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October 24-26, 2023
Northampton, MA

Introduction to Forward Capacity Market
Lesson 1A: Reason for Having a Capacity Market

Forward Capacity Market (FCM 101)

This presentation is based on the current information available for the rules as they are today. The information in this presentation may change based on upcoming decisions made regarding the future of FCA 19 and will be covered in future training.

Ryan McCarthy
Lead Analyst, Market Development

Some slides or portions of slides may be intentionally hidden in the printed and posted versions of this presentation.

Topics

- *Missing Money Problem*
- How Various Markets Solve *Missing Money Problem*
- An Alternative to Energy Only – Forward Market
- Concept of Pay-for-Performance (PFP)
- Example With Forward Market Construct

Objectives

- State how electricity markets alone do not provide adequate financial incentives to invest in new generating capacity
- Explain why there is a *missing money problem* in electricity markets
- Discuss how different electricity markets attempt to resolve *missing money problem*
- Identify key concepts of pay-for-performance

Common Acronyms

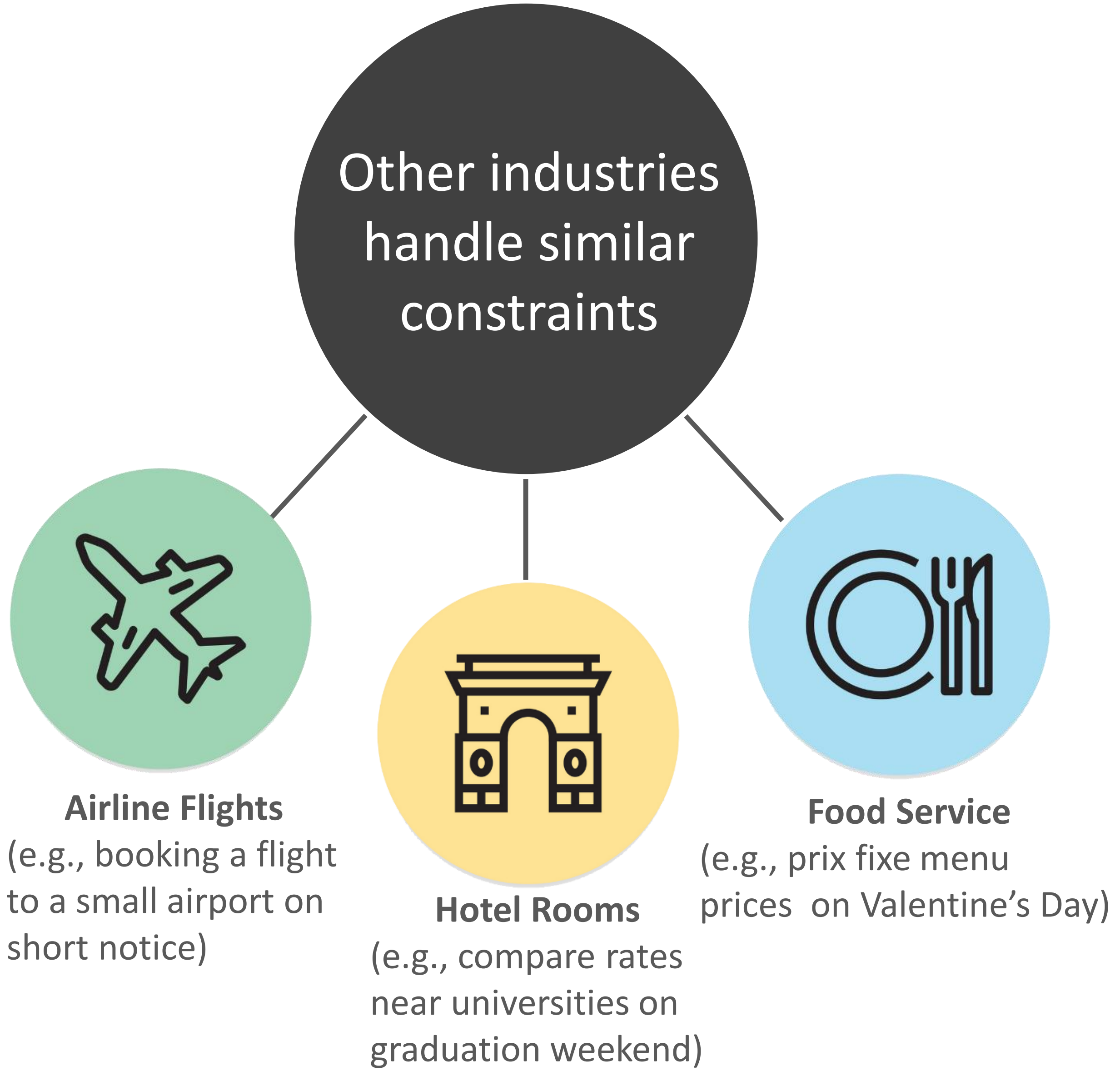
In Order of Appearance

PFP	pay-for-performance
LMP	locational marginal price
CSC	capacity scarcity condition
ERCOT	Electric Reliability Council of Texas
ORDC	operating reserve demand curves
CSO	capacity supply obligation

Missing Money Problem

Electricity markets have some problems:

- **Inelastic demand** – consumers typically aren't price sensitive
- **Capacity limits** – adding new supply requires long lead times
- **Limited storability** – inefficient and difficult to site/construct/finance



Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)					
Nameplate Capacity (MW)					
Hours of Operation (h)					
Hourly Profit ($/MWh)					
Energy Market Profit ($)					
Cash Flow					

Peaking Power Plant – Capital Expense

LMS100PB in NEMA/Boston

- 103 MW nameplate capacity
- Distillate fuel/natural gas capability
- Heat rate: 9.0 MMBtu/MWh
- Installed cost $1,477/kW
  - Total installed cost: $152 million (*P* in equation below)
- Weighted average cost of capital (WACC): 10% (*r*)
  - 60% equity (13.4%)
  - 40% debt (7.75%, 4.6% after tax)

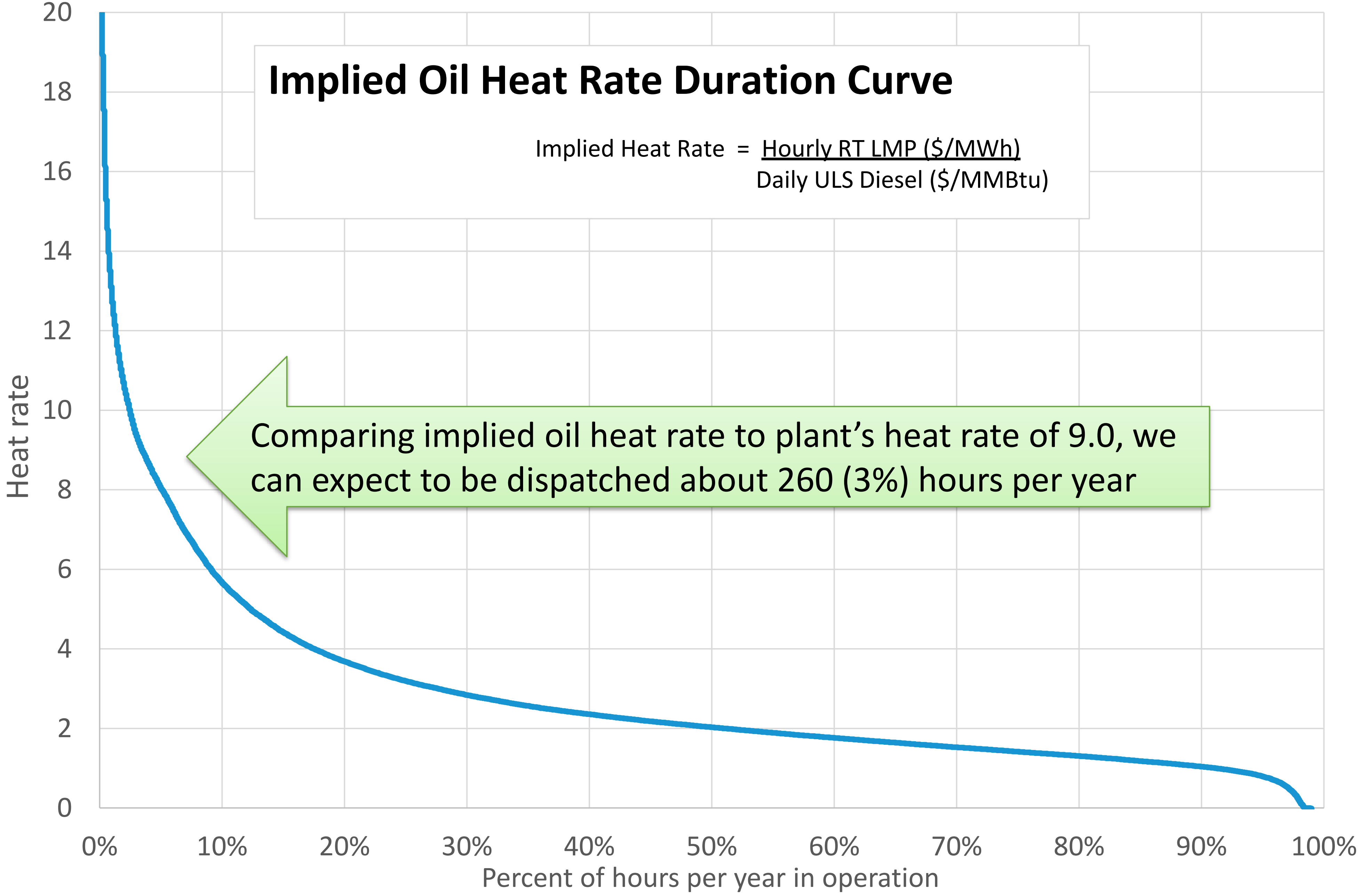
Annualized Capital Expense:

$$P \times \frac{r \times (1 + r)^n}{(1 + r)^n - 1} \; ; \; \$152m \times \frac{0.1 \times (1.1)^{20}}{(1.1)^{20} - 1} = \text{~}\$17,870,000$$

Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)	(17,870,000)	(17,870,000)	…	(17,870,000)	(17,870,000)
Nameplate Capacity (MW)	103	103	…	103	103
Hours of Operation (h)					
Hourly Profit ($/MWh)					
Energy Market Profit ($)					
Cash Flow					

Peaking Power Plant – Hours of Operation



Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)	(17,870,000)	(17,870,000)	…	(17,870,000)	(17,870,000)
Nameplate Capacity (MW)	103	103	…	103	103
Hours of Operation (h)	260	260	…	260	260
Hourly Profit ($/MWh)					
Energy Market Profit ($)					
Cash Flow					

Peaking Power Plant – Hourly Profit

- Heat rate spreads:

  Profit/MWh = (System Oil Implied Heat Rate - 9.0) x Fuel Cost

- Peaking plants are often the marginal resource
  - Capable of serving next increment of load during tight supply conditions

- Marginal resource earns $0 profit
  - Sets price equal to its bid, which is its marginal cost

Based on heat rate spreads at 1.5% level in **Implied Oil Heat Rate Duration** chart, average profit assumption can be $50/MWh

Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)	(17,870,000)	(17,870,000)	…	(17,870,000)	(17,870,000)
Nameplate Capacity (MW)	103	103	…	103	103
Hours of Operation (h)	260	260	…	260	260
Hourly Profit ($/MWh)	50	50	…	50	50
Energy Market Profit ($)	?				
Cash Flow					

Peaking Power Plant – The Missing Money

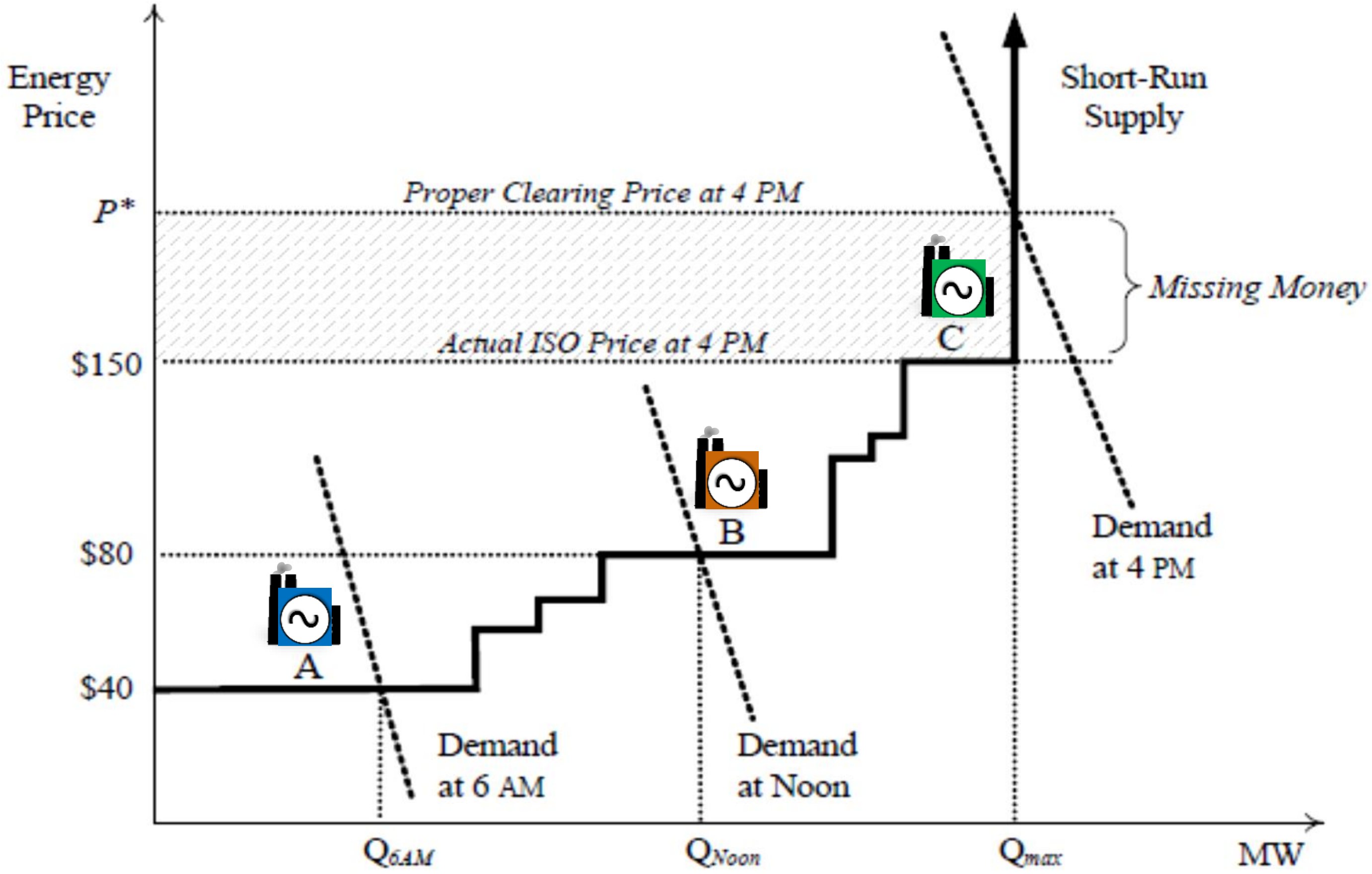
- Infrequent dispatch provides limited opportunities to recover fixed costs
  - High energy prices are needed to pay for capital expenditure
  - High energy prices also act as an efficient performance incentive

260 hours of 103 MW dispatch at an average profit of $50/MWh yields an energy market profit of $1,340,000. With an annual capital expense of $17,870,000, missing money is about **$16.53 million annually**.

- Not only a peaker problem
  - Base load generation is very capital intensive
    - Even though these resources operate frequently and earn substantial energy market profits, there is still a *missing money problem* due to size of initial investment
  - Daily cycled generation needs revenue certainty
    - Even though these resources can be expected to earn some energy market profits, the amount of profit earned in a given year will depend heavily on weather conditions

Missing Money Problem in Theory

- *P** is the efficient price but not the locational marginal price (LMP)
- Demand is willing to pay more than LMP
- At $150, some demand should go unserved



More Theory

- Offer caps limit ability of supply offers to approach *P**
  - Market power concerns require mitigation of supply offers that are determined to be non-competitive

FERC Federal Energy Regulatory Commission

- ISO does not observe a downward sloping demand curve, only a single point
  - Price-sensitive demand behavior can help by stacking the loads with highest willingness to pay

Capacity Market Objectives

- Capacity market uses a two-settlement design to create revenue stream that replaces missing money
  - Base payment provides financial incentives to invest in capacity

In our example, the necessary capacity payment is $16,530,000; or

$$\$16{,}530{,}000\ year \div 103\ MW \div 1000\ \frac{kW}{MW} \div 12\ \frac{Months}{Year} = \$13.37\ \text{kW-Month}$$

- "Spot market" adjustment provides additional compensation to good performers and charges poor performers during capacity scarcity conditions (CSCs)
  - Over time, region procures the most cost-effective set of resources to meet reliability standards
  - Resources have strong incentives to incur costs that improve their performance during capacity scarcity conditions
    - Good performers may be less likely to exit than poor performers because of additional payments they expect to receive

Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)	(17,870,000)	(17,870,000)	…	(17,870,000)	(17,870,000)
Nameplate Capacity (MW)	103	103	…	103	103
Hours of Operation (h)	260	260	…	260	260
Hourly Profit ($/MWh)	50	50	…	50	50
Energy Market Profit ($)	1,340,000	1,340,000	…	1,340,000	1,340,000
Cash Flow	(16,530,000)	(16,530,000)	…	(16,530,000)	(16,530,000)

Questions

How Do Various Markets Solve *Missing Money Problem*?

Why We Designed FCM the Way It Is

Missing Money Problem

As you may recall from earlier in the presentation, electricity markets have some problems:

- **Information** – Demand can't indicate willingness to pay for energy in real-time
- **Inelastic demand** – Consumers typically aren't price sensitive
- **Capacity limits** – Adding new supply requires long lead times
- **Limited storability** – Inefficient and difficult to site/construct/finance

> Markets solve these problems in various ways – markets for other goods' prices would rise until demand equals supply (demand would respond to high prices or new supply enters)

Let's look back at our previous example

Peaking Power Plant Simplified Cash Flows

Year	1	2	…	19	20
Capital Expense ($)	(17,870,000)	(17,870,000)	…	(17,870,000)	(17,870,000)
Nameplate Capacity (MW)	103	103	…	103	103
Hours of Operation (h)	260	260	…	260	260
Hourly Profit ($/MWh)	50	50	…	50	50
Energy Market Profit ($)	**1,340,000**	**1,340,000**	**…**	**1,340,000**	**1,340,000**
Cash Flow	(16,530,000)	(16,530,000)	…	(16,530,000)	(16,530,000)

Solving *Missing Money Problem* in Energy Market

In previous example, two values related to energy market:

- Average number of hours (h) unit would run per year: 260 (out of 8760)
- Hourly average profit ($/MWh) unit would make when running: $50

Dispatched at 103 MW: $1,340,000 (per year)

According to our evaluation, we need an additional **$16,530,000** to break even

How can we change the energy market to make up this difference?

Change Number of Hours We Run

- Number of hours unit runs is a function of where unit is on system supply curve
- Lowering heat rate makes the unit more efficient and allows you to run more hours economically

How many hours would you need to run at 103 MW to make enough (even assuming a $50 profit per MWh) to cover your costs?
$17,870,000 / 103 / $50) = ? Hours

We would need to run for **3,470 hours** of the year (8,760) to cover our costs

We would need to move from a **peaking** unit to an **intermediate** unit to accomplish this – not possible without major overhaul of unit design

Is There a Profit Made When Running?

How much profit would you need to average per hour if you assumed you were running for 260 hours?

(17,870,000/260 hours)/103 MW = $667.29/MWh

In order to be revenue adequate (cover costs), energy prices paid to this unit must average almost $700/MWh

How do electricity markets propose to achieve this outcome?

Energy Market With Higher Average Profit

- US power markets (and many overseas markets) have uniform clearing prices in the spot energy market
- Uniform clearing price usually reflects the offer cost to serve next MW on system (marginal price), subject to transmission constraints
- Many markets also use scarcity pricing to reflect value of service when there are not enough available MW to serve load plus meet all reserve requirements
  - Allows market to set a high price when supply/demand balance gets tight

Assuming scarcity price is only effective for a small number of hours and doesn't impact other hour prices that much, how high does it have to be?

How High Do You Go?

If scarcity occurs in 10 hours (an estimate to make the math simple) of our previous example, how high do you need the profit to be during the 10 hours of scarcity to get the $667.29/MWh average?

Note: For the other 250 hours, profit is $50/MWh (no scarcity)

Let's figure this out together:

((10h x SP) + (250h x $50/MWh)) / 260h = **$667.29/MWh**

((10h x SP) + $12,500/MW)) / 260h = **$667.29/MWh**

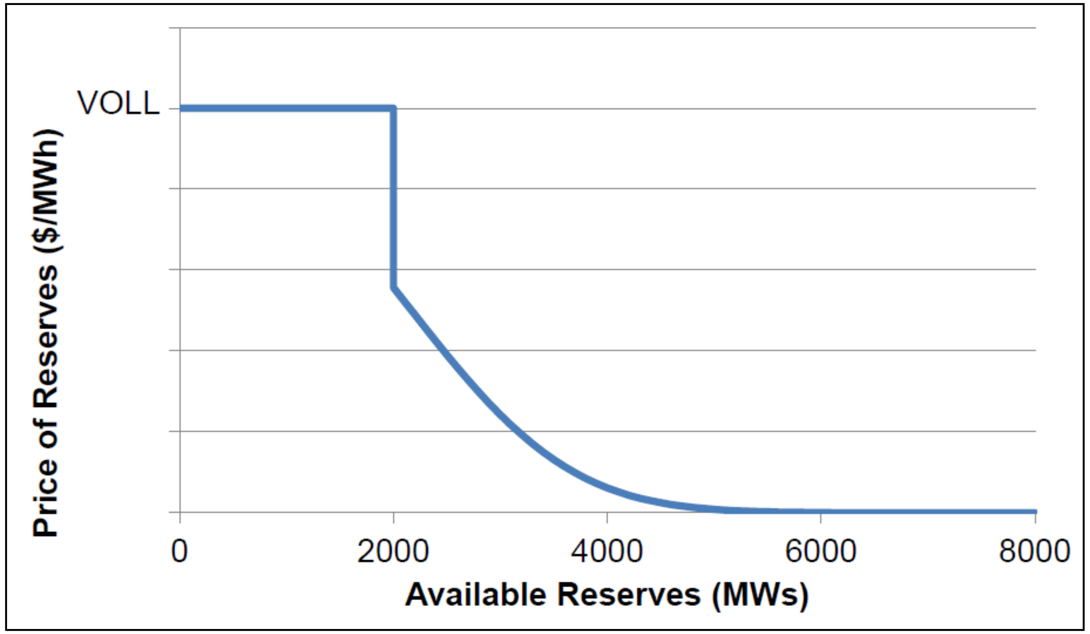
10 x SP + $12,500/MWh = 260 x $667.29/MWh = **$173,495/MWh**

10 x SP = $173,495/MWh – $12,500/MWh = **$160,995/MWh**

SP = $16,100/MWh

How to Get Scarcity Prices High Enough

- Electric Reliability Council of Texas (ERCOT) has a scarcity price adder to the real-time locational marginal price (LMP) as high as **$5,000/MWh**
  - Market price will also show up in reserve market prices
- Attempt to achieve average price (or similar average price) – as shown in calculation on previous slide
- Due to market being energy only:
  - Only source of revenue is energy/reserves market
  - Operating reserve demand curves (ORDC) introduce scarcity pricing gradually
    - Value of lost load (VOLL) = $9,000/MWh



Energy Only: Generator Perspective

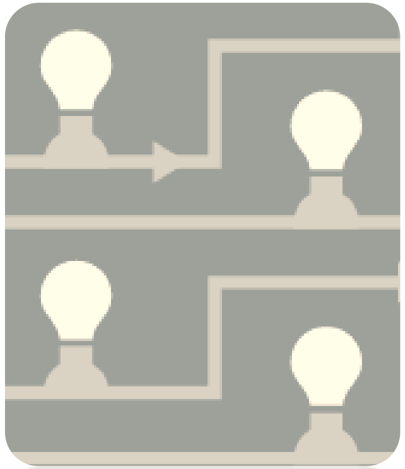
- Very volatile revenues for year
  - Low scarcity (less than 10 hours; maybe even 0) – low revenues ☹
  - High scarcity (greater than 10 hours) – high revenues ☺
- In this type of market, generator investors must try to estimate the scarcity rents they will collect in future years before making decisions to build
  - What happens to expectation of scarcity when a new generator enters the market
    - May tend to wait until scarcity becomes persistent before building

What happens if I’m out of service or unable to provide energy/reserves during hours of scarcity? **Lost Opportunity**

Does it matter why I’m out of service?

Energy Only: Demand Perspective

- Who pays scarcity price adder?
  - Demand pays locational marginal price (LMP) and pays reserve clearing prices
  - Expectation of scarcity is incorporated into day-ahead LMP
- What is impact of previous points about volatility?
  - Years with low scarcity demand pay less ☺
  - Years with high scarcity demand pay more ☹
  - High volatility also increases the risk in load-serving contracts



Alternative to Energy Only – Forward Market

Forward Market with Scarcity Pricing

- Forward market is a way to procure services or goods ahead of time
- What are the goals of this forward market?
  - Assure that system has enough generation to meet demand plus reserve (meet the one day in 10 years requirement)
  - Based on a defined requirement of delivery during the same scarcity events that we discussed in energy-only design

Features of Forward Markets

- Revenue of forward sale
  - Based on price that parties agreed upon (well ahead of time) when forward obligation was sold
  - Sellers and buyers agree on a schedule to make and receive payments
- Forward obligation (position)
  - Position or obligation that parties assume in the forward contract
- Determining deliveries of obligation and dealing with deviations from those deliveries
  - Governs what happens if parties live up to obligations
  - Typically, deviations from forward commitments are settled at spot price or in less liquid markets at a contractually-specified rate

	Last				Ticker	YTD
1) Energy	Value	Net Chg	% Chg	Time	Symbol	% Chg
4) NYMX WTI Crude Oil Active Month	101.56	+.82	+.81%	8:43	CLH2	+2.59
5) ICE Brent Crude Active Month	118.65	+1.30	+1.11%	8:43	COJ2	+11.28
6) Nymex Natural Gas Active Month	2.52	-.01	-.32%	8:43	NGH2	-16.28
7) Nymex Gasoline Active Month	300.15	+1.90	+.64%	08:40	XBH2	+13.04
8) Nymex Heating Oil Active Month	319.66	+3.18	+1.00%	8:43	HOH2	+9.95
9) ICE Gasoil Active Month	1002.25	+10.00	+1.01%	8:43	QSH2	+9.87

Example of a Forward Market: Day-Ahead Energy Market

- Day-Ahead Energy Market (DAM) is a forward market
  - Very short forward timeframe
- Generator clearing in DAM obtains a financial obligation to deliver in Real-Time (RT) Energy Market
  - **Forward obligation:** 50 MWh in DAM = financial obligation to deliver 50 MWh in RT
  - **Forward revenue:** DA LMP is $30/MWh, forward revenue is $30/MWh x 50 MWh = **$1,500**
- Settlement in spot market (RT market) is based on deviation from DA market obligation
  - Deliver less than 50 MWh in RT = charged at RT LMP (spot price)
  - Deliver more than 50 MWh in RT = credited at RT LMP

Forward Market for Capacity – New England's FCM

Forward Revenue	Forward Obligation	Settlement for Deviations
• Resources that clear in the Forward Capacity Auction are paid the FCA clearing price • Total forward payment is $FCA\ Price\ x\ CSO\ MW$	**Financial obligation:** resource is responsible for a share of the system's energy and reserve requirements during capacity scarcity conditions (CSCs)	• Resources receive performance payments for energy/reserves **actually delivered** during capacity scarcity conditions • Deliver more than share = additional compensation • Deliver less than share = charge

Pay-for-Performance Concept

- Pay-for-performance (PFP) makes the energy market look, from a supplier's perspective, like a very high-priced **energy-only** market. During scarcity conditions:
  - Prices can reach several thousand dollars per MWh (~$4,000+/MWh)
  - Suppliers get paid for the energy and reserves they actually provide
- Achieved by:
  - **Measuring** each resource's performance during a scarcity condition (i.e., when prices are high)
  - **Comparing** performance to resource's obligated share of system requirements (i.e., deviations)
  - **Crediting** for over-performance and **charging** for under-performance, at a high rate ($2,000+/MWh)

PFP compensation is separate from energy and reserve market revenues but as we will see, the combination adds up to several thousand dollars per MWh

Who Pays for the Performance Payment?

Charges are collected from under-performing suppliers (not load)
and credited to over-performing suppliers

Under-performing resources get charged

Over-performing resources get paid

- The rate (**$3,500/MWh**) is the same for all resource types
- It is **not** necessary to have a CSO to receive a credit; any resources providing energy or reserves will receive a performance credit

Questions

Same Example with Forward Market Construct

Let's Recap…

- **In energy markets, many resources don't earn enough revenue to recover their fixed costs (capital expenses); this is the *missing money***
  - In the peaking power plant example, the missing money was $16,530,000/year, which is equal to capital expenses ($17,870,000) less expected energy market profits ($1,340,000)
- **By participating in the capacity market, resources have the chance to earn the missing money; FCM revenue comes from two sources:**
  - Base payment (determined by Forward Capacity Auction)
  - Performance payments that depend on resource performance during capacity scarcity conditions (resources know Performance Payment Rate (PPR) when bidding into FCA)
- **A resource earns the missing money if:**
  - Base Payment + Performance Payments $\geq$ *Missing Money*

Monthly Capacity Market Settlement

Monthly capacity payments are based on the sum of two revenue streams

Capacity Payment =

Base Payment + Performance Payment

Base Payment

- Per MW of capacity supply obligation (CSO)
- Paid forward price (e.g., Forward Capacity Auction (FCA) clearing price)
- Charged to load (consumers)

Performance Payment

- Per MWh of energy and reserve provided during scarcity events
- Paid at performance payment rate $3,500, increasing to $9,337/MWh
- Can be negative, zero, or positive
- Transfer among suppliers

Example of Forward Capacity Market

- Resource's "missing money" is **$16,530,000/year**, or $13.37 per kW-month (kWm)
- Resource expects to earn positive performance payments of $3.00/kWm, as it expects to over-perform its forward position during scarcity hours
- Resource's competitive FCA bid is **$13.37/kWm – $3.00/kWm = $10.37/kWm**
  - Performance payments reduce the money the resource needs to recoup from the FCA-determined base payment
  - What if the resource expects to under-perform its forward position during scarcity hours, and therefore anticipates negative performance payments?

Example of Forward Capacity Market, *continued*

- Expected performance payments depend on expected number of capacity scarcity conditions (CSCs)
  - If the expectation was for 10+ hours of scarcity, would the competitive bid be greater than or less than $10.37/kW-month?
  - Would this same observation hold if the resource expected to under-perform its forward position?
- Capacity performance payments are not included as scarcity adders in Real-Time Energy Market locational marginal prices (LMPs)
  - Incentives would be same for generators if they were
  - By not including capacity performance payments in RT LMPs, load avoids some RT price volatility

What is the Value of Performance During a Capacity Scarcity Condition?

- An online and/or reserve-capable generator during the scarcity condition interval would be paid:

Value of Energy and/or Reserves	Value of Capacity Performance
• Reserve price will be *at least* \$1,000/MWh and included in energy price (LMP) • If marginal energy is \$750/MWh, LMP is *at least* \$1,750/MWh	Every MWh provided (energy or reserves) is worth an additional \$2,000/MWh

- From a supplier's perspective, value of delivering during a scarcity condition is:
  - **\$3,750+/MWh** for providing energy
  - **\$3,000+/MWh** for providing reserve
- Financial incentive to perform is **high**

Forward Markets: Generator Perspective

- Forward prices are less volatile than spot prices
  - Well known principal in economics *Samuelson Hypothesis*
  - Transient market shocks may not change long-run market expectations
- Generator investors will still try to estimate the forward scarcity rents they collect in future years before making building decisions
  - Recall that building a new generator tends to lower market expectation of scarcity
  - Same outward shift in (expected) supply would occur in forward market

Forward Markets: Generator Perspective, *continued*

What happens if I’m out of service or unable to provide energy/reserves during hours of scarcity when I must deliver to satisfy my obligation?
You must purchase energy/reserves from an available seller at the spot settlement rate

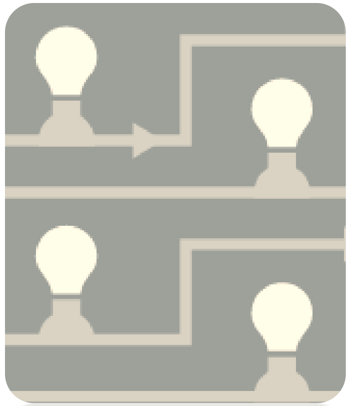
Does it matter why I’m out of service?
Similar to energy market, it doesn’t matter

Can I lose money?
Yes! If you spend more in the spot market to cover non-delivery than you collected through forward market sales, you will lose money

Forward Market: Demand Perspective

Who pays for this forward market obligation?

- Demand pays resources for the forward obligation at forward prices
- Just like day-ahead market
  - Instead of participant-bid demand, FCM uses ISO-derived demand curves



Comparison: Energy Only vs. Forward Market

Energy Only

- Generator profits largely depend on weather
  - Hot summers/cold winters increase scarcity hours
- Load is exposed to highly volatile LMPs
  - Consumption during scarcity hours is extremely costly
- Incentives are pure
  - Generation gets paid only for energy deliveries; no excuses

Forward Market

- Generator profits depend on market expectation of scarcity
  - Estimates are generally based on average historical values
- Load has price certainty
  - Forward price volatility is lower than spot price volatility
- Incentives depend on forward contract language
  - Excuses dilute incentives

ERCOT = Electric Reliability Council of Texas

Summary

In this lesson, you learned:

- How electricity markets alone do not provide adequate financial incentives to invest in new generating capacity
- Why there is a *missing money problem* in electricity markets
- Methods for dealing with *missing money problem*
  - Energy only
  - Forward market
- Pay-for-Performance
  - Key concept behind pay-for-performance
  - When pay-for-performance settlement occurs
  - How performance payments work

Questions

S&P Global
Market Intelligence

DATA DISPATCH

Summer forwards in Texas valued higher YOY as grid braces for tight supply

Wednesday, March 20, 2019 12:13 PM ET

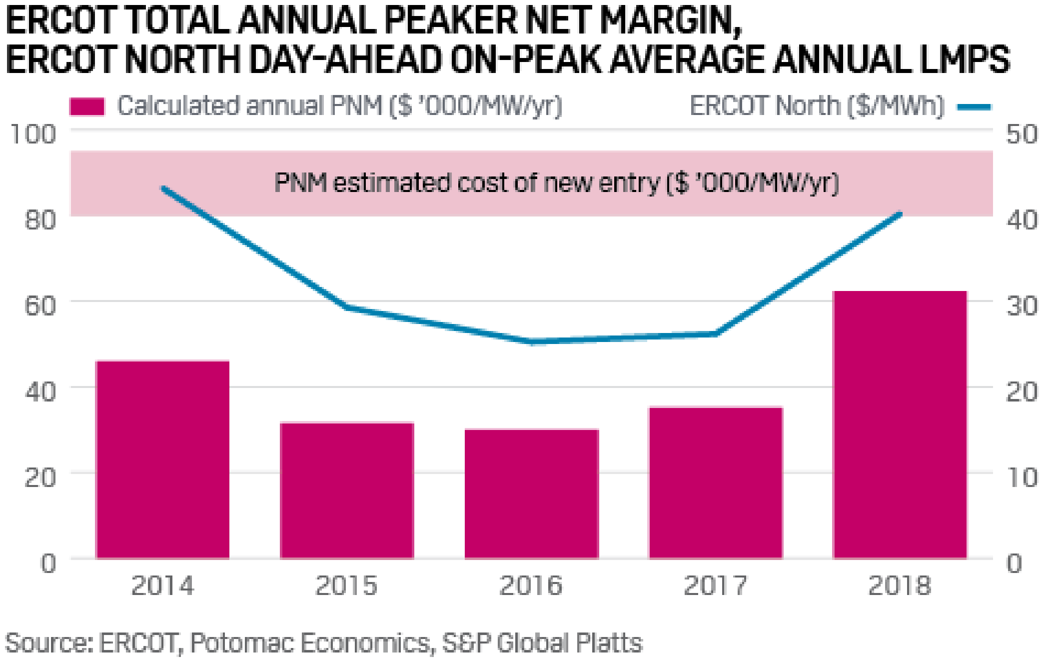
By Anna Duquiatan
Market Intelligence

Texas' power and gas forward strips for the upcoming summer are trending higher year over year, just as the state's grid operator anticipates tight supplies for the season.

In its preliminary "Seasonal Assessment of Resource Adequacy" for this summer, released March 5, the Electric Reliability Council Of Texas sees the combination of peak demand and outages leaving operating reserve shortfalls in both typical and extreme scenarios.

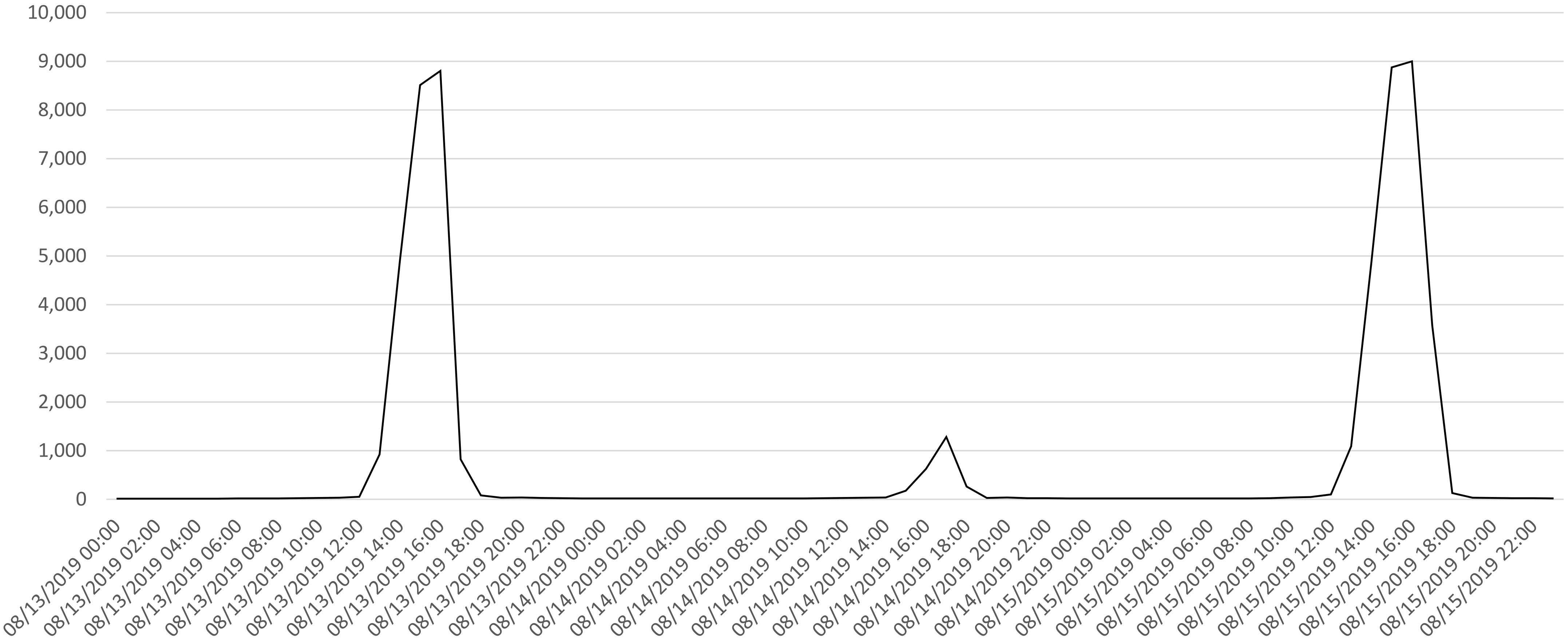
ERCOT Peaker Net Margin

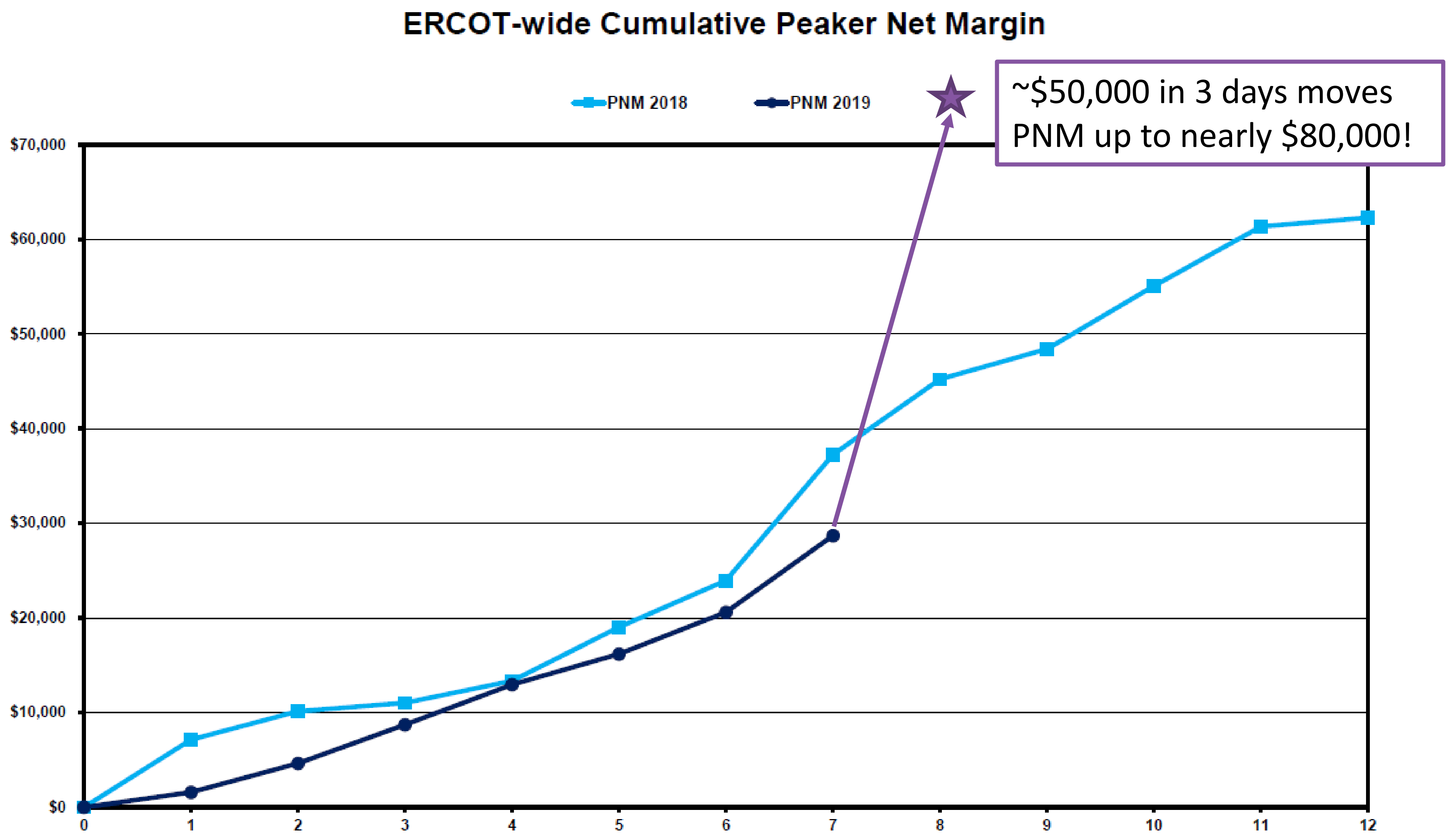
- ERCOT has seen robust load growth and fossil retirements
- ERCOT uses a measure of CT profitability in its scarcity pricing mechanism
- Net Peaker Margin =
  RTLMP - (10 x TX gas price)



- ERCOT CONE: $8.08/kW-m
- ISONE Gross CONE: $11.472/kW-m

ERCOT Heat Wave; RT Prices





https://www.potomaceconomics.com/markets-monitored/ercot/

Scarcity Prices are Awesome!!

- Well, not to everyone…
- Loads that aren't hedged pay that $9,000 LMP
  - This customer was on a "wholesale pass-thru"
- If demand is at a record highs, what happening to a LSE load portfolios?
- How do LSE's hedge this risk?

http://www.fox4news.com/news/consumer/some-texas-electric-customers-see-sticker-shock-after-heat-wave-spikes-wholesale-prices

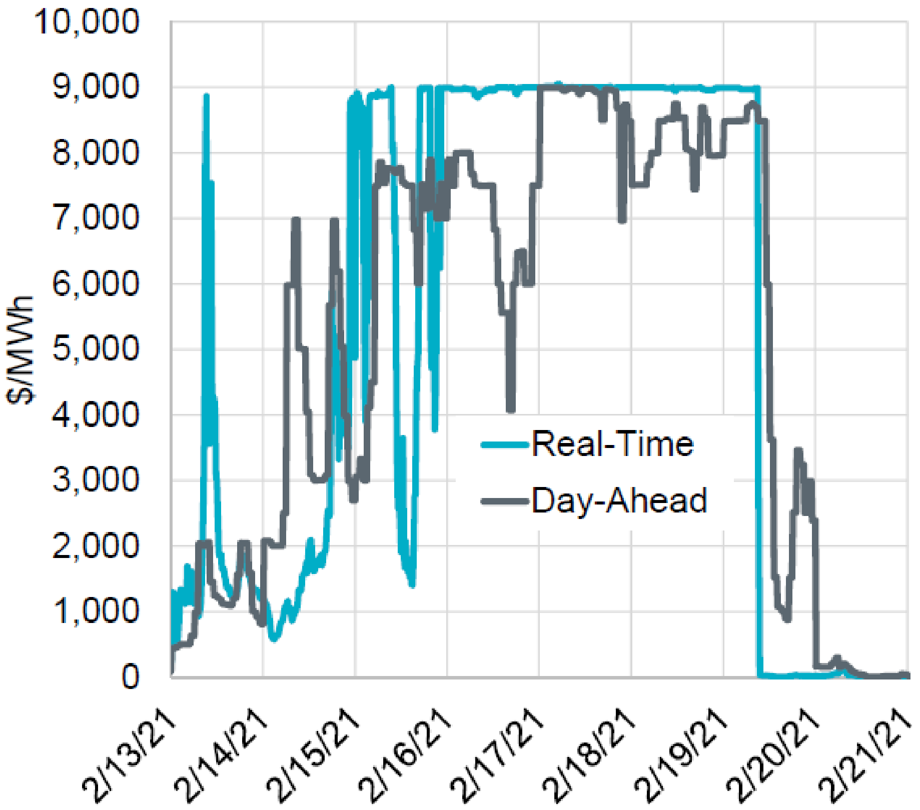
ERCOT Extreme Cold Weather Event

Overview of Cold Weather Event

- Record-setting, sub-freezing temperatures and wind chills across the state.
- Approximately 48.6% of generation was forced out at the highest point due to the impacts of various extreme weather conditions.
- Controlled outages were implemented to prevent statewide blackout.
  - Electric demand had to be limited to available generation supply.
- Local utilities were limited in their ability to rotate outages due to the magnitude of generation unavailability and the number of circuits with critical load.

ERCOT Extreme Cold Weather Event, *continued*

Real-Time and Day-Ahead System-Wide Pricing



Average system-wide pricing around the event relative to other historical periods (in $/MWh)

Date Range	Real-Time	Day-Ahead
2/14/21 2/19/21	$6,579.59	$6,612.23
January '21	$20.79	$21.36
February '20	$18.27	$17.74

Peaker net margin as of 4/22/2021: $727,932

This data is using the ERCOT Hub Average 345-kV Hub prices