Analysis of Power System Operational Uncertainty from Gas System Dependence

Sarah M. Ryan

Iowa State University

(smryan@iastate.edu)

PSERC Webinar
October 16, 2018

Presentation Outline

- Economic Risk in the Power System from Gas System Dependence
- Quantifying Economic Risk Due to Uncertainty in the Gas Spot Price
  - Dispatch Model with Constraint on Availability of Contracted Gas
  - Correlated Uncertain Loads and Gas Prices
  - Risk Quantification via Monte Carlo Simulation
- Using the Risk Metrics to Evaluate Alternative Risk-Mitigation Strategies
- Conclusions and Future Work

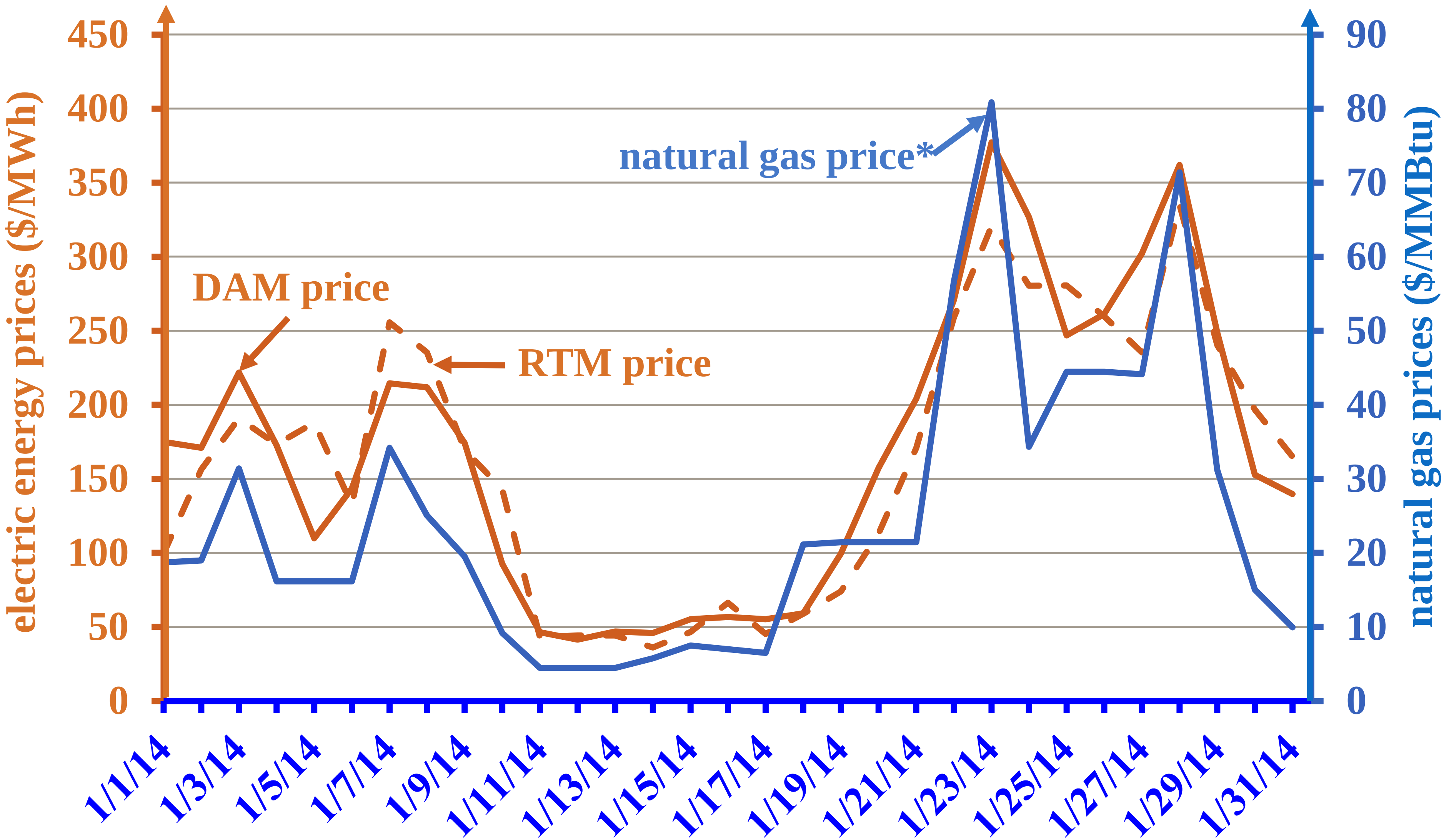
Acknowledgments

- PSERC Project M-36 was a collaboration between Iowa State and University of Illinois-UC.
  - George Gross
  - Dan Hu, PhD student in IMSE at Iowa State
  - Adriano Lima Abrantes, PhD student in ECE at UIUC
- Many industry advisors contributed advice, information and feedback.
- This presentation describes only the work done at ISU; project report describes UIUC analysis of a new form of gas transportation contract.

Presentation Outline

- Economic Risk in the Power System from Gas System Dependence
- Quantifying Economic Risk Due to Uncertainty in the Gas Spot Price
    - Dispatch Model with Constraint on Availability of Contracted Gas
    - Correlated Uncertain Loads and Gas Prices
    - Risk Quantification via Monte Carlo Simulation
- Using the Risk Metrics to Evaluate Alternative Risk-Mitigation Strategies
- Conclusions and Future Work

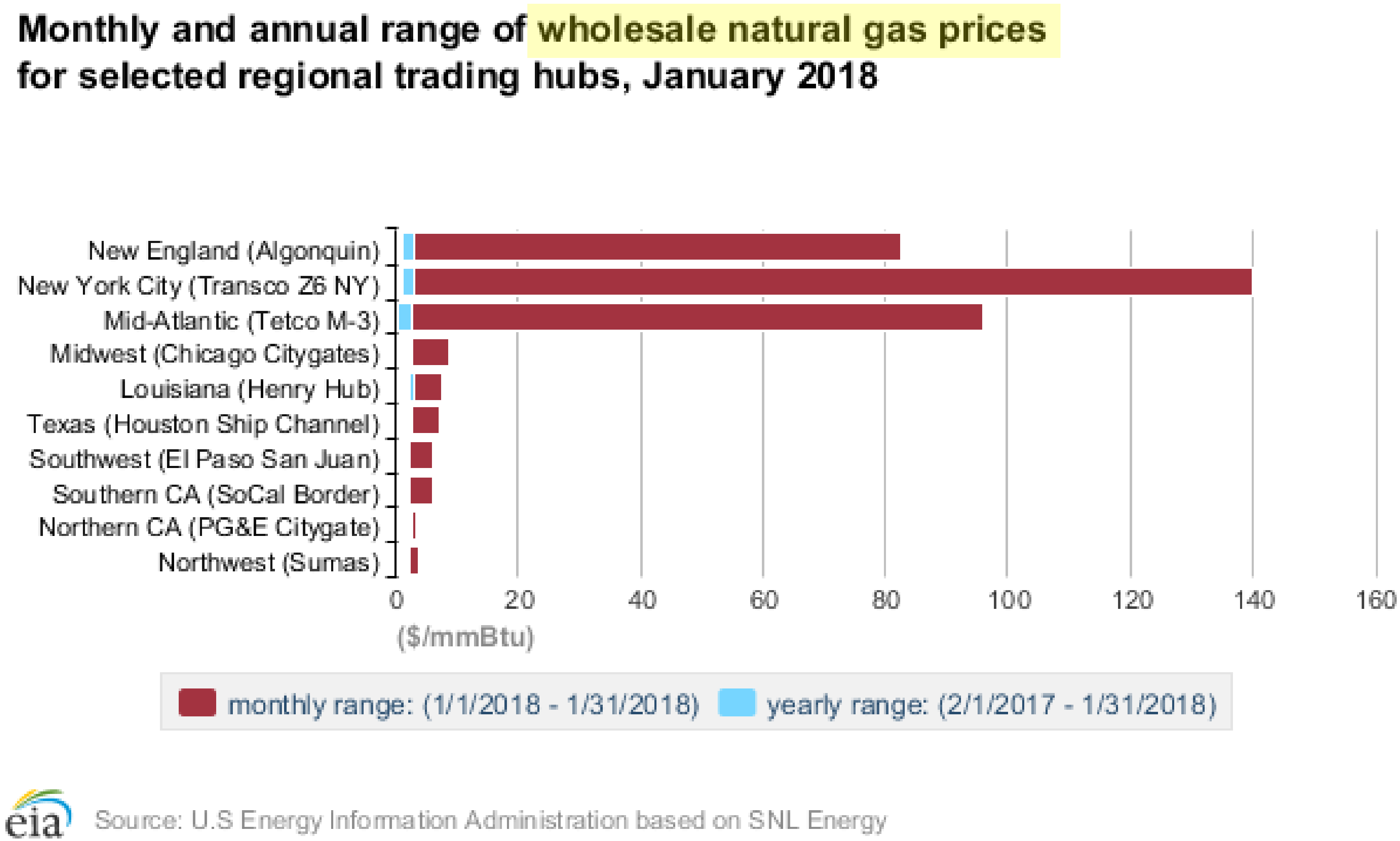
January 2014 Polar Vortex
Wholesale Electricity and Gas Prices



Source: ISO-NE

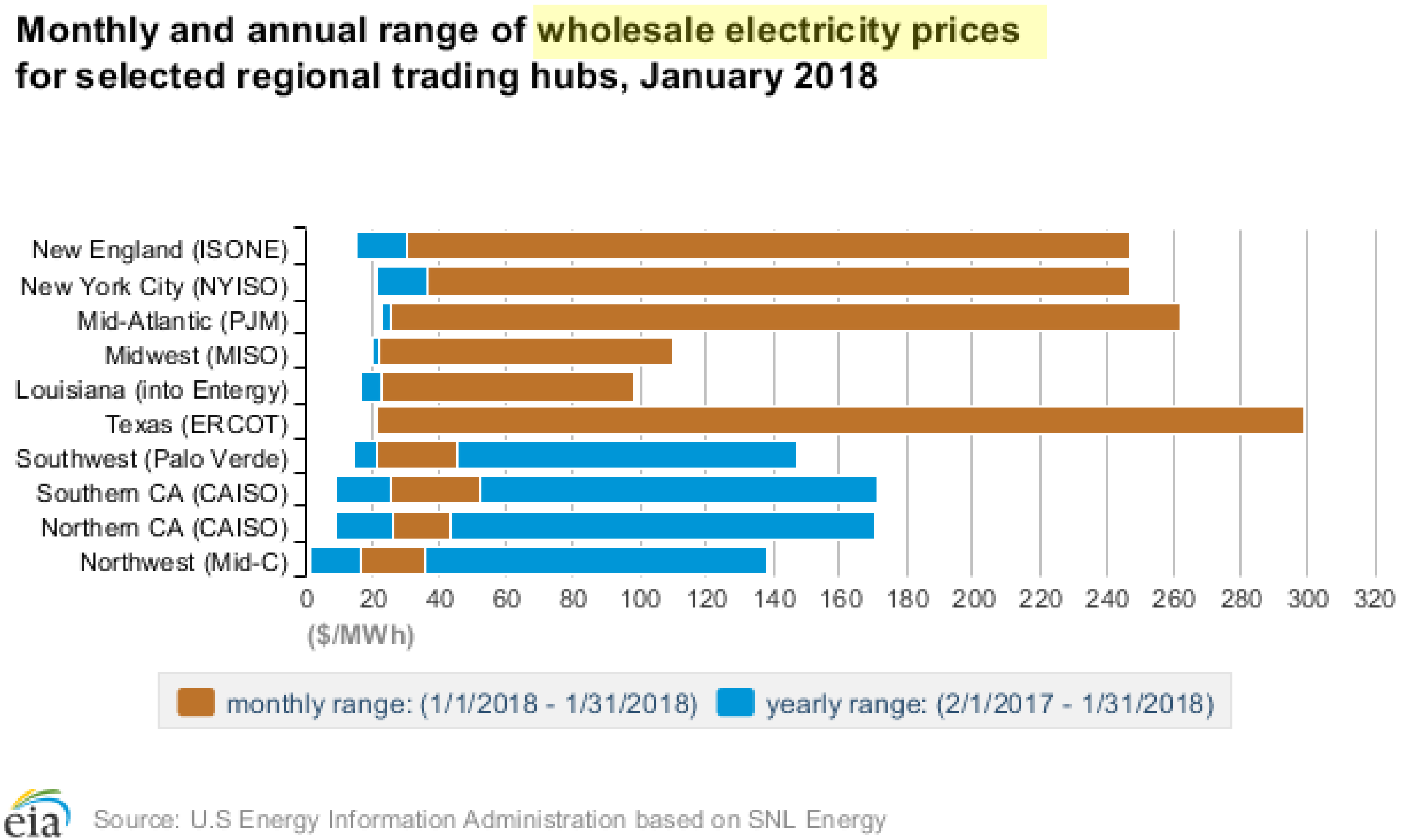
*natural gas price is average of MA delivery points

January 2018 Gas Prices



From *Electricity Monthly Update*, March 23, 2018

January 2018 Electricity Prices

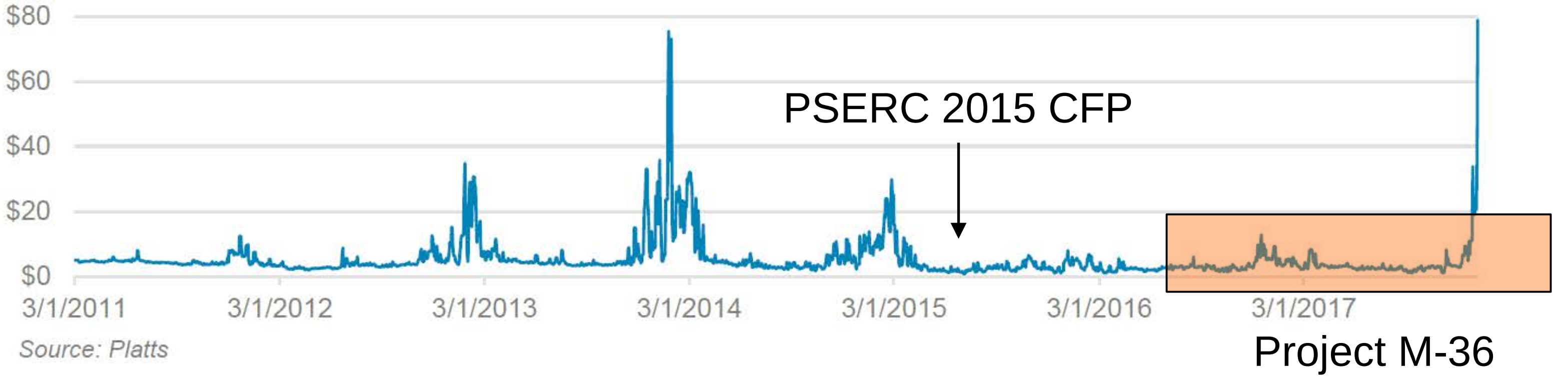


From *Electricity Monthly Update*, March 23, 2018

January 2018 Price Spikes

Algonquin City-Gates Daily Spot Prices ($/MMBtu)

New all-time high
1/5/2018



Project M-36

ENERNOC INSIGHTS: JANUARY 2018 NEW ENGLAND MONTHLY MARKET COMMENTARY

"Wholesale electricity prices hit 12-month highs at all selected trading hubs east of the Rockies. On January 5, prices reached $262/MWh in the Mid-Atlantic (PJM), just over $247/MWh in New England (ISONE) and New York City (NYISO), and $110/MWh in the Midwest (MISO). Annual high prices were also set on January 17 in Texas (ERCOT) at $300/MWh and $99/MWh in Louisiana (into Entergy)."

From *Electricity Monthly Update*, March 23, 2018

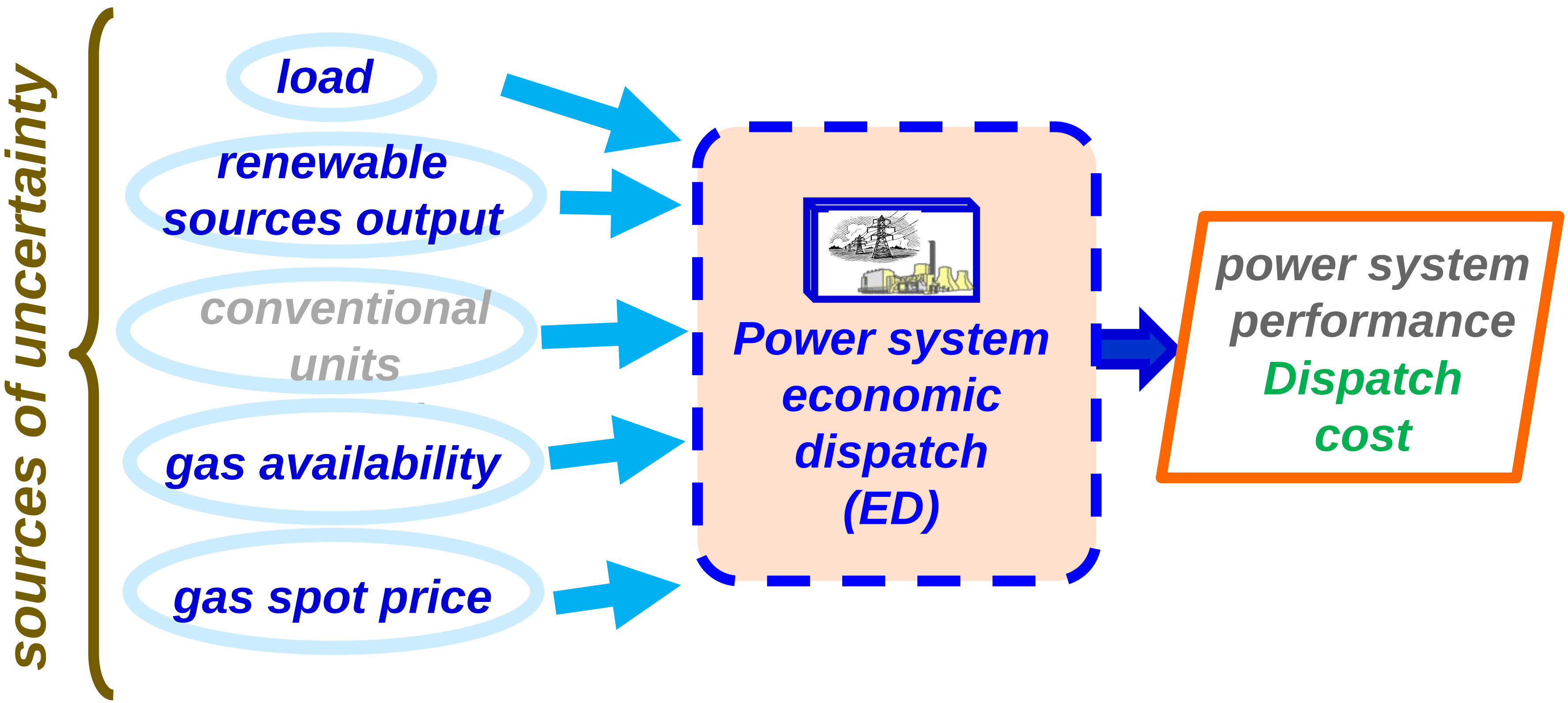
Questions

- How can we quantify the risk of high electricity prices imposed by:
  - limits on availability of gas from interruptible contracts, *combined with*
  - high spot prices for gas, *correlated with*
  - demand for electricity?
- How can we use risk metrics to evaluate alternative risk-mitigation strategies?

Presentation Outline

- Economic Risk in the Power System from Gas System Dependence
- Quantifying Economic Risk Due to Uncertainty in the Gas Spot Price
  - Dispatch Model with Constraint on Availability of Contracted Gas
  - Correlated Uncertain Loads and Gas Prices
  - Risk Quantification via Monte Carlo Simulation
- Using the Risk Metrics to Evaluate Alternative Risk-Mitigation Strategies
- Conclusions and Future Work

Problem Setting



Dispatch Model

Min Total daily dispatch cost

- Gas costs from interruptible contracts and the spot market
- Production cost of non-gas generators
- Net cost of gas flows from storage
- Penalties for non-served/excess electricity or gas

s.t. Usual constraints given unit commitment, *plus*

- Limit on availability of contracted gas
- Gas balance
- Limits on flows to/from storage
- DC approximation of transmission constraints

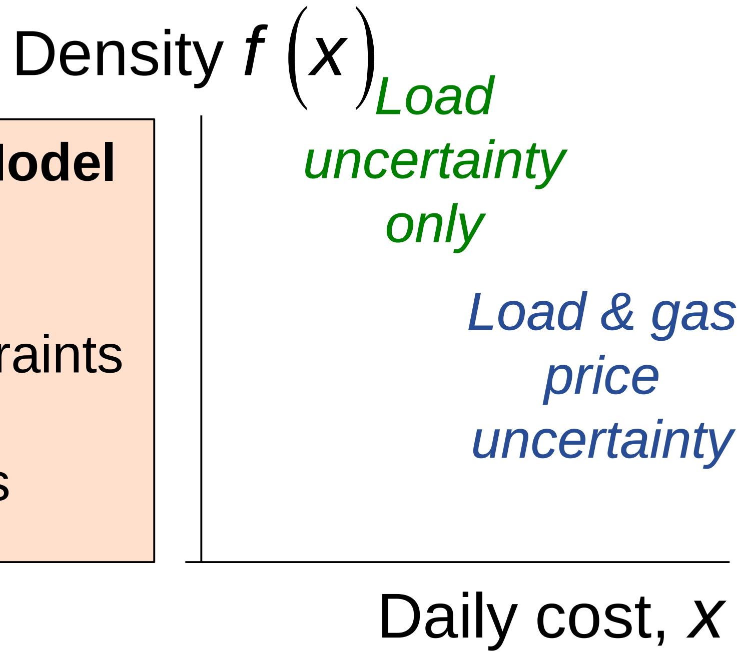
Impact of gas price uncertainty and constrained gas availability on dispatch cost

Sources of uncertainty

(Net) load

Gas spot price

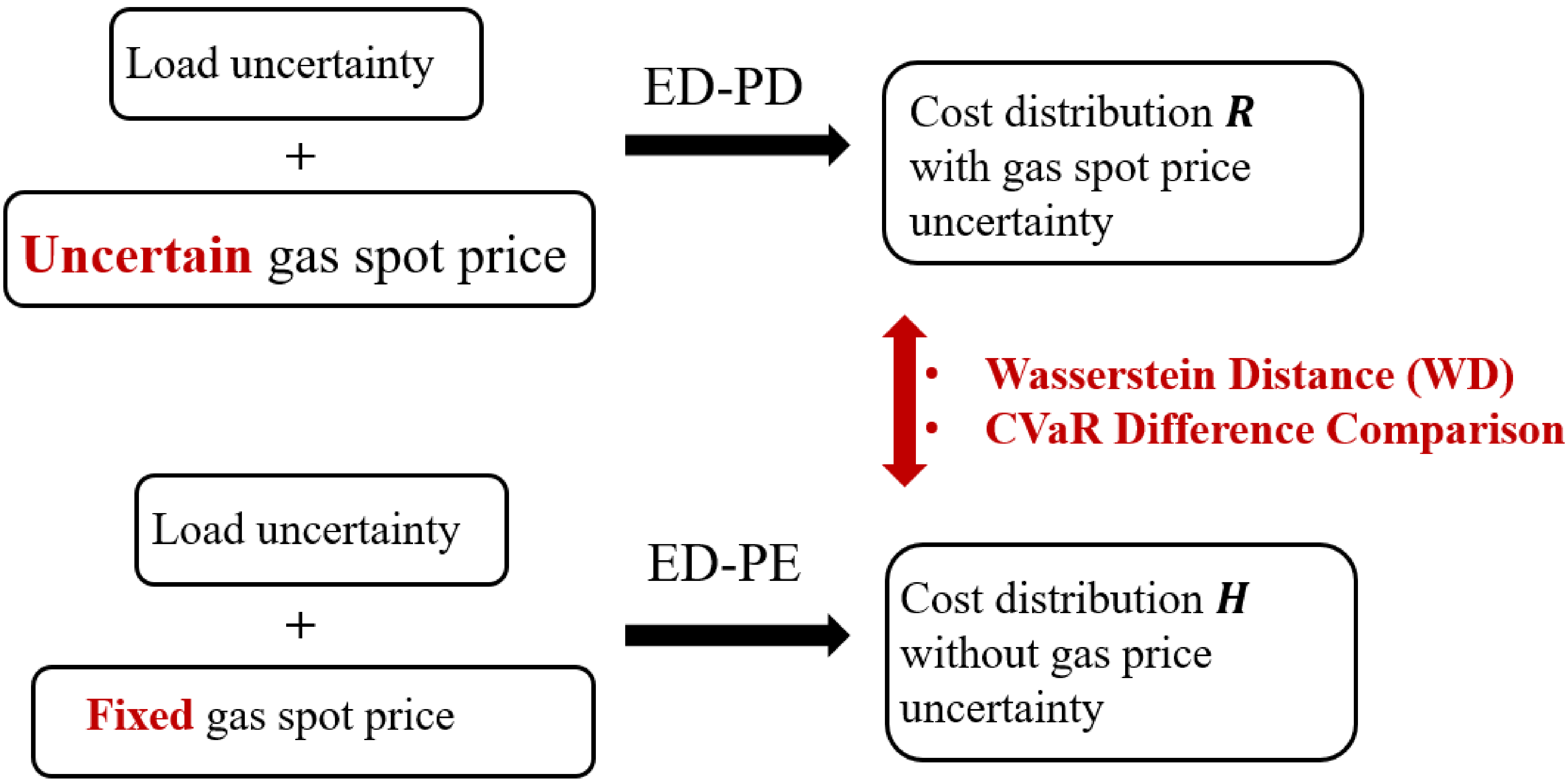
Economic Dispatch Model
Min daily dispatch cost, subject to
- Usual dispatch constraints
- Limit on gas from interruptible contracts



Monte Carlo simulation schemes:
- ED-PE: Economic dispatch (ED) with uncertain electric load and point estimate of gas price
- ED-PD: ED with correlated uncertain electric load and gas prices

Risk Quantification Procedure

Estimate joint distribution of electricity load and gas spot price



Gas Spot Price and Electric Load Jointly Depend on Weather

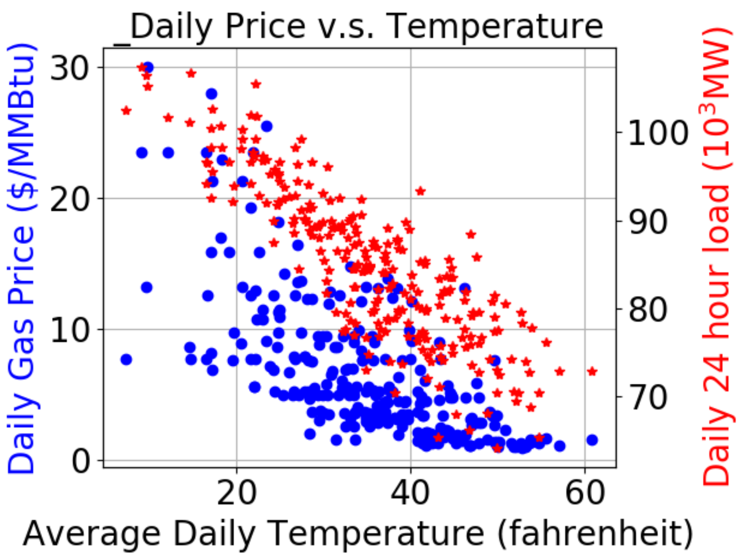
- Procedure for estimating joint distribution, illustrated for ISO-NE in winter
  - Cluster days based on average hourly temperature
  - Transform data, then test fit of bivariate Normal distribution
  - Estimate mean vector and covariance matrix in each cluster
- Monte Carlo sampling from marginal distribution of electricity load *or* from joint distribution
- Optimize dispatch cost for each sample point

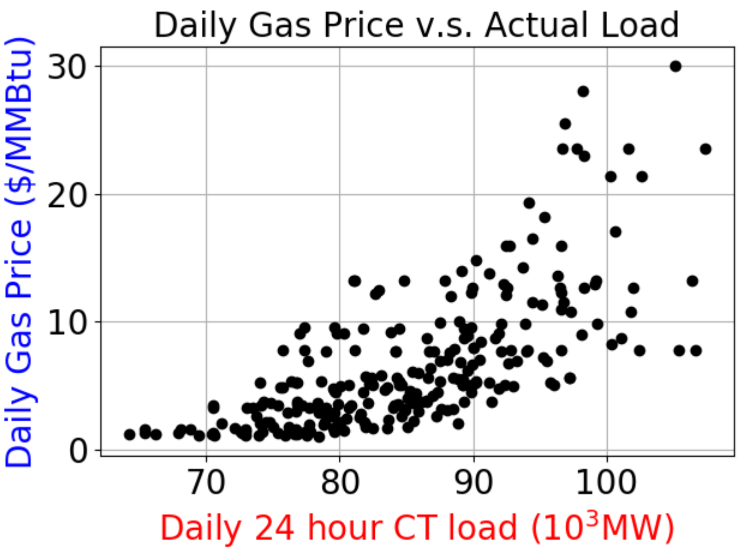
Case Study

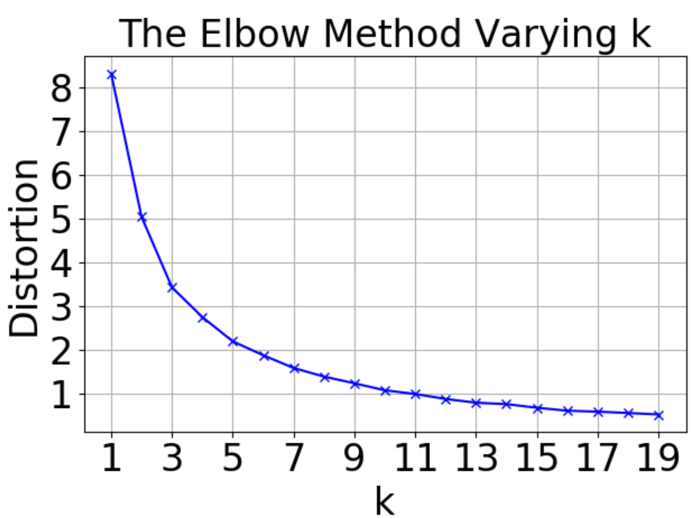
- Modified IEEE 24-bus system
- Modified Belgian 20-node gas system
- Nodes and buses linked by gas-fired generators
- Load and weather data provided by ISO-NE
  - Load in CT scaled to match total and allocated to buses as in IEEE system
  - Gas spot price data from Algonquin citygate
  - Demand for gas by non-electric users same as in Belgian system
- Units committed and gas transportation schedules optimized in pre-processing step

Winter Day Clusters

Algonquin Citygate Price & CT Load vs. ISO-NE Average Hourly Temperature



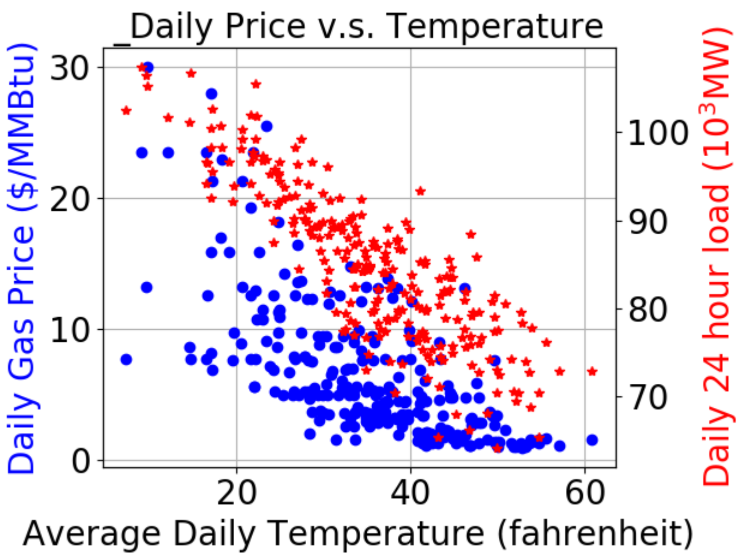


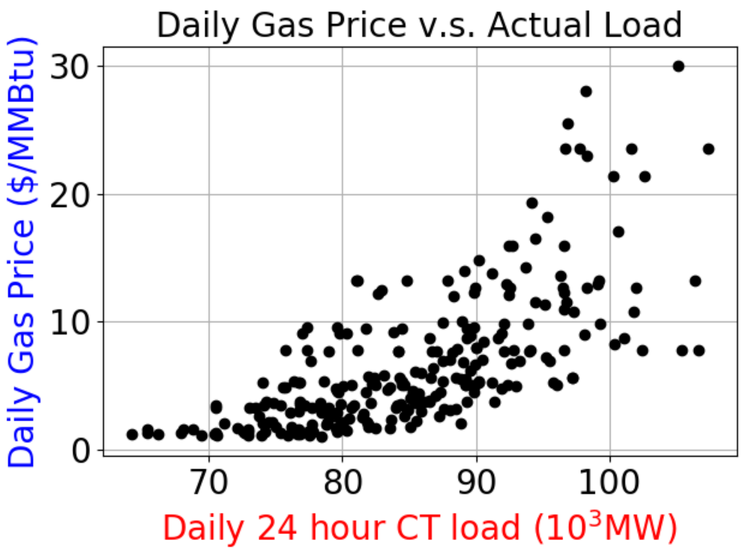


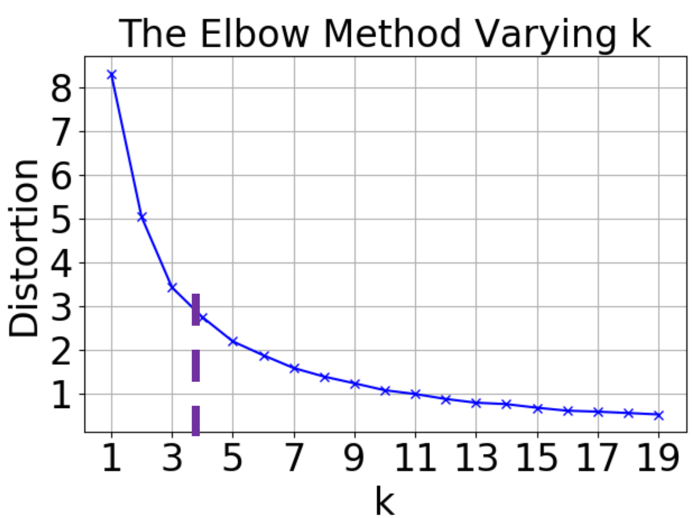
K-means cluster results -> We chose 4 segments

Winter Day Clusters

Algonquin Citygate Price & CT Load vs. ISO-NE Average Hourly Temperature



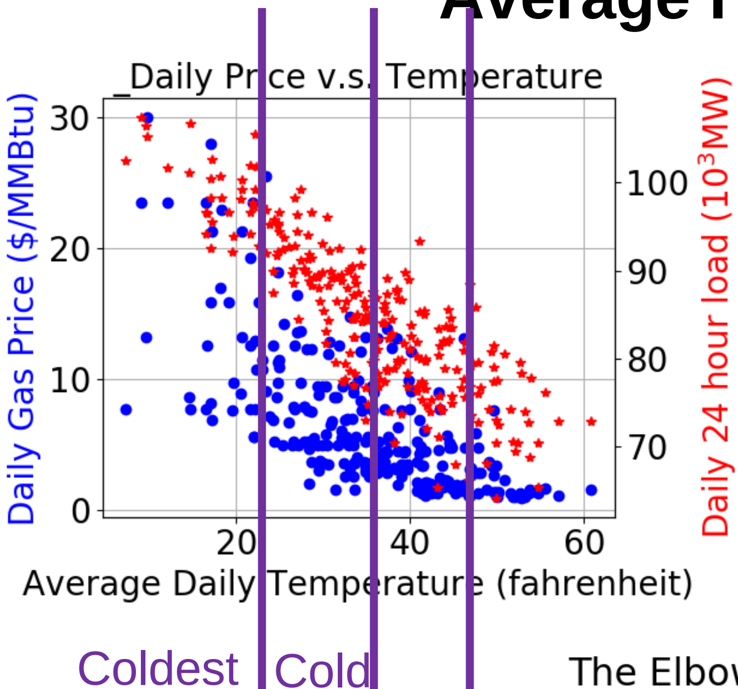


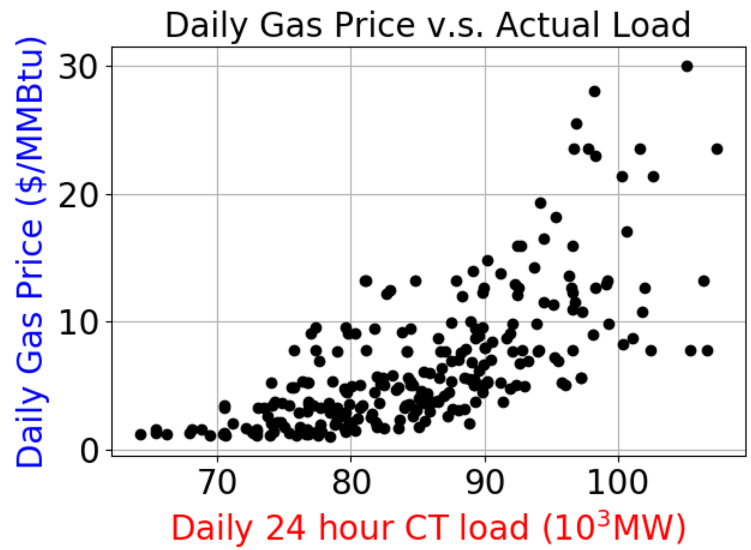


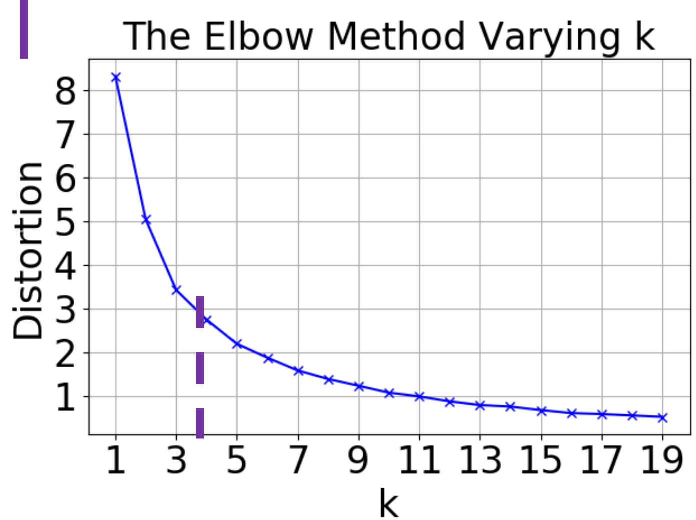
K-means cluster results -> We chose 4 segments

Winter Day Clusters

Algonquin Citygate Price & CT Load vs. ISO-NE Average Hourly Temperature



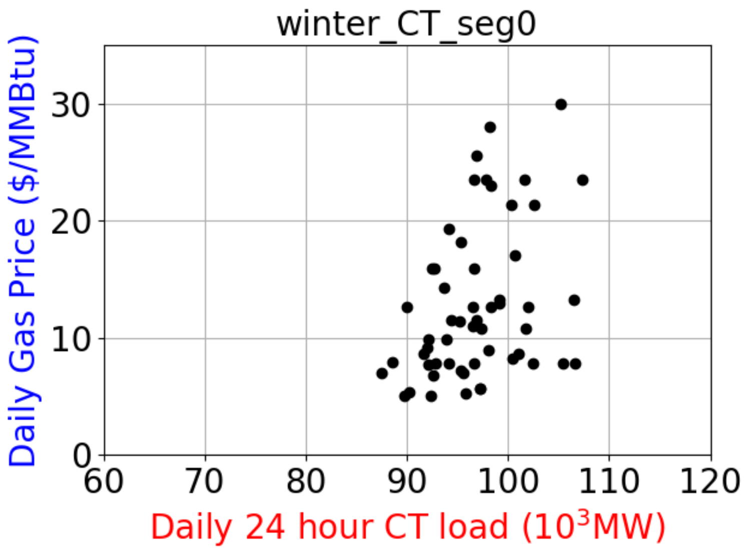


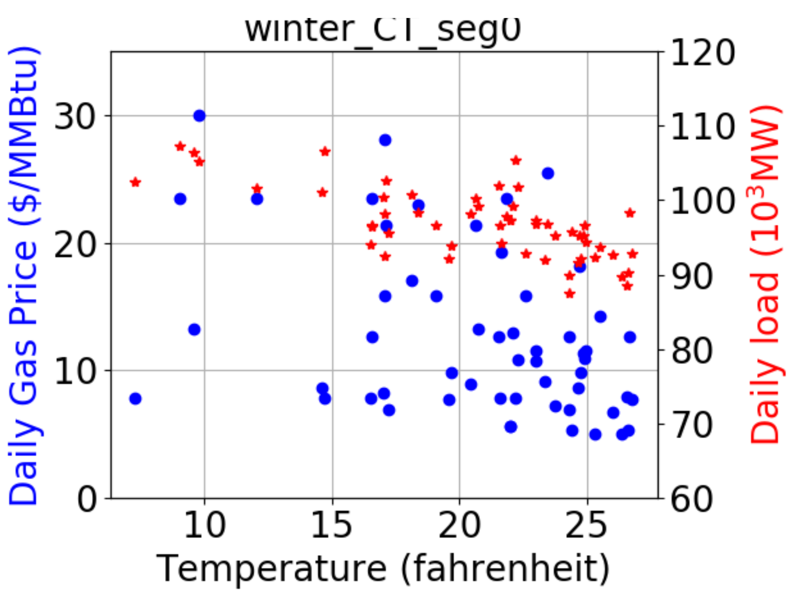


K-means cluster results -> We chose 4 segments

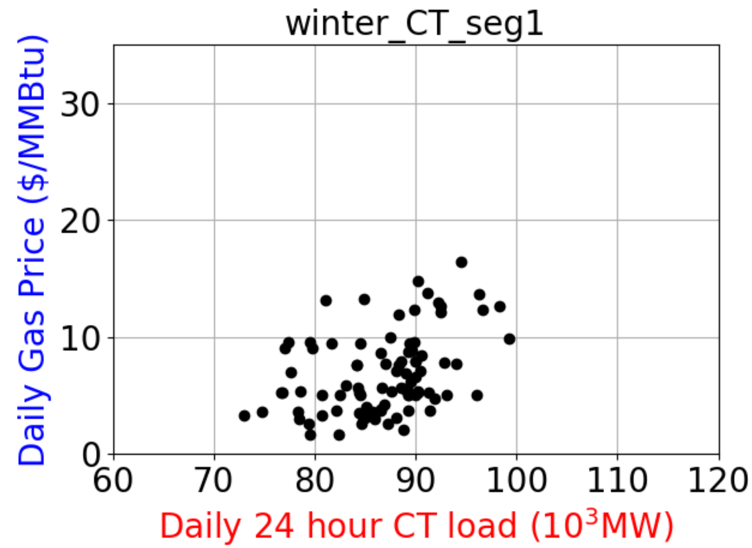
Daily Gas Price & Daily Load in CT

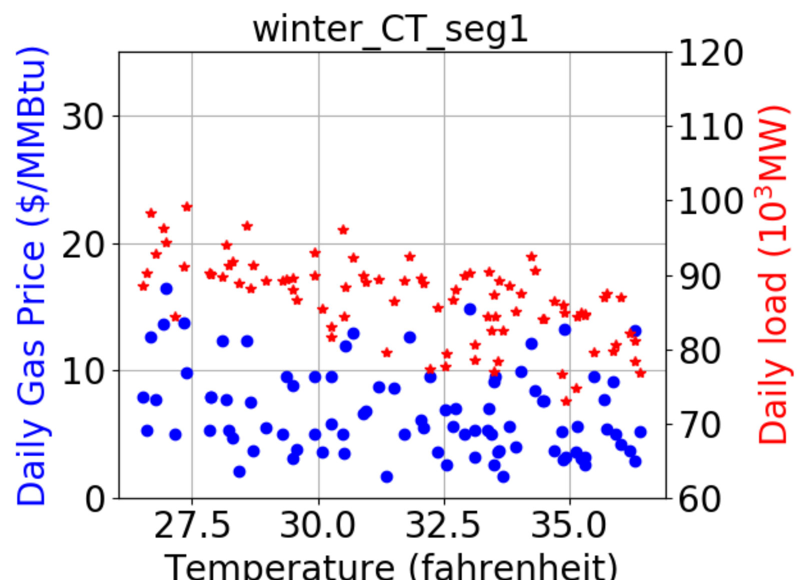
Coldest Days





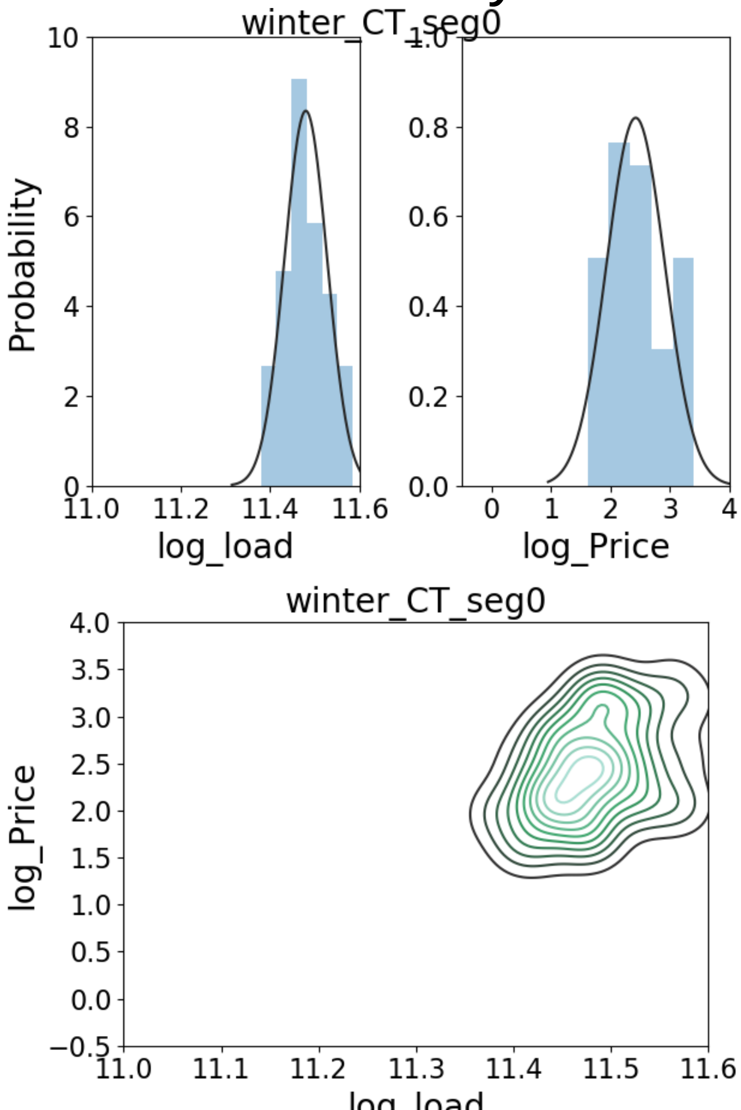
Cold Days



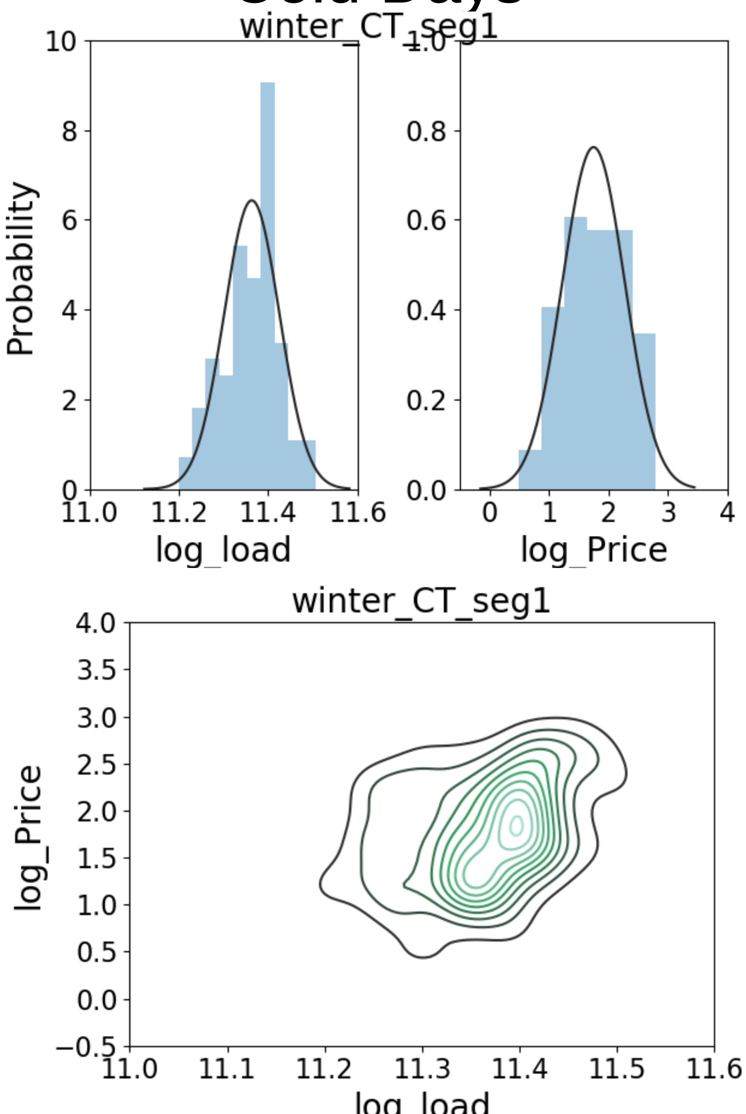


Joint Distribution of Log-Transformed Observations

Coldest Days



Cold Days



Multivariate Normal Distribution (MVN)

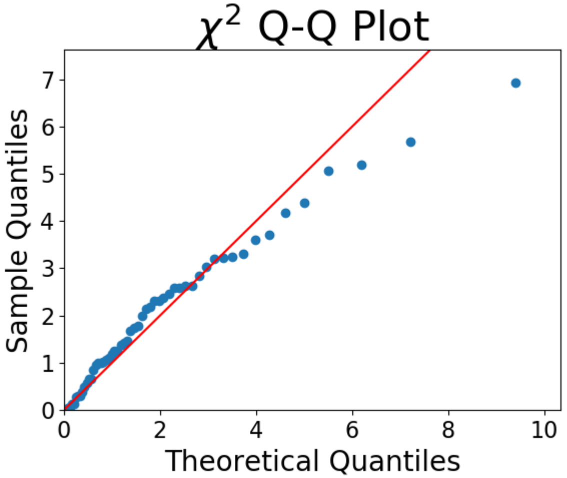
Let X be a set of n joint observations of K variables. Denote each of the n observations by $\boldsymbol{x_i} = [x_{i1}, x_{i2}, \ldots, x_{iK}]$ where $i \in \{1, 2, \ldots, n\}$ and each of the K marginals $\boldsymbol{X_k} = [x_{k1}, x_{k2}, \ldots, x_{kn}]$ where $k \in \{1, 2, \ldots, K\}$. If $\boldsymbol{X}$~MVN($\boldsymbol{\mu}$,$\boldsymbol{\Sigma}$), the following two properties (among others) hold:

1. All marginal distributions of $\boldsymbol{X}$ are univariate normal; i.e., $\boldsymbol{X_k} \sim N(\mu_k, \sigma_k^2)$
2. The squared Mahalanobis distances, $\boldsymbol{D_i^2} = (\boldsymbol{x_i} - \boldsymbol{\mu})^T \boldsymbol{\Sigma}^{-1} (\boldsymbol{x_i} - \boldsymbol{\mu})$, follow a χ^2 distribution with K degrees of freedom.

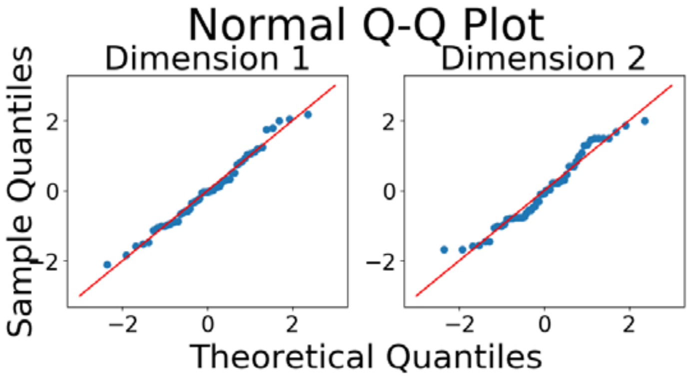
Bivariate Normal Goodness-of-Fit

Coldest Days

Joint Distribution

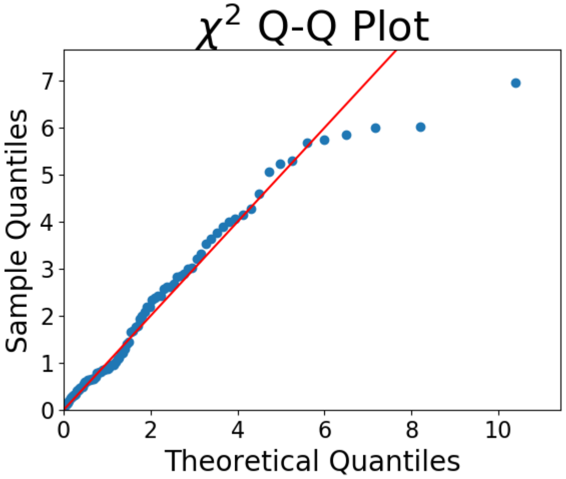


Marginal Distributions

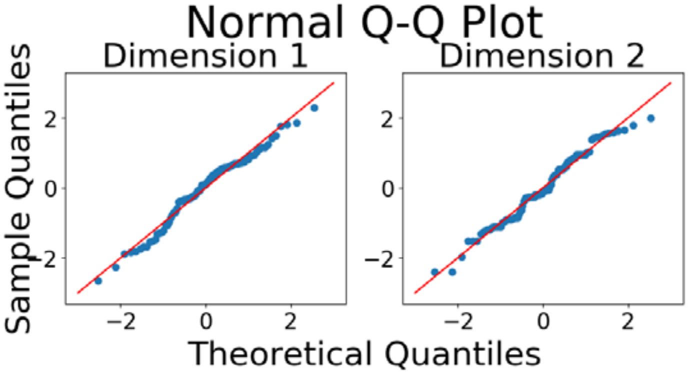


Cold Days

Joint Distribution

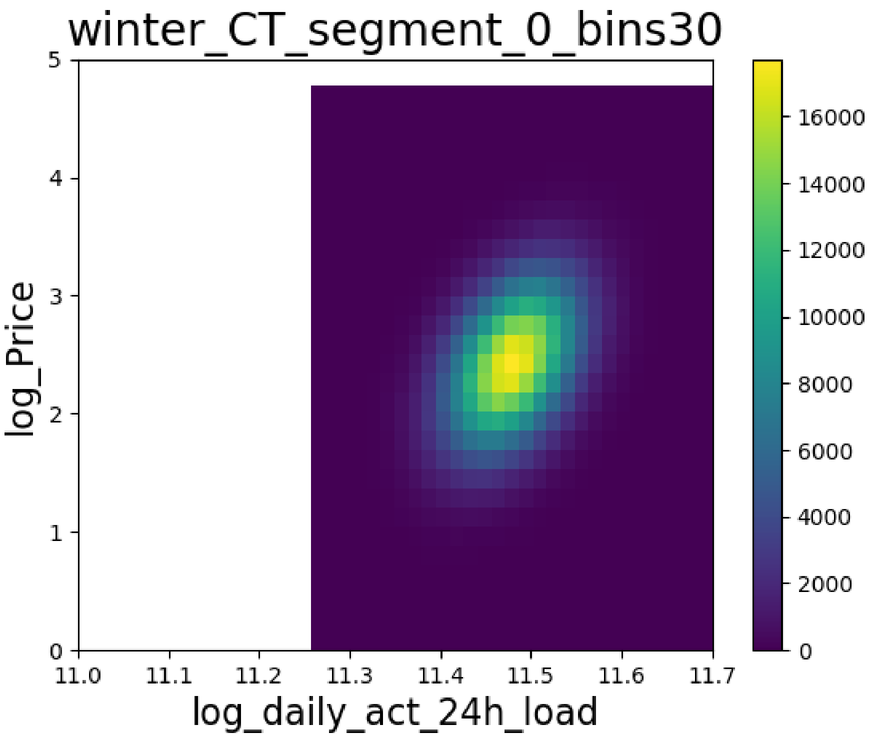


Marginal Distributions

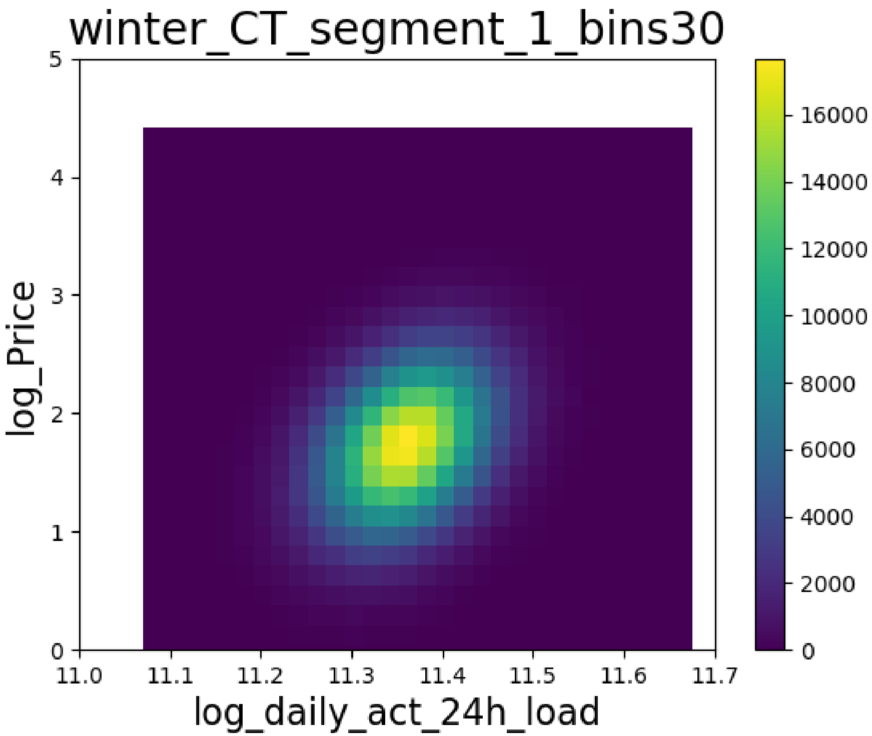


Histograms of 10^6 Bivariate Samples

Coldest Days



Cold Days

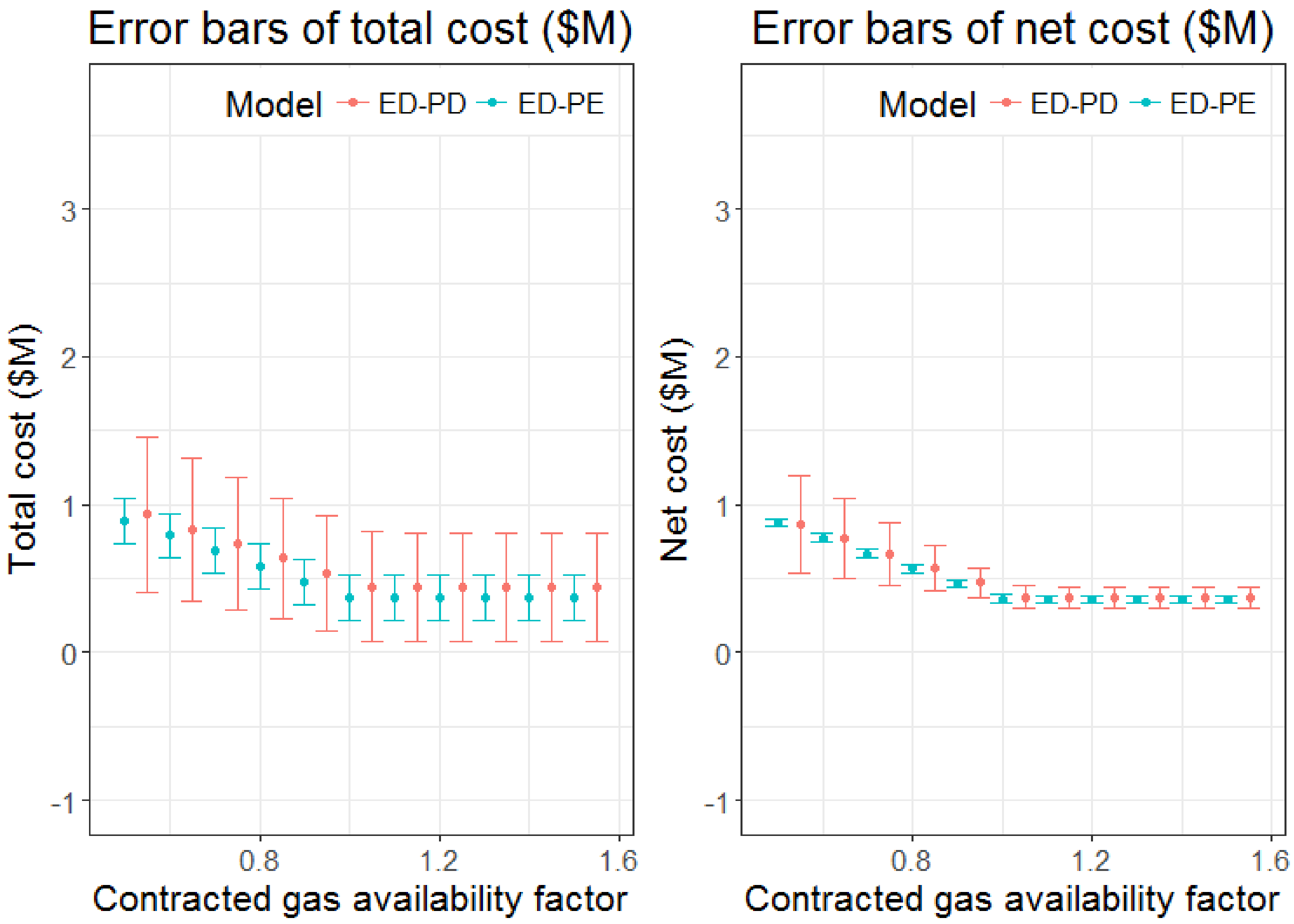


Summary of Winter Clusters

	Means			
Cluster	Log Load (MWh)	Log Price ($/MMBtu)	Covariance Matrix of Logs	Corre-lation
0 (Coldest)	11.48	2.45	$\begin{bmatrix} 0.0022 & 0.0078 \\ 0.0078 & 0.2426 \end{bmatrix}$	0.3360
1 (Cold)	11.37	1.79	$\begin{bmatrix} 0.0040 & 0.0128 \\ 0.0128 & 0.2736 \end{bmatrix}$	0.3862
2 (Moderate)	11.29	1.30	$\begin{bmatrix} 0.0046 & 0.0214 \\ 0.0214 & 0.3710 \end{bmatrix}$	0.5166
3 (Mild)	11.23	0.67	$\begin{bmatrix} 0.0047 & 0.0206 \\ 0.0206 & 0.3592 \end{bmatrix}$	0.5011

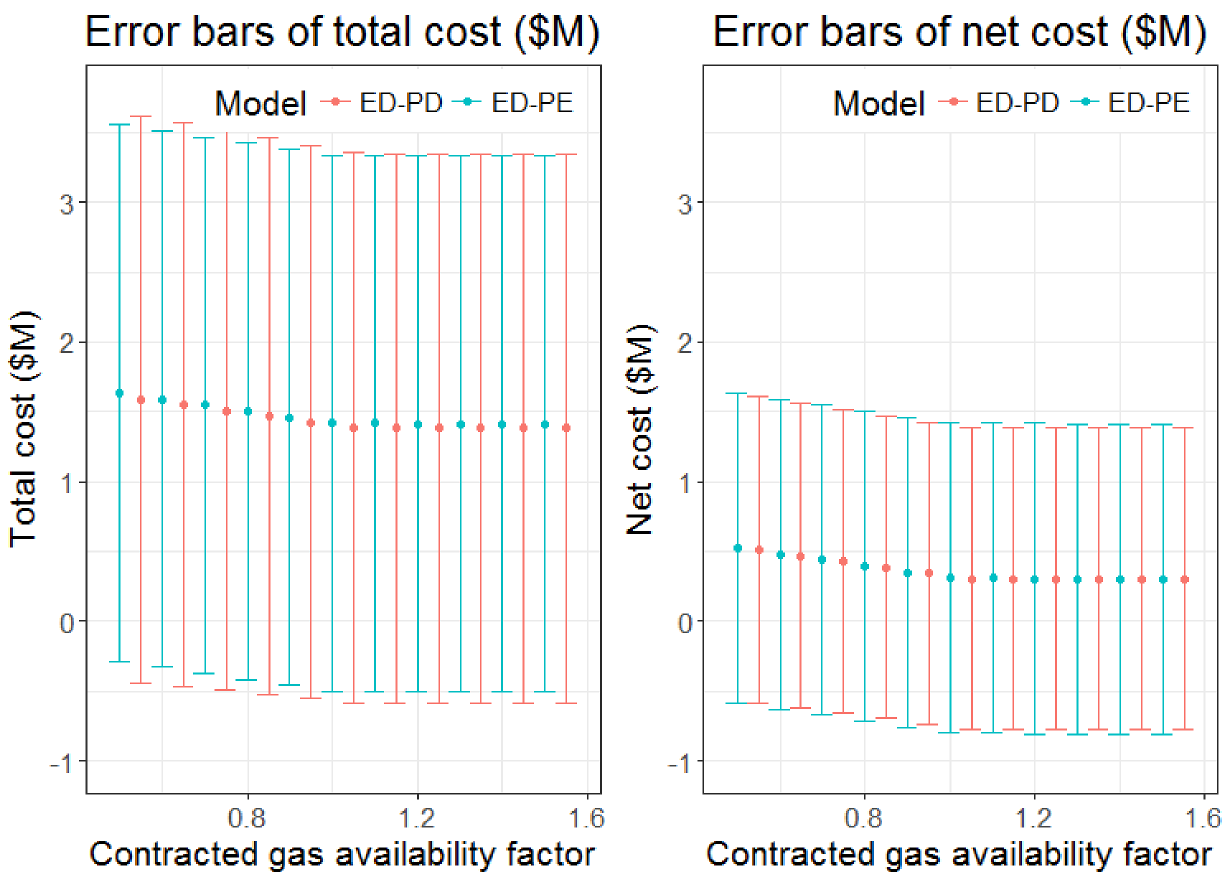
Total and Net Dispatch Cost for Various Availability Levels of Contracted Gas

Coldest Days



Total and Net Dispatch Cost for Various Availability Levels of Contracted Gas

Cold Days



Less gas contracted, higher variation in load than coldest days.

Presentation Outline

- Economic Risk in the Power System from Gas System Dependence
- Quantifying Economic Risk Due to Uncertainty in the Gas Spot Price
  - Dispatch Model with Constraint on Availability of Contracted Gas
  - Correlated Uncertain Loads and Gas Prices
  - Risk Quantification via Monte Carlo Simulation
- Using the Risk Metrics to Evaluate Alternative Risk-Mitigation Strategies
- Conclusions and Future Work

How to Quantify the Difference between Dispatch Cost Distributions?

ED-PD simulation approximates dispatch cost distribution with **no** gas price uncertainty;

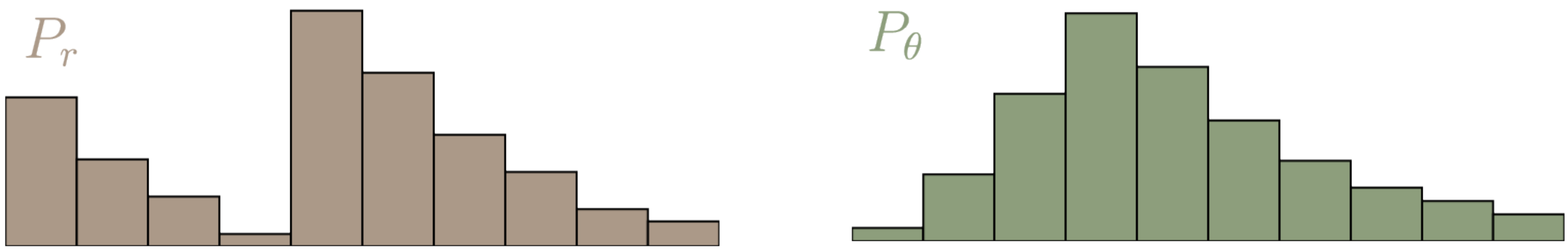
ED-PE simulation approximates dispatch cost distribution **with** gas price uncertainty

1. Apply a probability metric to quantify the difference between distributions

2. Apply an upper-tail focused risk metric to each distribution, then compute difference

Mass Transportation Distance (Earth Mover's, Wasserstein)

Minimum (probability mass) x (distance moved) to transform P_r to P_θ?



Metric equals optimal mass x distance moved

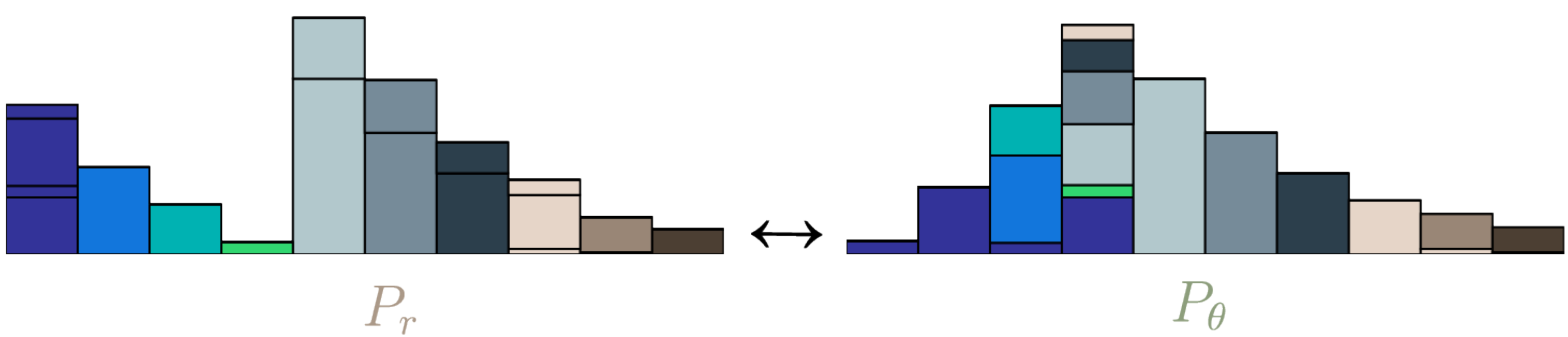
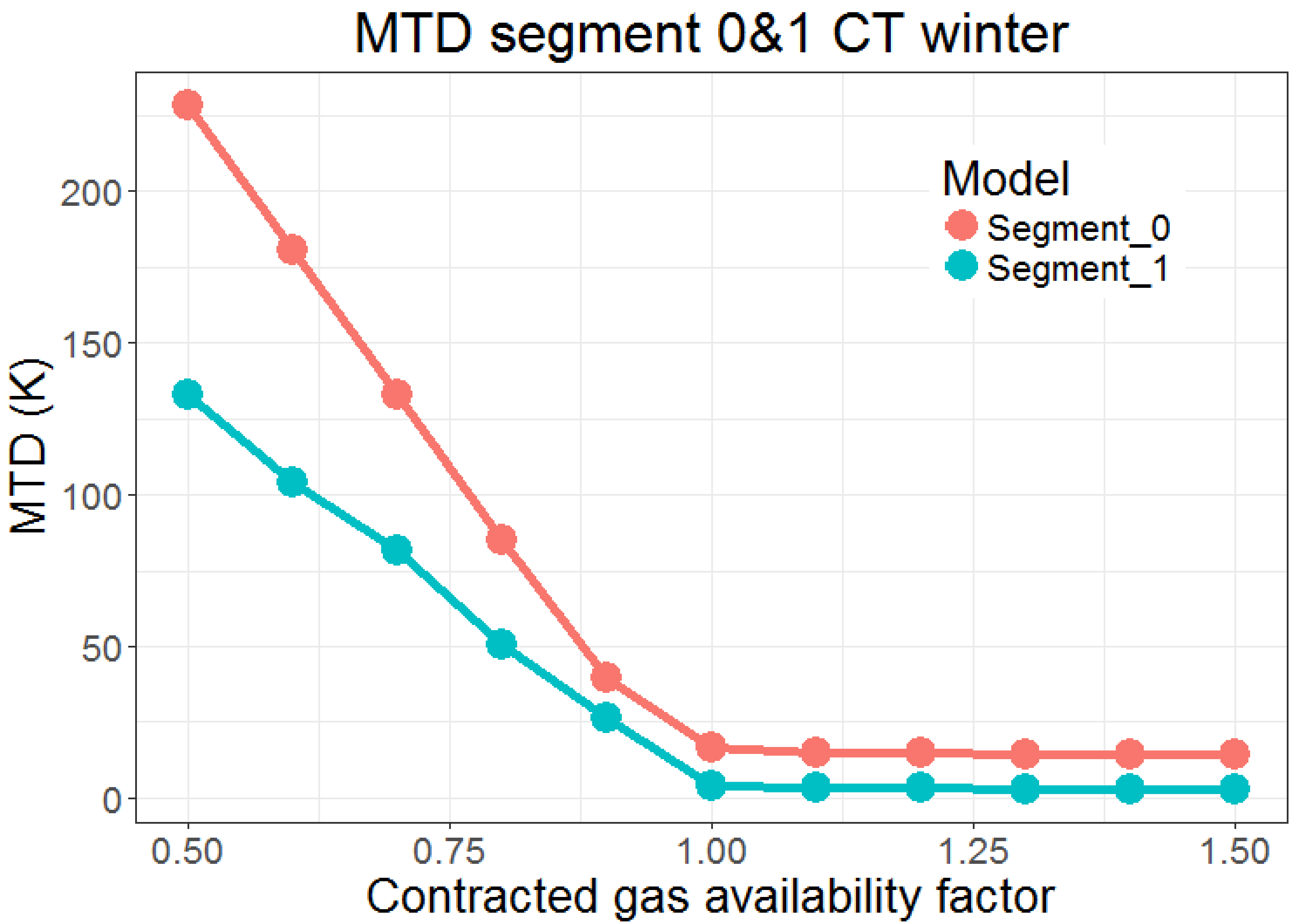
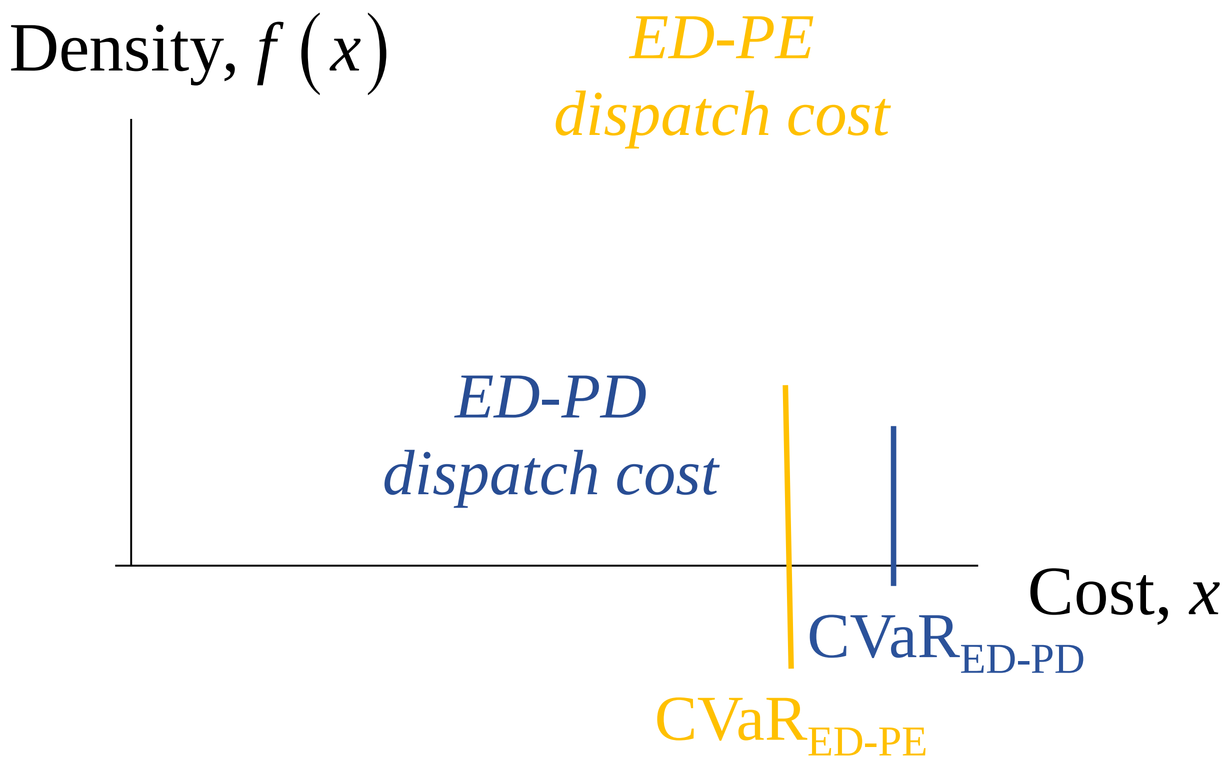


Illustration from https://vincentherrmann.github.io/blog/wasserstein/

Distances Between Cost Distributions for Various Availability Levels of Contracted Gas



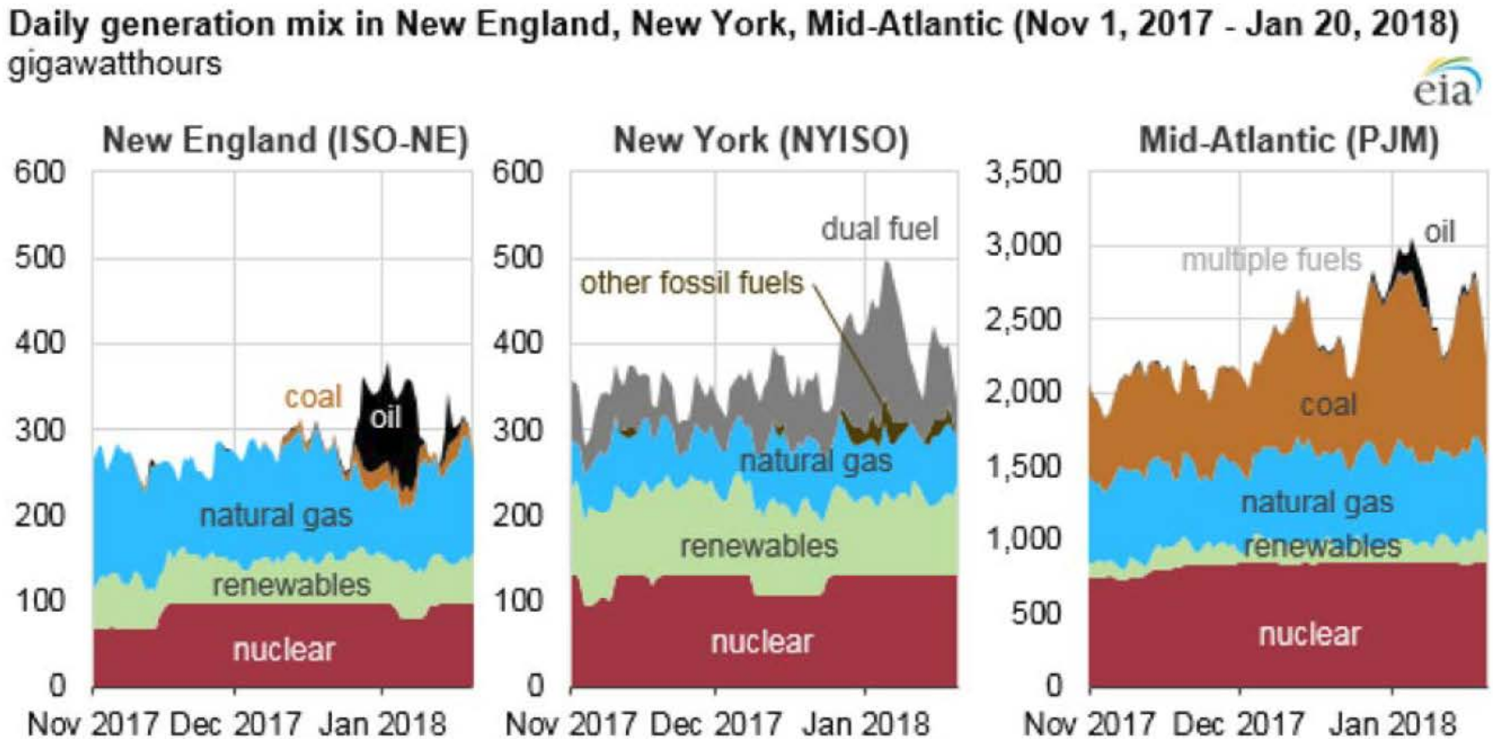
Conditional Value at Risk (CVaR) of the Dispatch Cost Distributions



CVaR is the conditional expectation in a specified upper tail of the distribution;

$\mathrm{CVaR}_{\text{ED-PD}}$ - $\mathrm{CVaR}_{\text{ED-PE}}$ quantifies risk added by gas price uncertainty.

Generation Mixes Adjusted to "Bomb Cyclone," January 2018



Source: U.S. Energy Information Administration, based on ISO-NE, NYISO, and PJM

Today in Energy, January 23, 2018

What if more gas storage capacity had been available?

Alternative Risk-Mitigation Strategies: Simple Engineering Economic Estimates

1. Dual-Fuel Capability

- Dual-fuel conversion for New England estimated to cost $3.15M
- Dispatch model modified to include fuel-switching in the optimization

2. Additional Gas Storage

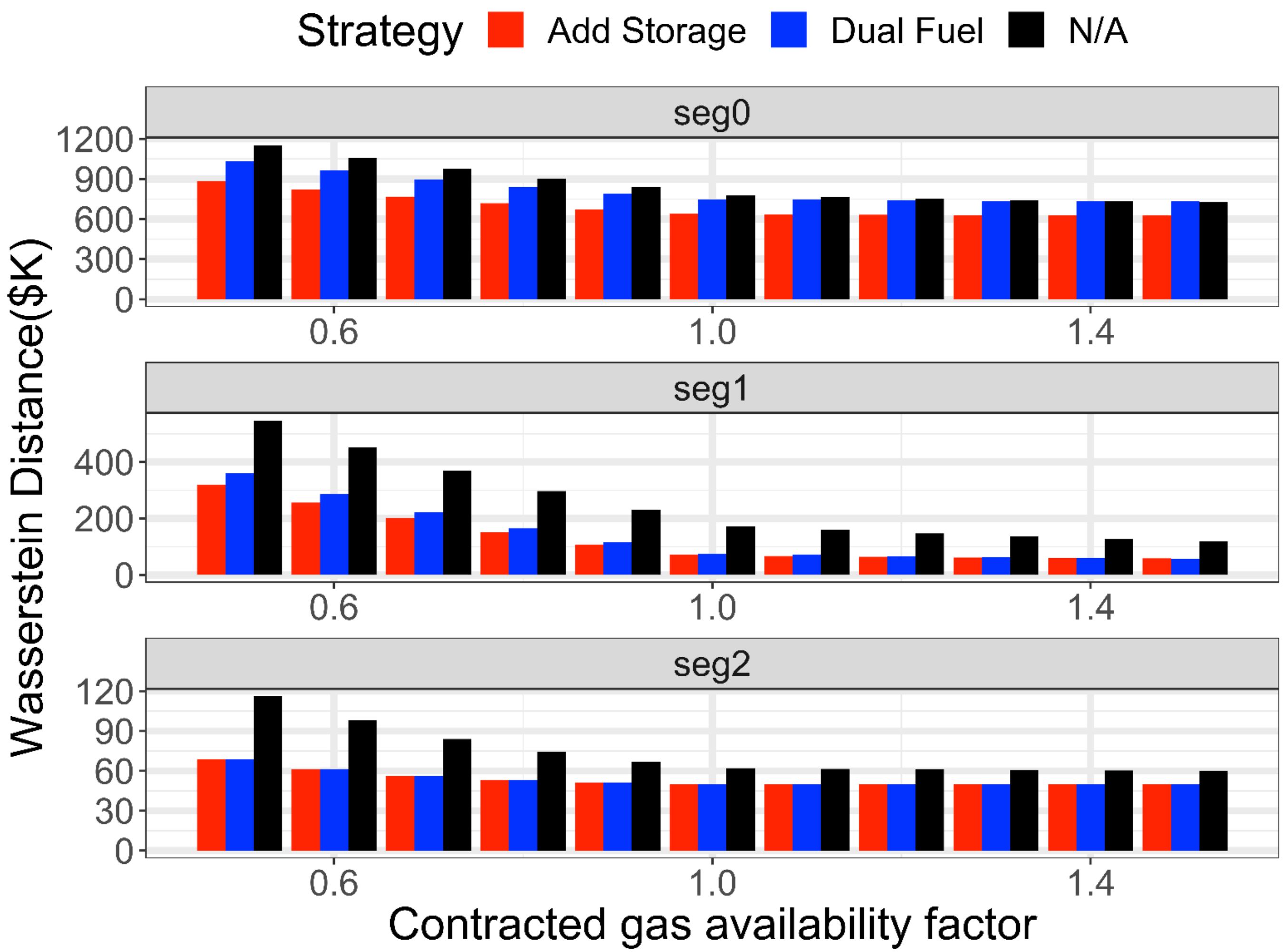
- Same investment could be used to build and fill a gas storage facility with capacity 106Mcf
- Dispatch model modified to include this additional storage

Evaluate risk metrics:

- MTD^1, $\Delta CVaR^1$
- MTD^2, $\Delta CVaR^2$

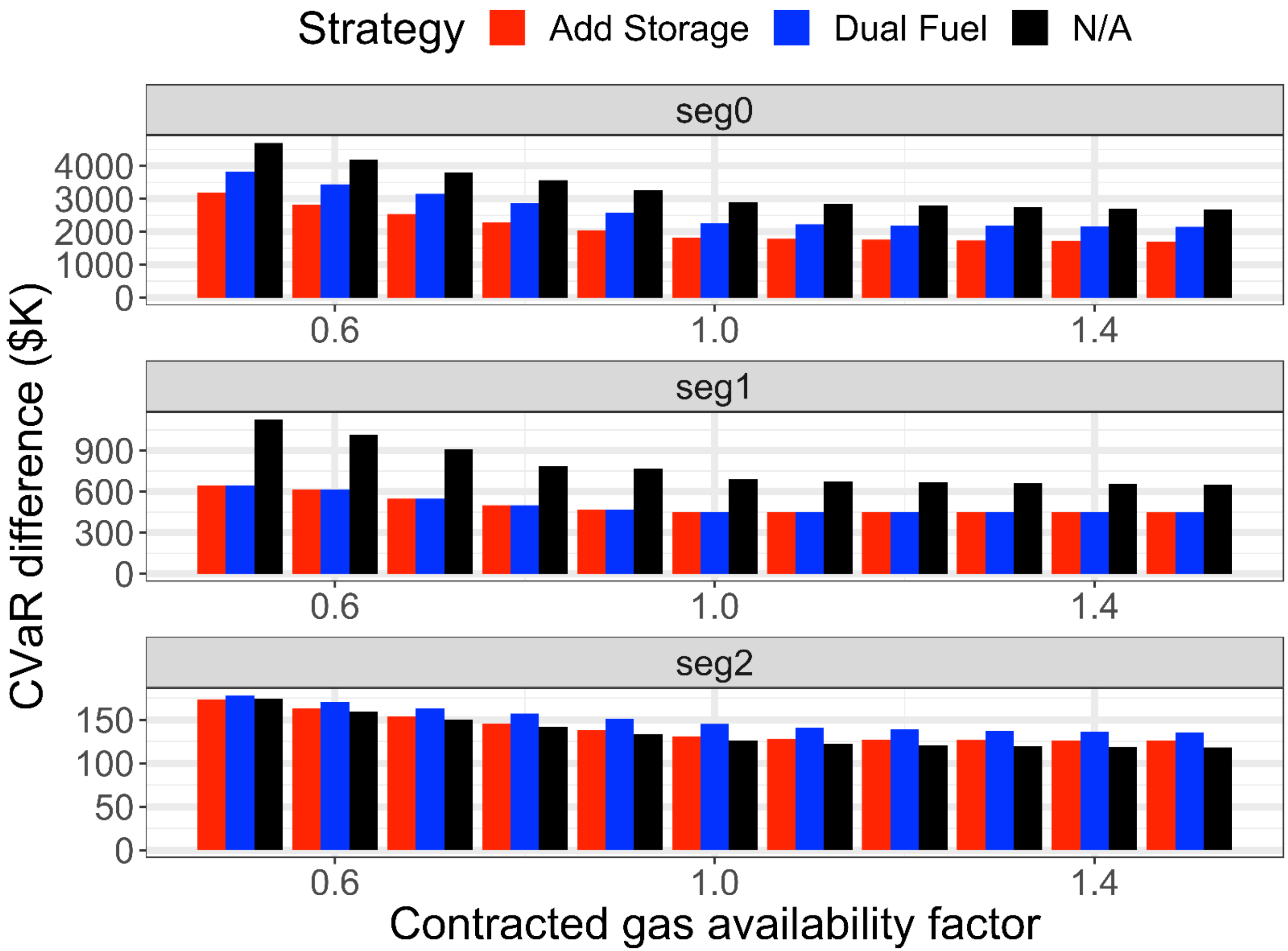
Strategy 1 preferred if $MTD^1 < MTD^2$, $\Delta CVaR^1 < \Delta CVaR^2$

Probability Metric Comparison



Adding gas storage reduces risk more than same $ investment in dual-fuel conversion

CVaR Difference Comparison



Adding gas storage reduces risk more on the coldest days than same $ investment in dual-fuel conversion

Presentation Outline

- Economic Risk in the Power System from Gas System Dependence
- Quantifying Economic Risk Due to Uncertainty in the Gas Spot Price
  - Dispatch Model with Constraint on Availability of Contracted Gas
  - Correlated Uncertain Loads and Gas Prices
  - Risk Quantification via Monte Carlo Simulation
- Using the Risk Metrics to Evaluate Alternative Risk-Mitigation Strategies
- Conclusions and Future Work

Conclusions

- Procedure to quantify the impact of gas spot price uncertainty on system operator’s electric energy purchase cost under restricted availability of contracted gas
  - Correlated electric load and gas spot price based on weather
  - Monte Carlo simulation of daily dispatch
  - Risk metrics to quantify difference in dispatch cost distribution with/without gas price uncertainty
- Numerical study illustrates the procedure
- Results indicate that gas storage mitigates risk more than dual-fuel conversion for the same dollar investment

Future Work

- Generate joint distributions of gas price and electric load on hourly rather than daily basis
- Represent contracted gas availability probabilistically rather than in a sensitivity study
- More realistic numerical test cases that represent the actual gas network supplying an actual power system
- … all these extensions require more and better data!

Questions?

Sarah Ryan

(smryan@iastate.edu)

This material is based upon work supported by the Power Systems Engineering Research Center as Project M-36.