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Technical University of Denmark

DTU Summer School: Uncertainty in Electricity Markets and System Operation

Coordination of Interdependent Natural Gas and Electricity Infrastructures for Firming the Variability of Wind Energy in Stochastic Day-ahead Scheduling

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Outline

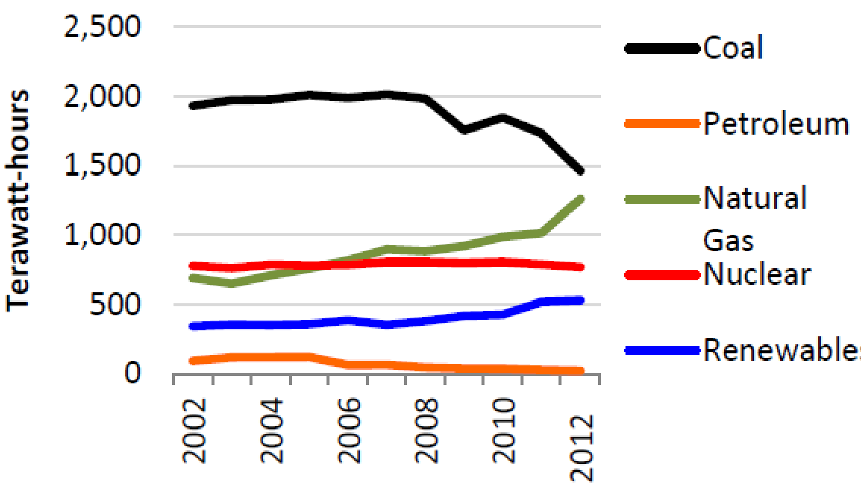
- Introduction to the Interdependency of Infrastructures
- Natural Gas System and Interdependency Concerns
- Coordination of Natural Gas and Electricity Infrastructures
  - Impact of Demand Response
  - Firming the Variability of Renewable Energy
- Case Studies
- Conclusions

Gas-fired power emits less than half as much carbon dioxide as coal-fired power on a life-cycle basis, but ~15–40x more than renewable energy sources.

Life-cycle CO$_2$ emissions per kWh

Source	Emissions (g/kWh)
Onshore wind	8-18
Offshore wind	9-21
Nuclear	5-40
Hydroelectric	10-85
Solar PV	13-105
Natural gas	400-510
Oil	650-790
Coal	810-1010

Source: World Energy Council

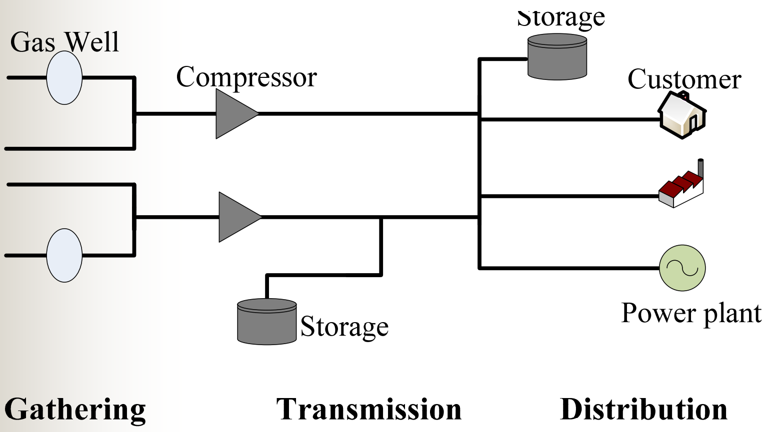


Natural Gas Units and the New Capacity

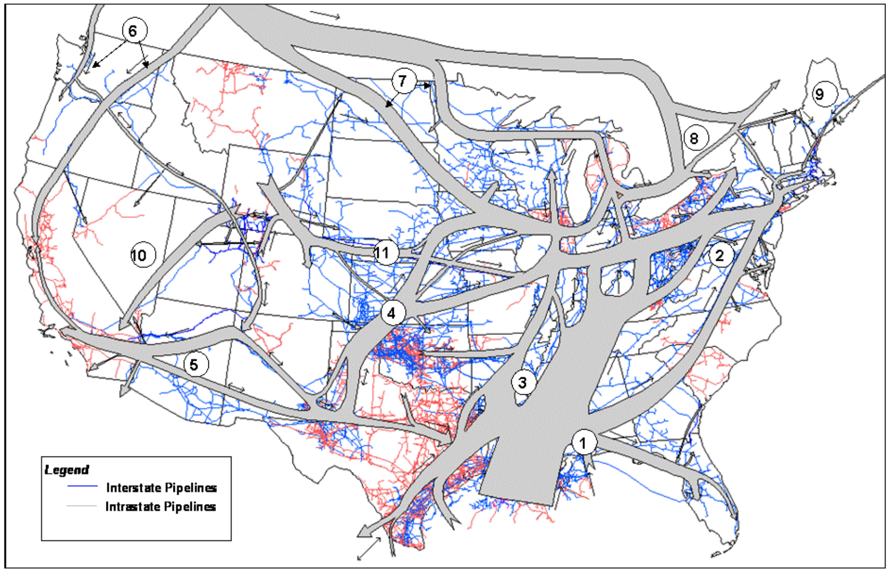
- Close to 50% of power generation in the United States was traditionally based on coal. Coal unit is the worst CO2 emitter and the worst particulate emitter, which is being ousted gradually as an energy resource. This battle is more or less won in the USA and Europe, but not in China or India.
- Low natural gas prices coupled with discoveries of abundant shale gas reserves have made the last couple of years an exciting time for energy in the United States.
- Shale gas discoveries have led to a broad consensus that the United States has enough domestic supplies of natural gas to power the U.S. for generations.
- Shale gas reserves are expected to account for 34% of total natural gas production in 2035, doubling from 18% in 2008.

Natural Gas System

- Natural gas supply chain:



Natural Gas System Architecture



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, GasTran Gas Transportation Information System.

U.S. Natural Gas Pipeline Network

Gas Units & Transmission Infrastructure

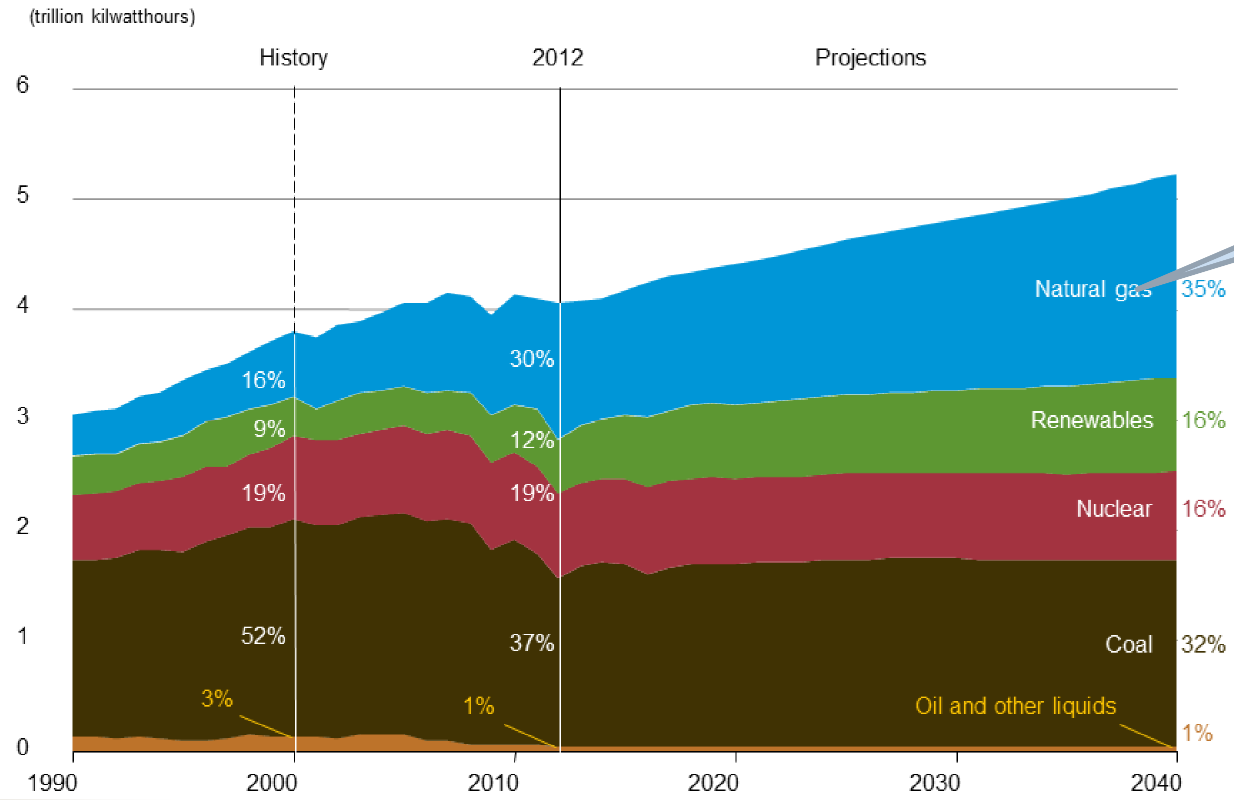
- Unlike coal or nuclear plants, natural gas plants can be built cheaply and quickly near load centers.
- The fact that gas plants can be built close to population centers gives it a decisive advantage – wind farms can only be built where the wind is blowing, and these areas can be remote locations that require additional investment in costly transmission and distribution infrastructure.
- Therefore, low natural gas prices might in fact make major grid-scale renewable energy projects more difficult for investors, unless these investments are to comply with RPS mandates.

Flexibility of Natural Gas Units

- In practice, the increasing supply of natural gas might be a blessing in disguise for clean energy technologies.
- Natural gas is an essential partner to the development of renewables, providing cleaner, reliable backup power when the sun is not shining or the wind dies down.
- Unlike most coal plants, natural gas plants have the flexibility to quickly scale up or down the quantity of electricity dispatch.
- The ability to adjust power production within minutes has key advantages for both integration with renewable energy sources and serving as a reliable supply for meeting peak demands.

Natural Gas and Renewable Energy

- Gas-fired generation and renewable energy demonstrate a rapid growth due to low gas price and environmental issues



2040:
35% Natural gas
16% Renewable

Gas-Fired Generation and Renewable Energy

- Natural gas and renewable energy are the two most vital energy resources in the electric power industry’s transition to an environmental-friendly operation
    - The attractive utilization of shale gas has introduced the lowest natural gas prices in a decade, which may further expand the investments on natural gas generating plants in electric power system
    - Renewable energy has long held the promise of making significant contributions to the future power system for environment benefits
    - Technological advancements in distributed control, off-grid generation and microgrid applications, and various government incentives have demonstrated a rapid growth in renewable energy deployments and utilizations throughout the world

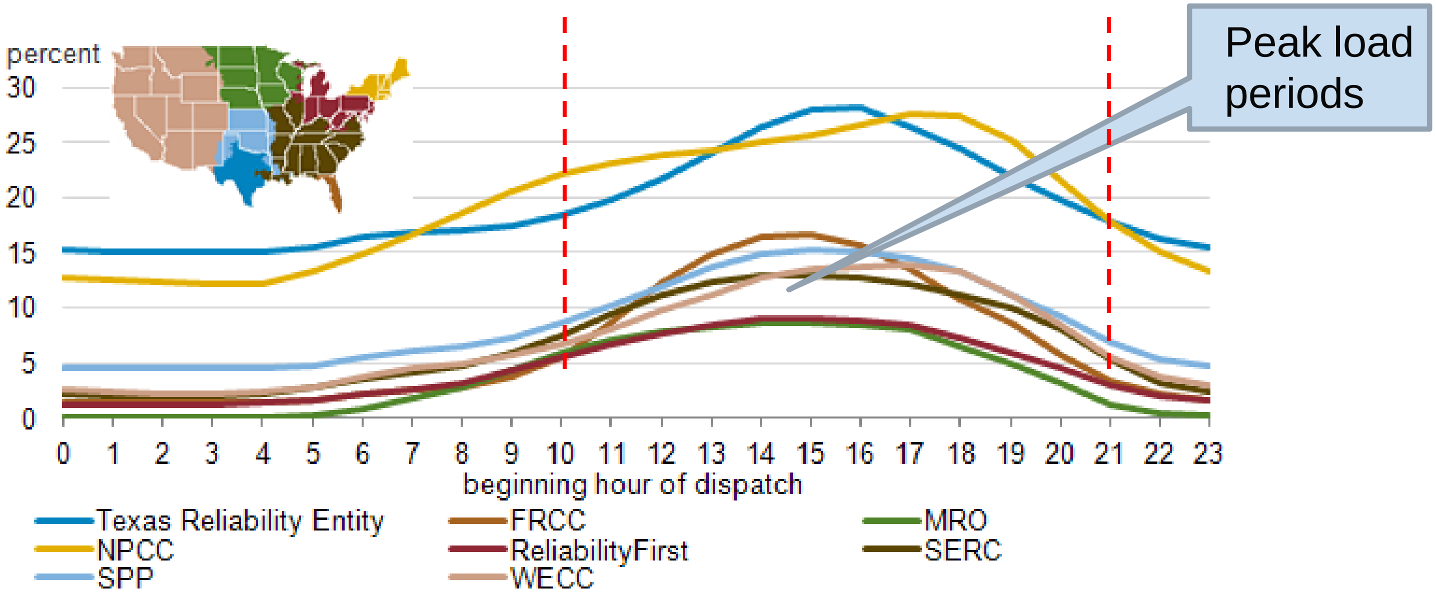
Gas-Fired Generation vs. Renewable Energy

	Natural Gas	Renewable
Fuel price	Gas price volatility	Zero fuel costs
Fuel availability	Low priority fuel supply	Adequate throughout a large geographic region ★
Environmental impacts	Release carbon dioxide and small amounts of nitrogen oxides (NO_x) & sulfur dioxide (SO_2)	No emissions ★
Dispatch accessibility and variability	Quick ramping capability	★ Resource variability and low capacity factor

★

Interdependency Concerns

- Gas-fired units: Interface between gas and electricity systems
- Gas transportation service priority
  - Gas-fired generation is often used to meet peak electricity loads
  - Rely on interruptible transportation service for cost consideration

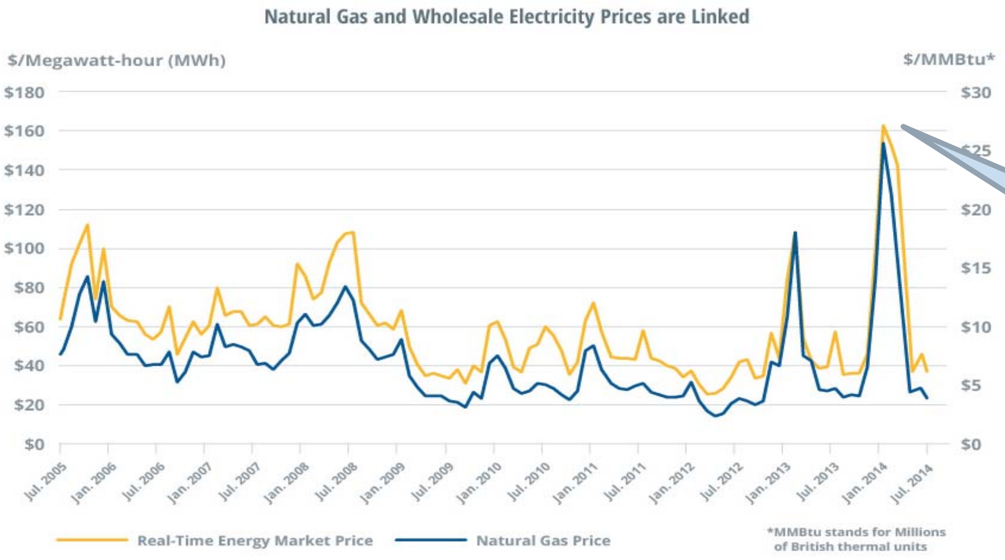


Peak load periods

Average capacity factors of natural gas combustion turbine plants

Interdependency Concerns

- Natural gas price volatility
  - Demand for electricity and gas peak together in severe weather situations cause price spike



January 2014

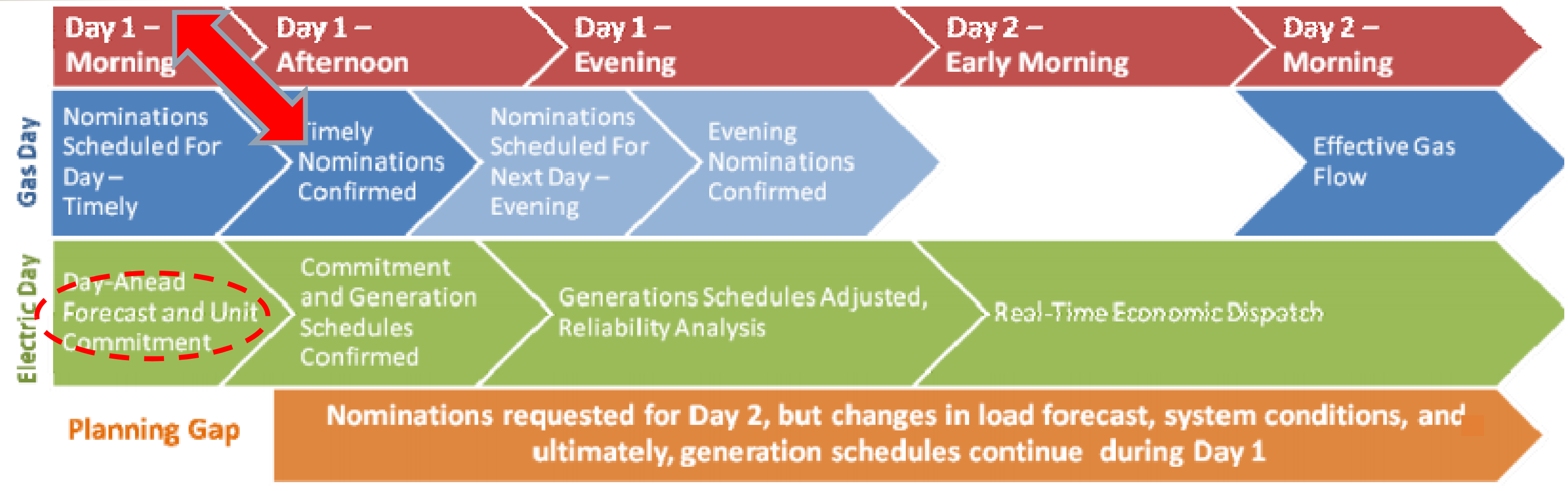
Gas price: $25/MMBtu

Electricity price: $160/MWh

Natural gas price vs wholesale electricity price

Interdependency Concerns

- Timing gap
  - Multi-hour gap in the timing between the Gas-day and Electric-day
  - Generator owners submit the next day’s gas demand to gas market before the unit dispatch schedule is confirmed in electricity market
  - FERC ORDER 787 (2013): Communication of operational information between natural gas pipelines and electric transmission operators



Coordination Benefits of Wind and Natural gas

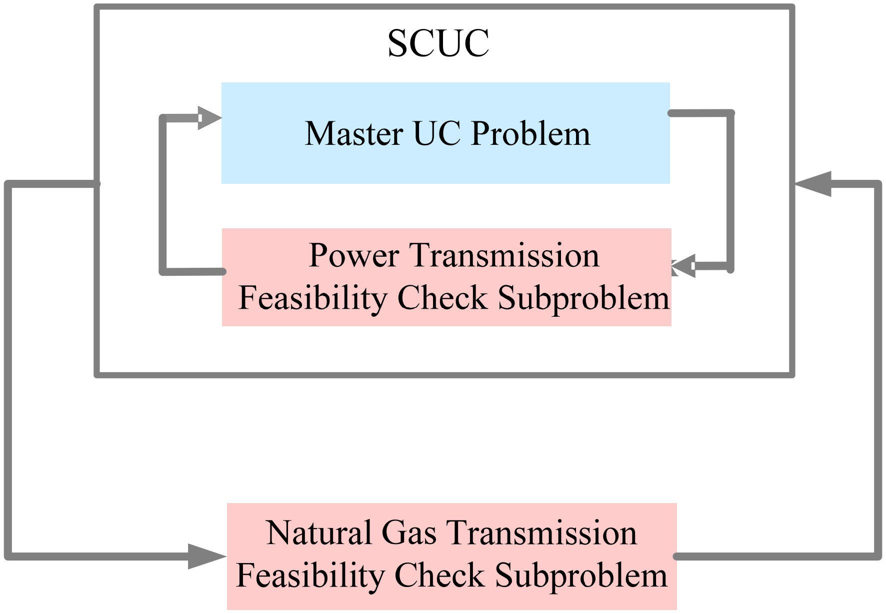
- Coordination between natural gas and renewable energy in integrated resource planning can be:
  - Hedging the risk of fuel availability and natural gas price volatility for gas-fired generation
  - Alleviating emission constraints by environmentally sustainable wind energy
  - Firming the variability of wind energy by flexibility and quick ramping ability of natural gas-fired units

Our Project Goals

- Coordination of electricity and natural gas infrastructures based on an integrated stochastic model
  - Incorporate electricity and natural gas transportation infrastructure constraints
  - Represent random network outages and wind energy forecast errors
  - Apply scenario-based approach for considering system uncertainties. Scenario reduction technique provides a smaller number of scenarios representing a reasonable approximation by measuring a distance of probability
    - General Algebraic Modeling System (GAMS) provides SCENRED
    - S scenarios are retained and a weight Pr_s is assigned to each scenario that reflects the possibility of its occurrence

Proposed Methodology

- An integrated model for SCUC with natural gas transmission constraints is discussed, for minimizing power system operating costs by taking into consideration power transmission constraints, natural gas transmission constraints, and natural gas contracts.
- Natural gas transmission is modeled as a group of nonlinear equations for representing gas node pressures, which can be linearized by Newton-Raphson or dc method.



SCUC

Master UC Problem

Power Transmission Feasibility Check Subproblem

Natural Gas Transmission Feasibility Check Subproblem

Day-ahead Scheduling Formulation

- Objective Function: minimize the expected cost of supplying the electric load over the scheduling horizon while satisfying various system constraints

$$\min \sum_{s=1}^{N_S} P_s \{ \sum_t \sum_\eta W_{\eta t} + \sum_t \sum_{i \notin GU} [F_{c,i}(P_{it}^s) \cdot I_{it}^s + SU_{it} + SD_{it}]\}$$

- Variables:

SU_i, SD_i	Start up and Shut down cost
F_i^c	Cost function of generating unit
W_i^{gas}	Fuel cost of natural gas-fired unit

Optimization Problem Constraints

- Power balance constraint

$$\sum_{i=1}^{N_U} P_{i,t}^{s} \cdot I_{i,t}^{s} + \sum_{i=1}^{N_W} P_{w,t}^{s} = \sum_{b=1}^{N_B} (DE_{b,t} - DL_{b,t}^{s})$$

- Unit capacity constraint

$$P_i^{\min} I_{i,t}^{s} \le P_{i,t}^{s} \le P_i^{\max} I_{i,t}^{s}$$

- Ramp up/down constraints

$$P_{i,t}^{s} - P_{i,(t-1)}^{s} \le [1 - I_{i,t}^{s}(1 - I_{i,(t-1)}^{s})]\, R_i^{up} + I_{i,t}^{s}(1 - I_{i,(t-1)}^{s}) P_i^{\min}$$

$$P_{i,(t-1)}^{s} - P_{i,t}^{s} \le [1 - I_{i,(t-1)}^{s}(1 - I_{i,t}^{s})]\, R_i^{dn} + I_{i,(t-1)}^{s}(1 - I_{i,t}^{s}) P_i^{\min}$$

- Minimum on/off constraints

$$(X_{i,(t-1)}^{s,on} - T_i^{on})(I_{i,(t-1)}^{s} - I_{i,t}^{s}) \ge 0$$

$$(X_{i,(t-1)}^{s,off} - T_i^{off})(I_{i,t}^{s} - I_{i,(t-1)}^{s}) \ge 0$$

Constraints

- Load shedding / hourly demand response constraints

$$DL_{b,t}^{s} \le DL_{b,t}^{\max}$$

- Power transmission constraints

$$E \cdot pf^{s} = C \cdot P_{i,t}^{s} - D \cdot \left(DE_{b,t} - DL_{b,t}^{s} \right)$$

$$pf_{br}^{s} = (\theta_j - \theta_k) / x_{jk} \quad (j, k \in br)$$

$$\left| pf_{br}^{s} \right| \le pf_{br}^{\max}$$

$$\theta_{ref} = 0$$

- Available hourly wind generation constraints

$$P_{w,t}^{s} \le PW_{w,t}^{f}$$

- System emission constraints

$$\sum_{i \in EG} \sum_{t=1}^{N_T} [F_i^{e}(P_{i,t}^{s}) \cdot I_{i,t}^{s} + SU_{i,t}^{e} + SD_{i,t}^{e}] \le EMS^{\max}$$

Coupling Constraints

- Natural gas fuel cost

$$W_{i,t}^{s,gas} = (\rho_{gas})F_{i,t}^{s,gas} \qquad (i \in GU)$$

- Natural gas consumption (depends on the gas unit dispatch)

$$F_{i,t}^{s,gas} = \alpha + \beta P_{i,t}^{s} + \gamma (P_{i,t}^{s})^2 \qquad (i \in GU)$$

- Natural gas supply contract (represented as load in gas network)

$$L_{l,t}^{s} = F_{i,t}^{s,gas} \qquad (i \in GU)$$

- Natural gas day contract volume

$$\sum_{t=1}^{N_T} F_{i,t}^{s,gas} \le F_i^{\max} \qquad (i \in GU)$$

Natural Gas Flow Constraints

- Steady state natural gas flow conservation

$$\sum_{sp=1}^{NGS} Av_{sp} - \sum_{l=1}^{NGL} BL_l - \sum_{n \in GC(m)} f_{mn} = 0$$

- Gas flow (Weymouth equation for gas pipeline flow)

$$f_{mn} = \mathrm{sgn}(\omega_m, \omega_n) \cdot C_{mn} \sqrt{\left|\omega_m^2 - \omega_n^2\right|}$$

$$\mathrm{sgn}(\omega_m, \omega_n) = \begin{cases} 1 & \omega_m \geq \omega_n \\ \text{-}1 & \omega_m < \omega_n \end{cases}$$

- Natural gas load limits

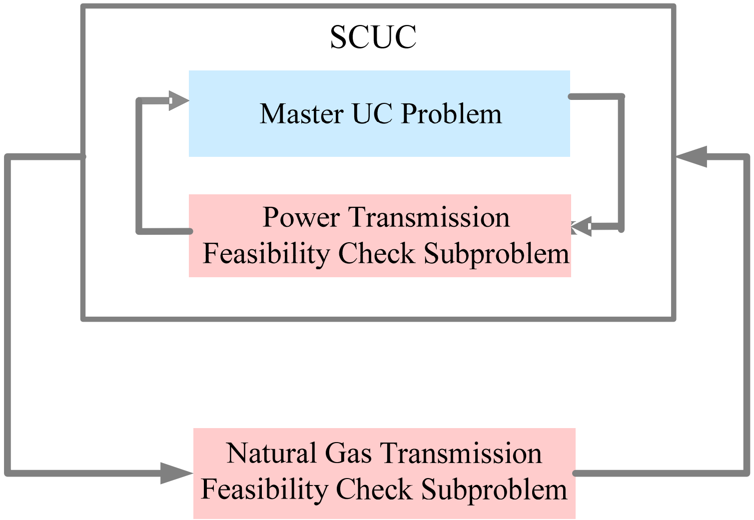
$$L_{gbht}^{\min} \leq L_{gbht} \leq L_{gbht}^{\max}$$

- Natural gas supplier volume

$$v_{sp}^{\min} \leq v_{sp} \leq v_{sp}^{\max}$$

- Power transmission feasibility check subproblem
  - Minimize the sum of bus power imbalances subjected to the relaxed DC transmission formulation.

$$
\begin{aligned}
&Min \quad w(\hat{\boldsymbol{P}}) = \sum_{p=1}^{NB} \left(S1_p + S2_p \right) \\
&S.t. \quad \boldsymbol{E} \cdot \boldsymbol{pf} = \boldsymbol{C} \cdot \hat{\boldsymbol{P}} - \boldsymbol{D} \cdot \boldsymbol{P_L} + \boldsymbol{S}1 - \boldsymbol{S}2 \qquad \lambda \\
&\qquad pf_b = \frac{\theta_p - \theta_q - \gamma_{pq}}{x_{pq}} \quad (p,q \in b) \qquad \forall b \\
&\qquad pf_{b,\max} \le pf_b \le pf_{b,\max} \qquad \forall b \\
&\qquad \boldsymbol{\gamma}_{\min} \le \boldsymbol{\gamma} \le \boldsymbol{\gamma}_{\max} \qquad \theta_{ref} = 0
\end{aligned}
$$


SCUC

Master UC Problem

Power Transmission Feasibility Check Subproblem

Natural Gas Transmission Feasibility Check Subproblem

  - Infeasibility cuts are fed back to the master problem if any hourly values of objective function are nonzero.

$$
w(\boldsymbol{P}) = w(\hat{\boldsymbol{P}}) + \sum_{i=1}^{NG} \mu_{it} (P_{it} - \hat{P}_{it}) \le 0
$$

Natural Gas Linear Constraints

- Nonlinear gas pipeline flow

$$f_{mn} = C\sqrt{\omega_m^2 - \omega_n^2}$$

  - Nonlinear optimizer: CONOPT
  - Linearization
    - Using first order Taylor series (dc model) around a fixed point $\omega I, \omega O$
    - Linear constraints are a group of tangent planes around the point
    - Gas flow through pipeline (m, n)

$$f_{mn} = C\,(\frac{\omega I}{\sqrt{\omega I^2 - \omega O^2}}\omega_m - \frac{\omega O}{\sqrt{\omega I^2 - \omega O^2}}\omega_n)$$

    - Newton-Raphson substitution method

- Natural gas transmission feasibility check subproblem
  - The Newton-Raphson method is applied to solve the nonlinear equations

$$\begin{cases} \boldsymbol{J}_k \Delta \boldsymbol{x}^{(k)} = -\boldsymbol{g}(\boldsymbol{x}^{(k)}) \\ \boldsymbol{x}^{(k+1)} = \boldsymbol{x}^{(k+1)} + \Delta \boldsymbol{x}^{(k)} \end{cases}$$

  - π, H, v, L represent the variables.

$$\begin{bmatrix} \boldsymbol{J}_{\pi}{}^{(k)} & \boldsymbol{J}_{H}{}^{(k)} & \boldsymbol{A} & -\boldsymbol{B} \end{bmatrix} \begin{bmatrix} \Delta\boldsymbol{\pi}^{(k)} \\ \Delta\boldsymbol{H}^{(k)} \\ \Delta\boldsymbol{v}^{(k)} \\ \Delta\boldsymbol{L}^{(k)} \end{bmatrix} = -\boldsymbol{g}(\boldsymbol{\pi}, \boldsymbol{H}, \boldsymbol{v}, \boldsymbol{L})$$

$$\begin{bmatrix} \boldsymbol{\pi}^{(k+1)} \\ \boldsymbol{H}^{(k+1)} \\ \boldsymbol{v}^{(k+1)} \\ \boldsymbol{L}^{(k+1)} \end{bmatrix} = \begin{bmatrix} \boldsymbol{\pi}^{(k)} \\ \boldsymbol{H}^{(k)} \\ \boldsymbol{v}^{(k)} \\ \boldsymbol{L}^{(k)} \end{bmatrix} + \begin{bmatrix} \Delta\boldsymbol{\pi}^{(k)} \\ \Delta\boldsymbol{H}^{(k)} \\ \Delta\boldsymbol{v}^{(k)} \\ \Delta\boldsymbol{L}^{(k)} \end{bmatrix}$$

$$\frac{\partial g_m}{\partial v_s} = A_{ms}$$

$$\frac{\partial g_m}{\partial L_l} = -B_{ms}$$

$$\frac{\partial g_m}{\partial \pi_m} = -\sum_{n \in m} \frac{\partial f_{mn}}{\partial \pi_m}$$

$$\frac{\partial g_m}{\partial \pi_n} = -\frac{\partial f_{mn}}{\partial \pi_n}$$

$$\frac{\partial g_m}{\partial H_j} = -\sum_{n \in GC(m)} \frac{\partial f_{mn}}{\partial H_j} - \sum_{j=1}^{NC} G_{mj} \cdot (2a_j + b_j)$$

- The Natural gas transmission feasibility check subproblem checks whether the available gas resources and controllable compressors could satisfy natural gas transmission limits, as well as natural gas demands of gas-fired units committed by the master UC problem.

$$Min \quad \omega(\hat{\boldsymbol{L}}) = \sum_{l=1}^{NGL}(SL_l)$$

$$S.t. \quad [\boldsymbol{J}_\pi \quad \boldsymbol{J}_{\boldsymbol{H}} \quad \boldsymbol{A} \quad \text{-}\boldsymbol{B}] \begin{bmatrix} \Delta\boldsymbol{\pi} \\ \Delta\boldsymbol{H} \\ \Delta\boldsymbol{v} \\ \Delta\boldsymbol{L} \end{bmatrix} = -\boldsymbol{g}(\boldsymbol{\pi}, \boldsymbol{H}, \boldsymbol{v}, \hat{\boldsymbol{L}}) \qquad \mu$$

$$\boldsymbol{SL} + \Delta\boldsymbol{L} = 0 \qquad -\hat{\boldsymbol{L}} \le \Delta\boldsymbol{L} \le 0$$

$$\boldsymbol{\pi}_{\min} \le \boldsymbol{\pi} + \Delta\boldsymbol{\pi} \le \boldsymbol{\pi}_{\max} \qquad \boldsymbol{v}_{\min} \le \Delta\boldsymbol{v} + \boldsymbol{v} \le \boldsymbol{v}_{\min}$$

$$\boldsymbol{H}_{\min} \le \boldsymbol{H} + \Delta\boldsymbol{H} \le \boldsymbol{H}_{\max}$$

$$\boldsymbol{R}_{\min} \cdot (\boldsymbol{\pi}_n + \Delta\boldsymbol{\pi}_n) \le \boldsymbol{\pi}_m + \Delta\boldsymbol{\pi}_m \le \boldsymbol{R}_{\max} \cdot (\boldsymbol{\pi}_n + \Delta\boldsymbol{\pi}_n)$$

- The iterative solution process of natural gas transmission feasibility check subproblem
  - **Step 1:** Calculate modified Jacobian matrix $\boldsymbol{J}$ and initial natural gas node mismatch vector $-\boldsymbol{g}(\boldsymbol{\pi}, \boldsymbol{H}, \boldsymbol{v}, \hat{\boldsymbol{L}})$ based on the initial gas load, system states, and generation schedules of natural gas providers.

  - **Step 2:** Minimize the objective function and calculate changes in state and control variables of the natural gas transmission system $\Delta\pi, \Delta H, \Delta v, \Delta L$. If the difference between current and previous iterative changes is less than a specified threshold, stop the process. Otherwise, go to Step 3.

  - **Step 3:** Update state and control variables. Calculate elements of Jacobian matrix and $\boldsymbol{SL}$. Go to Step 2.

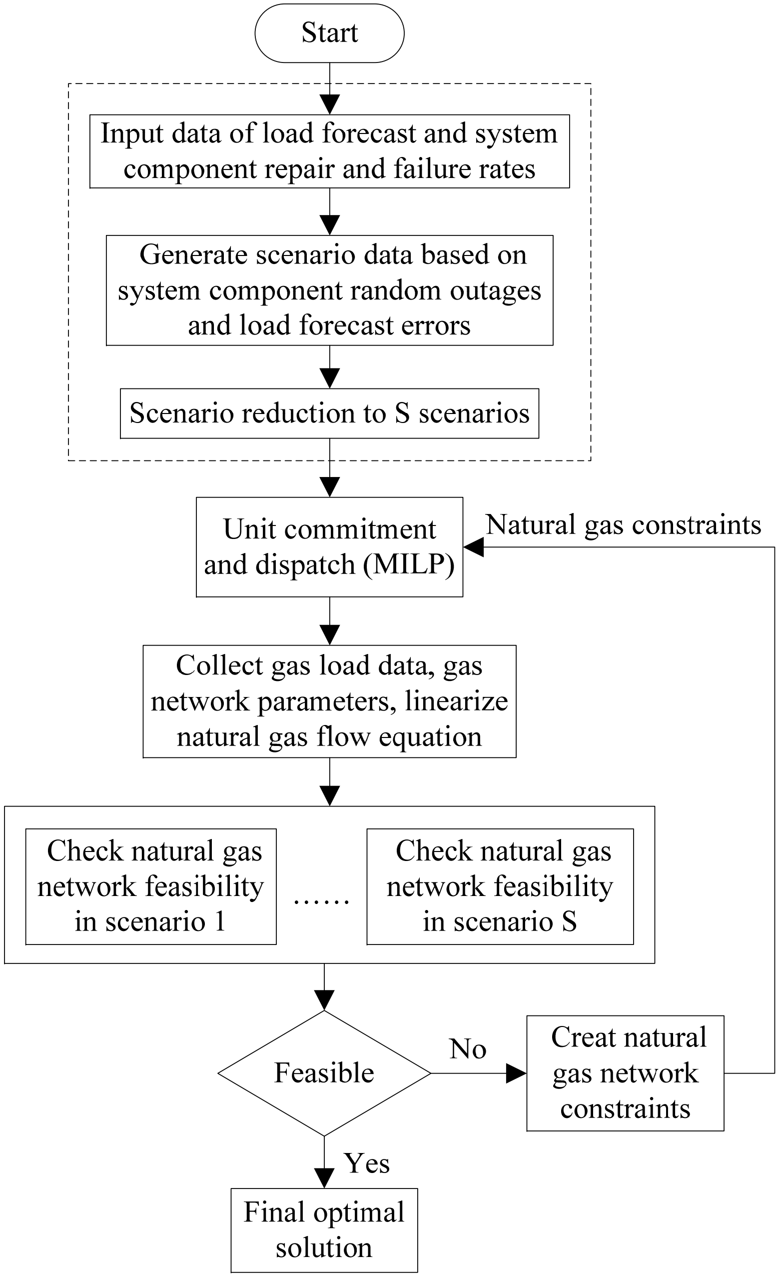
- Once a non-negative objective function is larger than the specified tolerance, which means that nodal gas suppliers and loads cannot provide a feasible natural gas flow solution. An energy constraint (Benders cut) will be formed.

$$\omega(F_{gas,\eta}) = \omega(\hat{F}_{gas,\eta}) + \sum B_{lm}^{T} \cdot \mu_m \cdot (F_{gas,\eta} - \hat{F}_{gas,\eta}) \le 0$$

- Benders cuts are generated from the solution of a successive approximation of a nonlinear equation.
- Pipeline equations may make the subproblems non-convex in feasible sets. So if the initial operating point of natural gas problem is not close enough to the global optimal points, the final solution of SCUC with natural gas constraints may result in a local optimal solution.
- Different initial points of natural gas flow could be used to find a good enough solution.

Solution Methodology

- Step1 Stochastic data processing
- Step 2 Solve unit commitment problem
- Step 3 Determine the natural gas demand for gas-fired units
- Step 4 Calculate the natural gas flow to check whether the gas demand can be supplied. If any violation is encountered, natural gas network constraints are generated and fed back to the master problem
- The iterative process will be repeated until final optimal solution is obtained when all violations are eliminated.

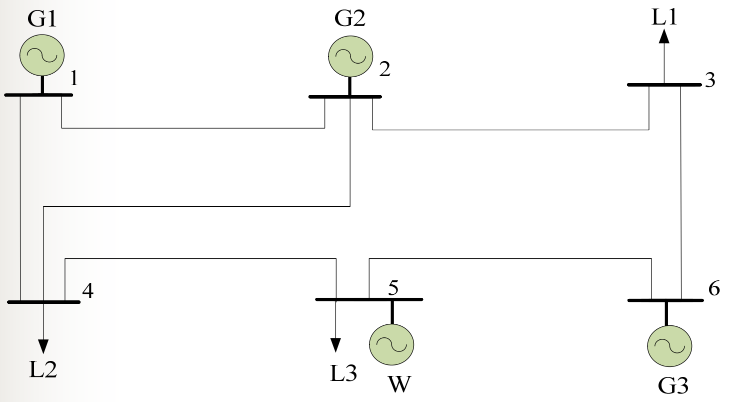


Case Studies

- Two systems
  - 6-bus power system with a 6-node natural gas system
  - IEEE 118-bus system with 10-node natural gas system

- Case 1: Deterministic base case without natural gas transmission constraints.
- Case 2: Natural gas transmission constraints are also considered.
- Case 3: A stochastic model with system uncertainties is also considered.

6-bus Power System and 6-Node Gas System

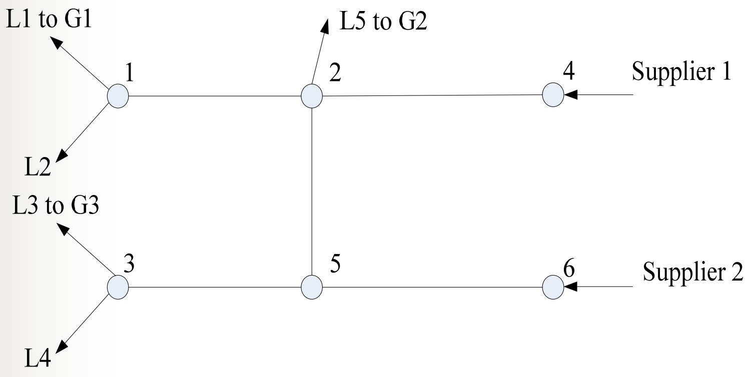


Power system :

3 Loads

3 Gas-fired units G1, G2, G3

Unit	af (MBtu/MW^{2}h)	bf (MBtu/MWh)	cf (MBtu/h)
G1	0.0004	13.51	176.95
G2	0.001	32.63	129.97
G3	0.005	17.70	137.41



Natural gas system:

5 Pipelines

2 Natural gas suppliers

5 Natural gas loads

Loads 1,3,5 represent the demand of three gas-fired units

Loads 2, 4 represent other gas customers

Case1: Deterministic Base Case

- Natural gas transmission constraints are not considered
  - Daily operation cost: $81,741
  - Least expensive unit G1 is committed during the scheduling horizon, while the expensive units are only committed at periods with higher load demand
  - Fuel consumptions of three units at peak hour 17 are 2951kcf/h, 1339kcf/h, 493kcf/h

Hourly schedule of Case1

Daily production cost: $81,741	
Unit	Hours (0-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	1 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 0 0 0
3	0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0

Case 2: Deterministic Case with Gas Constraints

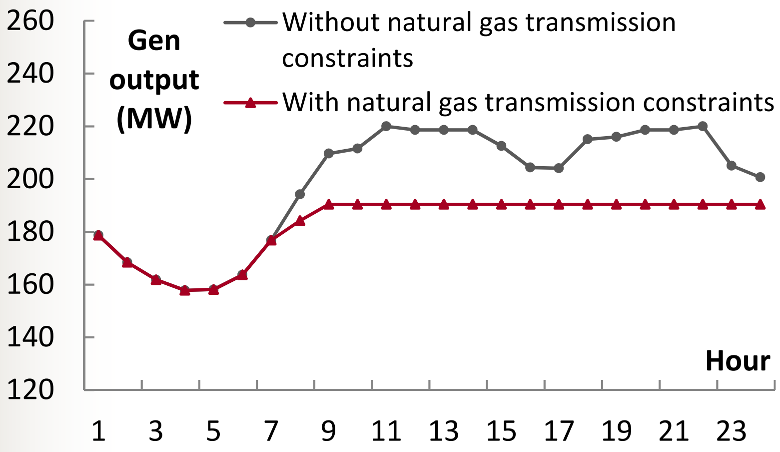
- Natural gas transmission constraints are incorporated
  - Daily operation cost: $88,297
  - Natural gas transmission constraints cause the expensive unit 2 to be committed additionally between hours 10 and 22 and unit 3 between hours 8 and 24
  - Fuel consumptions of three units at peak hour 17 are 2764kcf/h, 1786kcf/h, 493kcf/h

Hourly schedule of Case2

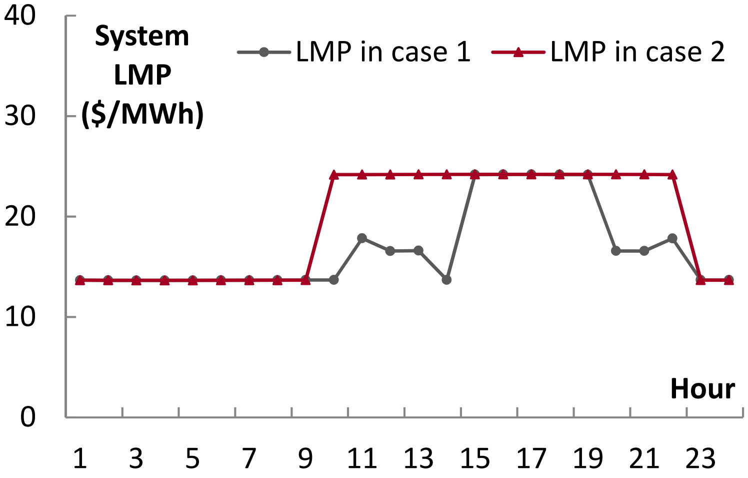
Daily production cost: $88,297	
Unit	Hours (0-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	1 0 0 0 0 0 0 0 0 0 **1 1** 1 1 1 1 1 1 1 1 1 1 **1** 0 0
3	0 0 0 0 0 0 0 0 **1 1** 1 1 1 1 1 1 1 1 1 1 1 1 1 **1 1**

Case Results

- Daily operation cost in case 2 increased to $88,297 as compared $81,741 in case1
- Dispatch of the least expensive unit G1 in case 2 is constrained by the gas network
- LMP spikes are extended in case 2 between hours 10 and 22
- In case 3, expected operation cost increased to $91,325 when load forecast errors and component outages are considered



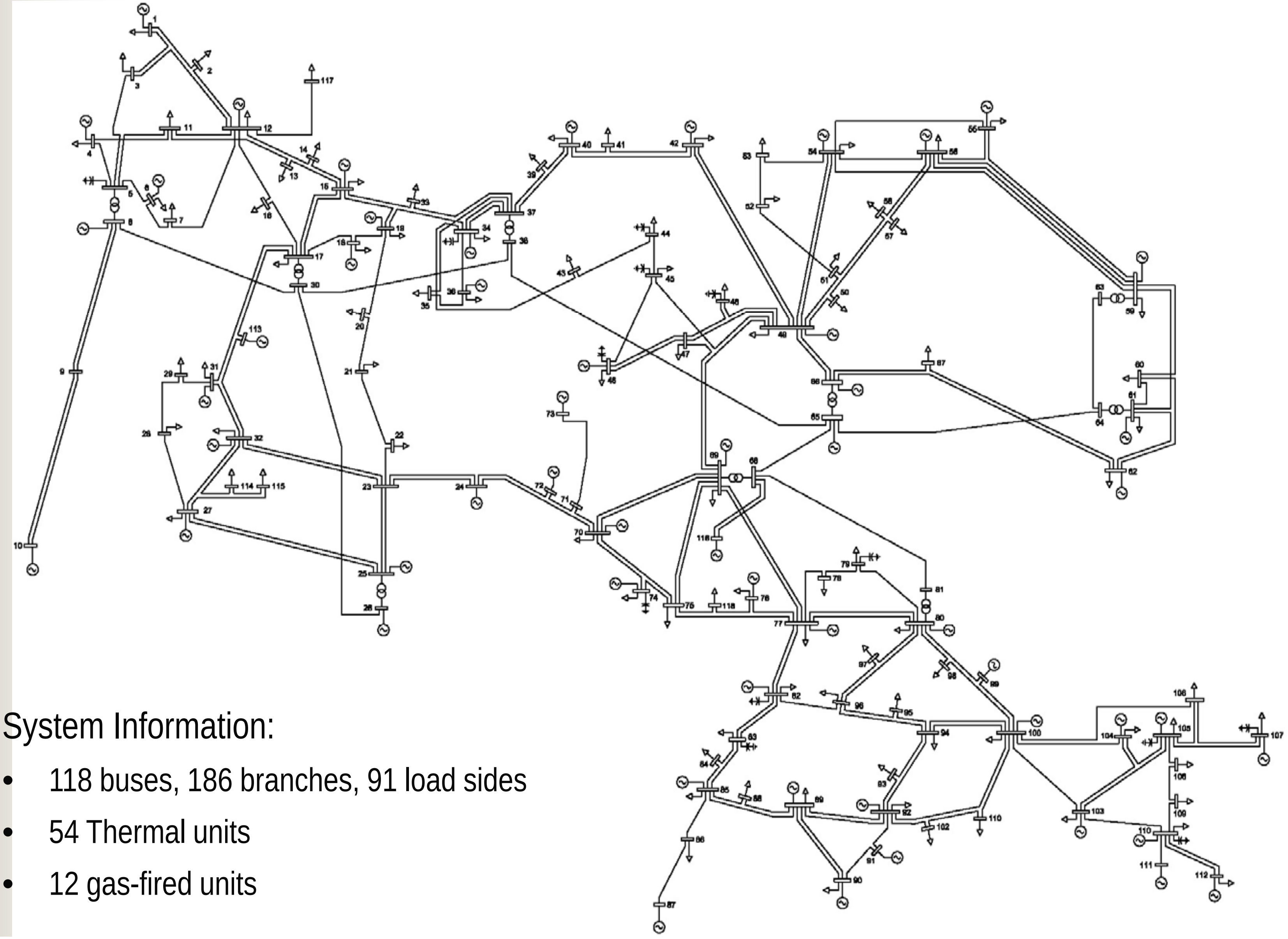
Hourly dispatch of unit G1



System hourly LMP

EES-UETP
Electric Energy Systems - University Enterprise Training Partnership

IEEE 118-bus System

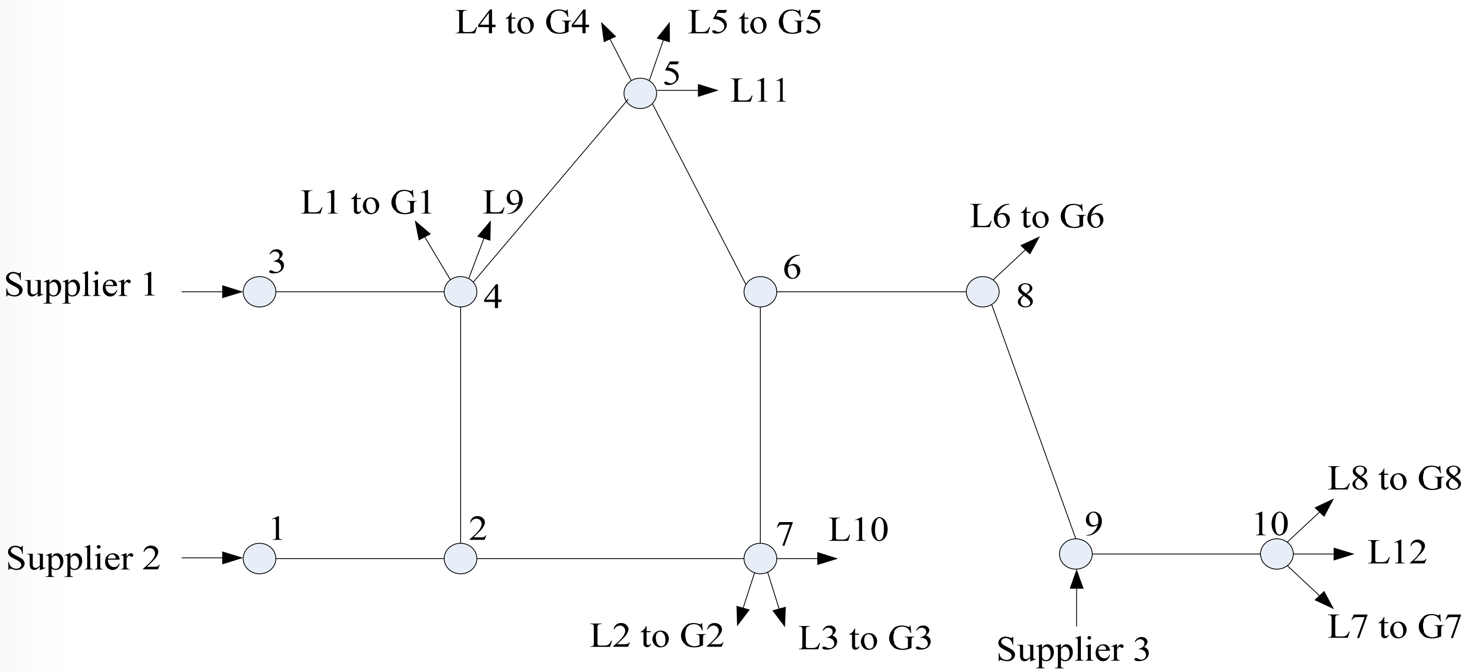


System Information:

- 118 buses, 186 branches, 91 load sides
- 54 Thermal units
- 12 gas-fired units

EES-UETP
Electric Energy Systems - University Enterprise Training Partnership

10-node Natural Gas System



System Information:

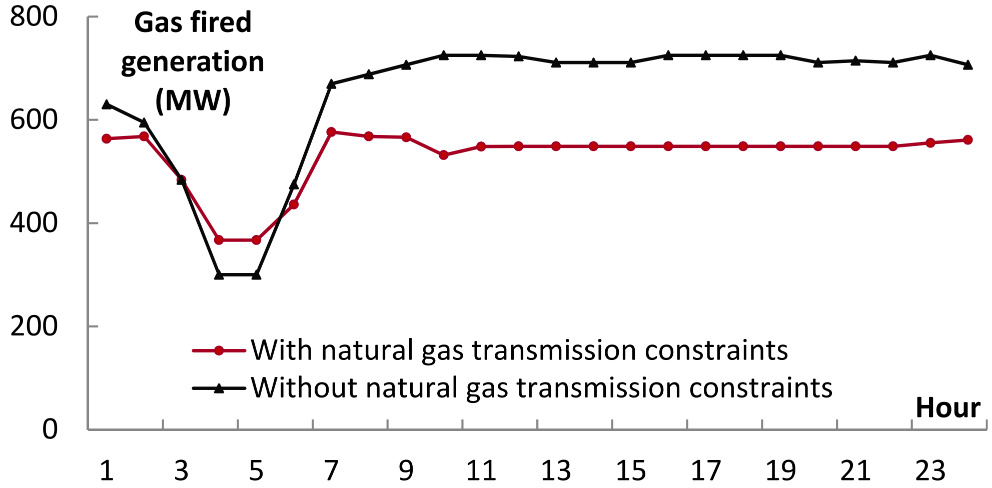
- 10 Node
- 10 Natural gas pipelines
- 8 Gas loads
- 3 Gas suppliers

IEEE 118-bus system

- Deterministic cost

Without natural gas transmission constraints	With natural gas transmission constraints
1,796,670	1,799,280

  - Total generation of the 8 gas-fired units is curtailed by 2,894MW by enforcing natural gas transmission constraints



Comparison of gas-fired unit generation

  - Stochastic cost: Expected operation cost increased to $1,822,945 when load forecast errors and component outages are considered

Role of Demand Response

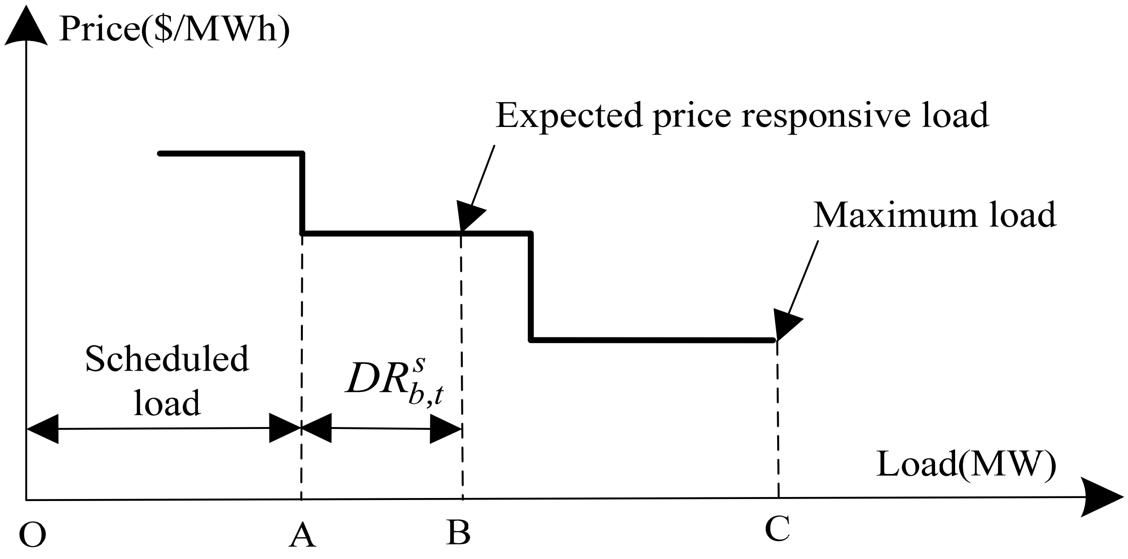
- Offer economical solution schedule
  - Insufficient natural gas transmission capacity for serving economic gas-fired power plants at peak load period
  - Hourly economic demand response can be used while expensive natural gas-fired units would not be committed or fully dispatched for a more economical solution schedule
- Offer security options
  - The fuel curtailment could lead to a number of natural gas-fired plant shutdown
  - Hourly economic demand response can be used by grid operators for managing outages, and incentives to customers to flatten their hourly load profiles for security purposes

Research Contributions

- We consider the hourly demand response in the short-term stochastic model as an economic option for optimizing the day-ahead scheduling of interdependent electricity and natural gas transmission systems
  - Natural gas infrastructures are modeled to represent the fuel transportation availability of gas-fired units
  - Hourly demand response is modeled to maximize social welfare for managing the fuel shortage risk caused by the constrained natural gas transmission system
  - Stochastic technique is used to ensure the capability of SCUC operation to withstand unpredictable events, while taking cost and benefit into consideration
  - The Monte Carlo simulation is applied to create multiple scenarios for representing the coordinated system uncertainties

Demand Response Bidding Curve

- We consider price responsive loads for the demand response program via price-sensitive load consumption curves
- Demand response can control the energy consumption in response to the market prices by curtailing or shifting loads to other operating hours



Stepwise demand response bidding curve

Stochastic Simulation

- Random outages of power plants and transmission lines
  - Sequential Technique
    Specify the initial state of each component. Simulate the duration of each component residing in its present state by a two-state continuous-time Markov model with parameters of failure and repair rates

- Load forecast errors
  - Described by a normal distribution
  - The distribution is divided into a discrete number of intervals. The load representing the interval mid-point is assigned probability for that interval.

Stochastic day-ahead Scheduling Formulation

- Objective function: maximize the expected social welfare over the scheduling horizon while satisfying system constraints

$$\max \sum_{s=1}^{N_S} \Pr_s \{ \sum_{t=1}^{N_T} \sum_{b=1}^{N_B} \sum_{n=1}^{NB_{b,t}^D} \lambda D_{b,t,\varepsilon} d_{n,b,t}^s - \sum_t \sum_\eta W_{\eta,t}$$

$$- \sum_t \sum_{i \notin GU} [F_{c,i}(P_{i,t}^s) \cdot I_{i,t}^s + SU_{i,t}^s + SD_{i,t}^s]\}$$

- Variables:

λD	Marginal benefit of the demand response bid
d	Load demand block of the stepwise demand bid
SU, SD	Start up and Shut down cost
F	Cost function of other generating unit
W	Fuel cost of natural gas-fired unit
P_s	Probability of scenario s

Power System Constraints

- Demand response constraints

- Correlation between block load and adjustable load at each period

$$DR_{b,t}^{s} = DE_{b,t} - \sum_{n=1}^{NB_{b,t}^{D}} d_{n,b,t}^{s}$$

- Constraints on adjustable load

$$\begin{array}{ll} DR_{b,t}^{\min} Y_{b,t}^{s} \le DR_{b,t}^{s} \le DR_{b,t}^{\max} Y_{b,t}^{s} & , if \;\; DR_{b,t}^{s} \ge 0 \\ DR_{b,t}^{s} \ge DE_{b,t} - D_{b,t}^{\max} & , else \end{array}$$

  - $Y_{b,t}^{s}$ indicates the status of demand response at bus at time ***t*** in scenario *s*, 1 means the load is shifted while 0 means the scheduled load is equal to the expected load

Power System Constraints

- Demand response constraints

- Total curtailment for each price responsive load

$$0 \le \sum_{t=1}^{N_T} DR_{b,t}^{s} \le E_b^{\max}$$

- Adjusted load between two successive periods is restricted by load pick-up/drop-off rates

$$(DE_{b,t} - DR_{b,t}^{s}) - (DE_{b,t-1} - DR_{b,t-1}^{s}) \le \Delta D_b$$

$$-\Delta D_b \le (DE_{b,t} - DR_{b,t}^{s}) - (DE_{b,t-1} - DR_{b,t-1}^{s})$$

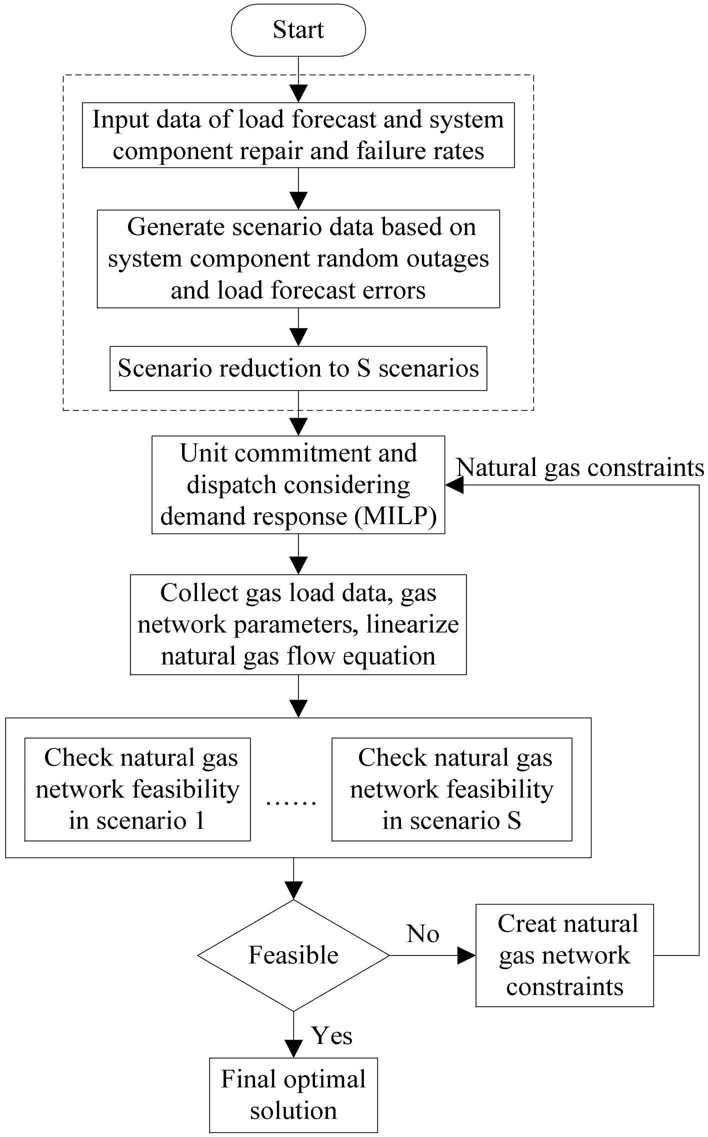
- Minimum on/off time: indicate that a specific load is supplied or curtailed in the scheduling horizon

$$(X_{b,(t-1)}^{s,on} - UT_b)(Y_{b,(t-1)}^{s} - Y_{b,t}^{s}) \ge 0$$

$$(X_{b,(t-1)}^{s,off} - DT_b)(Y_{b,t}^{s} - Y_{b,(t-1)}^{s}) \ge 0$$

Solution Methodology

- Step1 Stochastic data processing
- Step 2 Solve unit commitment problem
- Step 3 Determine the natural gas demand for gas-fired units
- Step 4 Calculate the natural gas flow to check whether the gas demand can be supplied. If any violation is encountered, natural gas network constraints are generated and fed back to the master problem
- This iterative process will be repeated until final optimal solution is obtained when all violations are eliminated.



Start

Input data of load forecast and system component repair and failure rates

Generate scenario data based on system component random outages and load forecast errors

Scenario reduction to S scenarios

Unit commitment and dispatch considering demand response (MILP)

Natural gas constraints

Collect gas load data, gas network parameters, linearize natural gas flow equation

Check natural gas network feasibility in scenario 1

……

Check natural gas network feasibility in scenario S

Feasible

No

Creat natural gas network constraints

Yes

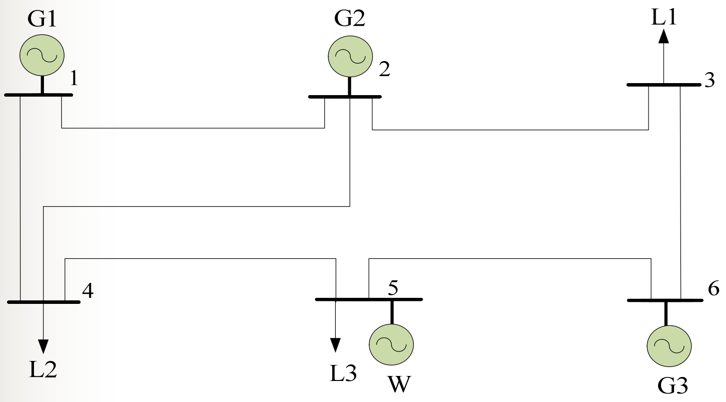
Final optimal solution

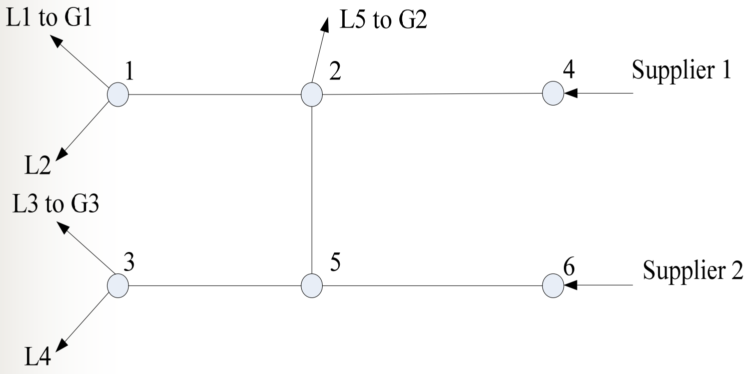
Case Study

- Two study system
- 6-bus power system with a 6-node natural gas system
- IEEE 118-bus system with 10-node natural gas system

- Case 1: Deterministic base case without any hourly demand response
- Case 2: Hourly demand response is introduced
- Case 3: A stochastic solution considering system uncertainties.

6-bus Power System and 6-node Gas System





Power system :

- 3 Loads
- 3 Gas-fired units G1, G2, G3

Unit	af (MBtu/MW^{2}h)	bf (MBtu/MWh)	cf (MBtu/h)
G1	0.0004	13.51	176.95
G2	0.001	32.63	129.97
G3	0.005	17.70	137.41

Natural gas system:

- 5 Pipelines
- 2 Natural gas suppliers
- 5 Natural gas loads
- L1, L3, L5 represent the demand of three gas-fired units
- L2, L4 represent other gas customers

Case1: Deterministic Base Case

- Hourly demand response is not considered
  - Expensive unit 2 is committed for a more periods when natural gas transmission constraints are enforced
  - Daily operation cost is increased due to the constrained fuel supply

Hourly schedule of Case1

Daily production cost: $81,741 (without natural gas constraints)	
Unit	Hours (0-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0
3	0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 0 0
Daily production cost: $85,687 (with natural gas constraints)	
Unit	Hours (0-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	0 **1 1 1 1 1 1 1 1 1 1** 1 1 1 1 1 1 1 1 1 1 1 **1 1** 0
3	0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 0 0

Case2: Deterministic Case with Demand Response

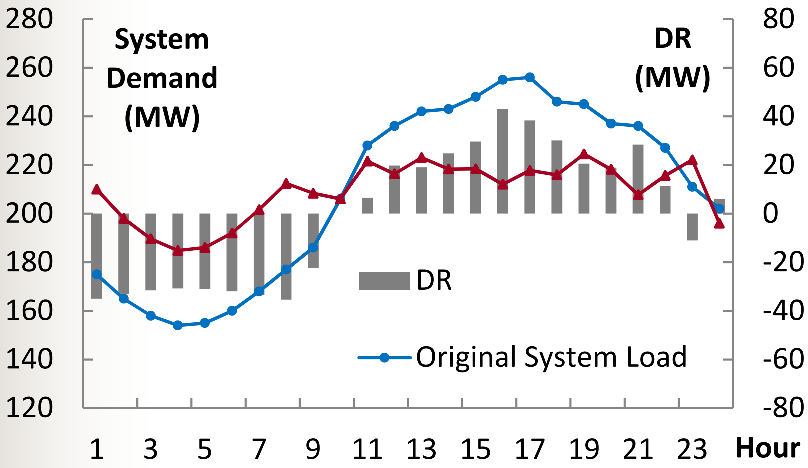
- Hourly demand response is introduced at all load buses
  - Load participation factor which is defined as the ratio of available price responsive load to the expected price responsive load, is 0.2.
  - Expensive generating unit G3 is not committed
  - Total generation dispatch of unit G2 is reduced from 405.22MWh in Case 1 to 244.93MWh

Hourly schedule of Case2

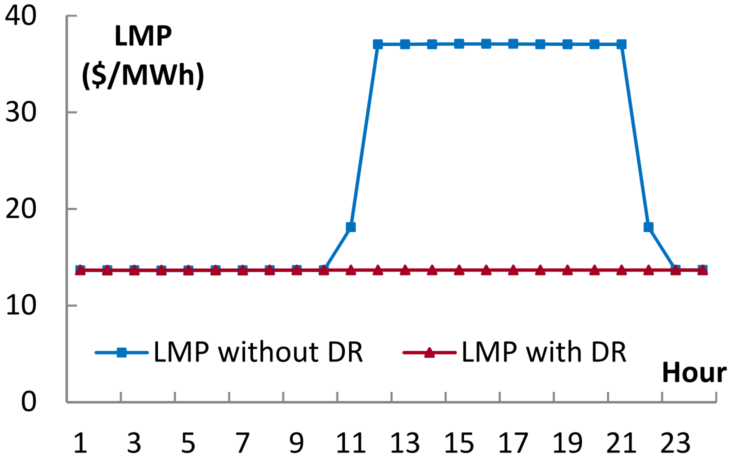
Daily production cost: $80,070	
Unit	Hours (0-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
3	0 0 0 0 0 0 0 0 0 0 0 **0 0 0 0 0 0 0 0 0 0 0 0** 0 0

Case1 vs. Case2

- Benefits of hourly demand response
  - Daily operation cost: $80,070 as compared $85,687 in case 1
  - System load profile: a more flat load profile
  - LMPs: lowered LMPs during peak hours 12 - 21



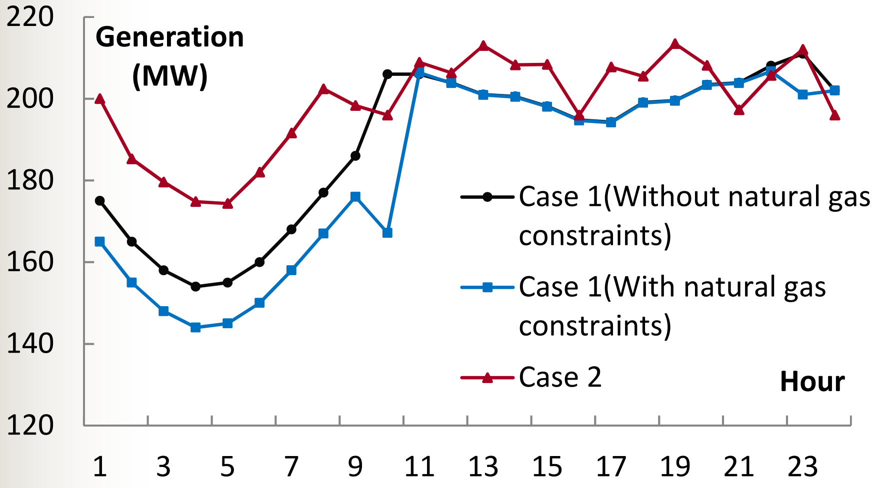
Hourly load profile comparison



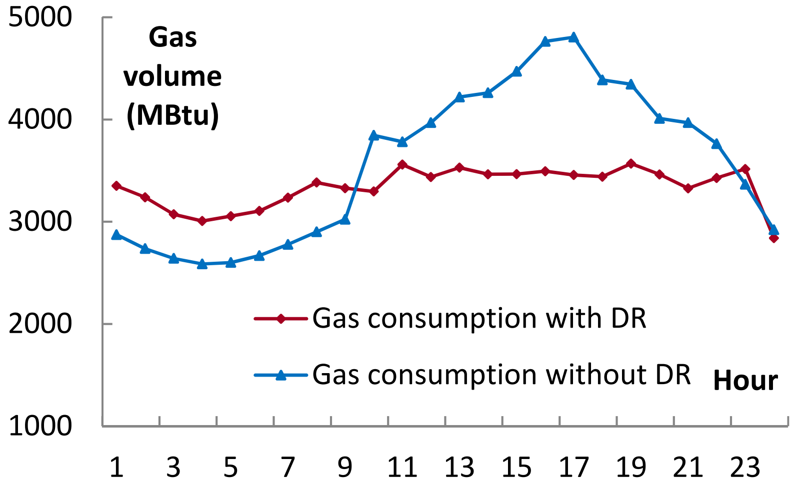
System hourly LMP

Case1 vs. Case2

- Impact of demand response on generation dispatch
  - Hourly dispatch of the cheapest unit G1 is less volatile
  - Total natural gas consumption profile of the three gas-fired units is more flat, which avoids the peak simultaneously with residential gas load and inadequate supplies of natural gas



Hourly dispatch of unit G1

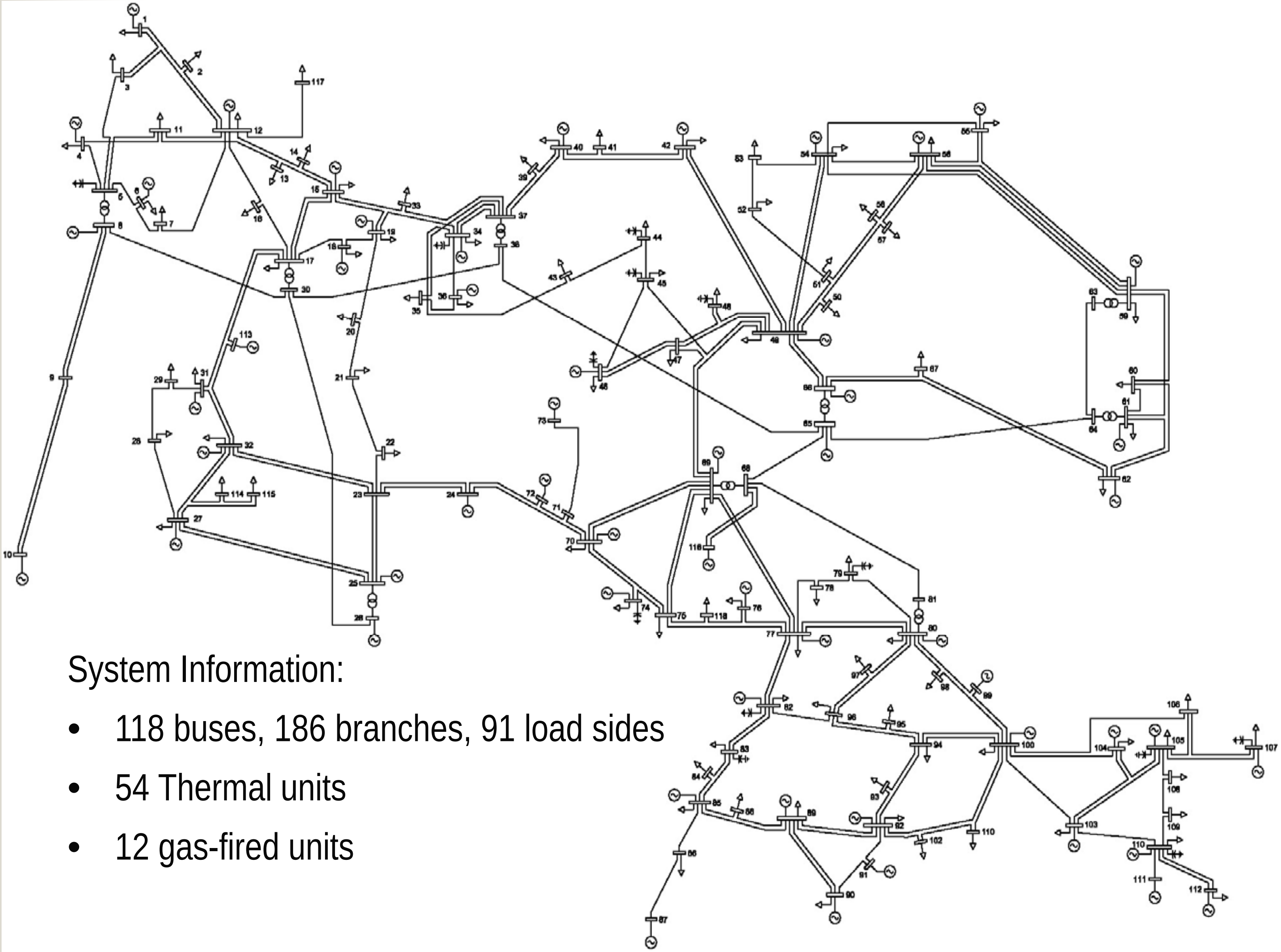


Hourly gas consumption comparison

Case3: Stochastic Case

- System uncertainties are introduced
  - Load forecast error follow a truncated normal distribution with a mean value equal to the load forecast and a standard deviation of 5% of mean value
  - Power system component outages are considered
  - 6561 scenarios are generated using the Monte Carlo simulation and 11 scenarios are retained
  - The expected operation cost is $79,778

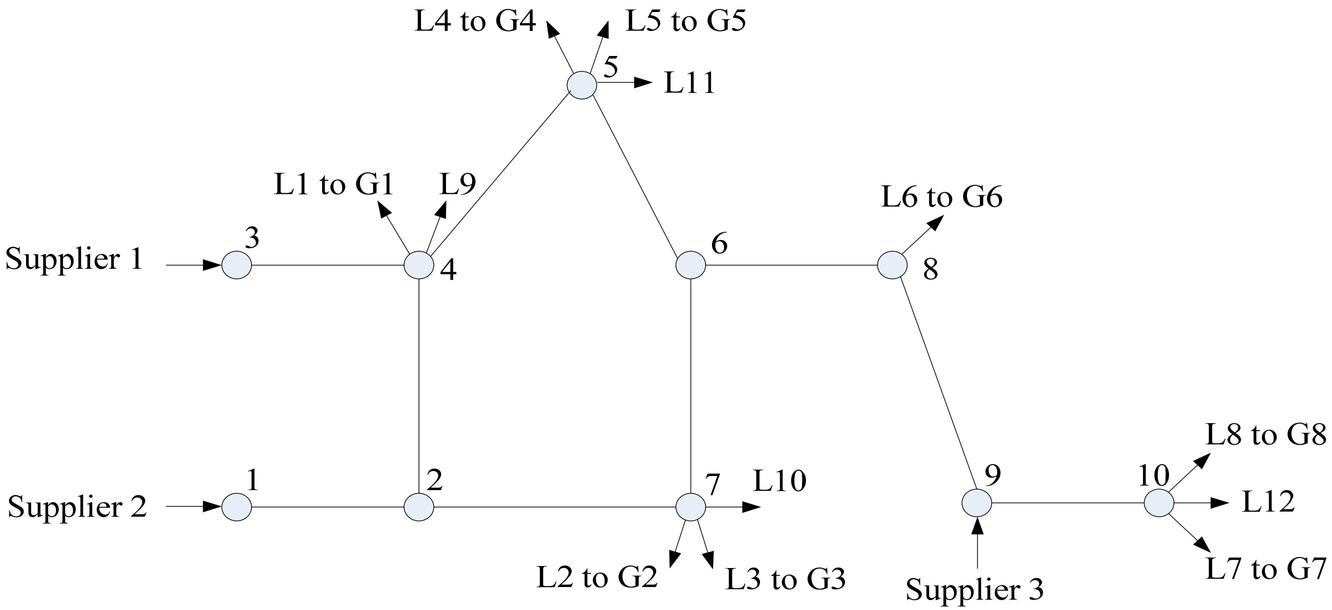
IEEE 118-bus System



System Information:

- 118 buses, 186 branches, 91 load sides
- 54 Thermal units
- 12 gas-fired units

10-node Natural Gas System



System Information:

- 10 Node
- 10 Natural gas pipelines
- 8 Gas loads
- 3 Gas suppliers

118-bus system

- Deterministic cost

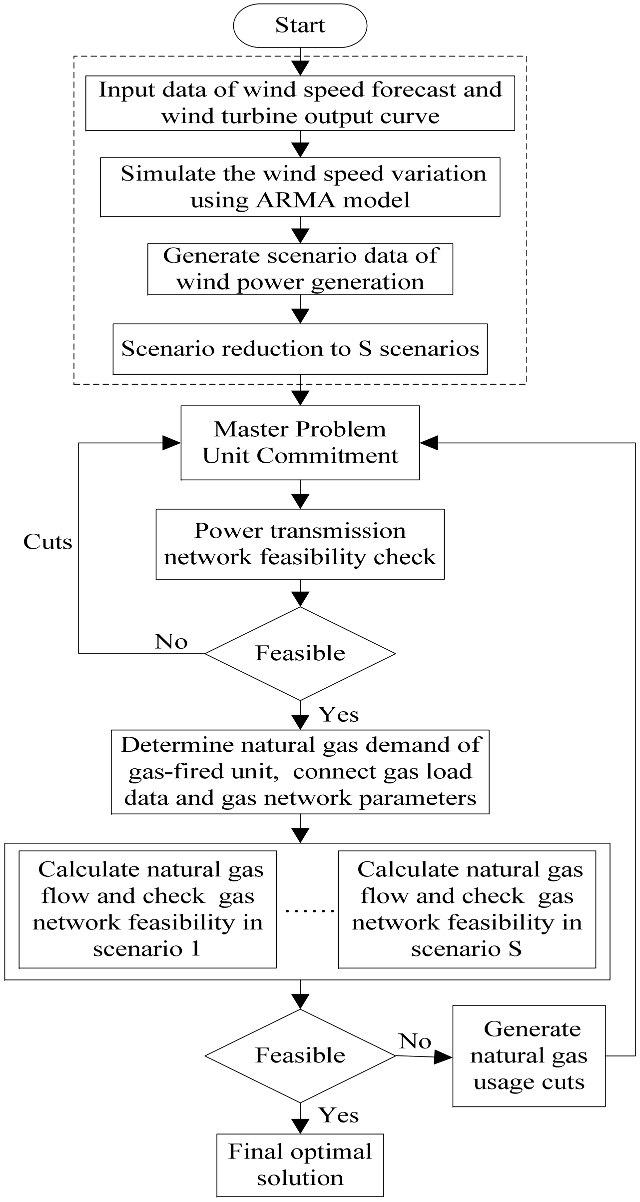
Without natural gas transmission constraints	With natural gas transmission constraints
1,699,510	1,701,014

  - The cheapest natural gas unit G6 cannot always operate at full capacity due to the natural gas node pressure constraints
  - The operation cost does not change much considering the natural gas constraints because the hourly demand response has improved the load profile by shifting the peak loads

- Stochastic system cost
  - Expected operation cost is $1,703,304 (cost difference is caused mainly by load forecast errors)

Flowchart for Considering Wind Energy Variability

- Step 1 Process stochastic data
- Step 2 Solve unit commitment
- Step 3 Check power transmission network constraints
- Step 4 Determine natural gas demand for gas-fired units
- Step 5 Calculate natural gas flow to find whether the gas demand can be supplied
- Continue the iterative process until the final optimal solution is obtained when all violations are eliminated.



Start

Input data of wind speed forecast and wind turbine output curve

Simulate the wind speed variation using ARMA model

Generate scenario data of wind power generation

Scenario reduction to S scenarios

Master Problem Unit Commitment

Power transmission network feasibility check

Feasible

No

Cuts

Yes

Determine natural gas demand of gas-fired unit, connect gas load data and gas network parameters

Calculate natural gas flow and check gas network feasibility in scenario 1

……

Calculate natural gas flow and check gas network feasibility in scenario S

Feasible

No

Generate natural gas usage cuts

Yes

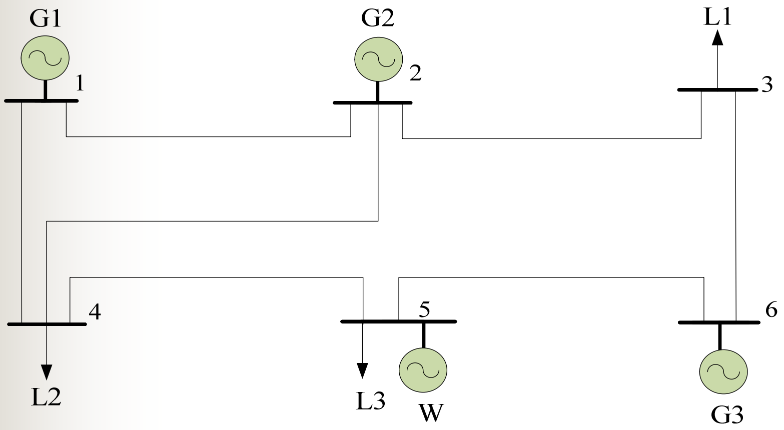
Final optimal solution

Cases for Considering Wind Energy Variability

- Coordinated Infrastructures:
  - 6-bus power system with a 6-node natural gas system
  - IEEE 118-bus system with 10-node natural gas system

- Case 1: Natural gas price volatility and fuel availability
- Case 2: Emission constraints are also considered
- Case 3: Wind energy variability is added
- Case 4: Stochastic solution with wind energy uncertainties

6-bus Power System

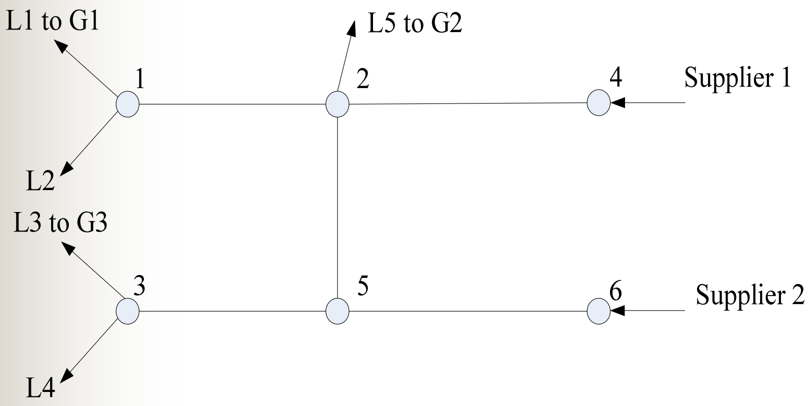


3 Gas-fired units G1, G2, G3

1 Wind farm

3 Loads

6-node Gas System



5 Pipelines

2 Natural gas suppliers

5 Natural gas loads

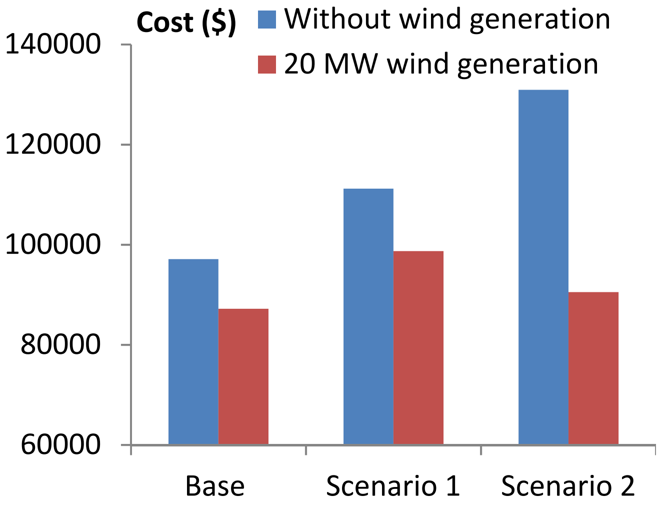
L1, L3 & L5: Three gas-fired unit demands

L2 & L4: other gas customers

Case 1: Gas Price Volatility and Fuel Availability

- Comparison of possible operation scenarios
  - Gas price volatility and fuel availability will greatly affect operation costs
  - Integration of wind energy play a complementary role in hedging the risk of fuel-constrained generation uncertainty

MW	$	Base case	*Scenario 1* Gas price goes up by 20%	*Scenario 2* Gas load is increased by 500kcf/h
System 1: Wind 0MW	Production cost = Load shedding cost = Total cost =	97,104 0 97,104	111,197 0 111,197	95,841 35,080 130,921
System 2: Wind 20MW (6.3%)	Production cost = Load shedding cost = Total cost =	87,190 0 87,190	98,710 0 98,710	87,059 3,480 90,539



Case 2: Emission Constraints

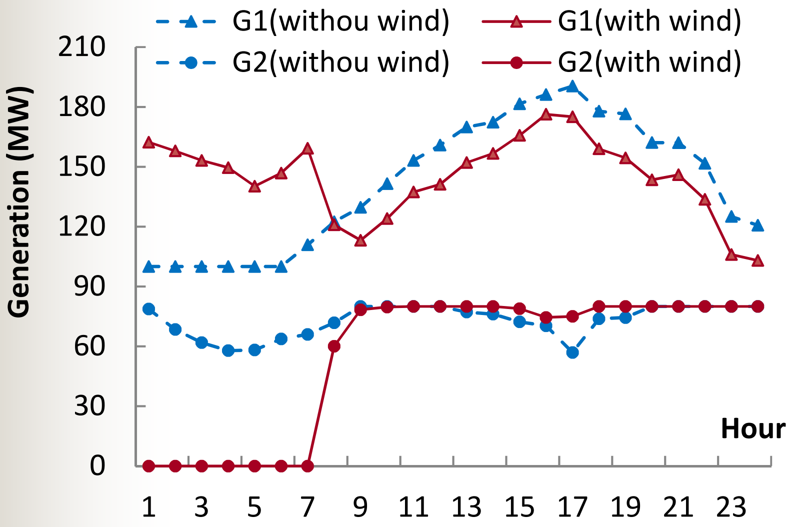
- Comparison of two cases: with/without 20MW wind energy
  - Zero-emission wind generation frees up emission-constrained and cheaper G1 unit to be scheduled additionally

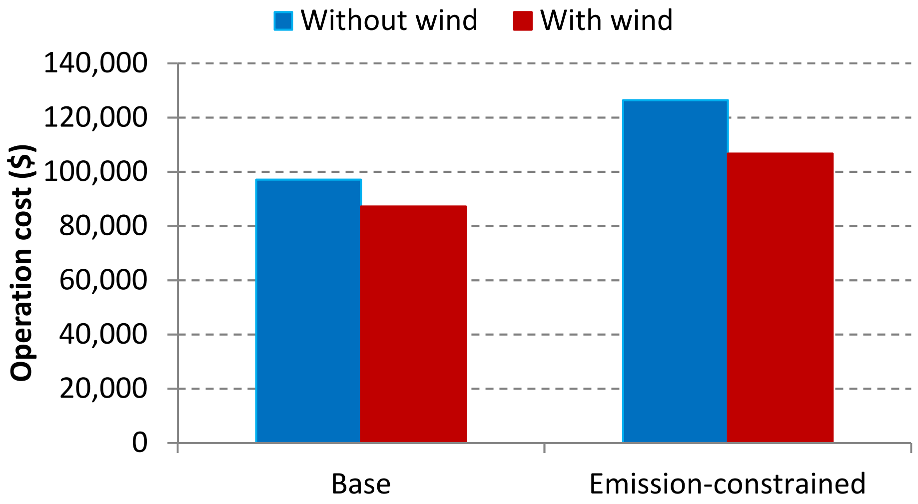
Emission curve

Unit	af(lbs/MW²h)	bf(lbs/MWh)	cf(lbs)
G1	0.0009	2.7	353.9
G2	0.0001	8.6	129.9
G3	0.01	35.3	274.8

Fuel curve

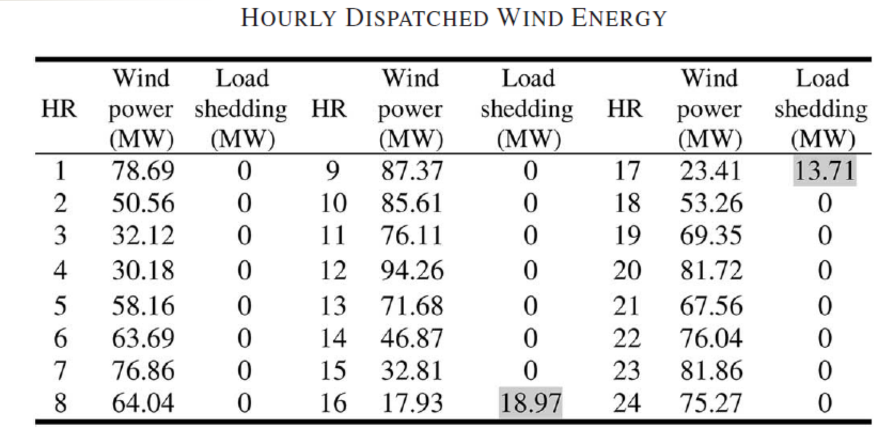
Unit	af (MBtu/MW²h)	bf (MBtu/MWh)	cf (MBtu/h)
G1	0.0004	13.51	176.95
G2	0.001	32.63	129.97
G3	0.005	17.70	137.41





Case 3: Variable Wind Energy

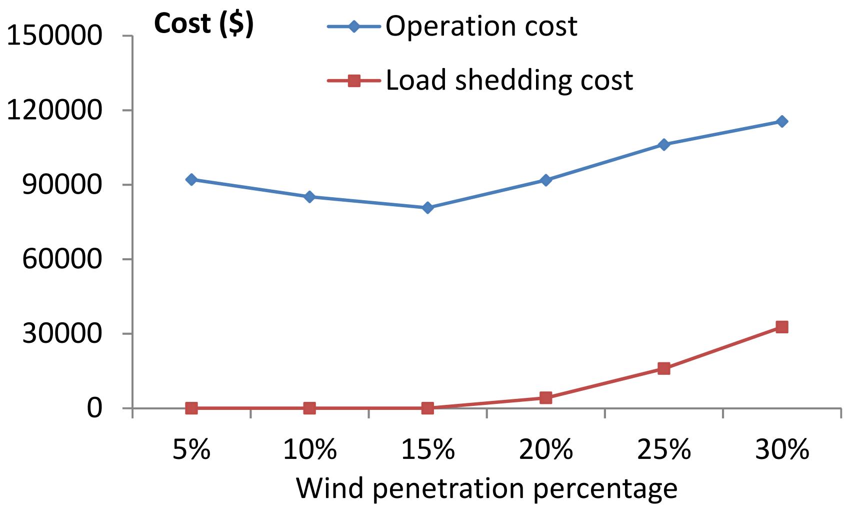
- Wind penetration level ranging from 5% to 30%
  - Daily operation cost decreases when wind energy penetration is lower than 15%
  - Load shedding is required for insufficient quick-ramping resource to pick up the load when wind energy penetration reaches 20%



HOURLY DISPATCHED WIND ENERGY

HR	Wind power (MW)	Load shedding (MW)	HR	Wind power (MW)	Load shedding (MW)	HR	Wind power (MW)	Load shedding (MW)
1	78.69	0	9	87.37	0	17	23.41	13.71
2	50.56	0	10	85.61	0	18	53.26	0
3	32.12	0	11	76.11	0	19	69.35	0
4	30.18	0	12	94.26	0	20	81.72	0
5	58.16	0	13	71.68	0	21	67.56	0
6	63.69	0	14	46.87	0	22	76.04	0
7	76.86	0	15	32.81	0	23	81.86	0
8	64.04	0	16	17.93	18.97	24	75.27	0

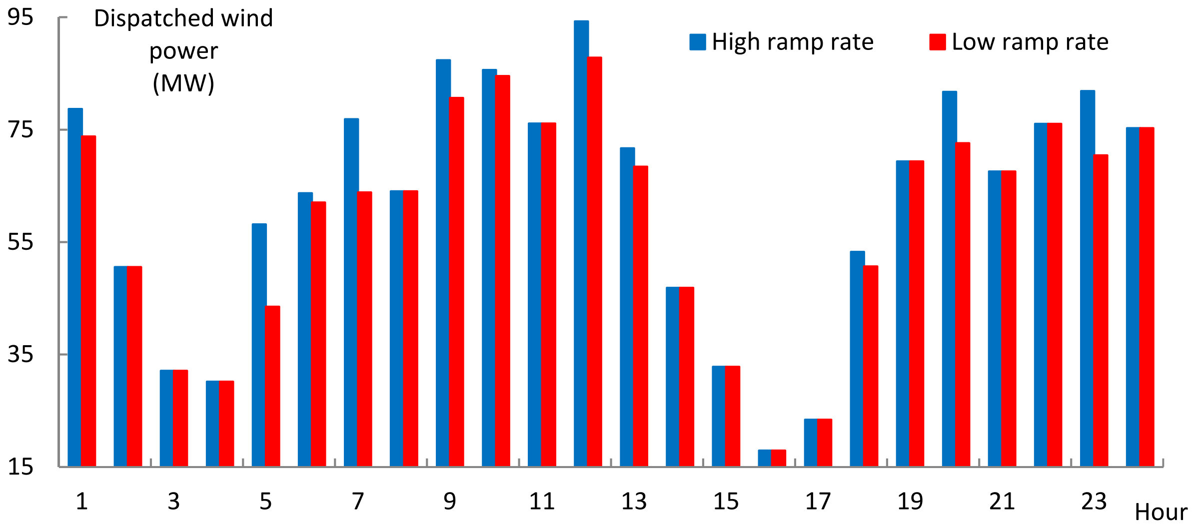
Hourly Load Shedding



Operation cost VS. wind penetration percentage

Case 3: Ramping Capability

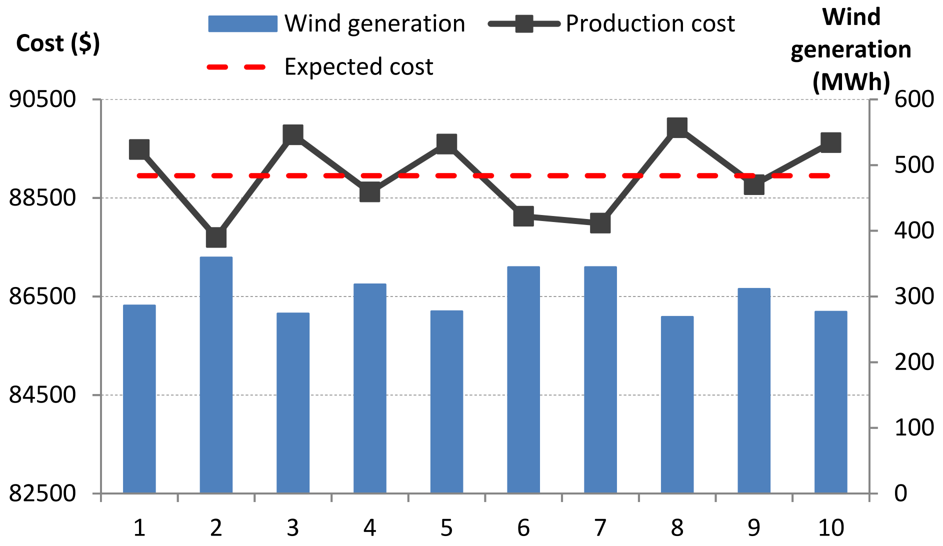
- Comparison of ramping capability
  - 96MW wind energy (30% of the system capacity)
  - The base ramp rates for gas-fired units are 55MW/hr, 40MW/hr, and 5MW/hr which is increased to 120MW/hr, 80MW/hr, and 20MW/hr, respectively
  - Ramping capability of gas-fired units would accommodate the wind energy variability to maximize the utilization of wind generation



Hourly dispatched of wind energy unit

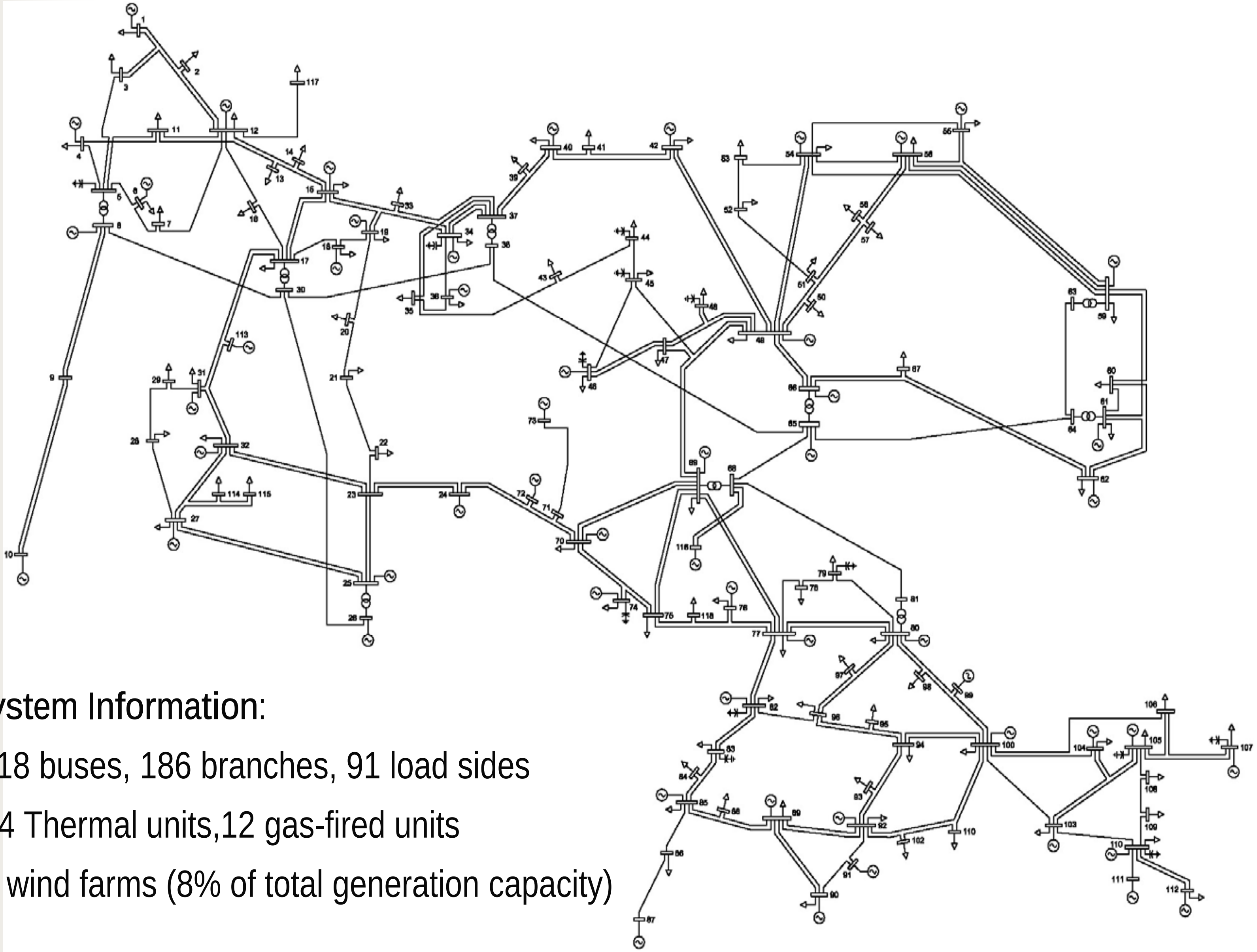
Case 4: Wind Energy Uncertainty

- The wind speed forecast follows a Weibull distribution function with a Weibull constant of 2 and the average wind speed of 6.5 m/s. The 1st order ARMA (1,1) time series is created to simulate wind speed forecast errors.
- The expected operation cost for the 10 scenario solution is $88,952 and the forecast wind energy in the 24-h scheduling horizon is 306 MWh.
- The operation cost deviation in each scenario is mainly caused by the amount of utilized wind energy since it does not incur any fuel cost. Higher wind energy utilization results in lower costs



Scenario cost comparison

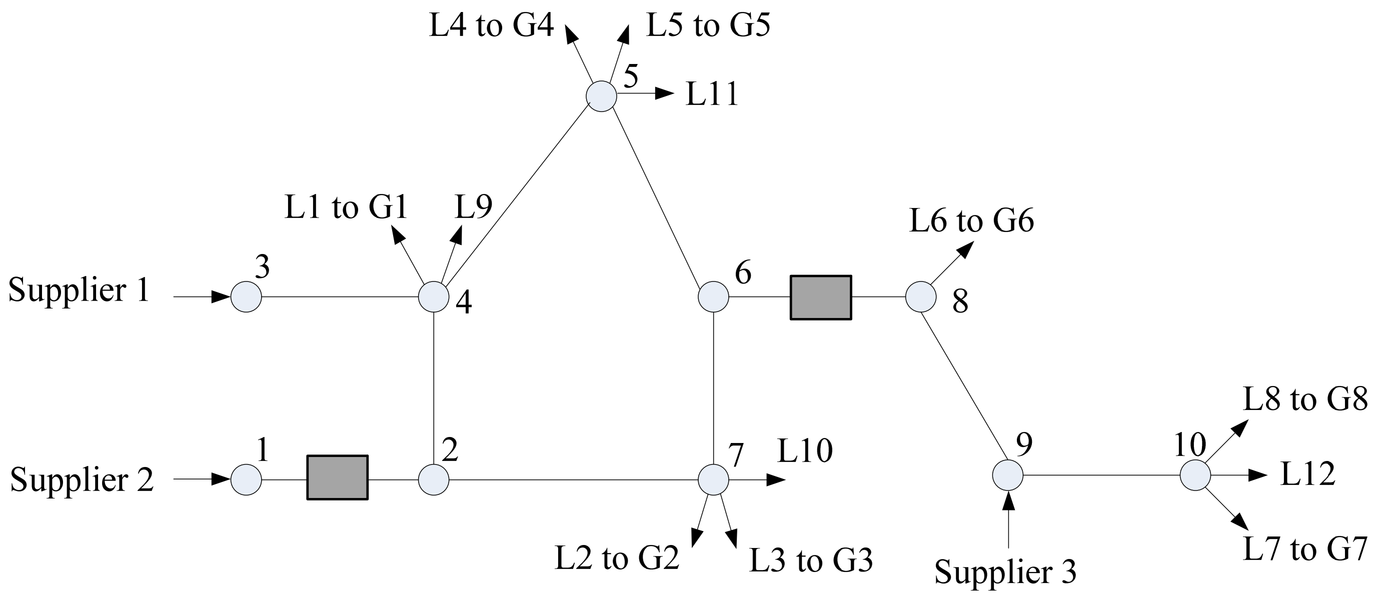
IEEE 118-bus System



System Information:

- •118 buses, 186 branches, 91 load sides
- •54 Thermal units,12 gas-fired units
- •7 wind farms (8% of total generation capacity)

10-node Natural Gas System



System Information:

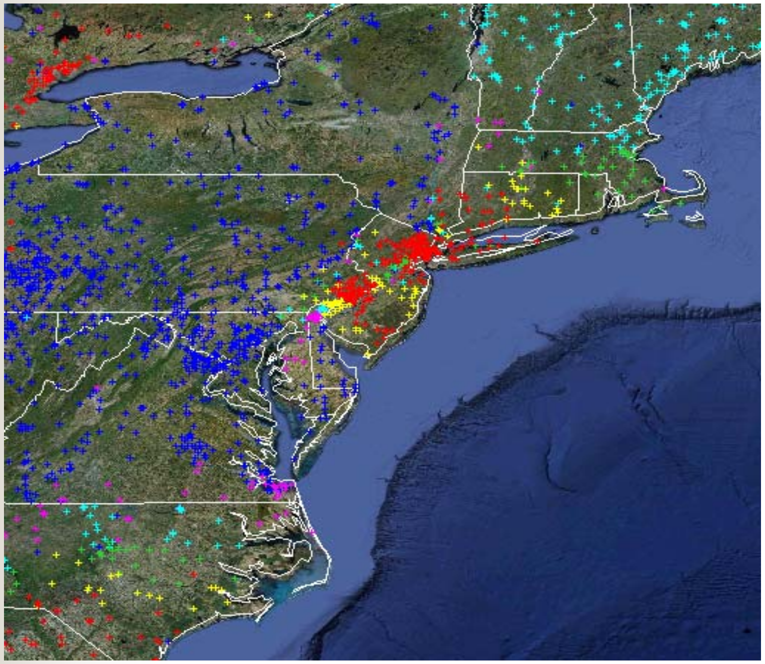
- 10 Node
- 10 Natural gas pipelines
- 8 Gas loads
- 3 Gas suppliers

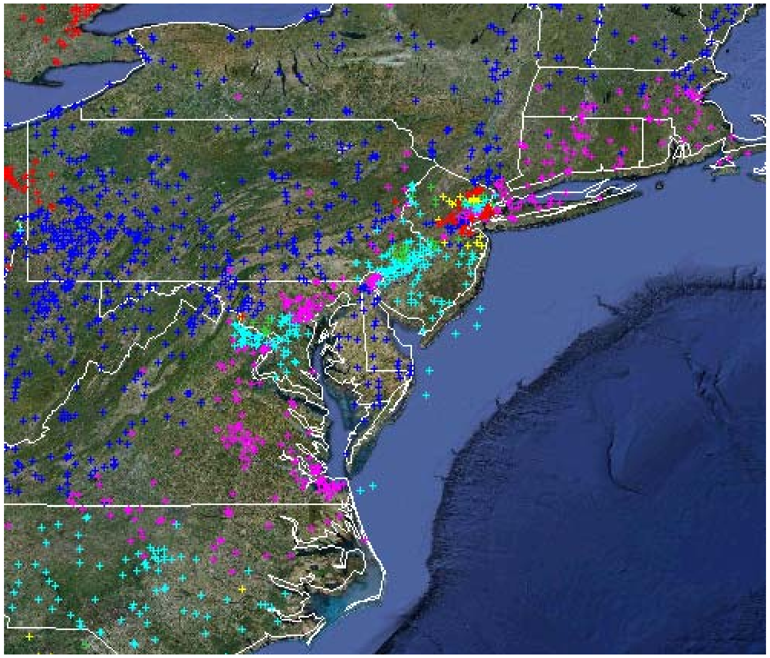
IEEE 118-bus System Solution

- Deterministic solution
    - Daily production cost: $1,918,361
    - Wind energy capacity 720MW
- Stochastic solution
    - Expected operation cost: $1,847,539
    - Scenarios 1, 3, 4 adopt more wind energy and correspondingly produce lower operation costs
    - Large system is more robust than the 6-bus system since thermal units can provide the necessary ramping capability to integrate the variable wind generation

Scenario	S1	S2	S3	S4	S5
Probability	0.171	0.124	0.356	0.206	0.143
Wind Energy (MWh)	11278	10415	11485	11899	10503
Production cost ($)	1840592	1984198	1808369	1748574	1977425

LMPs without Offshore Wind Integration	LMPs with Offshore Wind Integration





Bus LMPs

- <130
- 130-150
- 150-170
- 170-190
- 190-210
- >210

Conclusions

- The constrained natural gas availability and gas prices volatility would greatly affect the hourly thermal unit commitment and the system operation cost.
- The wind energy with zero fuel cost plays a complementary role in hedging the risk from fuel availability and price volatility for conventional gas-fired generation.
- The environmentally sustainable wind energy help to alleviate emission constraints, which may result in a lower cost considering the same emission threshold.
- The flexibility and quick ramping ability of natural gas units make them ideal resource for firming the variability of wind energy.

Thanks!

Dr. Mohammad Shahidehpour