified as having a RRR greater than a user adjustable limit.~~

~~Security Constraints:~~

~~The RTD function establishes unit basepoints that meet the twin objectives of meeting forecasted system load and relieving security constraints imposed by both real and contingency overloads. In order that AGC not undo the efforts of RTD to maintain system security, AGC shall take security constraints into account when ranking regulating units to minimize AR.~~

~~To facilitate this process, RTD can provide security constraint information to AGC using two possible alternatives – dynamic unit operating limits and generator shift factors.~~

~~Under the first alternative, RTD will calculate dynamic unit operating limits for each regulating unit. These limits, inside or equal to the Upper and Lower Operating Limits for each regulating unit, will constrain AGC from making active security constraint violations worse.~~

~~Alternatively, there exists already within the NYISO computer system a separate process that generates and maintains a matrix of generator shift factors (GSFs) for every generator vs. every predefined security constraint in the NYCA. These shift factors define the sensitivity of each generator to potential constraints on system facilities, along with an indication of the direction of power flow. The matrix will be recalculated for every significant change in network topology by the separate NYISO process. Every 5 minutes, RTD will identify to AGC those constraints that are active in the NYCA (including direction) and AGC shall avoid moving units in a manner that would make active constraints worse.~~

~~AGC shall identify the shift factors (i.e., elements on the active constraint rows in the GSF matrix) that correspond to “active” constraints. Depending on the sign and magnitude of the identified shift factors, AGC shall then determine whether the associated generators should be prevented from regulating in the raise direction, in the lower direction, or in either direction.~~

~~Only GSFs whose magnitudes are greater than an adjustable GSF threshold will be considered as “significant” for this process. The GSF threshold shall be calculated according to the following formula:~~

> ~~GSF Threshold = $k_1 - k_2$ * ½AR½, where k_1 and k_2 are user adjustable (positive) coefficients for each generator.~~

~~If all the “significant” GSFs for a regulating unit are positive, the unit will be not be used to regulate in a raise direction during that AGC program execution. If all the “significant” GSFs for a unit are negative, the unit will be not be used to regulate in a lower direction. If some “significant” GSFs are positive and some are negative, the unit will not be used for regulation in either direction, depending upon the magnitudes of these factors. If no GSFs are “significant,” there will be no restrictions on regulating unit movement. Depending upon the control requirement to raise or lower the regulating unit, AGC shall either set the Composite Priority Factor to zero or leave it unchanged.~~

~~The effect on system operation of preventing regulating units from making constraint violations worse is the reduction of regulation capability in one or both directions. Depending upon the magnitude of AR and the response rates of the remaining units, AGC may not be as aggressive in minimizing AR in the presence of security constraints. If AR becomes large and/or AGC response is not sufficiently aggressive, an alarm message shall be issued and the dispatcher may select additional regulating units based on their location in the network and/or shall be disable one or more security constraints for consideration in this process or choose to disable all security constraints on AGC.~~

~~Create Ordered List of Regulating Units:~~

~~Based upon the magnitude of the Composite Priority Factor (CPF) for each regulating unit, AGC shall create an ordered list of units available for regulation this control cycle ranging from the most desirable to the least desirable unit. Units with zero CPFs shall not be included on the list.~~

~~Create List of Total Available Regulation Response Rates:~~

~~AGC shall calculate the Total Available Regulation Response Rate (TARRR) for each combination of regulating units on the list of units available for regulation this control cycle. Beginning with the Effective Regulation Response Rate (ERRR) for the most desirable unit, this list will consist of increasing TARRRs for increasing numbers of less desirable units one at a time up to and including the TARRR for all units on the list.~~

~~AGC shall calculate the Required Regulation Response Rate (RRRR) this AGC cycle as a function of the magnitude of AR. The RRRR is a method of expressing the desired number of control cycles it will require to reduce |AR| to zero.~~

~~RRRR shall be determined from a calculation (e.g., RRRR proportional to |AR|), RRRR calculated from a segmented curve based upon whether |AR| is small, medium or large, or RRRR determined from a table lookup function). The goal of determining RRRR in this fashion is to vigorously respond to large values of |AR| while not moving units unnecessarily when |AR| is small.~~

~~Calculate NERC Compliance Criteria:~~

~~AGC shall determine the current and projected compliance of the NYCA with the NERC Performance Standard performance measures, CPS1 and CPS2, and the NERC Disturbance Control Standard (DCS).~~

~~AGC shall calculate current compliance with CPS1 and CPS2 in accordance with the Performance Standard Training Document and the Control Performance Criteria Training Document in NERC's Operating Policies. AGC shall calculate a CPS1 Compliance Factor and a CPS2 Compliance Factor that are functions of unfiltered ACE times frequency deviation and of |ACE|, respectively. When this compliance is poor over a user adjustable period of time, or is projected to be poor over the full accounting period based upon performance so far, AGC shall periodically issue an alarm message to the dispatcher, adjust the Composite Priority Factors defined above, and increase the Required Regulation Response Rate (RRRR) by a user adjustable amount.~~

~~AGC shall also detect disturbance conditions based upon NERC criteria and determine projected compliance with DCS over the ten minutes following the disturbance. AGC shall issue an alarm message to the dispatcher when a disturbance is detected and when the value of ACE returns either to zero or to its pre-disturbance value, as appropriate. When compliance is projected to be poor, AGC shall issue an alarm message to the dispatcher at a user adjustable periodicity and shall also increase the Required Regulation Response Rate (RRRR) as needed until ACE returns to either zero or its pre-disturbance value.~~

~~Minimize Unit Control Activity:~~

~~In order to reduce the amount of control issued to regulating units, AGC shall determine whether or not any regulation control changes should be issued this AGC cycle. This determination shall be based upon several factors, including how recently changes were issued, the magnitude of AR, the Required Regulation Response Rate, the NERC Compliance Criteria, and/or the net magnitude of the anticipated control error changes requested from regulating units but not yet acted upon.~~

~~Select Regulating Units & Calculate Final ERRRs:~~

~~Based upon the Required Regulation Response Rate (RRRR) this control cycle, AGC shall select the appropriate number of units for regulation. For example, if RRRR can be satisfied by the highest priority five units out of eight units available, the AR shall be distributed to these five~~

~~(ERRRs) set to zero for all units not selected for regulation.~~

~~If insufficient regulation response rate is available from all regulating units with non-zero CPFs, AGC shall invoke additional regulation response rates from regulating units ramping in the opposite direction. Up until this determination, the ERRR for these units represented simply stopping them from ramping (ERRR = |BPR|). However, in cases of insufficient TARRR, these units will be not only stopped, but will be reversed and the full Regulation Response Rate in the opposite direction shall be utilized. AGC shall change their ERRRs to include RRR (ERRR = RRR+|BPR|). The additional regulating response rate from these units shall be invoked one at a time in order of their CPFs for this purpose until RRRR is satisfied. The value of TARRR will be updated with each increase in ERRR. All other selected regulating units shall have their ERRR set to the values of PERRR determined previously.~~

~~Unit Desired Generation~~

~~AGC shall calculate Unit Desired Generation (UDG) for all units on control in the NYCA. UDG shall be determined in accordance with the following four steps:~~

- ~~Initialization and remove control wind-up, if any, in previous values of UDG~~
- ~~Calculate the value of UDG~~
- ~~Add an initial step change if required~~
- ~~Augment the UDG with governor action bias, if necessary.~~

~~UDG Initialization and Removal of Control Wind-Up:~~

~~When AGC control status first changes from OFF or TEST to TRIPPED or ACTIVE, AGC shall initialize the previous value of UDG for every unit to equal the value of its current actual generation.~~

~~For regulating units attempting to reduce AR to zero, the UDG values will always be ahead of unit actual generation since these units cannot follow UDG precisely. If AR suddenly returns close to zero or changes sign, the UDGs for these units will temporarily continue to request generation changes that are no longer required. Consequently, the previous value of UDG for a regulating unit with control windup shall be set either to the value of its current actual generation or its ramped RTD basepoint, which ever is closer to the previous UDG. Windup in a regulating unit UDG value shall be assumed when AR returns within its deadband or changes sign and the UDG is either greater than or less than both its actual generation and its ramped basepoint.~~

~~Calculate UDG:~~

~~AGC shall determine the value of UDG for all MANUAL, BASE and REGULATE units. The UDG for any unit shall not exceed its operating limits (UOL or LOL). UDG shall be calculated to the nearest tenth of a MW. The method of calculating UDG shall depend upon whether AGC is ACTIVE/TEST, SUSPENDED/TRIPPED, or OFF.~~

~~While AGC is in the ACTIVE or TEST control state, UDGs shall be calculated based upon their previous UDGs, their basepoint ramp rates, and, for regulating units, their ERRR values. The only difference between ACTIVE and TEST is that when AGC is in TEST control state, the final UDG values are not sent to the generating units.~~

~~The specific determination of UDG for each unit depends upon its unit control mode:~~

- ~~OFFLINE: No UDG is calculated~~
- ~~MANUAL & BASE: UDG shall equal the previous value of UDG calculated last AGC program execution plus the delta ramped RTD basepoint. The delta ramped RTD basepoint is calculated whenever the basepoint changes:~~

~~$UDG_i = UDG_{i-1} + \Delta RBP_i$~~

~~where:~~

~~UDG_i = Unit Desired Generation for regulating unit i~~
~~UDG_{i-1} = Previous value of UDG for regulating unit i~~
~~ΔRBP_i = Delta ramped RTD basepoint for regulating unit i~~

~~The dispatcher shall have the option of disabling basepoint ramping of all non-regulating units when the basepoint ramp is in the direction that increases |AR| and |AR| is greater than a user adjustable limit.~~

- ~~REGULATE (Unit Selected for Regulation This Cycle): UDG equals the previous value of UDG plus the delta ramped RTD basepoint less ERRR times the sign of AR.~~

~~$UDG_i = UDG_{i-1} + \Delta RBP_i - (ERRR_i/10)*SIGN(AR)$~~

~~where:~~

~~$ERRR_i$ = Effective Regulation Response Rate for Regulating Unit I~~
~~$ERRR_i/10$ = The amount of $ERRR_i$ available in 6 seconds (1/10th of a minute)~~
~~AR = Area Requirement~~

- ~~REGULATE (Unit Not Selected for Regulation This Cycle): UDG shall equal the previous value of UDG calculated last AGC program execution plus the delta ramped RTD basepoint:~~

~~$UDG_i = UDG_{i-1} + \Delta RBP_i$~~

~~The dispatcher shall have a separate option (separate from non-regulating units) to disable basepoint ramping of all non-selected regulating units when the basepoint ramp is in the direction that increases |AR| and |AR| is greater than a user adjustable limit.~~

~~When the AGC Control State is SUSPENDED, UDGs shall be determined as defined above for all units when AGC is ACTIVE except the UDG for all units with a unit control mode of REGULATE shall be determined as follows:~~

$$\cancel{UDG_i = UDG_{i-1} + \Delta RBP_i.}$$

~~The previous value of Unit Desired Generation~~ ~~UDG_{i-1}~~ ~~will include the last good value of the regulation component of UDG and there should be no “bump” in UDGI when AGC is SUSPENDED.~~

~~When the AGC Control State is TRIPPED, UDGs shall be determined as defined above for all units when AGC is ACTIVE except units with a unit control mode of REGULATE. The regulation component of UDG will be gradually removed from UDG of REGULATE units so that their UDGs will return to follow their ramped basepoint values within several minutes as follows:~~

$$\cancel{UDG_i = UDG_{i-1} + \Delta RBP_i - K*ERRR_i*SIGN(UDG_{i-1} - RBP_i)}$$

~~until~~ ~~$(UDG_{i-1} - RBP_i)$~~ ~~changes sign, whereupon~~

$$\cancel{UDG_i = UDG_{i-1} + \Delta RBP_i.}$$

~~where K is a user adjustable constant between 0 and 1.0 that controls how quickly the regulation component of UDG is removed, and~~

~~where UDGi is rate limited to a maximum change rate of RRR while the regulation component is being removed.~~

~~In a similar fashion, an individual regulating unit whose unit control mode is changed from REGULATE to MANUAL or BASE shall utilize the above calculation to remove the regulation component from its UDG whenever AGC is ACTIVE or SUSPENDED.~~

~~UDG While AGC Is OFF:~~

~~When the AGC Control State is OFF, UDGs shall be not be calculated or telemetered to any unit. The advisory 5-minute RTD basepoint calculated by RTD will still be sent to all units by RTD.~~

~~UDG with Reserve / Max Gen Pickup Activated:~~

~~When the either the Reserve Pickup or Max Gen Pickup mode in RTD-CAM is activated by the dispatcher, RTD-CAM executes immediately under relaxed limits and constraints including faster unit response rates (EMERGENCY vs. NORMAL) and higher upper limits (Upper Operating Limit less regulation margin vs. Upper Economic Limit). RTD-CAM sets the System Reserve Pickup flag and sets individual unit Reserve Pickup flags for all units selected for Reserve / Max Gen Pickup.~~

~~In Reserve / Max Gen Pickup mode, RTD-CAM calculates 10-minute basepoints for all units. At the end of the 10-minute period, the SPD cancels Reserve / Max Gen Pickup and RTD is restarted for normal execution.~~

- ~~Reserve Pickup Unit – ramp unit to its RTD-CAM basepoint at its Emergency Response Rate~~
- ~~Non-Reserve Pickup Unit – ramp unit to its RTD-CAM basepoint at its Normal Response Rate~~

~~When Max Gen Pickup mode is activated, AGC shall calculate basepoint ramps as follows:~~

- ~~Reserve Unit – ramp unit to its RTD-CAM basepoint at its Emergency Response Rate~~
- ~~Non-Reserve Unit - ramp unit to its RTD-CAM basepoint at its Emergency Response Rate~~

~~Reserve / Max Gen Pickup is canceled when any of the following conditions occur:~~

- ~~10-minutes time elapses~~
- ~~Reserve or Max Gen Pickup is cancelled by dispatcher~~
- ~~The value of AR enters the AR deadband~~
- ~~AGC goes to OFF control state.~~

~~The Unit Reserve Pickup flag is also transmitted to each Reserve Pickup unit and the System Reserve Pickup flag to all units to alert them to the Reserve Pickup condition.~~

~~Regulation will continue as usual for units providing regulation only (REGULATE mode without Reserve / Max Gen Pickup flags set). The large AR should cause regulating-only units to raise at their Regulation Response Rates. Units providing both regulation and reserve will raise to the new RTD-CAM basepoints at their Emergency Regulation Response rates, assuming ERR > RRR.~~

~~At the end of 10 minutes or if Reserve / Max Gen Pickup is canceled by the dispatcher or AR returns within its deadband, both RTD and AGC shall execute again in their normal modes. During the period between the cancellation of the Pickup or the end of 10 minutes and the calculation of new 5-minute basepoints by RTD, AGC shall set unit basepoints equal to their actual generation values. AGC shall issue an alarm message to the dispatcher describing the reason for the cancellation or indicating the completion of Reserve Pickup.~~

~~Initial Step Change in UDG:~~

~~Due to the deadband inherent in unit control logic, a regulating unit that is not currently moving may not respond to a small change in UDG. In order to force a unit to respond sooner, AGC shall, under certain conditions, issue an initial step change to a regulating unit selected for control that is a user adjustable number of MWs greater than the unit's control deadband. This step change shall only be issued if all of the following conditions are present:~~

- ~~The unit is not moving~~
- ~~A small change in UDG is required (the absolute value of the difference between the unit's actual generation and the rate-limited UDG is less than a user adjustable factor times the unit deadband and $ERRR_i$ ${}^{1}0$)~~
- ~~Little or no basepoint ramp (½BPR½< low limit)~~

~~After the step change, the unit's UDG shall not be modified for approximately "n" AGC control cycles, where n = (deadband)/(RRR/10) and RRR/10 = regulating response for one AGC control cycle.~~

~~**Remove Windup in Previous Values of UDG:**~~

~~When the value of AR returns within its deadband or changes sign, no further regulation in the direction to reduce AR is required since AR has already been satisfactorily controlled. To avoid control overshoot, the previous values of UDG for regulating units shall be adjusted to remove any windup in the regulation requirement to which a regulating unit had not yet responded.~~

~~Control windup shall be removed whenever AR returns to zero (within the AR deadband) or crosses zero (changes sign) and a regulating unit's UDG is either greater than or less than both its actual unit generation and unit ramped basepoint. Control windup shall be removed by setting the previous value of UDG to either unit actual generation or unit ramped basepoint, whichever is closer to UDG.~~

~~**Fast–Response Units Return to Basepoint:**~~

~~A unit that bids an RRR greater than a user adjustable response rate will be designated as a fast-response unit. To make better use of this category of unit, it will be operated close to its RTD basepoint whenever possible to allow it to respond quickly to a significant AR of either sign. Consequently, when AGC has controlled a fast-response unit to its Upper or Lower Operating Limit and the magnitude of AR becomes (or is already) less than a user adjustable limit, AGC shall control the unit back to its ramped RTD basepoint at a user adjustable rate. While it is being controlled to its basepoint, the unit shall not be available for regulation. When it is within its control deadband of its basepoint, it will again become available for regulation. If AR either becomes large or changes sign while a fast-response unit is being controlled back to its basepoint, the return to basepoint shall be cancelled and the unit shall become immediately available for regulation.~~

~~**UDG Initialization:**~~

~~Whenever the AGC Control State changes to ACTIVE or TRIPPED from OFF or TEST, AGC shall request an immediate execution of RTD. After RTD has generated new unit basepoints, AGC shall for each unit initialize the values of its UDG and the value of its old (previous) unit basepoint to the value of its actual generation.~~

~~**Forbidden Operating Regions:**~~

~~Normally, unit limits established for the generators will constrain unit operations under AGC control to regions that do not involve areas of rough unit operation. Nevertheless, each unit may have a forbidden region established by user adjustable high and low forbidden region limits. When the UDG for a unit falls less than halfway through the forbidden operating region, AGC shall move the unit only as far as the boundary of the forbidden operating region and move the unit no further. When the UDG for a unit falls more than halfway through or beyond a forbidden operating region, AGC shall notify the dispatcher. Upon dispatcher approval (per incident), AGC shall control the unit completely through the forbidden operating region at its fastest response rate (Emergency, Regulation or Normal). At the dispatcher's option for each unit, notification~~

~~frequently than a dispatcher entered delay period.~~

~~Governor Action:~~

~~Governor action forces unit generation to change in response to frequency deviations from 60 Hz. However, the control system at an individual generating unit may or may not automatically compensate its received UDG value for governor action.~~

~~For a unit controller that automatically biases its primary unit control action for governor action, AGC will continue to send UDG without change when an actual or scheduled frequency change occurs. For a unit without a governor or whose unit controller does automatically adjust UDG for governor action, AGC shall bias UDG so as to send the unit its desired generation inclusive of anticipated governor action. A user adjustable Governor Action Bias flag for each unit, whether regulating or not, shall indicate whether or not governor action bias should be added.~~

~~For a unit with the Governor Action Bias flag set, UDG shall be offset by the anticipated amount of governor action based on the actual frequency according to the following formula:~~

$$\cancel{UDG_g = UDG + \beta_g * (F_{Af} - 60)]}$$

~~where:~~

- ~~UDG_g = UDG with governor action bias~~
- ~~UDG = Unit Desired Generation calculated as defined previously~~
- ~~β_g = Unit governor frequency bias (negative value)~~
- ~~F_{Af} = Actual Frequency (filtered frequency from 1- second samples).~~

~~Each UDGg value shall be restricted to be within its associated UOL and LOL.~~

~~The values of UDG_g shall be telemetered to the appropriate Transmission Owner for retransmission to the units in its local area. AGC shall save the value of UDG_g, along with the governor action bias flag, for the Performance Tracking System. Actual frequency used for this calculation shall be filtered to reduce the sensitivity to high-periodicity variations in system frequency.~~

~~Monitoring Conditions To Request Immediate RTD Execution~~

~~AGC shall request an immediate execution of the RTD function whenever it detects conditions that may result in poor response to the NERC CPS1, CPS2 or DCS criteria. These conditions include the following:~~

- ~~Excessive AR~~
- ~~Change of AGC control state from OFF/TEST to ACTIVE or TRIPPED~~
- ~~Insufficient Raise and/or Lower Regulating Margins~~
- ~~Insufficient Total System Regulation Response Rate.~~

~~AGC shall calculate the Available Raise and the Lower Regulation Margins every AGC cycle to determine whether either value falls below corresponding user adjustable limits for longer than a user adjustable period. The values of the Regulation Margins be the sum, for all units in REGULATE mode, of the absolute values of the difference between a unit's actual generation and its corresponding Upper or Lower Operating Limit. When a regulating unit is limited by security constraints from moving in one or both directions, the unit shall not be included in the calculation of the corresponding Regulation Margin.~~

~~If either Regulating Margin falls below separate user adjustable thresholds for longer than a user adjustable interval, AGC shall issue an alarm message to the dispatcher and request an immediate run of RTD. The alarm message shall be repeated periodically if necessary. RTD, as part of its normal logic, will redispatch all generating units to reestablish the proper regulating margin if possible.~~

~~Total Available Regulation Response Rate:~~

~~AGC shall also compare the Total Available Regulation Response Rate (TARRR) in the direction to reduce AR with the Required Regulation Response Rate. If TARRR falls below RRRR for more than a user adjustable number of control cycles, AGC shall issue an alarm message to the dispatcher and issue an immediate run request to RTD. This alarm message shall be repeated periodically if necessary.~~

~~Unit Response Testing~~

~~AGC shall be able to test the response characteristics of generating units to control signals of various magnitudes in both directions over different unit operating regions. AGC shall monitor the unit performance during the test and compile statistics, such as average response rate in raise and lower directions and overshoot. Two tests shall be able to run simultaneously (e.g., move two units in opposite directions to minimize the impact on AR).~~