Ohio Energy Workshop O
Supply-Side Cost Components of Your Electric Bills … Evaluating the Various Commodity Product Options & Developing an Effective Selection Process in the PJM Marketplace

Tuesday, February 20, 2018
3:15 p.m. to 4:30 p.m.
Biographical Information

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George has an extensive background in the energy industry, with understanding of retail and wholesale deregulated markets in power and gas, as well as regulated rate structures. George began his career in facility planning and pipeline project development with ANR Pipeline Company, working on preliminary pipeline design and natural gas service proposals to gas utilities and electric generators. From there, George moved to the competitive retail electric supply business, working in the early stages of the industry to set up and manage all phases of retail electric operations. George’s retail experiencing includes full oversight and P&L responsibility, as well as business development, strategic partnerships, retail operations, pricing and portfolio management.

Jim joined AEP Energy in October 2012, and has served in a variety of executive roles with AEP Energy, including product development, retail pricing, structuring and risk management activities, and now services as the head of the commercial and industrial front office sales organization. George’s primary responsibilities for AEP Energy include developing and executing broad market strategy for the C&I business of AEPE, sales force planning and development, and key customer outreach.

George is a graduate of Wayne State University in Detroit, MI, with a B.S. in Chemical Engineering
Supply-Side Cost Components of Your Electric Bills: Evaluating the Various Commodity Product Options & Developing an Effective Selection Process in the PJM Marketplace

Manufacturer’s Education Council 2018

George Deljevic
Vice President, C&I Solution Sales and Development
Standard Energy Buying Process

Product Specification is typically the most overlooked – and least well executed – part of the energy buying process.
Typical Shortcomings of Energy Product Specification

Buyers lack sufficient information, understanding regarding product options

Buyers choose a ‘standard’, all-inclusive price energy product

Leads to significant lost savings opportunities
Typical Shortcomings of Energy Product Specification

Why is it important to consider your energy product options?

- The energy product you select will determine the results when it comes to your long term buying objectives
- By selecting a ‘standard’ product (typically all-inclusive fixed price products) by default, you could be losing significant cost control opportunities

What’s preventing energy buyers from doing so?

- You don’t have clarity and understanding around the variety of cost factors and market conditions underpinning energy products
- You don’t have clarity and understanding around how available product and service options address those cost factors
Helping You Understand Energy Cost Factors

Major Cost Categories Driving Your Total Energy Spend

Demand Based Costs
- Driven by your peak energy demand
- Determines 20-40% of your total cost

Energy Based Costs
- Driven by your overall energy usage
- Determines 60-80% of your total cost
Cost Factors: Energy Based Costs

• **Energy & Losses**
  – Metered customer consumption & system losses

• **Load Shaping**
  – Accounting for differences in actual customer load shape vs. standard forward contract peak and off peak blocks

• **Load Variability/Volatility**
  – Accounting for risk of load deviating from expected levels

• **Renewable Portfolio Standards**
  – Set at state level, percentage of total load

• **Certain Ancillary Services Costs**
  – Costs for grid services
### Primary Cost Factors: Energy Based

**Energy Based Costs**

Determined by your total energy usage and electric energy purchased on the market

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### Energy Market Purchases may be either **Spot** or **Forward**

<table>
<thead>
<tr>
<th>Spot Energy Purchasing</th>
<th>Forward Energy Purchasing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prices set daily through centrally administered markets</td>
<td>Prices set for forward term through bi-lateral markets</td>
</tr>
</tbody>
</table>

Spot markets generally provide lowest prices over the long term, though prices can vary over shorter terms

While providing fixed prices over the contract term, forward markets typically embed risk and carrying cost premiums, and prices will vary with each contract

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*Over the long term, volatility in energy based costs cannot be avoided, even with forward energy market purchasing. A blended purchasing strategy provides the best balance of long term cost control and stability.*
Energy and Losses: Spot Settlements

• Supplier Settlement (and ultimately your cost) based on:
  – Hourly Metered Load X (1 + Utility T&D Loss Factor) X (1 – Loss Deration Factor) X Locational Marginal Price (LMP)

• Most suppliers calculate, and will often present, losses separately from base, metered ‘energy’
  – Be careful to consider how this is presented/contracted

• Loss Deration Credits are meant to prevent double payment of transmission loss costs
  – Transmission losses are included in utility factors
  – Transmission loss costs are also included in Regional Transmission Organization (RTO) Locational Marginal Pricing (LMP)
  – Take care to consider whether this is included when losses are ‘passed through’
Electric Spot Markets: How are Locational Marginal Prices Determined?

How are prices set?

- In any hour, the supply is stacked from the lowest to highest cost (the bid stack)
- Generation plants are dispatched in that order in order to meet demand
- The price of the last unit dispatched sets the price for the market

Actual Supply-Demand Curves

- Actual PJM bid stack for generation (note the load growth)
- Actual PJM Load on July 6, 2015
Electricity Spot Markets: Day Ahead and Real Time Settlement

• There are two settlements on Load in the RTO:
  – Day Ahead Settlement:
    • Day Ahead Forecasted/Scheduled Load X Day Ahead LMP
    • The Day Ahead Forecast/Schedule is known as a Demand Bid
  – Real Time Settlement:
    • (Actual Metered Load with Losses (Derated) –DA Demand Bid) X Real Time LMP
Electricity Spot Markets: LMP Components

• **Components of LMPs:**
  - Energy
    • Base Supply/Demand Cost
  - Congestion
    • Price difference between generation and load
    • Congestion arises from transmission constraints
      – More constraint = More congestion
    • Financial Transmission Rights (FTRs)/Auction Revenue Rights (ARRs) are meant to cover this risk/cost
  - Marginal Losses
    • Cost to supply losses to a particular location
Electricity Forward Markets

• Necessary for longer term price setting
• Forward Markets are not operated by RTOs
  – Bi-Lateral: Direct counterparty to counterparty
  – Exchange: Primarily ICE (InterContinental Exchange)
• Forward Curves Indicate Forward Market Value, priced by:
  – Pricing Point:
    • Gen Hubs, or Hubs: AD Hub (Ohio), West Hub (Pennsylvania), NI Hub (ComEd)
    • Load Zones: Local Utility Areas
  – Month
  – Peak Period: Monday through Friday 7 AM to 11 PM, excluding six holidays – New Years Day, Memorial Day, July 4th, Labor Day, Thanksgiving, Christmas
  – Off Peak (aka Wrap) Period: Monday through Friday 11 PM to 7 AM, Weekends, and Holidays
Electricity Forward Markets

• Basis
  – Pricing difference between two points
  – Generally Load Zone to Hub
    • AEP Zone to AD Hub
    • FE OH to AD Hub
    • Dayton to AD Hub
    • DE OK to AD Hub
  – Approximates congestion, transmission constraints, value of ARR/FTR
  – Basis should be marked between highly correlated locations
    • Prices move together, differences between prices are relatively steady
  – Forward Basis tends to trade at a premium to settled basis
    • Perhaps consider hedging energy at Hub rather than Zone?
## Basis Spreads

### Realized

<table>
<thead>
<tr>
<th>Period</th>
<th>AEP</th>
<th>ComEd</th>
<th>Dayton</th>
<th>DEOK</th>
<th>FE OH</th>
<th>PECO</th>
<th>PPL</th>
<th>PSEG</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>$0.23</td>
<td>$0.18</td>
<td>$0.88</td>
<td>$(0.49)</td>
<td>$0.88</td>
<td>$0.11</td>
<td>$(0.70)</td>
<td>$0.86</td>
</tr>
<tr>
<td>2013</td>
<td>$0.14</td>
<td>$0.11</td>
<td>$0.54</td>
<td>$(0.88)</td>
<td>$1.52</td>
<td>$(0.33)</td>
<td>$(0.42)</td>
<td>$3.57</td>
</tr>
<tr>
<td>2014</td>
<td>$0.66</td>
<td>$0.16</td>
<td>$1.04</td>
<td>$(0.73)</td>
<td>$2.29</td>
<td>$1.55</td>
<td>$1.10</td>
<td>$5.99</td>
</tr>
<tr>
<td>2015</td>
<td>$0.66</td>
<td>$0.01</td>
<td>$0.97</td>
<td>$0.38</td>
<td>$1.20</td>
<td>$(2.52)</td>
<td>$(0.58)</td>
<td>$(0.45)</td>
</tr>
<tr>
<td>2016</td>
<td>$(0.11)</td>
<td>$(0.02)</td>
<td>$0.49</td>
<td>$(0.01)</td>
<td>$0.57</td>
<td>$(5.22)</td>
<td>$(2.46)</td>
<td>$(4.36)</td>
</tr>
<tr>
<td>2017</td>
<td>$0.09</td>
<td>$0.09</td>
<td>$0.75</td>
<td>$(0.01)</td>
<td>$0.89</td>
<td>$(1.24)</td>
<td>$(0.49)</td>
<td>$(0.23)</td>
</tr>
</tbody>
</table>

### Market/Forwards

<table>
<thead>
<tr>
<th>Period</th>
<th>AEP</th>
<th>ComEd</th>
<th>Dayton</th>
<th>DEOK</th>
<th>FE OH</th>
<th>PECO</th>
<th>PPL</th>
<th>PSEG</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>$0.55</td>
<td>$0.35</td>
<td>$1.16</td>
<td>$0.56</td>
<td>$1.77</td>
<td>$(2.64)</td>
<td>$(2.76)</td>
<td>$(0.87)</td>
</tr>
<tr>
<td>2018</td>
<td>$0.59</td>
<td>$0.41</td>
<td>$1.24</td>
<td>$0.65</td>
<td>$1.80</td>
<td>$(2.08)</td>
<td>$(2.18)</td>
<td>$(0.12)</td>
</tr>
<tr>
<td>2019</td>
<td>$0.65</td>
<td>$0.49</td>
<td>$1.34</td>
<td>$0.72</td>
<td>$1.87</td>
<td>$(1.40)</td>
<td>$(1.50)</td>
<td>$0.43</td>
</tr>
<tr>
<td>2020</td>
<td>$0.73</td>
<td>$0.57</td>
<td>$1.42</td>
<td>$0.81</td>
<td>$1.94</td>
<td>$(1.11)</td>
<td>$(1.19)</td>
<td>$0.85</td>
</tr>
<tr>
<td>2021</td>
<td>$0.83</td>
<td>$0.63</td>
<td>$1.50</td>
<td>$0.98</td>
<td>$1.99</td>
<td>$0.03</td>
<td>$(0.11)</td>
<td>$2.34</td>
</tr>
<tr>
<td>2022</td>
<td>$0.79</td>
<td>$0.69</td>
<td>$1.55</td>
<td>$1.18</td>
<td>$2.20</td>
<td>$2.23</td>
<td>$1.22</td>
<td>$2.33</td>
</tr>
</tbody>
</table>
Electricity Forward Markets: Forward Contracts

• **Physical**
  - Delivered at a location (generally Hub or Zone)
  - Scheduled through RTO by Seller and Buyer
  - RTO removes Physical quantities from energy settlements

• **Financial (Swap)**
  - Load (Buyer) pays RTO @ LMP
  - Buyer pays Seller @ Fixed Price
  - Seller pays Buyer @ LMP
  - Load/Buyer net exposure = Fixed Price

• **Forward Contracts are Sized as ‘Blocks’**
  - Fixed Quantity for each Peak Hour of the Month
  - Fixed Quantity for each Off Peak Hour of the Month
Valuing Fixed Price Energy: Shaping Valuation

• **Load Shaping Valuation Principles**
  – Forward contracts are purchased in Peak and Off Peak Blocks
    • Peak Block Quantity = Average Customer Usage over Peak Hours in the month
    • Off Peak Block Quantity = Average Customer Usage over Off Peak Hours in the month
  – In any given hour, customer load likely will not match Peak and Off Peak Block quantities
  – Therefore, in some hours supplier will be long (have extra) energy, in other hours supplier will be short (not have enough) energy
  – Long energy must be sold at LMP
  – Short energy must be bought at LMP
Valuing Fixed Price Energy: Shaping Valuation
Valuing Fixed Price Energy: Load Variability

- **Load Variability Valuation Principles**
  - Energy & Shaping Valuations assume stable load and prices
  - Of course, customer load & LMP will likely vary from expectations
  - This presents cost:
    - If load is likely to be higher in tandem with higher prices, this is a cost
    - If load is likely to be lower in tandem with lower prices, this is a cost
  - How do we value?:
    - Assess relative volatility of load – i.e., standard deviation of hourly, daily, monthly loads, compared to expected loads
    - Assess relative volatility of prices (LMP) – i.e., standard deviation of hourly, monthly LMPs relative to average prices
    - Correlation of load variability with price variability
  - Contrast with shaping
    - Shaping covers known/expected deviation of load with respect to block
    - Variability covers unknown deviation of load and price with respect to historical/expected load
Customer Usage Basics: Load Variability

Load Variability/Volatility

KW

Hour

1 2 3 4 5 6 7 8 9 10 11 12
Renewable Portfolio Standards: Basics

- Renewable Portfolio Standards (RPS) require suppliers to purchase certain percentages of their total supply from designated generating sources, e.g., wind, solar, biomass.
- Suppliers meet these requirements by purchasing Renewable Energy Credits (RECs).
- RPS standards vary by state.
- Most times, there will be varying percentages for different renewable sources.
## Renewable Portfolio Standards: Example

### OH RPS Requirements

<table>
<thead>
<tr>
<th>REQUIREMENT</th>
<th>CY 2018</th>
<th>CY 2019</th>
<th>CY 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non Solar</td>
<td>4.32%</td>
<td>5.28%</td>
<td>6.24%</td>
</tr>
<tr>
<td>REC Price ($/MWh)</td>
<td>$ 5.65</td>
<td>$ 6.45</td>
<td>$ 6.95</td>
</tr>
<tr>
<td>Non Solar Cost</td>
<td>$ 0.24</td>
<td>$ 0.34</td>
<td>$ 0.43</td>
</tr>
<tr>
<td>Solar</td>
<td>0.18%</td>
<td>0.22%</td>
<td>0.26%</td>
</tr>
<tr>
<td>REC Price ($/MWh)</td>
<td>$ 8.25</td>
<td>$ 8.75</td>
<td>$ 10.00</td>
</tr>
<tr>
<td>Solar Cost</td>
<td>$ 0.01</td>
<td>$ 0.02</td>
<td>$ 0.03</td>
</tr>
<tr>
<td>TOTAL %</td>
<td>4.50%</td>
<td>5.50%</td>
<td>6.50%</td>
</tr>
<tr>
<td>TOTAL COST</td>
<td>$ 0.26</td>
<td>$ 0.36</td>
<td>$ 0.46</td>
</tr>
</tbody>
</table>
Renewable Portfolio Standards: Issues

- Renewable Portfolio Standard costs/requirements can be hedged by purchasing and inventorying RECs
- There are no spot markets for RECs
- Given the lack of visibility and transparency around REC costs and prices, passing through RPS is not advisable
Ancillary Services (Energy Based)

- Variety of services provided by grid, settled to suppliers based on total real time consumption (included losses)
  - Scheduling, dispatch and control; reserves; regulation; frequency and voltage control
- Usually around $1/MWh
- Be especially mindful of Balancing Operating Reserves for Deviations on Real Time spot/index products
- Marginal Loss Overcollection Credits (MLO)
  - Meant to compensate load for difference between revenue collected in LMP (marginal cost of losses) and average/actual cost of losses
  - As this is a credit, be careful to note where included in ‘pass through’ products
# Ancillaries: Major Items

<table>
<thead>
<tr>
<th>Item</th>
<th>NSPL or Usage Base</th>
<th>Type</th>
<th>Market or Cost Based</th>
<th>Change Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Auction Revenue Rights</td>
<td>NSPL</td>
<td>Credit based on Load/Trans Rights</td>
<td>Market Based</td>
<td>Planning Year</td>
</tr>
<tr>
<td>Regional Transmission Enhancement Projects (RTEP/TE)</td>
<td>NSPL</td>
<td>Facility Cost</td>
<td>Cost Based</td>
<td>On Filing</td>
</tr>
<tr>
<td>Marginal Loss Overcollection</td>
<td>Usage</td>
<td>Credit based on Load</td>
<td>Market Based</td>
<td>Monthly</td>
</tr>
<tr>
<td>Day Ahead Scheduling Reserve</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Cost Based</td>
<td>Hourly</td>
</tr>
</tbody>
</table>
## Ancillaries: Major Items

<table>
<thead>
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<th>Type</th>
<th>Market or Cost Based</th>
<th>Change Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Reserves (Day Ahead/RT/Balancing)</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Market Based</td>
<td>Daily</td>
</tr>
<tr>
<td>Regulation</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Market Based</td>
<td>Hourly</td>
</tr>
<tr>
<td>Synch Reserve</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Market Based</td>
<td>Hourly</td>
</tr>
<tr>
<td>Black Start</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Cost Based</td>
<td>Annual</td>
</tr>
<tr>
<td>Reactive Supply &amp; Voltage Ctrl</td>
<td>Usage</td>
<td>Ancillary Service (Resource)</td>
<td>Cost Based</td>
<td>Annual</td>
</tr>
</tbody>
</table>
Primary Cost Factors: Demand Based

Two Primary Demand Based Cost Components

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rates fixed for one year periods to cover demand based services purchased from power generators</td>
<td>Rates fixed for one year (or longer) periods to cover demand based services purchased from power transmission companies</td>
</tr>
<tr>
<td>Costs are a product of capacity rates and your individual demand contribution (typically set over 5 hours of the year)</td>
<td>Costs are a product of transmission rates and your individual demand contribution (typically set over 1-5 hours of the year)</td>
</tr>
</tbody>
</table>

All-In products create greater monthly volatility and provide much lower ability to control your demand based costs.
Capacity: Cost to Load

PJM

PLC × FPR × ZSF × Capacity Price (x Days) = Cost to Customer

PLC = Customer Peak Load Contribution

FPR = Forecast Pool Requirement

ZSF = Zonal Scaling Factor
Capacity: PLC

- Peak Load Contribution (PLC):
  - Set based on customer load coincident with the five highest peak demand hours on the PJM system, aka 5 Coincident Peaks (5CP)
  - Grossed up for Distribution and Transmission Losses
  - Weather Normalized
    - Except AEP Ohio

<table>
<thead>
<tr>
<th>Date</th>
<th>HE</th>
<th>Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>7/19/27</td>
<td>18</td>
<td>145,331</td>
</tr>
<tr>
<td>7/20/17</td>
<td>17</td>
<td>145,097</td>
</tr>
<tr>
<td>7/21/17</td>
<td>17</td>
<td>142,003</td>
</tr>
<tr>
<td>6/12/17</td>
<td>18</td>
<td>140,660</td>
</tr>
<tr>
<td>6/13/17</td>
<td>17</td>
<td>138,365</td>
</tr>
</tbody>
</table>
Capacity: FPR/Reserve Margin

- Forecast Pool Requirement (PJM FPR)
  - Reflects the reserve margin to account for load spikes or higher than expected generator outages
  - Based on minimizing loss of load expectation to one event every ten years
  - Usually between 9-10%
  - Does not include expected forced outages
    - Generators have to de-rate capacity offer based on expected forced outage rate (EFORd)
Capacity: Zonal Scaling Factor

- Zonal Scaling Factor (ZSF)
  - Sort of a ‘true up’ factor
  - Accounts for differences between forecasted and purchased capacity vs. actual capacity demanded based on PLCs
  - Different Zonal Scaling Factors:
    - Base
      - Set for each zone by PJM based on final load forecast and purchased capacity
      - Changes with each incremental auction, as load forecasts and PLC based demand assessments are updated (should move towards 1 as we get closer to Delivery Year)
    - Daily
      - Set by utilities to account for sum of PLCs vs purchased capacity
      - Generally close to one, some larger deviations in certain cases (in particular with FirstEnergy utilities)
    - AEP
      - Additional scaling factor to account primarily for weather normalization
      - Not published anywhere – supplier retrieves from utility
Capacity: Capacity Prices (PJM)

- Capacity Prices at PJM are determined through a series of Auctions
  - Base Residual Auction (Three years prior to delivery year)
  - Incremental Auctions
    - 1<sup>st</sup>, 2<sup>nd</sup>, 3<sup>rd</sup>
- Base Residual Auction
  - Basic Supply and Demand Clearing Mechanism
  - Demand Determination:
    - Weather Normalized, Growth Adjusted Load Forecast
    - Reserve Margin
  - Variable Resource Requirement Curve
Capacity: Capacity Prices (PJM)

- Base Residual Auction (cont’d)
  - Variable Resource Requirement Curve
    - PJM will adjust purchases to some degree based on prices offered by generators
      - Increase risk tolerance for loss of load if prices are high
      - Reduce risk tolerance if prices are low
  - Generator Offers
    - All generators must offer into auction
    - Offer Price Cap set at Cost of New Entry (CONE)
      - Approximates fully loaded cost for new gas fired combustion turbine
      - Varies by Zone
    - Generators can offer Unforced Capacity (UCAP), not Installed Capacity (ICAP)
      - UCAP is ICAP adjusted for the generator’s expected forced outage rate (EFORd)
      - If EFORd increases as a result of actual experience, generator must buy additional capacity in incrementals to cover
        - Generator incentive to perform
Capacity: Capacity Prices

- Incremental Auctions
  - Meant to account for changes in
    - Load Forecast
    - Generator Expected Forced Outage Rate (EFORd) changes
    - Participants wishing to trade positions
  - PJM is generally the main participant, primarily as a result of load forecast changes
    - Sell back excess capacity purchased in prior auctions
    - Purchase deficient capacity
  - Three Auctions
    - 1st: September of Calendar Year two years prior to delivery year
      - E.g., September 2018 for DY 2020/21
    - 2nd: July of Calendar Year one year prior to delivery year
      - E.g., July of 2018 for DY 2019/20
    - 3rd: March of delivery year
      - E.g., March of 2018 for DY 2018/19
  - Final Zonal Capacity Prices and Scaling Factors set after 3rd Incremental Auction
    - Accounts for PJM gains/losses on excess capacity sold back or deficient capacity purchased
Demand Based Costs: Transmission

• Transmission costs in Ohio are generally non-bypassable
  – Exceptions: Special Programs in First Energy utilities and Dayton Power and Light

• Utility Transmission Costs in Ohio generally allocated based on monthly demand
  – Exception: Special Tariff in AEP Ohio based on zonal coincident peak
Transmission Costs (PJM)

NSPL (aka Net PLC) = Customer Network Service Peak Load

DZSF = Daily Zonal Scaling Factor
Transmission: Rates

• NITS Rates are ‘Postage Stamp’
  – Same rate, in any given zone, no matter where generation is sourced

• NITS Rates are based on Transmission Owners (TO) Cost of Service
  – Cost of Capital on Rate Base (total facility investment not depreciated)
  – Depreciation and Amortization
  – Tax
  – O&M

• NITS Rates may be changed via:
  – Annual Formula Rate Update:
    • TOs file annual updates to cost of service
  – FERC Filing/Case

• FERC has incentivized transmission investment in recent years
  – High allowed rates of return (cost of capital)
  – Driver behind recent transmission rate increases in many zones
Transmission: NSPL/CP

- **Network Service Peak Load (PJM):**
  - Set based on customer load coincident with either (depending on Transmission Owner):
    - Single highest annual peak load
      - Sometimes occurs in winter
    - Can lead to NSPL at customer level (depending on whether winter or summer peaking)
  - Five highest peak loads
  - Grossed up for Distribution and Transmission Losses
  - Generally not weather normalized

- **DZSF**
  - Many utilities will apply a Daily Zonal Scaling Factor to ensure sum of NSPLs is equal to peak load on which rates are based
• **Primary NSPL Based Ancillaries**
  - Auction Revenue Rights (Credit)
    - Financial Transmission Rights (FTRs) provide owners with protection against congestion cost risks
    - Congestion revenues are allocated to FTR owners
    - Each year, PJM runs auctions to determine prices for FTRs
      - FTR auction results are based on perceived values for future congestion set by buyers and sellers
    - LSEs are granted revenue rights from the FTR auctions
  - Regional Transmission Enhancement Projects
    - Meant to recover costs associated with projects not mostly allocable to one zone
### Energy Cost Factors and Product Options

#### Three General Product Categories

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
</tr>
</thead>
</table>
| **All-Inclusive**                 | - Demand Costs are averaged and charged over all energy usage  
                                    |   - Reducing demand has minimal impact on cost  
                                    |   - Energy Costs are locked in 100% through Forward Purchases                                                                 |
| **True Demand Cost + Fixed Energy** | - Demand Costs are based on actual demands and RTO rates  
                                            |   - Reducing demand can have large impact on costs  
                                            |   - Energy Costs are locked in 100% through Forward Purchases                                                                 |
| **Demand Cost + Spot/Blended Energy** | - Demand Costs are based on actual demands and RTO rates  
                                           |   - Reducing demand can have large impact on costs  
                                           |   - Energy Costs are based on a blend of Spot and Forward Purchases  
                                           |   - Provides a balance of forward cost stability with long term low cost spot pricing |
# Product Selection: Examples, Impacts

## Fixed Energy Products

<table>
<thead>
<tr>
<th></th>
<th>All IN</th>
<th>True Demand Cost + Fixed Energy</th>
<th>True Demand Cost + Fixed Energy (w 20% Load Management)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy &amp; Losses</td>
<td>$33.58</td>
<td>$33.58</td>
<td>33.58</td>
</tr>
<tr>
<td>Shaping &amp; Load</td>
<td>$1.20</td>
<td>$1.20</td>
<td>1.20</td>
</tr>
<tr>
<td>Variability</td>
<td>$12.40</td>
<td>$12.40</td>
<td>9.92</td>
</tr>
<tr>
<td>Capacity</td>
<td>$1.00</td>
<td>$1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Ancillary</td>
<td>$0.25</td>
<td>$0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>RPS</td>
<td>$0.22</td>
<td>$0.22</td>
<td>0.20</td>
</tr>
<tr>
<td>Taxes/Fees</td>
<td>$48.65</td>
<td>$48.65</td>
<td>46.15</td>
</tr>
<tr>
<td><strong>Total Cost</strong></td>
<td>$48.65</td>
<td>$48.65</td>
<td>46.15</td>
</tr>
</tbody>
</table>
# Product Selection: Examples, Impacts

## Spot Energy Product

<table>
<thead>
<tr>
<th></th>
<th>True Demand Cost + Spot Energy 100% (Base)</th>
<th>True Demand Cost + Spot Energy 100% (Low)</th>
<th>True Demand Cost + Spot Energy 100% (High)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy &amp; Losses</td>
<td>$ 30.84</td>
<td>$ 25.29</td>
<td>$ 36.39</td>
</tr>
<tr>
<td>Shaping &amp; Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Variability</td>
<td>$ 1.20</td>
<td>$ 1.20</td>
<td>$ 1.20</td>
</tr>
<tr>
<td>Capacity</td>
<td>$ 12.40</td>
<td>$ 12.40</td>
<td>$ 12.40</td>
</tr>
<tr>
<td>Ancillary</td>
<td>$ 1.00</td>
<td>$ 1.00</td>
<td>$ 1.00</td>
</tr>
<tr>
<td>RPS</td>
<td>$ 0.25</td>
<td>$ 0.25</td>
<td>$ 0.25</td>
</tr>
<tr>
<td>Taxes/Fees</td>
<td>$ 0.21</td>
<td>$ 0.19</td>
<td>$ 0.23</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$ 45.90</td>
<td>$ 40.32</td>
<td>$ 51.47</td>
</tr>
</tbody>
</table>
## Product Selection: Examples, Impacts

### Blended Energy Product

<table>
<thead>
<tr>
<th></th>
<th>True Demand Cost + Blend Energy 50% (Base)</th>
<th>True Demand Cost + Blend Energy 50% (Low)</th>
<th>True Demand Cost + Blend Energy 50% (High)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy &amp; Losses</strong></td>
<td>$32.21</td>
<td>$29.43</td>
<td>$34.98</td>
</tr>
<tr>
<td><strong>Shaping &amp; Load Variability</strong></td>
<td>$1.20</td>
<td>$1.20</td>
<td>$1.20</td>
</tr>
<tr>
<td><strong>Capacity</strong></td>
<td>$12.40</td>
<td>$12.40</td>
<td>$12.40</td>
</tr>
<tr>
<td><strong>Ancillary RPS</strong></td>
<td>$0.25</td>
<td>$0.25</td>
<td>$0.25</td>
</tr>
<tr>
<td><strong>Taxes/Fees</strong></td>
<td>$0.21</td>
<td>$0.20</td>
<td>$0.22</td>
</tr>
<tr>
<td><strong>Total Cost</strong></td>
<td>$46.27</td>
<td>$43.48</td>
<td>$49.05</td>
</tr>
</tbody>
</table>
LMP settlements have not cleared above the equivalent 12 month rolling product since the polar vortex.
Starting in January 2016 the LMP settlements have been trending closer to the 12 month curve.
A product that combines both forward & index pricing hedges against the volatility displayed above.