REAL-TIME PERFORMANCE METRICS FOR GENERATORS PROVIDING THE REGULATION ANCILLARY SERVICE

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1. INTRODUCTION

Independent system operators manage ancillary-service markets in four parts of the United States: California, mid-Atlantic, New York, and New England. Regional transmission organizations (RTOs) will likely operate similar markets in other parts of the country within the next few years.

Because these ancillary services are expensive and are bought and sold in competitive markets, the electricity industry needs methods to measure the services delivered, generally in real time. The prices for the regulation service range from less than \$10/MW-hr in New England to almost \$50/MW-hr in the PJM Interconnection. Currently, the lack of performance metrics requires these system operators to pay for the amount of capacity reserved rather than for the service delivered.

This project develops and applies metrics for the regulation service (Hirst and Kirby 2000b). These metrics measure the hour-to-hour regulation performance of individual and groups of generators relative to the control-center requests. We examine the output of a particular control area's generating units in two ways. First, we analyze the contribution of these generators to overall system performance defined by the North American Electric Reliability Council (NERC) standards. Second, we analyze performance relative to what the control center requested of the generators.

Regulation is the use of online generating units that are equipped with automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for unintended fluctuations in generation (Hirst and Kirby 1998). In so doing, regulation helps to maintain Interconnection frequency, manage differences between actual and scheduled power flows among control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.

Because the restructuring of the U.S. electricity industry is still a work in progress, the industry has not yet agreed how best to develop and apply metrics for regulation.* Developing metrics that quantify individual generator supply of regulation is proving to be difficult for the electricity industry. For example, should the metrics compare individual generator performance to overall system performance [e.g., as measured by the NERC (1999) Control Performance Standards (CPS)]? Or should individual generator performance be compared only to the system-operator instructions sent to that generator?

2. METRICS

We examined the performance of generators providing regulation two ways:

- Relative to NERC's CPS1 and 2.# For example, to what extent does generator output improve compliance with CPS1 and CPS2?

- Relative to control-center requests for regulation up and down movements. For example, to what extent does generator output conform to the AGC requests from the control center?

PERFORMANCE RELATIVE TO SYSTEM REQUIREMENTS

Focusing on CPS compliance raises three complications.

- Measuring generator performance is complicated by the fact that both CPS1 and CPS2 are pass-fail measures; either the control area is in compliance (i.e., CPS1 is greater than 100% *and* CPS2 is greater than 90%) or it is not in compliance. Improving CPS2 from, for example, 92% to 94% is of little value to the control area except, perhaps, as insurance against possible later poor CPS performance. Thus, generator AGC movements benefit the control area only when they bring a noncompliant CPS metric into compliance.

- CPS compliance is measured over long times, monthly for CPS2 and annually for CPS1. How do we assess the hourly or daily performance of a generator when any problems it might cause for CPS could be offset during other hours?

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*NERC's Interconnected Operations Services Subcommittee (formerly a Task Force) continues to work on the technical and policy issues associated with such metrics. The Task Force published draft compliance templates, including one for regulation and load following, in June 2000.

#CPS1 limits, on a 1-minute basis, the relationship between control-area area-control error (ACE) and Interconnection frequency; it is an annual measure. CPS2 limits the magnitude of ACE every 10 minutes; it is a monthly measure.

- How should performance on these two metrics, CPS1 and 2, be weighted? What happens if the output of a particular generator improves CPS1 but worsens CPS2?

The overall measure of generator performance relative to system requirements is based on two sets of ACE values, with and without the generator(s) in question. We then calculate hourly values for CPS1 and 2 based on these two sets of ACE values. In both cases, we assume that the generator continues to perform its load-following function, if any. That is, we analyzed only the regulation portion of each generator's output. First, its regulation performance can be *subtracted* from the actual ACE values, and the resultant 2-minute ACE values can be used to calculate new hourly values for CPS1 and 2. The differences between these new CPS values and the original (actual) values show the effects of this generator on the CPS metrics.

Second, the regulation component of all the generation can be subtracted from the actual ACE values, yielding a set of ACE values and associated CPS metrics as if the units within that control area provided no regulation service. Then, the regulation performance of the unit in question can be *added* to ACE and the change in CPS performance associated with this generator determined. The two sets of metrics yielded results that were qualitatively similar.

Whether and how to use regulation metrics related to system performance is unclear. In the discussions leading up to NERC's (2000) proposed Policy 10, some task force members felt that if a generator behaves in a way that affects the overall performance of the control area in meeting the CPS requirements it should be paid or charged for its effects on that performance. Generators that help reduce ACE and frequency deviations should be rewarded regardless of whether or not those actions were taken in response to control-center requests. Other task force members felt that individual suppliers should not "look over the shoulder" of the system operator at either system ACE or Interconnection frequency. To do so, they argued, would permit individual suppliers of the regulation service to second guess the system operator's AGC dispatch instructions.

Although there is merit to both arguments, we believe generators should respond to control commands from the system operator. While CPS, ACE, and frequency are important reliability indicators, they are not the only factors the system operator controls. The system operator may direct a specific generator up or down for other reasons, such as reducing transmission-line loading or accommodating another generator that is about to come on- or off-line. Turning the operator's directions into mere "suggestions" could undermine system control and reliability.

Because the system operator is ultimately responsible to NERC for CPS performance, it is inappropriate for other entities to independently try to meet these standards. For example, it is reasonable to charge a generator for the costs of CPS noncompliance if the unit's failure to respond contributes to the control area's noncompliance. But what if the noncompliance results from the system operator's failure to ask for enough resources or response? It may be better to leave the responsibility for CPS violations with the system operator and only burden the generators with failure to follow the operator's directions. For these reasons, we conclude that generator performance should be measured against the system operator's instructions only.

EXPECTED VALUES OF GENERATION

The data we received include the AGC ramp-rate capability (in MW/minute) of each unit. In addition, we received 30-second data for each unit on its actual output, upper and lower limits on that output (which determine the regulation range for the unit), and the AGC request from the control center. This *desired* value of output for each unit reflects the system operator's request for generator movement unconstrained by the physical limitations of the unit. [AGC systems can be (and are) designed and tuned to request movements consistent with unit constraints.] That is, the desired value assumes the unit has no upper or lower limits and can respond with an infinite ramp rate to AGC requests.

In principle, we should also constrain the expected values by the acceleration limits of the unit. Ignoring the acceleration limits of generators worsens *apparent* generator performance (Spicer 2000). Because data on unit-specific acceleration limits were not available, we ignored these constraints in this project. Thus, the expected values we derived are optimistic and the performance-metric results are worse than they actually are.

We developed a new variable called *expected* output to reflect the physical characteristics and limits of each generator. The *expected* output at each time step is the closest the generator could come to the *desired* output without exceeding the stated ramp rate or moving outside the high and low limits. We modify the *expected* output slightly to reflect faster-than-stated ramping or operation above the high limit or below the low limit. This modification to the expected value is made only if the unit was able to deliver better performance and that is what the system operator called for.

PERFORMANCE RELATIVE TO EXPECTED

We explored several possible metrics for individual generators to measure their performance against the expected values of generation discussed above. (Exhibit 1 lists several desirable characteristics for such metrics.) These generally follow the SCE concept developed by NERC in its proposed Policy 10. SCE is the supplier control error, equal to $\text{Output}_{\text{Actual}} - \text{Output}_{\text{Expected}}$. Two possible metrics are:

Metric 1: $1 - [\text{StDev}(\text{SCE}_t)/\text{StDev}(\text{Exp}_t)]$

Metric 2: $\text{Correlation}(\text{Actual}_t, \text{Expected}_t) \times [\text{StDev}(\text{Actual}_t)/\text{StDev}(\text{Exp}_t)]$.

In these formulations, t refers to the 30 2-minute values in an hour and the standard deviations are calculated with the 30 2-minute values in an hour. If the standard deviation of the actual is greater than the standard deviation of the expected value, the second metric yields a value greater than 1.0, implying a performance greater than 100%. In actuality, this over-response is as bad as an under-response and should be treated the same way. For example, a value of 1.2 should be considered equal to 0.8 in terms of providing compensation for that hour. Our definition of expected automatically values overperformance when such overperformance is consistent with the desired request.

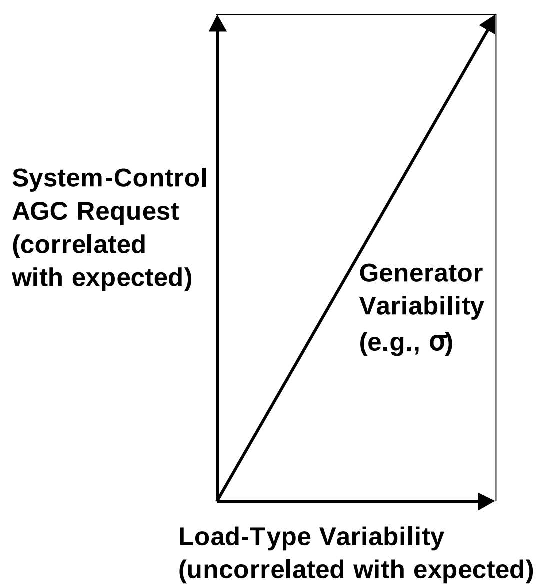
Both metrics discussed above should have a maximum value of 1.0 (100% compliance or perfect performance) but a minimum value that can be negative. A value of zero implies complete disregard to the control center requests, while a negative value implies generator movement counter to that requested (which would hurt system performance). In principle, the metric would be used to decide how much each generator providing regulation would be paid (or charged, if its performance was sufficiently poor) each hour. As a practical matter, it may make sense to limit payments and charges to the range ±100% of the hourly regulation price.

When a unit is not on AGC, we set the expected output of the unit equal to zero and the regulation metrics described above are not computed.

Finally, we developed and tested a pair of metrics, the first of which measures the contribution to the provision of the regulation service and the second of which measures the load-type use of regulation by the generator. Both metrics rely on the correlation coefficient between actual and expected output, as described above:

Regulation contribution (MW) = StDev(Actual) $\times$ Correlation(Actual_t, Expected_t)

Load requirement (MW) = StDev(Actual) $\times \sqrt{[1 - \text{Correlation}^2]}$



As suggested by the figure, the actual generator movements are split into orthogonal components, one corresponding to the control-center requests and the other independent of those requests. These two metrics, unlike the ones discussed above, have units of capacity. The prior metrics are dimensionless and are scaled so that 1.0 implies perfect regulation performance.

Two additional factors need to be considered. First, it may be necessary to include a deadband in the metric because a generator cannot respond exactly to requested movements. That is, the AGC systems at a generator may have some error that prevents the unit from following precisely the AGC request. In addition, generators are sufficiently complicated

Exhibit. 1. Desirable Characteristics of Generator Performance Metrics

Linearity

The metric should reflect the generator performance in a manner that is proportional to the useful work the generator did. If the generator supplied half of what it should have the metric should indicate 50%.

Harm vs Non-Performance

The metric should *appropriately* distinguish between failure to provide the desired response and introduction of undesirable fluctuations. Fluctuations that are exactly opposite to the desired behavior are worse than random fluctuations. Random fluctuations are similar to those imposed by loads.

Useful Enhanced Performance

The metric should not penalize a generator that exceeds its ramp rate or high/low limits *if* doing so helps the system operator. Our use of "Desired" and "Expected" helps by allowing the Expected value to exceed the generator's stated capabilities if the generator chooses to do so *and* the extra generator movement is consistent with the Desired value.

Capacity vs Performance

The metric should appropriately recognize that the system operator reserves a certain amount of regulating capacity ahead of time, whether or not the operator uses that capacity in real time. For example, the system operator might reserve 100 MW of regulation capacity before hand and then call on only 60 MW in real time. If the unit delivers 40 MW of regulation service, how should it be compensated?

Adjusting Performance Compensation for Small Requests

When asked to provide zero or small amounts of regulation the natural random motion of the generator may swamp the desired response. Judging and paying for performance on the percentage compliance with such small requests would be unfair and inappropriate. It may be appropriate to establish a deadband in the performance metric(s) near zero regulation request so that generator performance in this region is not even judged.

Regulation Delivery vs Regulation Consumption

A generator is simultaneously a provider and consumer of regulation. Specifically, a generator can be providing the desired regulation but also having a random regulation component. These two components should be measured separately.

Support of NERC Standards (CPS 1 and 2)

Generator performance and compensation could be tied in part to the control area's compliance with the NERC Control Performance Standards. It may, however, be difficult for a control-area operator to demonstrate that a generator's poor performance harmed the control area (e.g., caused a violation of NERC requirements or caused it to spend money on other resources).

machines that, with or without AGC, they cannot maintain desired output exactly. A unit should not be penalized for small errors in its performance.

Second, the metric may need to account for the fact that the amount of regulation *delivered* during an hour may be less than the amount *requested* during an hour, which, in turn, may be less than the amount *reserved* for that hour. Consider the situation in which the system operator reserves 100 MW of regulation capacity, the system operator requests 50 MW during the hour, and the unit delivers 30 MW that hour. Does the unit get paid for the 30 MW provided, for 80 MW (the 100 reserved minus the 20 not delivered) or for 60 MW (because 60% of the requested amount was provided)? This is less an analytical issue and more a policy one. In today's ancillary-services markets, managed by independent system operators in California and the Northeast, suppliers are paid primarily for the amount of regulation capacity reserved rather than the amount of service delivered in real time.

3. RESULTS

The control area provided 30-second data on generation and load for 12 days in winter 1999 and another 12 days in summer 1999. For each 30-second interval, the data include total generation, net exports, total load, area control error (ACE), and Interconnection frequency. In addition, the data include the output from 11 of the control area's generating units (accounting for 90% of the system's total capacity) and the desired output from each unit. To improve readability, this paper presents results for only three of these units.

We aggregated the 30-second data to 2-minute averages based on the dynamics of the generators in this control area (Hirst and Kirby 2000a). To focus on regulation, we subtracted the load-following component of each variable from its total (Kirby and Hirst 2000). We defined load following as the 30-minute rolling average of the 2-minute data. Thus, the generator data we analyze here is the residual, the up and down movements relative to this rolling average.

During the 12-day winter period, this control area had an average of 0.16 CPS2 violations per hour (the NERC minimum performance is 90% on a monthly basis, equivalent to no more than 0.6 violations per hour). Its CPS1 performance averaged 161% (the NERC minimum requirement is 100% an annual basis). Thus, this control area easily met the NERC requirements. Although the summer performance (0.31 CPS2 violations per hour and CPS1 equal to 118%) was not as good as the winter performance, the control area still complied fully with the NERC requirements.

We then removed the regulation component (but not the load-following component) of generation from ACE and recalculated compliance with CPS1 and 2. CPS1 performance improved slightly in the winter, from 161% to 168%. On the other hand, CPS2 performance declined slightly, from 0.16 to 0.35 violations per hour (i.e., from 97% to 94%). For the summer, both CPS1 and CPS2 declined slightly (from 0.31 to 0.47 CPS2 violations per hour, and from 118% to 115% for CPS1) when we removed the regulation component of generation.

Thus, as a practical matter, the regulation component of generation had little effect on CPS performance and no effect on CPS compliance, for both the winter and summer periods. These results suggest two conclusions. First, the contribution to CPS performance from the *fast* movements of the generators are minor and ambiguous. Second, the *regulation* component of generation is not needed to maintain compliance with NERC's CPS requirements. That is, the AGC systems could be disconnected from all the control area's generators and CPS compliance would still be above the minimums required. However, the generation *is* needed for load following!

Turning to the performance of generation relative to the AGC requests, Table 1 summarizes the performance of three generators and the total portfolio over the two analysis periods. The amount of time on AGC differed across the units and between the two seasons. As noted above, the performance metric was calculated for only those times a unit was on AGC:

$$\text{Correlation}(\text{Actual}_t, \text{Expected}_t) \times [\text{StDev}(\text{Actual}_t)/\text{StDev}(\text{Exp}_t)] .$$

Overall, generation provided 52% of the expected regulation service in the winter (Table 1). Among the three units, Unit C performed best with a metric of 86% and Unit B performed worst (25%). In the summer, the overall performance was lower (37%), primarily because Unit C did not follow its regulation requests as well as it had in the winter.

Figure 1 shows the winter performance for two generators, A and C. Unit A had average performance (48% from Table 1), whereas Unit C had excellent performance (86%). A comparison of the two figures shows that the actual regulation standard deviation is much closer to the expected value for C than for A. Similarly, the SCE for C is much smaller relative to its actual value than for A.

Figure 2 shows the details of the winter regulation performance for these two units for a 2-hour period. For the first hour shown, A had a 68% performance and C had a 94% performance; for the second hour, the comparable metrics were 26% and 80%. For the summer period, performance at both units declined (from 48 to 22% for unit A, and from 86 to 45% at unit C).

Table 1. Regulation performance (standard deviations in MW and dimensionless metric) of individual generators

Unit	Time on AGC (%)	Expected	Actual	SCE	Actual × correlation coefficient	Performance metric (1.0 = perfect)
			Winter			
A	91	7.4	5.6	5.4	3.8	0.48
B	85	4.9	3.4	5.0	1.2	0.25
C	96	8.9	9.2	4.3	7.9	0.86
Total generation	--	25.0	18.8	17.6	13.4	0.52
			Summer			
A	73	5.5	3.7	5.6	1.4	0.22
B	89	5.3	3.9	5.3	1.4	0.27
C	96	7.7	6.9	6.9	3.8	0.45
Total generation	--	29.2	20.6	25.0	11.2	0.37

4. CONCLUSIONS

Using 2-minute data on generator output and control-center requests, we analyzed the performance of generation resources in delivering regulation, a key real-power ancillary service. To conduct these analyses, we first developed suitable performance metrics that can be applied to individual generators as well as to the entire resource portfolio. We developed two types of metrics. The first focuses on compliance with NERC Control Performance Standards. The second type focuses on performance relative to the control-center requests to each generator. We conducted these analyses using 12 days of data from February 1999 and 12 days of data from August and September 1999.

We found that CPS compliance was good enough that removal of the entire regulation component of generation had almost no effect on these compliance values. Thus, we conclude that the contribution of generation regulation output to CPS performance is minor and ambiguous. However, the load-following output of these generators is essential to maintain compliance with CPS1 and 2.

We developed and applied several metrics to measure the hour-to-hour regulation performance of individual generators relative to the control-center requests. These metrics use the standard deviation as the measure of volatility in control-center requests, generator output, the components of generator output (aligned with the request and independent of the request), and the supplier control error.

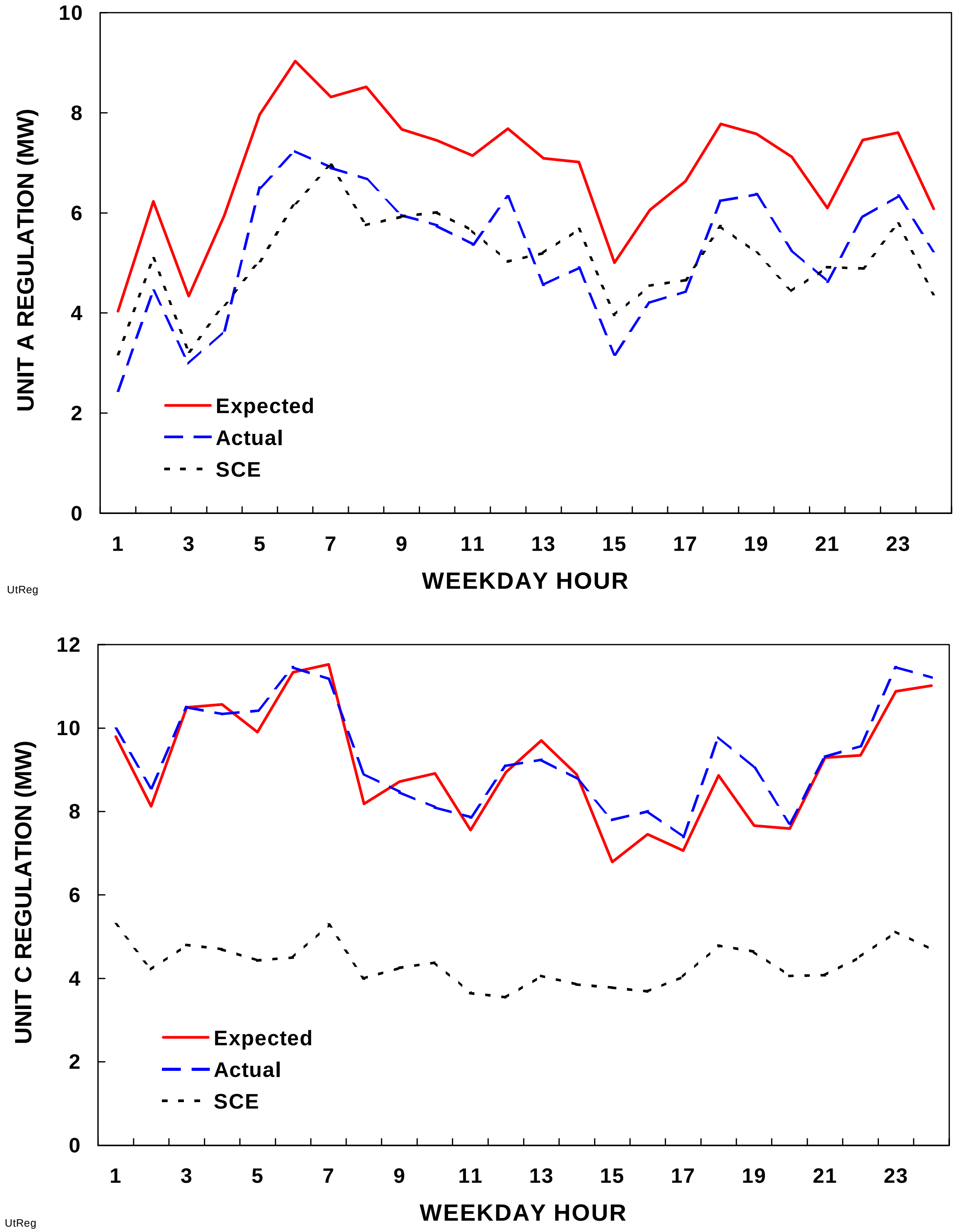


Fig. 1. **Average winter hourly regulation requests (expected), output (actual), and supplier-control error (SCE) for unit A (top) and unit C (bottom).**

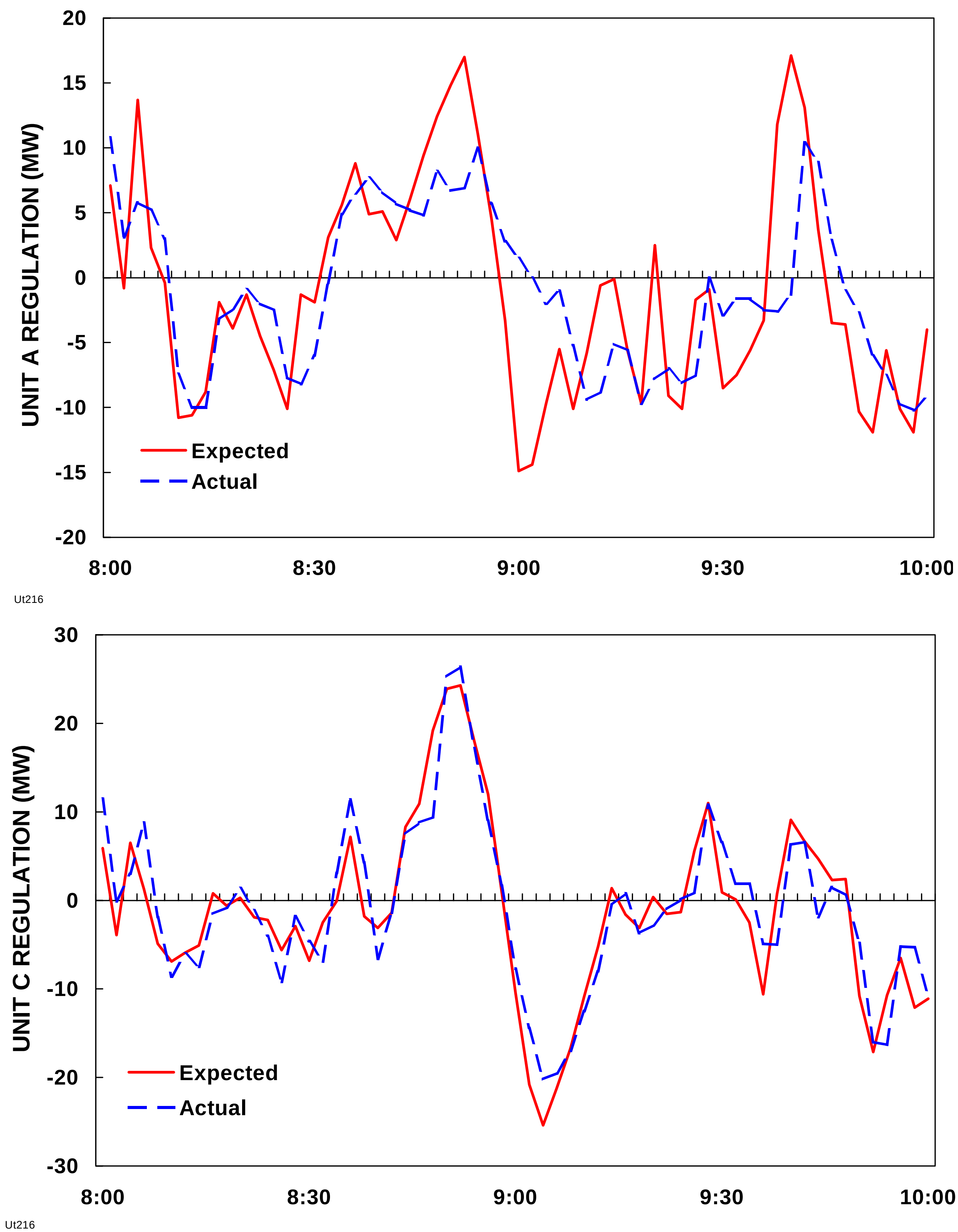


Fig. 2. **Regulation performance at the 2-minute level for units A and C for two hours on one winter day.**

The individual units differ substantially in their regulation performance, both in the amount of regulation provided and in their performance metric. Overall, Unit C provided the most regulation (8 MW on average) in the winter. Overall, generation provided an average of 19 MW of regulation, of which 13 MW was aligned with the expected value, yielding a score of 52%. In the summer, Unit C (4 MW) again provided the most regulation. Overall, generation provided an average of 21 MW in the summer, of which 11 MW was aligned with the expected value, yielding a score of 37%. Thus, regulation performance was better in the winter than the summer.

In summary, we defined and applied metrics to measure the real-time performance of generators, in aggregate and individually, in delivering the regulation service. Although these metrics should be tested in other utility settings, the results developed here suggest that these metrics can be used by traditional, vertically integrated utilities and in RTO competitive-market settings. Such metrics are especially important in competitive markets, where the RTO would pay suppliers for real-time performance in delivering the requested regulation and load-following services.

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