Unit Commitment Under Gas-Supply Uncertainty and Gas-Price Variability

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$$(\mathbf{P}^{G}_{\mathbf{g},\mathbf{t}-1} + \mathbf{r}^{G,U}_{\mathbf{j},\boldsymbol{\xi},\mathbf{t}-1} - \mathbf{r}^{G,D}_{\mathbf{g},\boldsymbol{\xi},\mathbf{t}-1}) - (\mathbf{P}^{G}_{\mathbf{g},\mathbf{t}} + \mathbf{r}^{G,U}_{\mathbf{g},\boldsymbol{\xi},\mathbf{t}} - \mathbf{r}^{G,D}_{\mathbf{g},\boldsymbol{\xi},\mathbf{t}})$$
$$\leq \mathbf{RD}^{G}_{\mathbf{g}}; \square\mathbf{g} \square \boldsymbol{\Omega}^{G}, \mathbf{t} \square \mathbf{T}, \boldsymbol{\xi} \square \boldsymbol{\Xi}; \quad (20)$$
$\mathbf{x}^{T,\mathbf{t}}\square$

units. Constraints (19) and (20) impose upward and downward an ‘uncapacitated’ scenario, in which the hourly pipeline capacities are not binding even if the two natural gas-fired units are operating at maximum load. The other two scenarios represent cases in which some contingency restricts pipeline use, especially in the middle of the planning horizon.

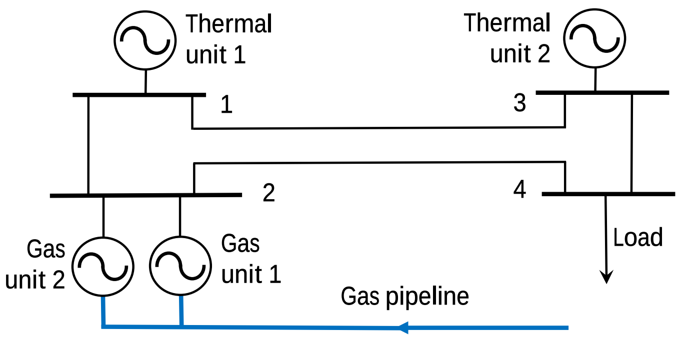

Fig. 1. Four-node power system and single natural gas pipeline used in the examples of Section III.

TABLE I
FOUR-NODE POWER SYSTEM TRANSMISSION DATA

From Node	To Node	B	$C^{\max}$
1	2	4.4	12
1	3	[illegible]	12
2	4	[illegible]	12
3	4	[illegible]	12

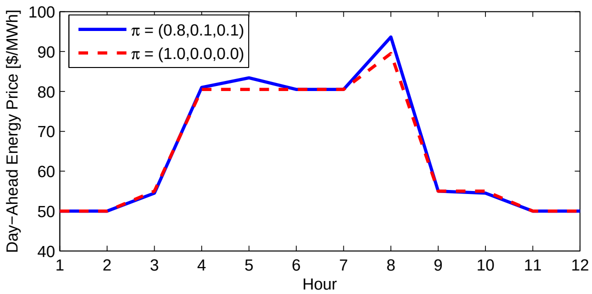

Fig. 4. Day-ahead prices at the demand node in the low-gas-price example.

Fig. 4 shows hourly day-ahead prices at the demand node under the two pipeline-capacity distributions. As expected, prices tend to be higher with the capacitated probability distribution. This is because the pipeline-capacity constraints result in greater use of higher-cost thermal units, which set the margin during hours when the pipeline could be binding. It is important to stress that the possibility of binding pipeline constraints impact day-ahead prices, regardless of whether those binding constraints are actually realized in real-time.

The VSS for this example, with probability distribution vector $\pi = (0.8, 0.1, 0.1)$, is 0.0638 (the VSS is, by definition, 0 with probability distribution vector $\pi = (1.0, 0.0, 0.0)$, because there is no uncertainty in this case). This means that when there is uncertainty regarding available natural gas, explicitly modeling this uncertainty in determining unit commitments reduces expected operating costs by 6.38%. Expected operation costs increase if the system is committed using expected pipeline capacities (in the deterministic model) because less thermal generation is committed (compared to the stochastic model). As a result, loads must be curtailed in some of the scenarios in which the natural gas pipeline is capacitated.

B. High-Gas-Price Example

1) Data: This example assumes the same physical power system structure shown in Fig. 1 and summarized in Table I and the same pipeline-capacity scenarios shown in Fig. 2. Table IV and Fig. 5 summarize the generator and load data, respectively, for this example. This example has higher natural gas prices of $\$12$/MBTU, resulting in a cost reversal between the thermal and natural gas-fired units relative to the low-gas-price example. The load profile in this example has steeper ramps before and after the peak, which requires the use of the expensive natural gas-fired units.

TABLE IV
THERMAL AND NATURAL GAS-FIRED UNIT DATA FOR THE HIGH-GAS-PRICE EXAMPLE

Unit	Marginal Cost	Start-Up Cost	RU, RD	$P^{\max}$	$P^{\min}$
Thermal					
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Natural Gas					
1	[illegible]	[illegible]	[illegible]	[illegible]	2
2	[illegible]	[illegible]	[illegible]	[illegible]	2

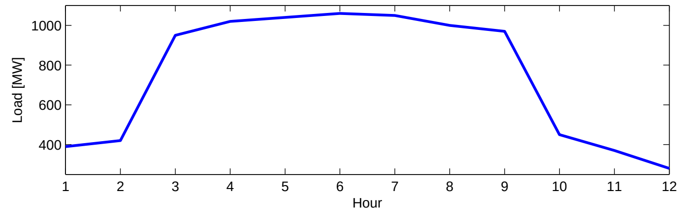

Fig. 5. Load data for the high-gas-price example.

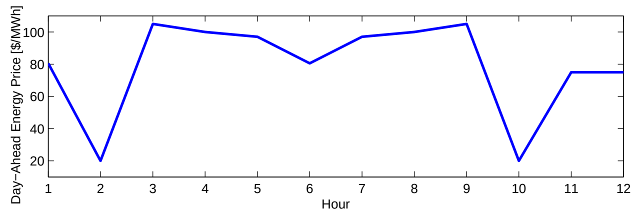

Fig. 6. Day-ahead prices at the demand node in the high-gas-price example.

2) Results: 2(e)-1.66638(a)-1.66393(d(u)-51(i)6.99635(6552]TJ11.897-

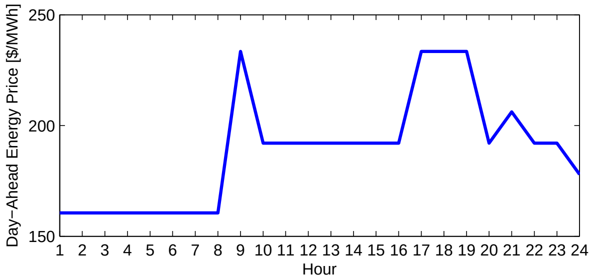

Fig. 8. Load-weighted day-ahead LMPs in the ISO New England-based eight-zone case study.

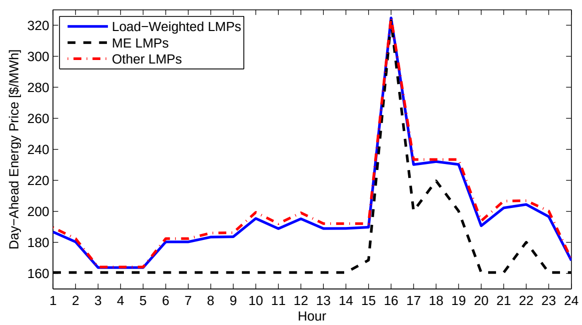

Fig. 9. Load-weighted day-ahead LMPs for the entire system footprint, ME zone, and other zones in the ISO New England-based eight-zone case study with restricted transmission capacity.

differences are caused by transmission-line congestion. The commitment status of the thermal and gas-fired units are similar between the congested and uncongested cases, showing that the commitment decisions are fundamentally driven by natural gas-pipeline capacities. The high prices in hour 16 are caused by binding upward ramping limit for all of the thermal units that are on-line as well as limited natural gas availability in some scenarios. Additional thermal unit would be started-up if the load in hour 16 is further increased.

The VSS for the cases with and without transmission congestion are 0.0724 and 0.074, respectively. As with the low-gas-price example examined in Section III-A, if the system is committed using a deterministic model with expected pipeline capacities, fewer thermal units are committed as compared to those committed by the stochastic model. As a result, there is non-zero energy curtailment in some of the scenarios in which the natural gas pipelines are capacitated.

The model is programmed using GAMS version 24.4.6 and solved using CPLEX version 12.6.2.0 on a computer with an Intel Core i7 2.6 GHz processor with 8 GB of RAM. The computation time of each of the eight-zone cases is approx5]TJ/R469.9621970.08016(p)-5.88993(p)-5.89054(r)-4.2 tis
appr42e.w.88993(n)-5.88543.706(-0.700861(h)-5.29539(h)-5.88993(e)-53(m2-4.9251(t)]T-5.88350.93a)-1.66Bo)-5.88993:aoo

TABLE VII
UNIT LOCATION, COST, AND CONSTRAINT DATA FOR WECC-BASED 24-NODE CASE STUDY

Unit	Node	Marginal Cost	RU, RD	$P^{\max}$	$P^{\min}$