Investigation of Generator Ramp Rates in High Renewable Penetration Systems using an Academic New York Network Model

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***Abstract*—This paper presents an Academic Model of the NYISO transmission system that mimics key features of the New York network on a smaller scale without the use of confidential information. A day-ahead and real-time Market Model is developed using MatPower. Real time dispatch and commitment engines operate on 5 and 15 minute time scales, respectively. Startup notification and the ability to curtail renewable resources are modeled. Simulations show the effects of doubling steam unit ramp rates on two days in both low and high renewable penetration scenarios.**

***Index Terms*—Energy Market, DAM, RTM, RTC, RTD, Curtailment, MatPower**

I. Introduction

The New York power system operator anticipates high renewable penetration by 2030, to perhaps 50% renewable energy [1]. Analysis is underway examining the readiness of the current generating fleet to allow for reliable operation in the future. On a high renewable day with lots of in-front and behind-the-meter solar PV generation, it is entirely possible that the measurable load power consumption during mid-day will drop to a very low level, with twin peaks occurring during morning and evening. Such an operating scenario will test the limits of the current NY generating fleet.

Such scenario-based analysis will be very time consuming. Thus there is a desire to develop a reasonable size power system model with realistic features of a practical power system, and use a readily available multi-period optimal dispatch software. The two popular models, the PJM 5-bus system [2] and the 8-bus ISO-NE system [3], are deemed too small for such an investigation. Instead the NPCC 68-bus, 16-machine system [4] is used, because of the flexibility it can provide. We refer to it as the NY Academic Model (NYAM). As to the multi-period optimization program, the MATLAB-based software MatPower [5] and MatPower Optimal Scheduling Tool (MOST) [6], collectively 'MatPower', are selected.

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Four NYISO base cases from 2016 were selected for investigation. The actual load consumption and masked renewable resource data are consolidated onto the NYAM. For each case, a 2030 case is built, containing 2.6 times more installed renewable resources. Then MatPower is used to obtain the Day-Ahead Market (DAM) and the Real-Time Market (RTM) commitment and dispatch. In particular, the impact of the generator ramp rates on the dispatch, including renewable curtailment, is analyzed.

The paper is organized as follows. Section II describes the NYAM. Section III presents the market model used, and its implementation in MatPower. Section IV analyzes the simulation results.

II. Academic Network Model

The NY power market is organized into 11 Load Zones. The NYAM does not need this large number of zones. Instead, the 68 buses in the NPCC model were organized into 4 zones or regions and an external region, as shown in Figure 1. These regions correspond with NYISO zones as follows: NYISO Zones A-F become Upstate New York, Zones G-I become Lower Hudson Valley, Zone J is still New York City, and Zone K is still Long Island. New England is the external area connected to both the Lower Hudson Valley and New York City.

The generating fleet in the NYAM was constructed to approximately match the generation capacity of New York State by type and region [7]. Each generator in the NYAM represents multiple generators in the NYISO system. The NYAM generators are bound by operating constraints including ramp rates, minimum and maximum generation, and minimum run and down times.

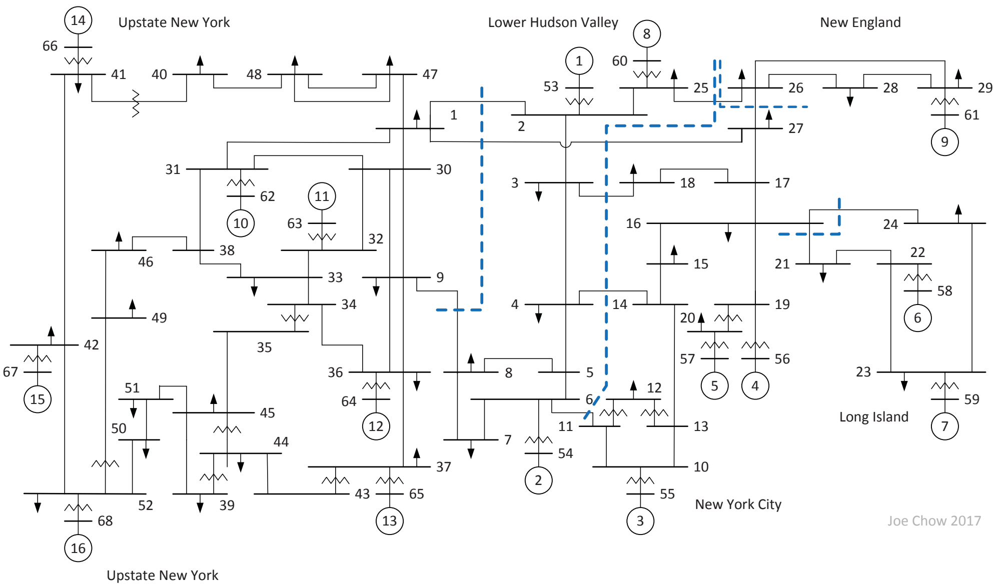

Fig. 1. Academic NYISO Network Model by Region.

NY system load and renewable generation data for 4 days in 5-minute intervals were used to further develop the model. These 4 days were in different seasons with different renewable generation profiles. The load and generation values in the NYAM were adjusted to match these scenarios. The load profiles of two days will be shown in Section IV.

Although not used in this paper, the regions can be used to set up congestion scenarios and to model imports from ISO-NE.

III. Market Model

It is important to fully capture the dispatch of power systems with high renewable penetration, and the energy market model should have both DAM and RTM components. Most stochastic optimization approaches addressing the impact of renewable penetration only account for the average hourly variation of load and renewable generation in the DAM [3], thus missing the more volatile 5-minute load and renewable fluctuation in RTM. The situation becomes further complicated by the DAM in which some of the committed units are designated as must-runs in RTM.

The DAM and RTM computation is enabled in MatPower. First, the DAM is solved as a 1-hour period optimization simultaneously over 24 hours. The more complex RTM model consists of Real-Time Commitment (RTC) and Real-Time Dispatch (RTD) processes that run every 15 and 5 minutes, respectively, each passing data forward to the next run. Here as in real power system dispatch, the DAM results will impact the RTM results, as the DAM commitment imposes constraints on the RTM optimization.

A. Real Time Commitment

The RTC engine is a scrolling multi-period analysis considering a 2.5-hour horizon advancing 15 minutes each iteration. It can commit or de-commit units that can start within 30 minutes. RTC cannot commit or de-commit units with startup times greater than 30 minutes. If a unit with a startup time greater than 30 minutes is DAM committed, it is must-run in RTC. The RTC results for the first 15 minutes of the 2.5-hour window are binding while results for the remaining period are advisory.

B. Real Time Dispatch

RTD is performed every 5 minutes, dispatching the set of committed units from the binding interval of the last RTC run to meet demand. In order to ensure ramp limits are honored between consecutive RTD runs, temporary maximum and minimum generation limits are calculated for each generator equal to the previous RTD value subject to the 5-minute ramping capability and the maximum and minimum generation limits.

C. Startup Notification

A new startup notification mechanism was implemented to ensure RTC did not start units out of merit, i.e., without having received advanced notification through advisory RTC commitments. As startup notification was unnecessary prior to the development of scrolling multi-period problems, it was not built into MatPower or MOST. The proposed RTC engine used here has a mechanism for preventing units from starting until the earlier of their startup notification time and their last RTC advisory commitment advanced by 15 minutes.

D. Study Window

Traditionally, the DAM and RTC results in the first 30 minutes of the day are dependent on generator states at the close of the previous day [1]. Since this data was not available, every generator was made available to run in the first hour of the DAM. Since only 24 hours of data was available, RTCs 2.5-hour horizon prevented it from operating after 9:30 pm each day. Limits on transmission line flows were ignored in this analysis and the network uses a lossless DC model.

E. Optimization Setup

The day-ahead and real-time optimization problems have the same structure. They seek to minimize generator operating and startup costs subject to a set of constraints. Renewable generators are modeled as having no operating cost with energy bids at \$0/MWh and thermal units have quadratic cost functions. The optimal solution will minimize the operating cost needed to match thermal and renewable generation in each interval with the net load while ensuring generators honor their operating restrictions.

F. Evaluation Parameters

Using the DAM and RTM results, the Load Cost is calculated in (1) as the sum of day-ahead and real-time energy price times the day-ahead and balancing MW of load, L_{DAM} and L_{Bal}, respectively, over all buses and periods. N_g and N_b are the number of NYAM generators and buses, respectively.

$$\begin{aligned}\text{Load Cost} &= \sum_{i=1}^{N_b}\sum_{h=1}^{24}\mathrm{LMP}_{\mathrm{DAM},i,h}\times \mathrm{L}_{\mathrm{DAM}i,h}\\ &+\frac{1}{12}\sum_{i=1}^{N_b}\sum_{t=1}^{288}\mathrm{LMP}_{\mathrm{RTM},i,t}\times \mathrm{L}_{\mathrm{Bal},i,t}\end{aligned} \tag{1}$$

Payment (charge) for real-time generation is issued at the RTD price for real time production above (below) its DAM commitment. $\mathrm{P}_{\mathrm{DAM}i,t}$ represents the DAM commitment while $\mathrm{P}_{\mathrm{Bal},i,t}$ represents the difference between scheduled DAM and actual RTD output for each of the twelve 5-minute periods in the hour.

Generator Net Revenue is calculated as the sum of DAM and RTM revenue less actual operating costs and startup cost, SUP_{RTM}. A quadratic cost curve with coefficients ($C_{j,i}$) is used to calculate operating costs. A margin assurance payment assures non-negative daily total generator net revenue.

$$\begin{aligned}\text{Net Revenue}_{\mathrm{i}} &= \sum_{h=1}^{24}\mathrm{LMP}_{\mathrm{DAM},i,h}\times \mathrm{P}_{\mathrm{DAM}i,h}\\ &+\frac{1}{12}\sum_{t=1}^{288}\mathrm{LMP}_{\mathrm{RTM},i,t}\times \mathrm{P}_{\mathrm{Bal},i,t} \\ -\frac{1}{12}\sum_{t=1}^{288}&(\mathrm{C}_{0,i}+\mathrm{C}_{1,i}\mathrm{P}_{\mathrm{RTM}i,t}+\mathrm{C}_{2,i}\mathrm{P}^2_{\mathrm{RTM}i,t})\\ &-SUP_{RTM}\end{aligned} \tag{2}$$

for generator i, where for each 5-minute interval t in a given hour h

$$\mathrm{P}_{\mathrm{DAM}i,h}+\mathrm{P}_{\mathrm{Bal},i,t}=\mathrm{P}_{\mathrm{RTM}i,t} \tag{3}$$

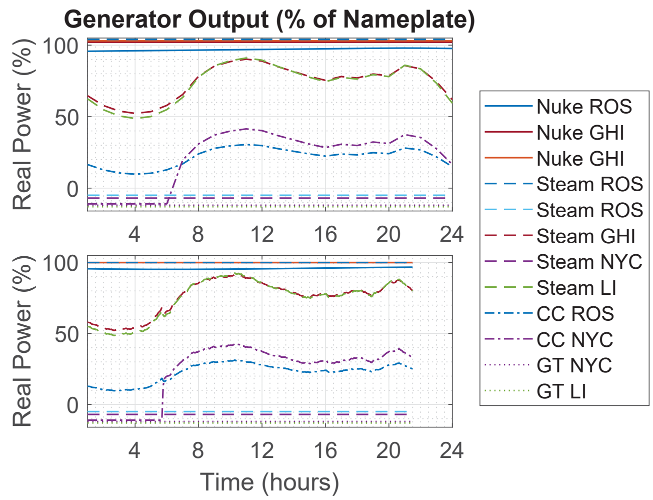

Fig. 2. 2016 Spring Day DAM (top) and RTM (bottom) Results: Generator Output as a percent of Nameplate.

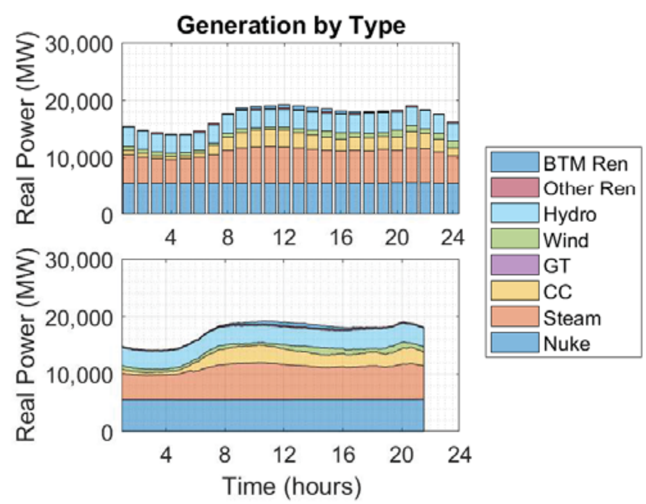

Fig. 3. 2016 Spring Day DAM (top) and RTM (bottom) Results: Generator Output by Type.

IV. Simulation Results

Results are presented for a fall and spring day under the 2016 and 2030 cases. On each day, for each case, two simulations were performed, identical except steam unit ramp rates were doubled in the High Steam Unit Ramp simulations. The simulation results are listed in Table I. The RTM objective function value is consistently lower than the DAM as it only covers a 22.5-hour period.

A. Spring Day

As steam unit ramp rate had negligible impact on the results in the 2016 spring day, Figures 2 and 3 show a single set of DAM and RTM results. When offline, the units in Figure 2 have staggered output below zero for easy identification. The same is true for units at maximum output. These legends,

Day	Case	Steam Unit Ramp Rates	Objective Function Value		Load Cost (k$)	Curtailment (MWh)		Avg. Steam Unit Net Revenue (k$)
			DAM	RTM		DAM	RTD	
Spring	2016	Low	3,338	3,057	4,889	-	-	69
		High	3,338	3,057	4,889	-	-	69
	2030	Low	2,178	1,960	4,082	2,563	1,581	47
		High	2,149	1,959	3,946	1,880	1,553	42
Fall	2016	Low	3,440	3,152	4,896	-	-	78
		High	3,440	3,152	4,896	-	-	78
	2030	Low	2,044	1,861	3,919	1,941	1,646	31
		High	2,027	1,848	4,301	-	50	50

TABLE I
SIMULATION RESULTS.

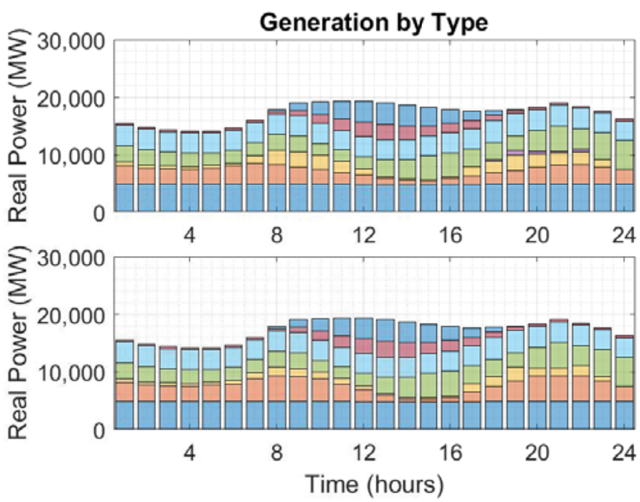

Fig. 4. 2030 Spring Day DAM Results: Generator Output as a percent of Nameplate with Low (bottom) and High (top) Steam Fleet Ramp Rates.

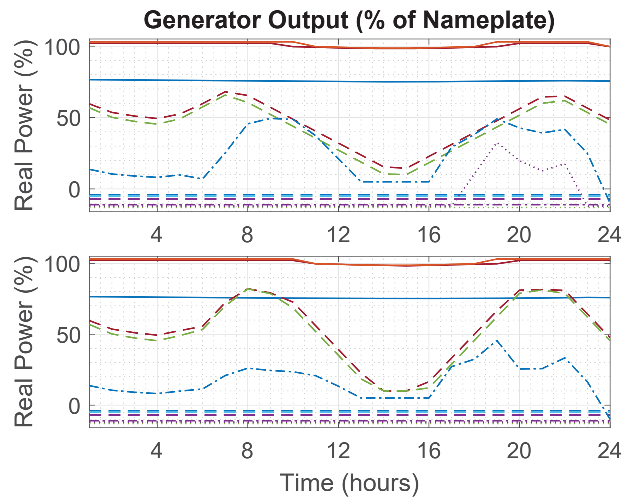

Fig. 5. 2030 Spring Day DAM Results: Generator Output as a percent of Nameplate with Low (bottom) and High (top) Steam Fleet Ramp Rates.

applicable to other similar figures in this paper, are not repeated for brevity.

The same simulations were repeated for the 2030 Case with 2.6 times more renewable generation with results shown in Figures 4 through 8.

Increasing penetration while holding steam fleet ramp rates constant resulted in (i) reduced Load Cost, (ii) reduced objective function value for both DAM and RTM, (iii) reduced average steam unit revenue, and (iv) increased renewable curtailment. In high penetration, increasing steam unit ramping ability resulted in reduced renewable curtailment.

A mid-day curtailment window exists between hours 12 and 16 because total generation is greater than load and must-run thermal units are unable to reduce their output, constrained either by minimum generation or ramp rate. The only option is to curtail the no-cost renewable generation. When either DAM or RTM curtailment occurs, the energy price is zero. This model extends the concept of curtailable wind generation in unit commitment developed by [8] to day-ahead and real-time applications.

DAM curtailment, although useful in providing insight to DAM unit commitment, is advisory in the sense that no

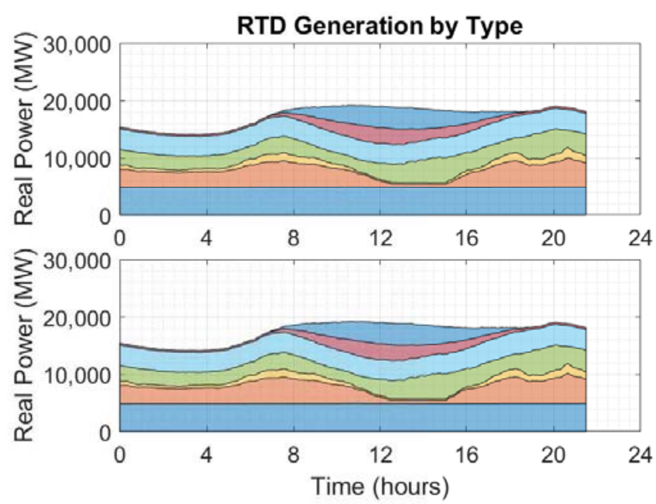

Fig. 6. 2030 Spring Day RTM Results: Generator Output by Type with Low (bottom) and High (top) Steam Fleet Ramp Rates.

actual energy is rejected, but meaningful in terms of the selection of DAM committed units. However, RTD curtailment represents the actual amount of rejected renewable energy in

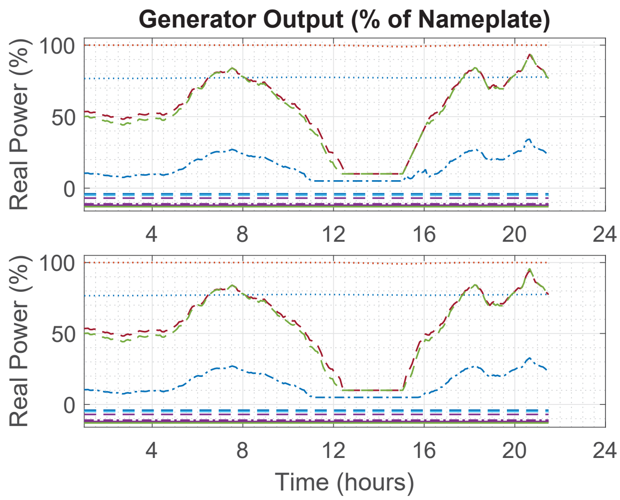

Fig. 7. 2030 Spring Day RTM Results: Generator Output as a percent of Nameplate with Low (bottom) and High (top) Steam Fleet Ramp Rates.

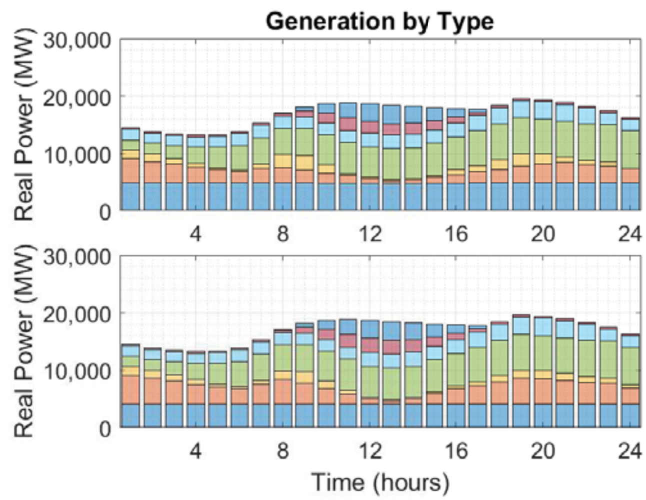

Fig. 9. 2030 Fall Day DAM Results: Generator Output by Type with Low (bottom) and High (top) Steam Fleet Ramp Rates.

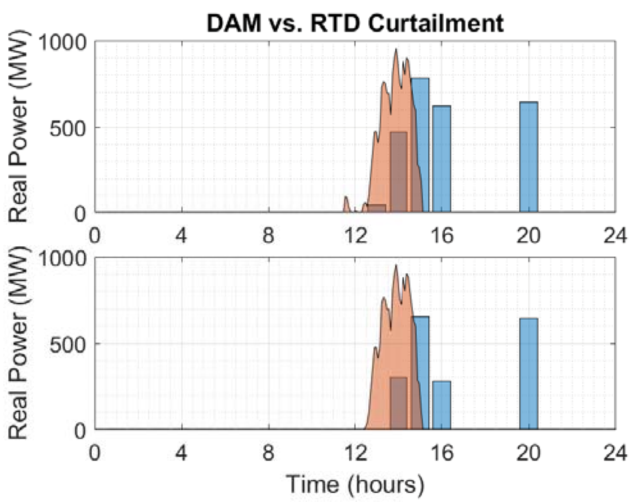

Fig. 8. 2030 Spring Day DAM vs. RTM Renewable Curtailment with Low (bottom) and High (top) Steam Fleet Ramp Rates.

the simulation period.

On the 2030 spring day, the majority of curtailment occurred when the steam units were at minimum generation. Reducing steam unit minimum generation levels may reduce the amount of renewable curtailment in high penetration environments.

Even though the steam units were mostly bound by minimum generation during the curtailment window, increasing steam unit ramp rate resulted in a modest decrease in curtailment and savings in terms of Load Cost and DAM and RTM objective function value.

B. Fall Day

The results of another set of simulations performed for a fall day with high wind output are seen in Figures 9 through 13. As with the spring day, increasing renewable penetration while holding steam unit ramp rates constant reduced Load Cost, DAM and RTM objective function values, and average steam unit revenue. However, in high penetration, increasing steam unit ramping ability resulted in an increase in Load Cost by nearly $380k.

High steam unit ramp ability resulted in the DAM commitment of one less baseload nuclear unit. While there was a small improvement of $17k for the DAM objective function value and curtailment was reduced by 1600 MWh, the Load Cost increased by nearly $380k. DAM and RTM optimization minimizes operating costs, not Load Cost. Negative impact to Load Cost was 380k\$/17k\$ $\approx$ 22 times worse than the improvement of the DAM objective function value.

With reduced steam unit ramp rate, commitment of the additional baseload nuclear unit elongated the midday curtailment window, creating a period where generators were not compensated for producing energy, reducing the Load Cost. Indifferent to Load Cost, the DAM engine found the reduction in operating costs outside the curtailment window from committing a 3rd nuclear unit outweighed the potential operating cost savings from avoiding curtailment inside the window.

The optimal result for the reduced ramp rate fleet must be achievable for the high ramping fleet, but the optimization chose to reduce operating cost not Load Cost. Although reduction in operating cost does not always occur at an expense to Load Cost, this case shows that such undesirable results can occur in a high penetration environment.

V. Conclusions

Using an Academic Network Model of the NYISO and a two-settlement energy market model, increasing levels of renewable penetration were shown to generally reduce the Load Cost. Steam fleet ramp rates were shown to have negligible impact on average steam unit net revenue at 2016 penetration levels. There may not be any near-term economic incentive for steam units to improve their ramping capability. As renewable penetration increases, simulation results showed steam units

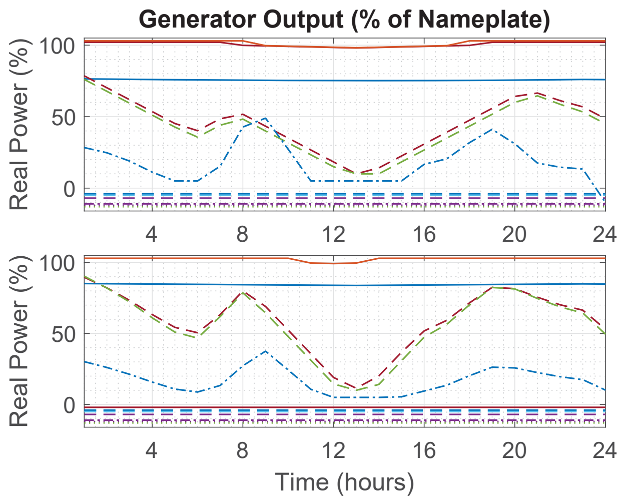

Fig. 10. 2030 Fall Day DAM Results: Generator Output as a percent of Nameplate with Low (bottom) and High (top) Steam Fleet Ramp Rates.

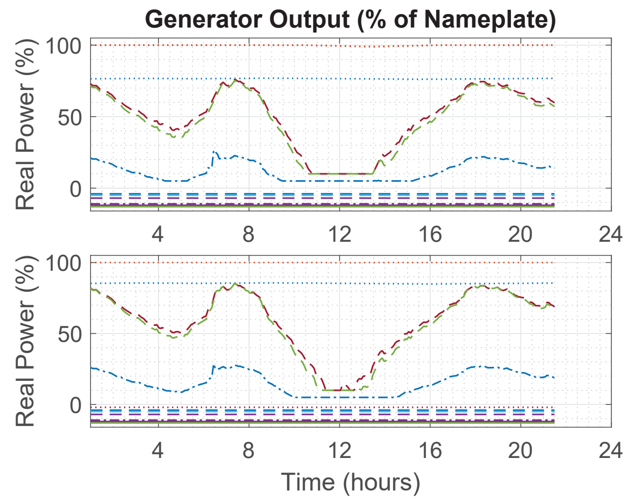

Fig. 12. 2030 Fall Day RTM Results: Generator Output as a percent of Nameplate with Low (bottom) and High (top) Steam Fleet Ramp Rates.

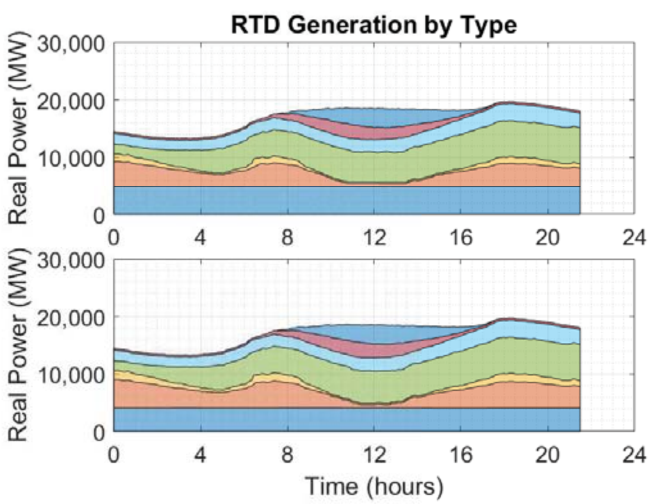

Fig. 11. 2030 Fall Day RTM Results: Generator Output by Type with Low (bottom) and High (top) Steam Fleet Ramp Rates.

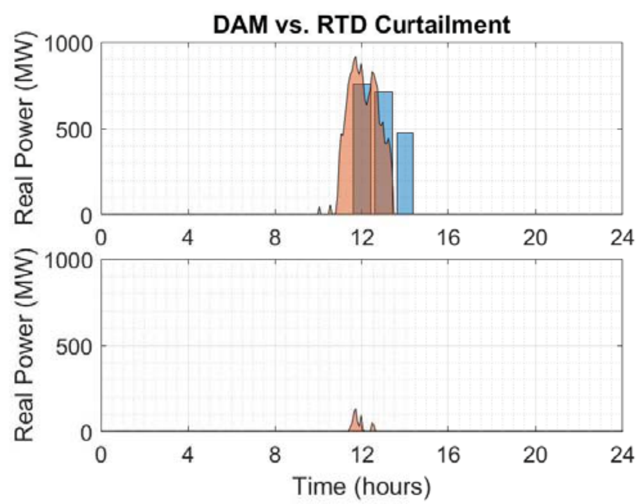

Fig. 13. 2030 Fall Day DAM vs. RTM Renewable Curtailment with Low (bottom) and High (top) Steam Fleet Ramp Rates.

generally become less profitable. In terms of average net revenue, steam unit ramp rate may be able to improve net revenue under the right circumstances.

Higher base load ramp rates enabled the solver to commit fewer base load units which while reducing total curtailment, significantly increased Load Cost in high penetration. A case was shown where the optimal solution that minimized operating costs resulted in a far-from-optimal Load Cost. A small improvement in objective function value worsened the Load Cost 22 times as much. As renewable penetration increases, it may be necessary to revisit the optimization formulation to ensure the objective function value properly prioritizes Load Cost and curtailment.

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