Computational and Design Needs in RTO Markets: A PJM Perspective

FERC Computational Technical Conference

Paul M. Sotkiewicz, Ph.D.
Chief Economist, Markets

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Confluence of Policy, Industry Environment, and Modeling and Computational Needs

- EPA Clean Power Plan under CAAA 111(d)
  - Need faster, higher powered algorithms to handle scenarios that were once not that big a deal in scenario modeling
  - Need for thinking about algorithms and computational shortcuts in SCUC and SCED to handle a multiplicity of run-time restrictions
- Gas-Electric Coordination
  - Speed up computational clock times on clearing DA market to match up with timely nomination cycle
  - But still have to coordinate with the commodity gas market traditions of weekend strips
- Short-term load forecasting
  - How to account for behind the meter generation that will increasingly affecting commitment decisions.

MODELING AND COMPUTATIONAL CHALLENGES TO MEET THE CLEAN POWER PLAN UNDER CAAA 111(D)

Existing Source vs. New Source Performance Standards Proposals

	111(d)	111(b)
Relevant dates	• Interim compliance 2020-2029 • Final compliance 2030 and beyond	Scheduled promulgation January 2015
Units impacted	• Existing and Under-construction: ST Coal, NGCC, ST Gas/Oil, High-utilization CT Gas/Oil, IGCC and some CHP • Units under 111(b) not subject to 111(d) but could be included at a state's discretion	• New Gas-Fired CT, fossil-fired utility boilers and IGCC units • CTs running under a 33% capacity factor are exempt

Standard	• State-based compliance with a CO_2 emissions rate target or converted to a mass-based target
	• Options for regional compliance
		Federal compliance (NSPS):
		• Large CT - 1,000 lbs/MWh
		• Steam Turbine and IGCC:
		  • 1,100 lbs/MWh (12 mos.)
		  • 1,000-1,050 lbs/MWh (84 mos.)

Impact on units	• Reduced net energy market revenues • Potentially CO_2 allowance price or restrictions on unit operation	• New gas/dual fuel CCs meet limit • New coal units require partial carbon capture and sequestration or similar to meet limits

Used PROMOD for simulation modeling

- Models hourly security constrained economic generation commitment and dispatch
- Assumptions consistent with 2014 RTEP Market Efficiency Analysis
- Regional Dispatch of PJM Generators to serve PJM load

Regional Compliance

- No one state needs to comply in isolation, but in aggregate the region cannot exceed the regional mass- or rate-target
- Iterate on a single PJM-wide CO_2 price until the region is in compliance
- **4-6 hours per iteration…6 iterations to converge**
- **Interchange turned off**

State-by-State Compliance

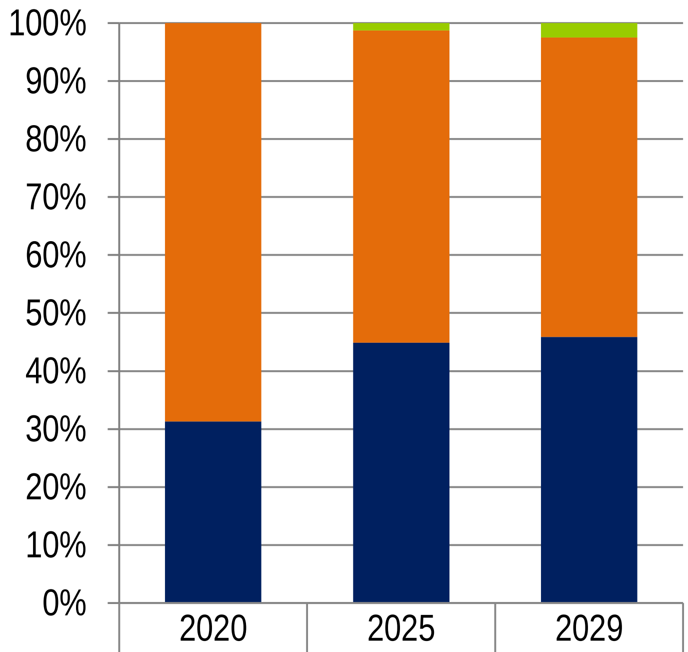
- Each state (12 states in the simulation) has its own unique CO_2 price
- Simultaneously iterate on individual state CO_2 prices until all states are in compliance
- **4-6 hours per iteration…6 iterations to converge on mass basis**
- **Up to 20 iterations to converge on rate basis**

Current Modeling Tools are Insufficient

- Chosen tools by EPA, RFF, and DOE lack the following important representations of the system
  - No SCUC or SCED…3 season load duration without actual operational constraints
  - No modeling of the actual transmission system…pipes and bubbles transmission which miss important congestion patterns and effects of actual transmission models even in a DC framework
  - Not representing all units on the system…use of model plants rather than each individual units
  - Designed to solve quickly rather than "accurately"
- Miss some very important and crucial aspects of system operation and results that ensue

Mechanisms for Achieving Emissions Reductions
Zero Emitting and Low Variable Cost Resources

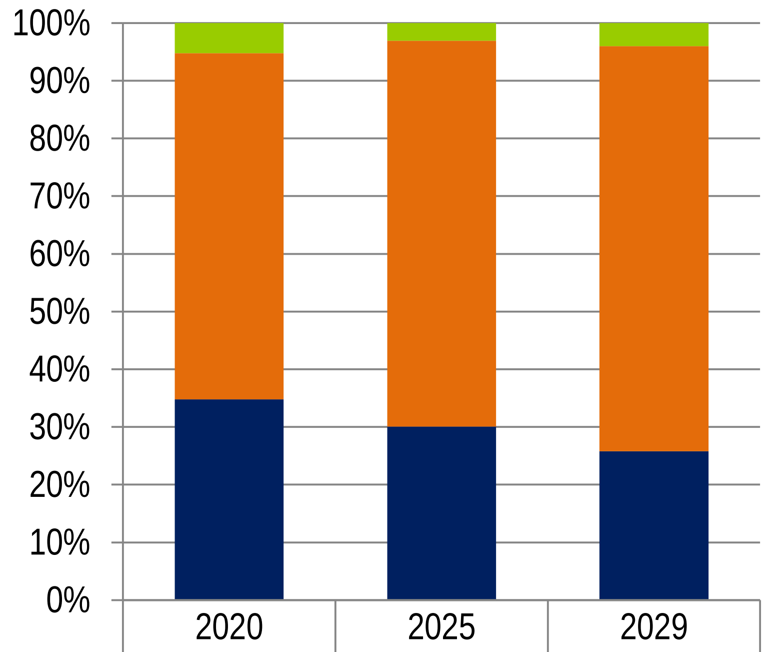
Energy Displacement due to Wind Resources



	2020	2025	2029
Other	0.0%	1.3%	2.5%
Natural Gas	68.7%	53.8%	51.6%
Coal	31.3%	44.9%	45.9%

OPSI 2b.1 and OPSI 2a used to calculate displacement percentage

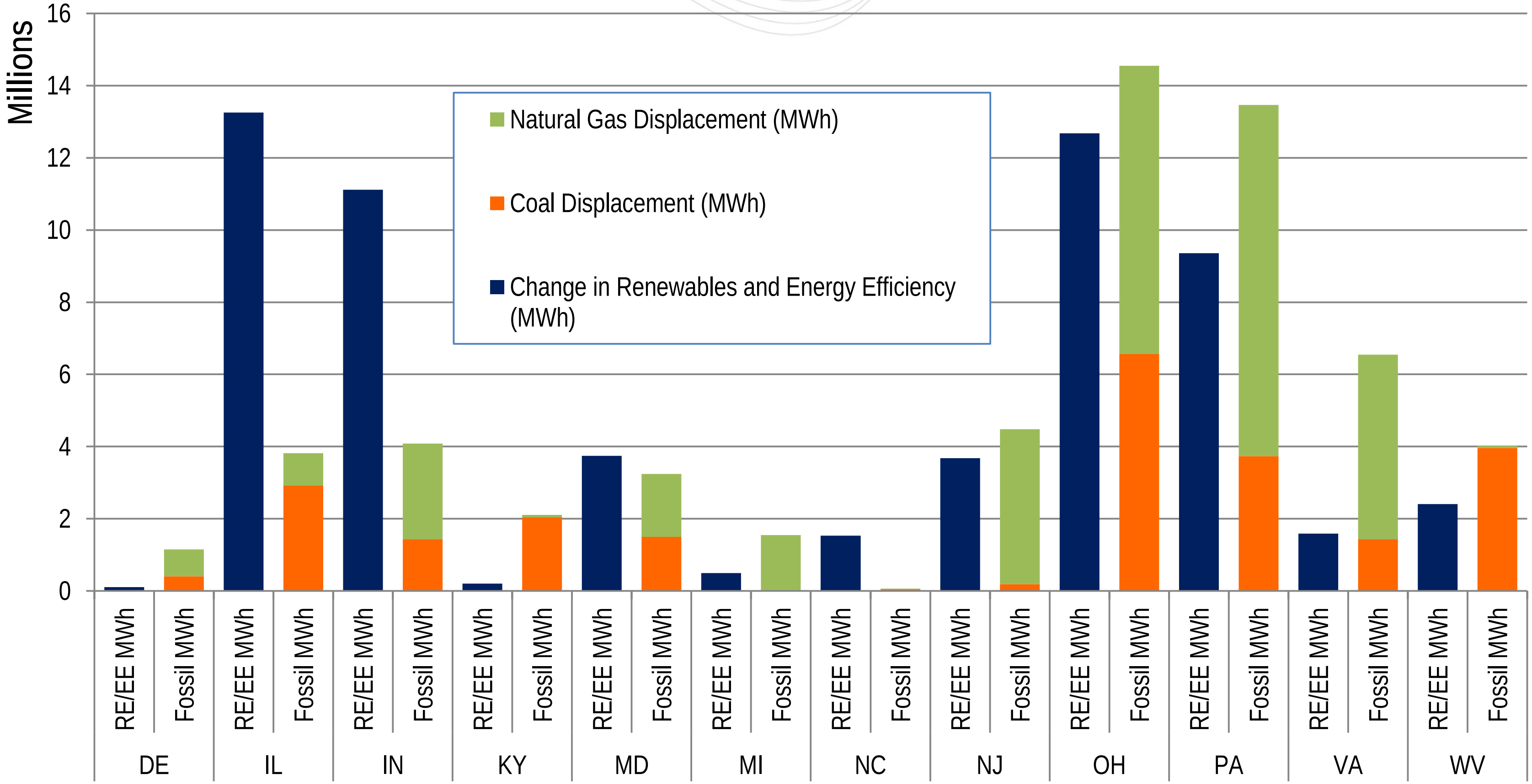
Energy Displacement due to Energy Efficiency



	2020	2025	2029
Other	5.2%	3.1%	4.0%
NGCC	60.0%	66.9%	70.2%
Coal	34.8%	30.1%	25.8%

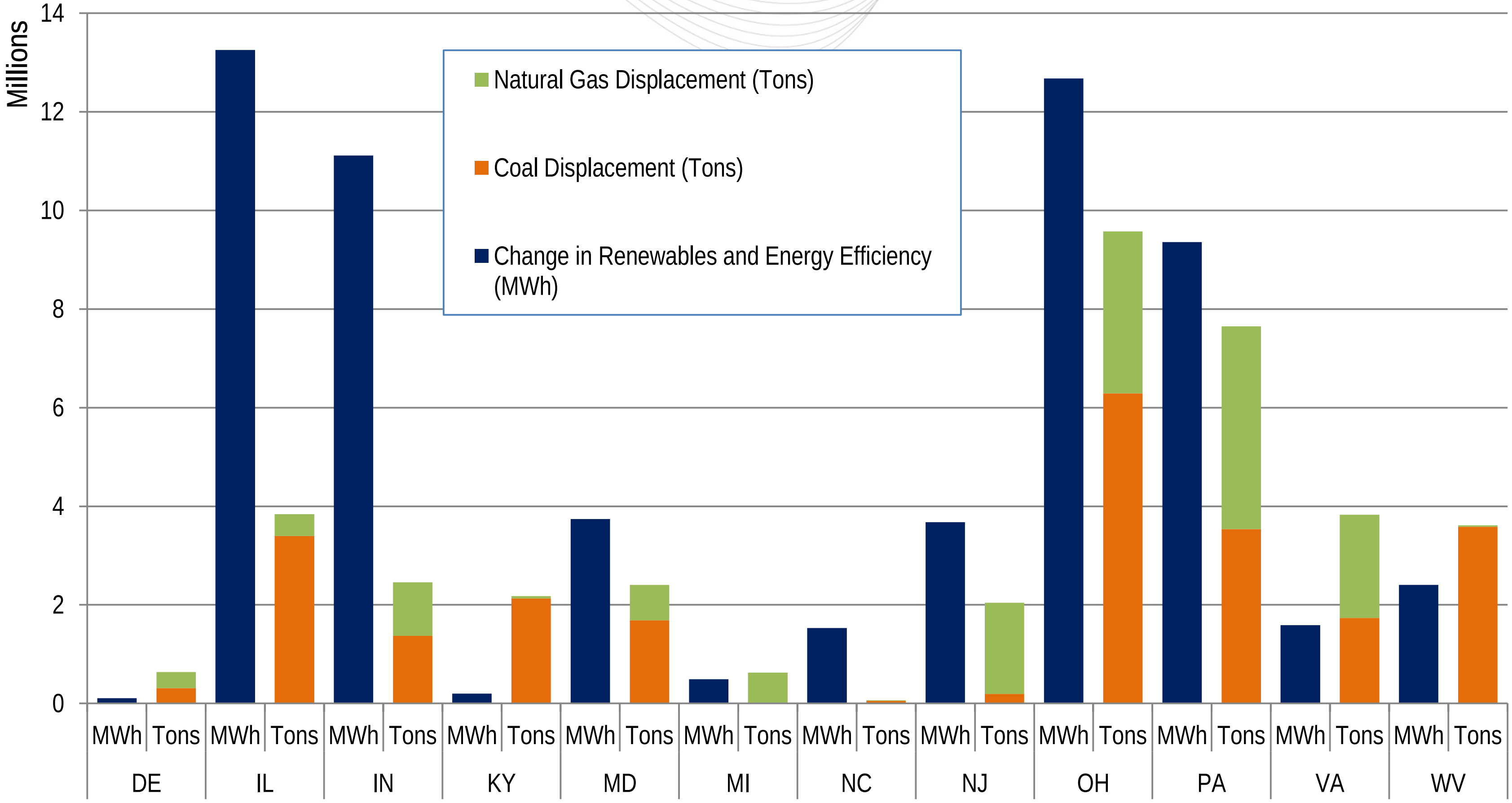
OPSI 2b.2 and OPSI 2a used to calculate displacement percentage

Generation Investment Location doesn't always Match the Energy (MWh) Displacement Location



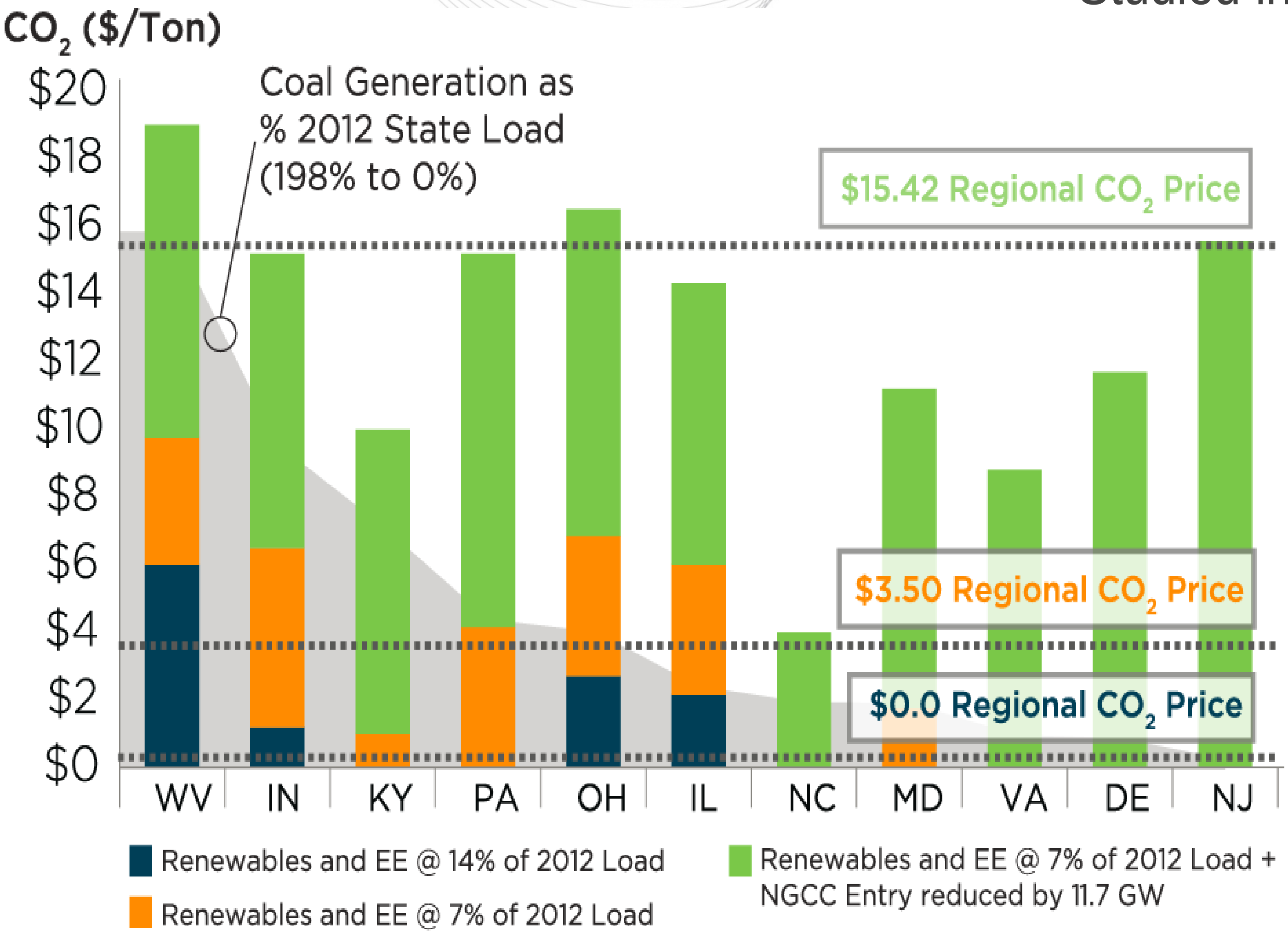
*Data based on OPSI 2a (Achieve State RPS and EPA EE targets) versus PJM 4 (Lower Growth in Renewables and EE) Scenario in 2020

Generation Investment Location doesn't always Match the Emissions (Tons) Displacement Location



*Data based on OPSI 2a (Achieve State RPS and EPA EE targets) versus PJM 4 (Lower Growth in Renewables and EE) Scenario in 2020

CO_2 Prices for Regional and State Compliance Studied in 2020



Thinking about Run-time/Emissions Limits Going Forward with the Clean Power Plan

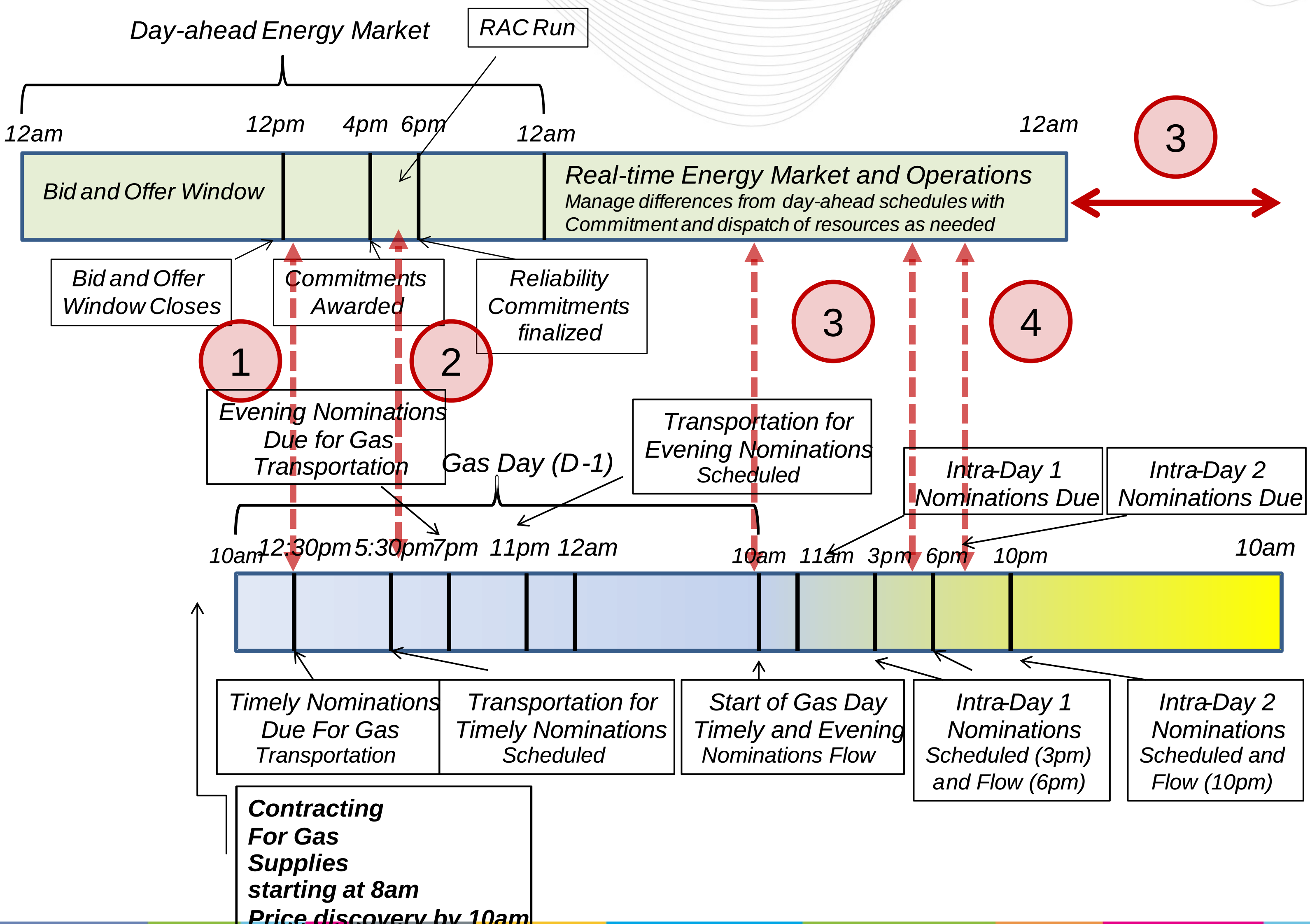
- Many states and other interested parties are opining the EPA must regulate sources "within the fence-line"
  - Thinking a limit to heat rate improvements only…
- But inside the fence-line can also mean emissions/heat input/run time restrict a large set of fossil units on the system
  - Already happens today with peaking units
  - But would affect a much larger set of resources
- Complications
  - Compliance 2020-2029 is a 10 year average
  - Compliance 2030 and beyond is on a 3 year rolling average
  - How do year long, let alone compliance time frame restrictions get factored into the SCUC and SCED?
  - How to handle so many of these restrictions?

Thinking about Run-time/Emissions Limits Going Forward with the Clean Power Plan

- Energy and Environmentally Limited Opportunity Cost (PJM Manual 15)
  - Already in place, but voluntary
  - Only looks out a year…and with the Clean Power Plan, need a longer look ahead
  - Affects price formation over time as well as in specific hours
  - Is unit specific, decentralized, and can be updated on a daily basis as hours are used
  - But how to implement on such a scale?
  - Would place a price on each individual run time restriction
- But how to model to examine effects of such policies
  - Current software does not model such restrictions well, if at all, just do examine scenarios
  - Crucial because there needs to be a way to allocate run hours to ensure there is sufficient resources available to meet winter and summer peaks.
  - If 12 prices on a rate basis takes 20 iterations (at 4-6 hours per pass)…what about hundreds of restrictions???

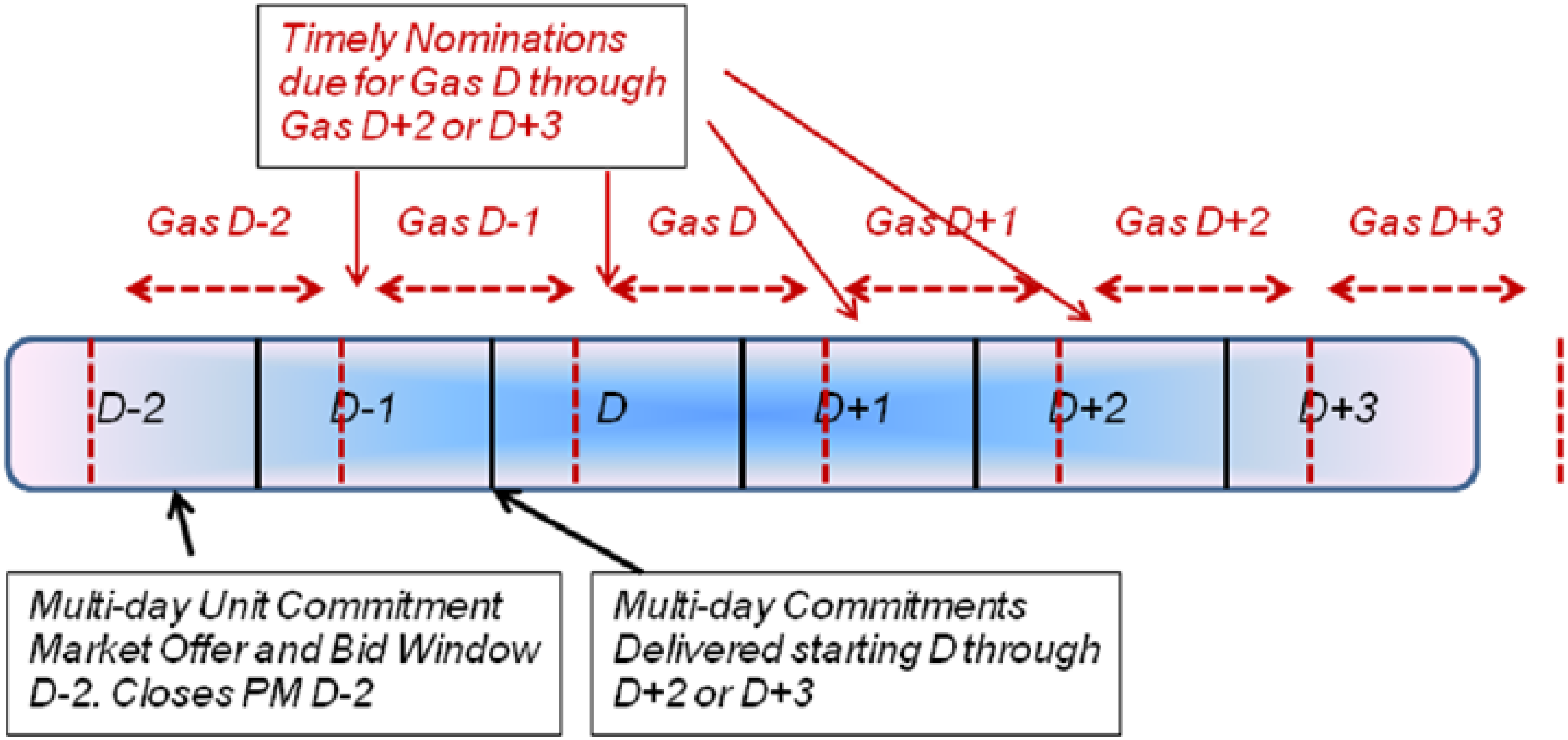
MULTI-DAY UNIT COMMITMENT MARKET: HARMONIZING ELECTRIC MARKETS WITH COMMODITY GAS MARKET PRACTICES

Gas Electric Coordination in PJM: Pre-FERC Order on Gas-Electric Coordination



- Would have all the same characteristics as the current Day-ahead market
- Good for weekend (3 and long 4 day weekend strips)
- Offer window and clearing 2 days before delivery
  - Sufficient time to schedule transportation in the timely cycle
  - Makes FT more valuable and attractive to gas-fired generation
  - Intraday nomination cycles become moot since gas is already scheduled using FT
  - Provides certainty of commitments when securing commodity gas on a daily basis
  - But do not know gas costs when submitting offers so far in advance

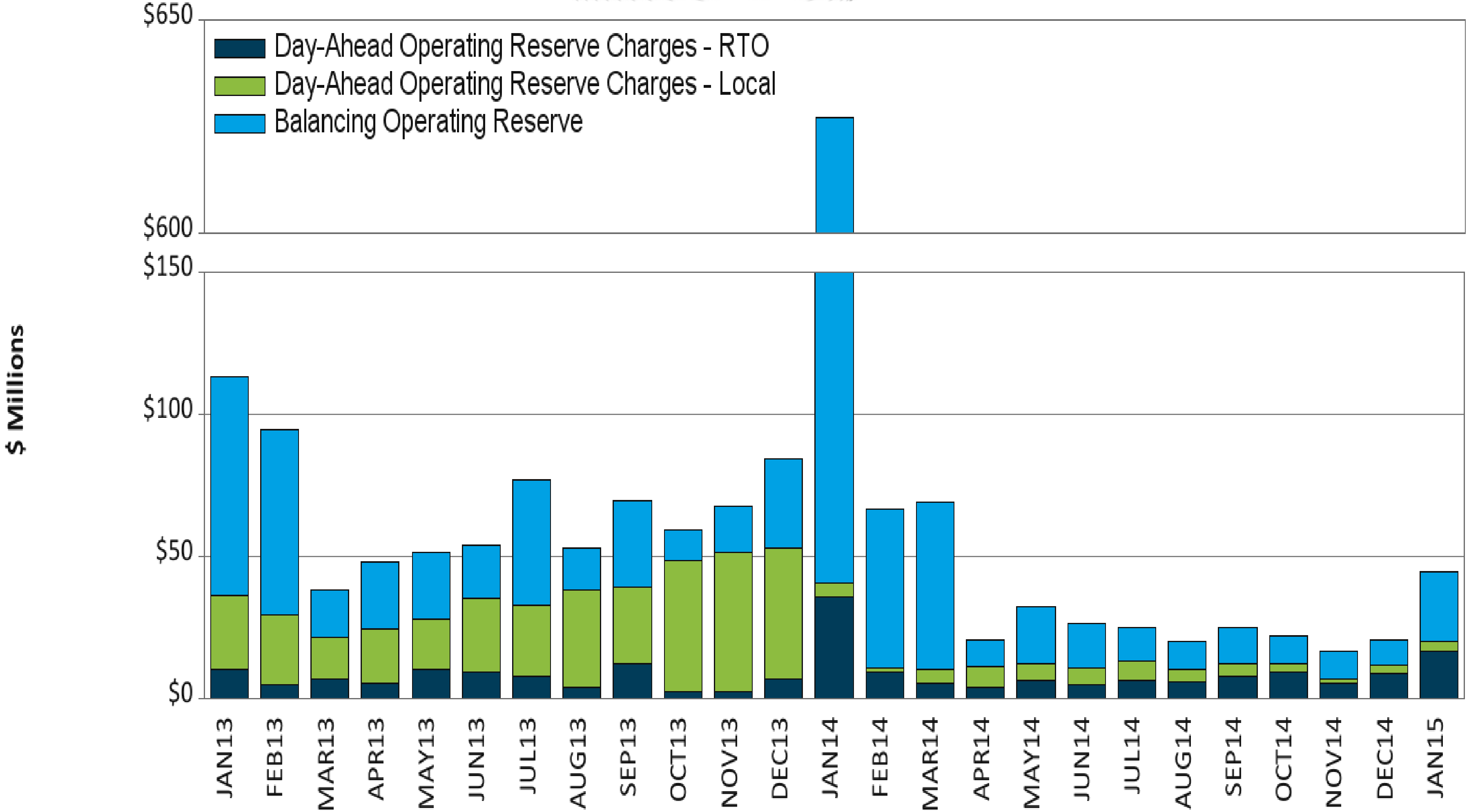
Proposed Timeline for Multi-Day Unit Commitment Market



Multi-Day Unit Commitment Market: Features

- Run 2 times per week.
  - Thursday commitment for Saturday, Sunday, and Monday (and possibly Tuesday) for long holiday weekends…corresponds to gas market practices on weekends
  - Monday commitment for Wednesday through Friday…though not much call for this
- Financially binding
- Load and financial players viewed as active participants
- Clearing Options
  - Allow parties to lock-in commitments without clearing…looks like a price guarantee but could lead to uplift
  - Full market clearing principles with commitments to be settled against future day-ahead market and real-time operation creating a 3 settlement system

Monthly Operating Reserve Costs

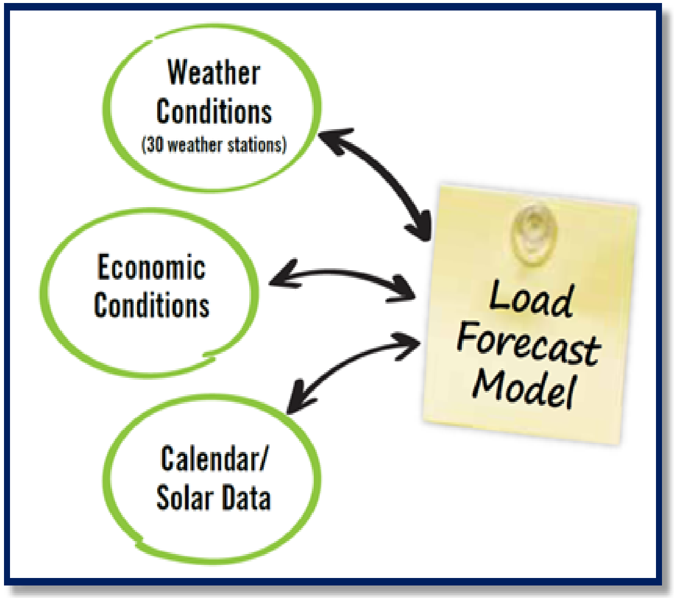


Multi-Day Unit Commitment Market: Possible Benefits

- Increase the value of FT for generators making it more likely they will take that service
- Conforms to commodity gas market practices in place on weekends helping reduce gas price risk
- Allows generators to lock in 3-4 day strips and being committed and financially binding
  - Reduce need for uplift to run generation for days out of order as happened in January 2014
- Gives load and generation a tool to manage short-term price risk while retaining the ability to change these position twice (day-ahead and real-time)
  - May be especially attractive in the winter

LOAD FORECASTING IMPROVEMENTS

Load Forecast Model



Weather Conditions

- ✓ Weighted average temperature, humidity & wind speed
- ✓ 30+ weather stations across PJM.

Economic Dimensions

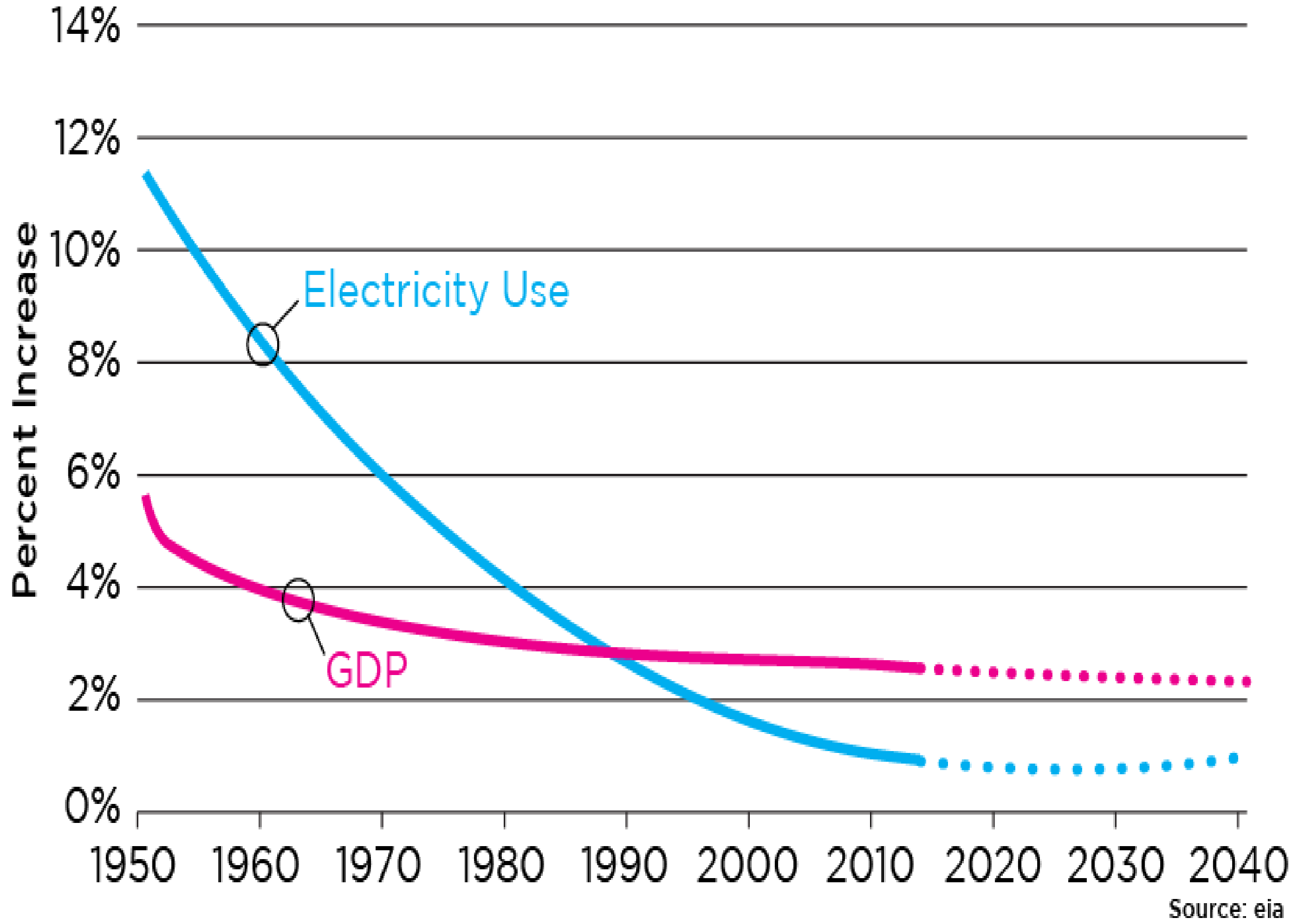
- ✓ Gross Domestic Product,
- ✓ Gross Metropolitan Product,
- ✓ Real personal income,
- ✓ Population,
- ✓ Households,
- ✓ Non-manufacturing employment

Calendar / Solar Data

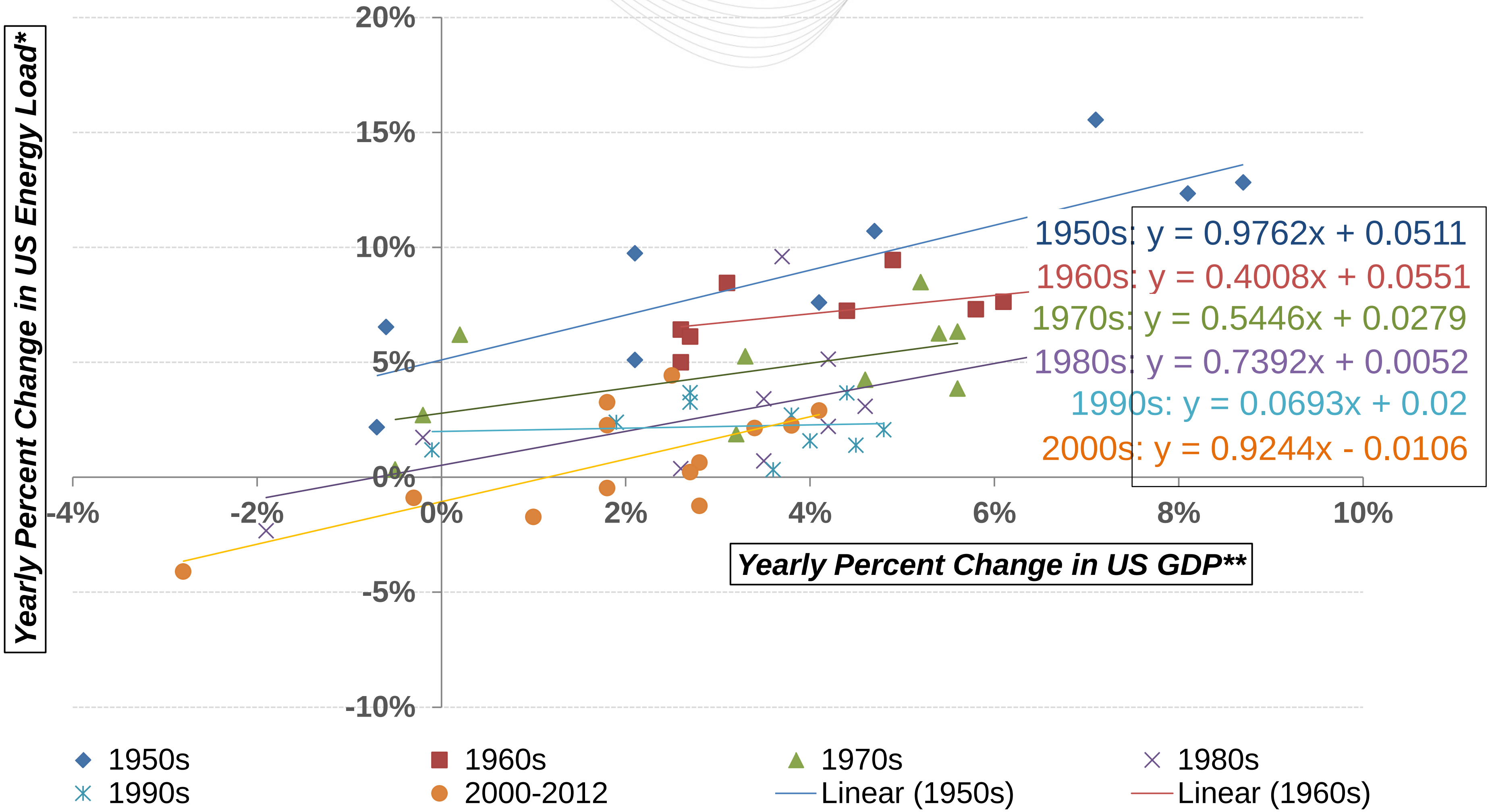
- ✓ Day of week
- ✓ Month
- ✓ Weekends / Holidays
- ✓ Minutes of Daylight

- The link between GDP and load growth and load has largely broken down
  - Or was it really ever there??
  - Load forecasts are coming down
- Increasing prevalence of behind the meter generation
  - PJM has little operational visibility to much of this
  - Driven by state and federal policies (RPS, PTC, ITC)
- Implications
  - Has an impact on the commitment of resources in the RAC run
  - Over or under commitment based on load forecast has implications for price formation and uplift
  - In the long-term has implications for new entry and exit

Electricity Use and Economic Trend

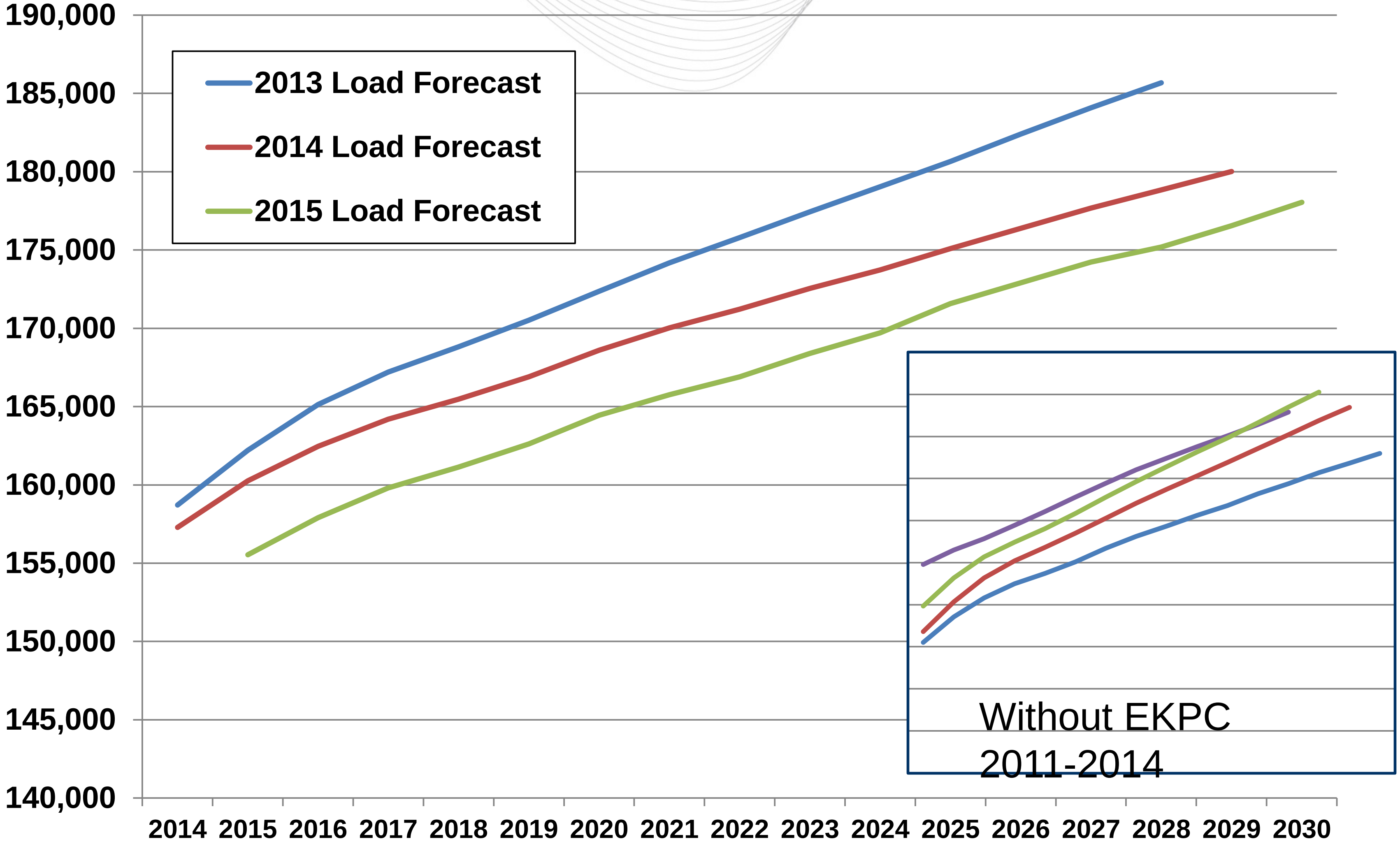


Regression of US Load Growth vs US GDP



*Based on EIA "Net Generation"
**Chained 2009 GDP

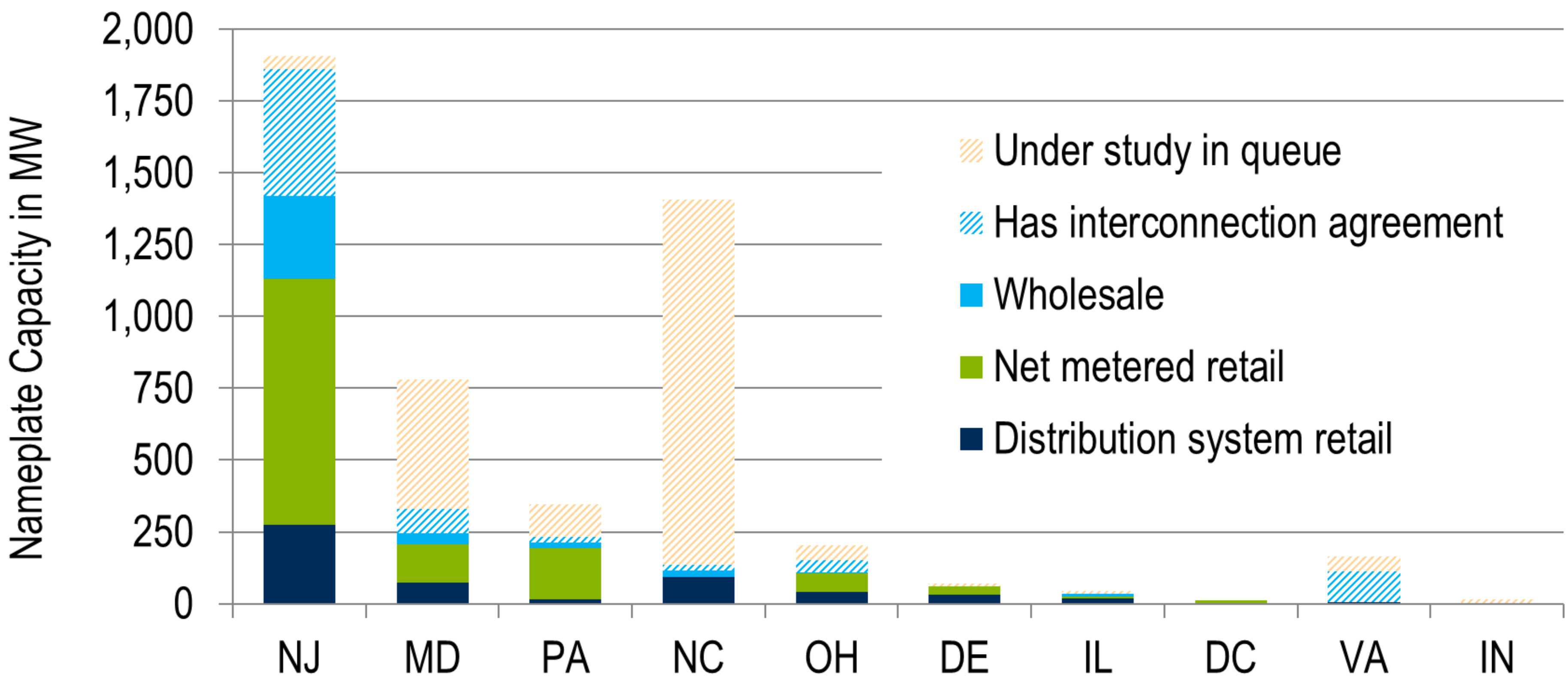
Lingering Low Peak Electricity Demand



Work to Be Done in Load Forecasting

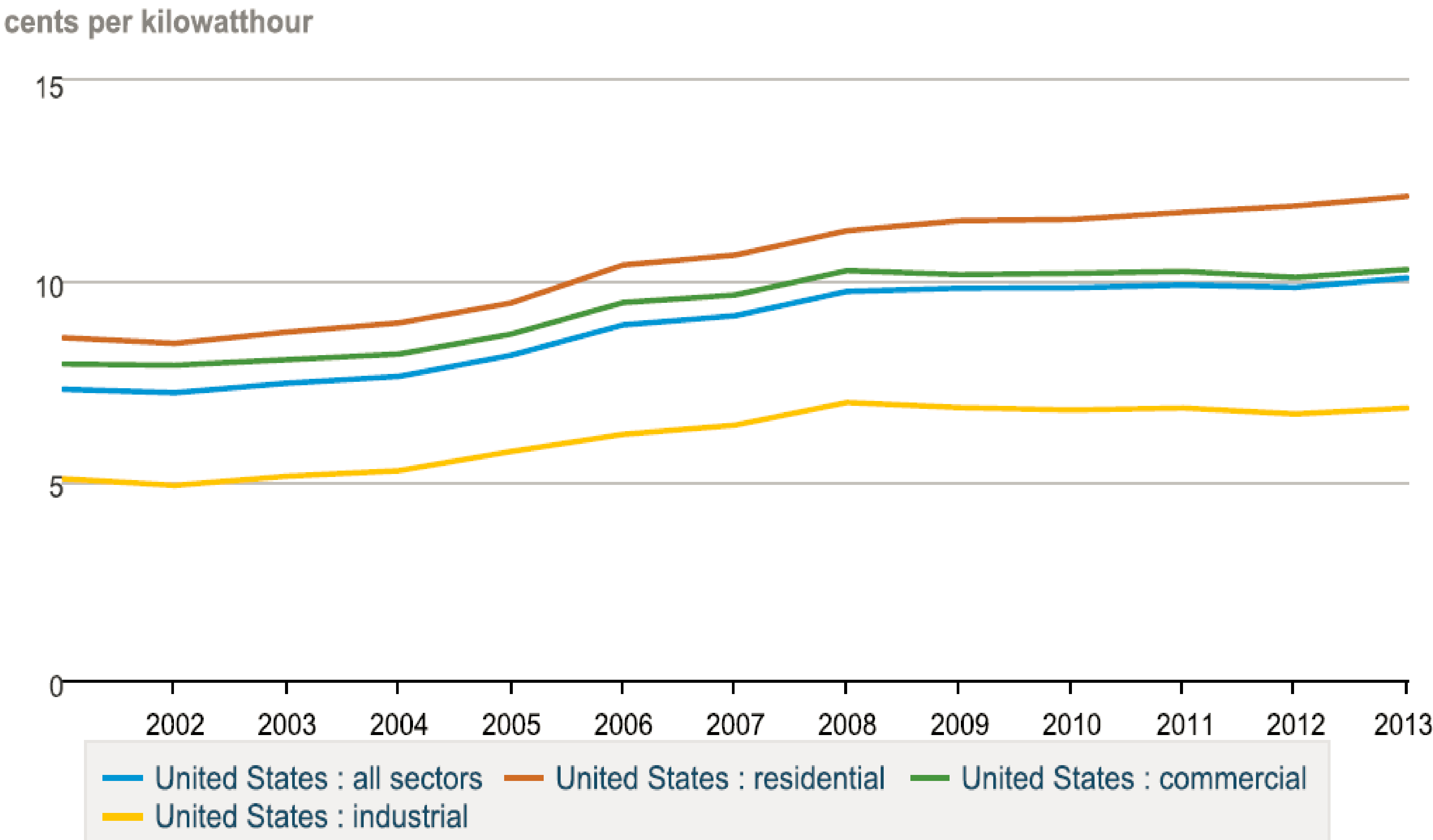
- This is more of a data and specification problem than it is a real computational problem
  - What variables are we missing?
  - What deserves more emphasis?
  - We pretty well understand weather and seasonal drivers
  - Better visibility into BTM solar and other technologies
- Think about some different economic drivers
  - Total employment from a demand side perspective
  - Median income
  - Turnover in building and appliance capital stock…EIA has a way of accounting for this
  - Income and retail rate interactions

Solar Capacity in PJM by State

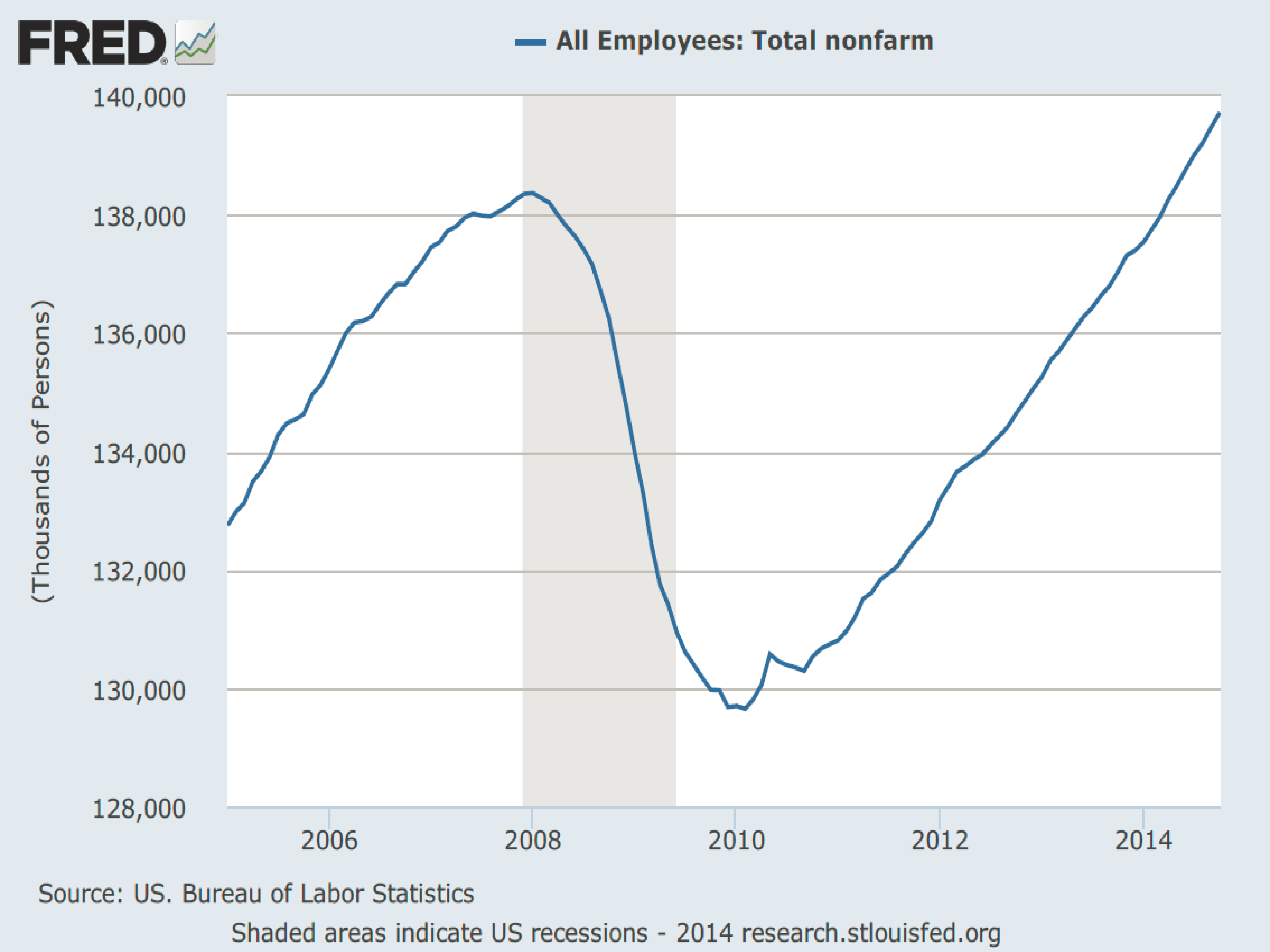


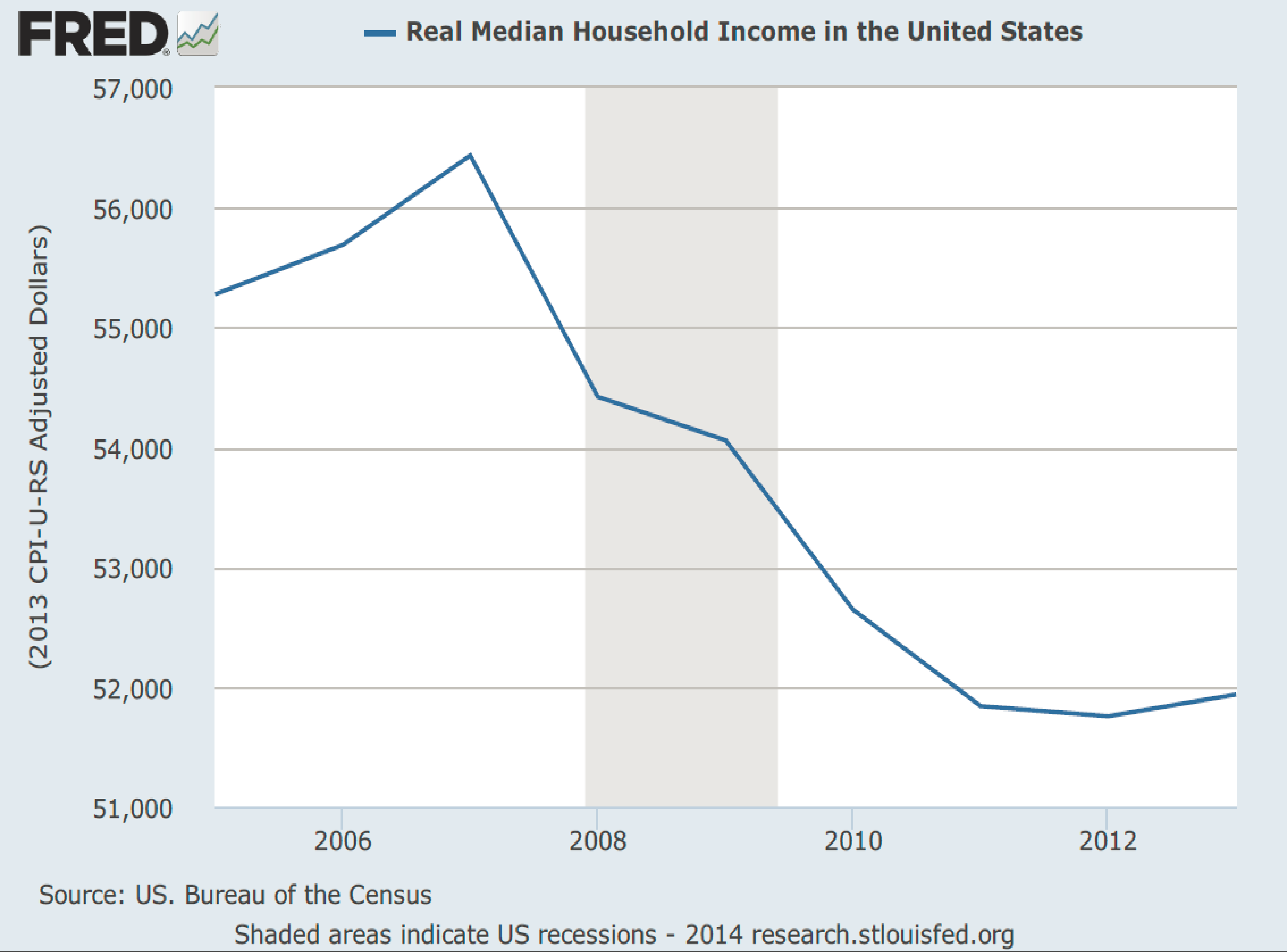
Note: Graph includes data only for the portion of each state within the PJM footprint

Average retail price of electricity, annual

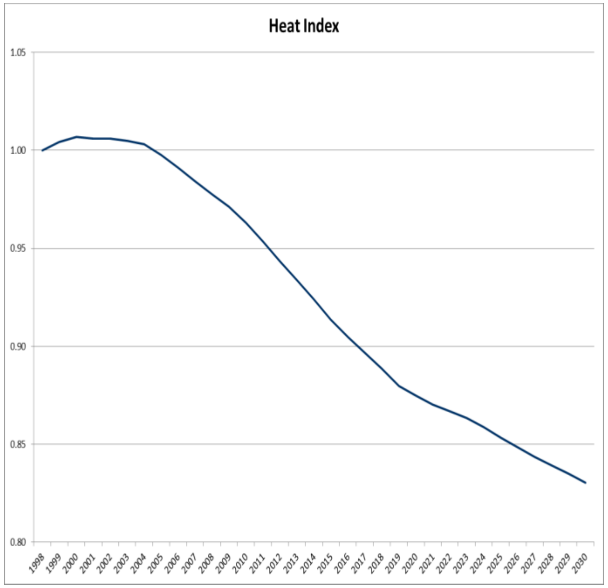


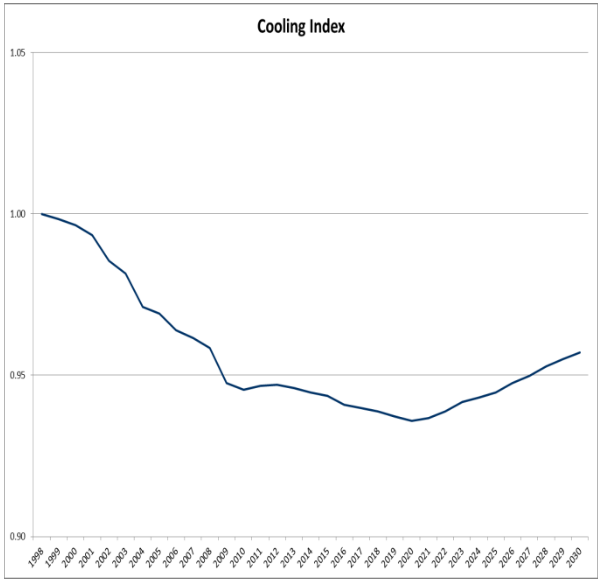
Data source: U.S. Energy Information Administration

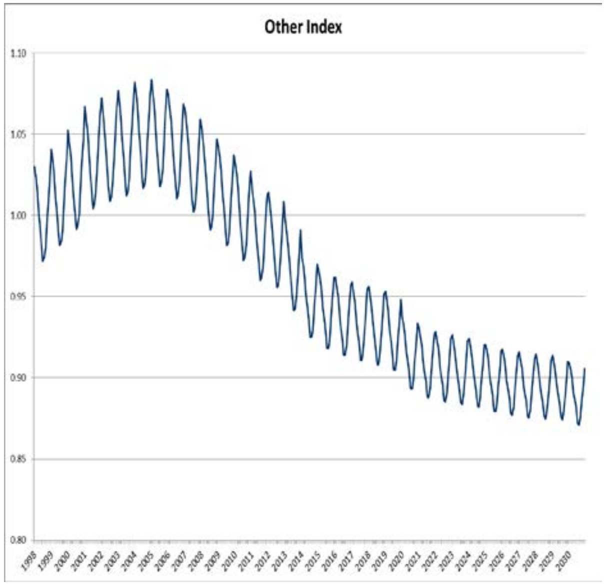

FRED
All Employees: Total nonfarm
140,000
138,000
136,000
134,000
132,000
130,000
128,000
(Thousands of Persons)
2006
2008
2010
2012
2014
Source: US. Bureau of Labor Statistics
Shaded areas indicate US recessions - 2014 research.stlouisfed.org


FRED
Real Median Household Income in the United States
(2013 CPI-U-RS Adjusted Dollars)
57,000
56,000
55,000
54,000
53,000
52,000
51,000
2006
2008
2010
2012
Source: US. Bureau of the Census
Shaded areas indicate US recessions - 2014 research.stlouisfed.org

Equipment Index Examples







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Conclusion: A PJM Perspective on Computation Needs

- EPA Clean Power Plan under CAAA 111(d)
  - Even if 111(d) never happens, we need to better understand how to model run-time restrictions as they are becoming a larger problem
  - Need it for system operation and policy modeling software
- Gas-Electric Coordination
  - Speed up computational clock times on clearing DA market to match up with timely nomination cycle is a must…about algorithms
  - Thinking about modeling multi-day unit commitment that is market/settlement quality
- Short-term load forecasting
  - Need more attention of the industry in this area…many puzzles and no great answers to date…we are working toward this, but is slower than it needs to be