E&AS Revenue Offset Update

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MIC Special Session – Reserve Price Formation Order

July 30, 2020

Updates

- Brattle finalized recommendations
- Developed forward prices, results posted
- Developed resource parameters
- Developed DA/RT dispatch on reference resource
- Refining ancillary service methodology
- Refining resource-specific methodology

Resources

Projected Economic Dispatch at Forward LMPs

- CT
- CC
- Coal
- Storage

Assumed Output Model Applied to Forward LMPs

- Nuclear
- Solar (Fixed and Tracking)
- Wind (Onshore)
- Wind (Offshore)

Other

- Energy Efficiency
- Demand Response - Generation

Combustion Turbine

The net energy and ancillary services revenue estimate shall be determined by a simulated day-ahead and real-time energy and ancillary service dispatch of a 367 MW combustion turbine (with heat rate of 9,134 BTU/kWh, 50 MW/min ramp rate, variable operations and major maintenance expenses being a blend of $1.95/MWh and $11,732/start*, and a 2 hour minimum run time) using hourly day-ahead and real-time forecasted zonal LMPs and RTO ancillary service prices, developed from forward power prices, forward gas prices, and forward ancillary services prices, plus assumed reactive services revenues of $2,199/MW-year.

*Application of major maintenance costs are a factor of number of starts and hours run per year. Costs used were based on using 50% of each $1.70/MWh ($0.85/MWh), which was added to the $1.10/MWh consumables to get the $1.95/MWh VOM, and $23,464/start ($11,732/start) to ensure major maintenance costs are covered.

Reference Resource (CT) Parameters

Parameter	Value	Notes
Max Capacity	367 MW	Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Stable Level	244 MW	Turn down ratio = 1.5, Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Ramp Rate	50 MW/min	Sargent & Lundy
Heat Rate	9134 Btu/kWh	Average heat rate of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Run	2 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	1 hr	
Time to Start	21 min	Sargent & Lundy
VO&M	$1.95/MWh and $11,732/start	Consumables and major maintenance, Sargent & Lundy
Start Fuel	491 MMBtu/start	Average fuel use of CONE Area units
Fuel Pricing Points	Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2	
NOx	0.0093 lb/MMBtu	2018 CONE Study; historical allowance prices escalated for forward
	55 lb/start	
SO2	0.0006 lb/MMBtu	EPA; historical allowance prices escalated for forward
CO2	117 lb/MMBtu	EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	6.331%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	First two weeks in October	PJM

The net energy and ancillary services revenue estimate shall be determined by a simulated day-ahead and real-time energy and ancillary service dispatch of a 1,188 MW combustion turbine employing duct-firing (with heat rate of 6,501 BTU/kWh, 50 MW/min ramp rate, variable operations and maintenance expenses, inclusive of major maintenance costs, of $2.11/MWh and a 4 hour minimum run time) using hourly day-ahead and real-time forecasted zonal LMPs and RTO ancillary service prices, developed from forward energy prices, applicable forward gas prices, and historical real-time ancillary service prices, plus assumed reactive services revenues of $3,350/MW-year.

Combined Cycle

Parameter	Value	Notes
Max Capacity	1,188 MW w/ Duct Burner; 1,060 MW w/o Duct Burner	Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Stable Level	460 MW	
Ramp Rate	50 MW/min	Sargent & Lundy
Heat Rate	6,501 Btu/kWh w/ Duct Firing; 6,269 Btu/KWh w/o Duct Firing	Average heat rate of CONE Area units at ISO conditions (59oF, 14.7 psia)
Min Run	4 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	3.5 hr	
Time to Start	135 min	Sargent & Lundy
VO&M	$2.11/MWh	Sargent & Lundy
Start Fuel	8242 MMBtu/start	Average fuel use of CONE Area units
Fuel Pricing Points	Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2	
NOx	0.0074 lb/MMBtu 160 lb/start	2018 CONE Study; historical allowance prices escalated for forward
SO2	0.0006 lb/MMBtu	EPA; historical allowance prices escalated for forward
CO2	117 lb/MMBtu	EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	3.045%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	First two weeks in October	PJM

Coal

The net energy and ancillary services revenue estimate shall be determined by a simulated day-ahead and real-time energy and ancillary service dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance expenses, inclusive of major maintenance costs, of $9.50/MWh) using hourly day-ahead and real-time forecasted zonal LMPs and RTO ancillary service prices, developed from forward energy prices, Northern Appalachian coal forward prices, and historical real-time ancillary service prices, plus assumed reactive services revenues of $3,350/MW-year. Modeled as an economic unit with an eco max/eco min of 650/433 MW. The time to start is 5 hours and the minimum runtime and minimum downtime are 6 hours.

Coal

Parameter	Value	Notes
Max Capacity	650 MW	EIA (Case 1)
Min Stable Level	433 MW	Turn down ratio = 1.5, Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Ramp Rate	5 MW/min	PJM
Heat Rate	8638 Btu/kWh	EIA (Case 1)
Min Run	6 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	6 hr	
Time to Start	5 hr	
VO&M	$9.5/MWh	PJM
Start Fuel	Coal: 124 MMBtu, Oil: 8746 MMBtu	PJM
Fuel Pricing Points	Coal: Northern Appalachia, Oil: New York Harbor Heating Oil	
NOx	0.06 lb/MMBtu	EIA (Case 1); historical allowance prices escalated for forward
SO2	0.09 lb/MMBtu	
CO2	Coal: 206 lb/MMBtu, Oil: 159 lb/MMBtu	EIA (Case 1), EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	11.776%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	None	

The net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch of a 1 MW / 4 MWh resource with an 85% roundtrip efficiency against hourly day-ahead and real-time forecasted zonal LMPs and RTO ancillary service prices, developed from forward energy prices and historical real-time ancillary service prices, plus assumed reactive services revenues of $3,350/MW-year. The resource is assumed to be dispatched between 95% and 5% state of charge.

Battery Storage

Parameter	Value	Notes
Max Capacity	Modeled as 1 MW / 4MWh resource	EIA (Case 18)
Roundtrip Efficiency	85%	NREL ATB
State of Charge	Between 95% and 5%	PJM/Brattle, industry practice
Forced & Maintenance Outages	None at this time, to be determined	

The net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [hourly zonal day-ahead forecasted LMP, developed from forward prices, times 8,760 hours, adjusted for forced & maintenance outages] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of major maintenance costs, plus an assumed reactive services revenue of $3,350/MW-year.

Parameter	Value
Max Capacity	Modeled as 1 MW resource, operating 8760 hours per year
VO&M	*Multi*: $7.66/MWh
	Single: $9.02/MWh
Forced Outages (EFORd)	1.101%
Maintenance Outages	None at this time, to be determined

The net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the hourly zonal real-time forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus assumed reactive services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource.

Onshore Wind

The net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the hourly zonal real-time forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus assumed reactive services revenue of $3,350/MW-year.

The net energy and ancillary services revenue estimate shall be the product of [the hourly zonal real-time forecasted LMP, developed from forward prices, times 8,760 hours times at an assumed 45% of rated output], plus assumed reactive services revenue of $3,350/MW-year.

Onshore Wind, Fixed Tilt Solar PV, Single-Axis Tracking Solar PV:

Parameter	Value
Output	Hourly capacity factor profiles applied to a 1MW resource
VO&M	$0/MWh
Forced & Maintenance Outages	Accounted for in profile

Offshore Wind:

Parameter	Value
Output	1MW resource at 45% capacity factor for 8760 hours per year
VO&M	$0/MWh
Forced & Maintenance Outages	Accounted for in profile

- Develop future hourly DA and RT AS prices based on the historical correlation between energy and AS prices
  - Forward RT AS price determined by multiplying historical RTO RT AS price by the ratio of hourly forward and historical RT energy prices at Western Hub
    - Regulation, Synchronized Reserve, Non-Synchronized Reserve
  - Forward DA AS price determined by the multiplying historical RT AS price by the ratio of hourly forward DA to historic RT energy prices
    - Synchronized Reserve, Non-Synchronized Reserve
  - DA and RT 30 minute reserve price is modeled as \$0/MWh
  - Hourly forward AS prices used in a co-optimized dispatch with DA and RT energy prices

- Develop forward prices, hourly by zone
  - Monthly on and off peak LMP forwards for delivery year from liquid hubs
    - Western, Northern Illinois and AEP-Dayton hubs
  - Use long-term FTRs to reflect expected annual congestion between each zone and its respective hub
    - Add losses to congestion to yield the total basis differential
    - Develop forward losses by scaling historical losses by ratio of forward price to historical price
  - Monthly forwards are shaped to hourly values using historical hourly DA and RT LMP shapes from most recent 3 years
    - Use ratio of hourly price to monthly average on/off peak price
    - Conduct for each of 3 years individually

Price Development – Natural Gas

- Forward prices from 6 liquid hubs: Dominion South, Chicago Citygates, MichCon, Transco Zone 6 Non-NY, Tetco M3 and Columbia-Appalachia TCO
- Basis to highest correlated local hub using monthly prices from three most recent years
  - Mapping on following slides
- Shaped with three most recent historical years, individually, using daily prices

Electric and Natural Gas Mapping

- Six hubs (Dominion S, Chicago, MichCon, Transco Zone 6 Non-NY, TETCO M3 and TCO) have sufficient forward liquidity

Zone	Forward Electric Hub	Basis Gas Hub	Forward Gas Hub
AECO	Western	Transco Z6 NNY	Transco Z6 NNY
AEP	AEP-Dayton	Columbia-Appalachia TCO	Columbia-Appalachia TCO
APS	Western	Dominion South	Dominion South
ATSI	AEP-Dayton	MichCon	MichCon
BGE	Western	Transco Z6 NNY	Transco Z6 NNY
COMED	Northern Illinois	Chicago Citygates	Chicago Citygates
DAYTON	AEP-Dayton	MichCon	MichCon
DEOK	AEP-Dayton	MichCon	MichCon
DOM	Western	Transco Z5 Dlv.	Transco Z6 NNY
DPL	Western	Transco Z6 NNY	Transco Z6 NNY

- Six hubs (Dominion S, Chicago, MichCon, Transco Zone 6 Non-NY, TETCO M3 and TCO) have sufficient forward liquidity

Zone	Forward Electric Hub	Basis Gas Hub	Forward Gas Hub
DUQ	AEP-Dayton	Tetco M3	Tetco M3
EKPC	AEP-Dayton	Tenn LA 500 Leg	Columbia-Appalachia TCO
JCPL	Western	Transco Z6 NNY	Transco Z6 NNY
METED	Western	Tetco M3	Tetco M3
PECO	Western	Tetco M3	Tetco M3
PENELEC	Western	Dominion South	Dominion South
PEPCO	Western	Transco Z5 Dlv.	Transco Z6 NNY
PPL	Western	Tetco M3	Tetco M3
PSEG	Western	Transco Z6 NY	Transco Z6 NNY
RECO	Western	Transco Z6 NY	Transco Z6 NNY

Methodology Update – Dispatch

- Use of 10% adder
  - Continue to use when dispatching a CT to account for gas charges, balancing fees, etc…, consistent with Quadrennial review
  - Do not extend to other resources

Decision Matrix – Price Development

Decision Item	Choices	Current Thinking	Reasoning
Price method	• Heat Rate Scalar • Forward Scalar	Forward Input Scalar	Forward prices shaped for volatility
Forward sample	• Single day • Multiple days	Multiple days	Provides adequate sample to address anomalous data
Power hub	• West hub • Local hub	West, NI, AEP-Dayton	Liquid hubs with basis to local hub
Gas hub	• Henry hub • Local hub	DomS, Chicago, MichCon, Transco Z6-NNY, Tetco M3, TCO	Liquid hubs, match to Electric hub. Basis to local gas hub
Basis method	• Historical • FTR	FTR	Match electric and gas hubs. Make use of forwards
Day of Week Adjustment	• Adjust • Do not adjust	Do not adjust	Further investigate
Market for scalar	• DA/RT • DA	DA/RT	Model how market operates
Scalar sample	• One-year • Three-year	Three year	Provides adequate sample to address anomalous data

Decision Matrix – Dispatch

Decision Item	Choices	Current Thinking	Reasoning
Dispatch method	• Peak-hour based • Optimal based	Optimal based	Removes peak hour limitations. More applicable to dispatchable unit operations
Offers modeled	• Cost • Cost-based plus 10% • Price-based	Cost-based plus 10% for CT; else Cost	Use of 10% adder for CT approved as part of Quadrennial review.
Maintenance Outages	• Two-weeks in October	Two-weeks	
Forced Outages	• Account for in EFORd	EFORd	
Optimization	• 24-hour look ahead • None	24-hour look ahead	Closer to Day-ahead optimization
Daily start limitations	• Yes • No	No	Allows for economic operation
Emissions adders	• Yes • No	Yes	Included for units in allowance trading programs (NOx, SO2, CO2)
Gas mapping	• PJM • IMM	PJM	Matches decisions agreed to in Quadrennial review

Dispatch Methods Applied to Historical Day-Ahead LMPs

RTO Average Results

	Resource	Net Revenue ($/MW-year)				Run Hours*			
		2017	2018	2019	Average	2017	2018	2019	Average
Optimal-Based	Reference CT (No 10% Adder)	$37,320	$54,583	$28,046	$39,983	3,539	3,576	3,285	3,467
	Reference CT (10% Adder)	$27,360	$41,245	$20,127	$29,577	3,470	3,731	3,325	3,509
	MOPR CC	$81,593	$100,600	$69,185	$83,793	8,365	8,274	8,350	8,329
	MOPR Coal	$20,553	$51,170	$10,649	$27,458	1,692	2,070	730	1,498
	MOPR Battery * Discharge Hours	$33,164	$50,639	$27,200	$37,001	1,834	2,022	1,777	1,877
Assumed Output	MOPR Nuclear (Single)	$190,182	$246,310	$158,789	$198,427	8,760	8,760	8,760	8,760
	MOPR Nuclear (Multi)	$178,300	$234,408	$146,896	$186,535	8,760	8,760	8,760	8,760
	MOPR Onshore Wind	$81,232	$101,335	$71,367	$84,645	8,760	8,760	8,760	8,760
	MOPR Offshore Wind	$118,367	$145,244	$101,096	$121,569	8,760	8,760	8,760	8,760
	MOPR Fixed-Tilt Solar PV	$1,560,140	$1,830,460	$1,339,960	$1,576,853	4,717	4,716	4,717	4,717
	MOPR Tracking Solar PV	$2,534,740	$2,985,210	$2,188,860	$2,569,603	4,749	4,748	4,749	4,749

Dispatch Methods: Peak Hour vs Projected Economic

RTO Zonal Average Results for Reference CT

Dispatch Method	Net Energy Revenue ($/MW-year)				Run Hours			
	2017	2018	2019	Average	2017	2018	2019	Average
Peak-Hour	9,838	16,071	7,831	11,247	1,658	2,334	1,822	1,938
Projected Economic	19,577	28,106	17,218	21,634	3,510	3,760	3,367	3,546

Dispatch Methods Applied to Forward Day-Ahead LMPs

RTO Zonal Average Results for CT

- Results to be posted

Resource-Specific Forward E&AS Offsets

- A resource-specific E&AS calculation is needed for:
  - MOPR resource-specific exception requests for New Entry
  - MOPR resource-specific exception requests for Cleared Resources
  - MOPR Default ACR elections for Cleared Resources (resource-specific E&AS offset)
  - Offer Cap unit-specific exception requests

In-service Units	Planned Units
Standard Model: Projected Economic Dispatch or Assumed Output Model, as applicable to resource type **Standard Inputs**: Unit's actual operating parameters, cost data, pricing points, etc. are used in model • Deviations from those values allowed in unit-specific exception requests with supporting documentation	**Standard Model**: Projected Economic Dispatch or Assumed Output Model, as applicable to resource type **Standard Inputs**: Capacity Market Seller will need to provide applicable operating parameters, cost data, etc. to use in the model with supporting documentation • e.g. OEM specs, operating data from similar units, etc.
Alternatively, Capacity Market Sellers may also rely upon their own models in unit-specific requests to determine the net E&AS offset with supporting documentation	

CT, CC, and Coal Resource-Specific Parameters

Parameter	Standard Value (in-service units)	Notes
Max Capacity	Installed Capacity MW	
Min Stable Level	Max Capacity / Turndown Ratio limit	The current proxy or unit-specific adjusted parameter limits of the unit
Min Run	Min Run limit	
Min Down	Min Down limit	
Time to Start	Notification + Start Up limits	
Ramp Rate	Historical maximum ramp rate of the unit	Use history going back to Jan. 1 of prior calendar year
Heat Rate	Average heat rate at full load. Two heat rates used for CC (with and without duct burning)	The current approved values for the unit's cost-based offers, as stored in MIRA
VO&M	Approved VOM adders	
Start Fuel	Approved start fuel values	
Fuel Pricing Points	Specified hub(s) if liquid forwards exist; otherwise highest correlated liquid hub	
Emission Rates (NOx, SO2, CO2)	Approved emission rates	
LMP	Forward zonal LMPs with basis adj. to node	
Forced Outages	Most recent EFORd-1 of the unit	
Maintenance Outages	CT/CC: First two weeks in October	

Deviations from standard values allowed in unit-specific exception requests with supporting documentation

Nuclear Resource-Specific Parameters

Parameter	Standard Value (in-service units)	Notes
Max Capacity	Installed Capacity MW, operating 8760 hours per year when not on outage	
VO&M	Approved VO&M adders	The current approved value for the unit's cost-based offers, as stored in MIRA
Fuel	Same as Reference Resource	
LMP	Forward zonal LMPs with basis adjustment to node	
Forced Outages	Most recent EFORd-1 of the unit	
Maintenance Outages	Use expected refueling schedule for future Delivery Year	

Deviations from standard values allowed in unit-specific exception requests with supporting documentation

Intermittent Resource-Specific Parameters

Parameter	Standard Value (in-service units)	Notes
Output	Historic hourly unit-specific output profiles	Use up to three years of history (if available)
VO&M	$0/MWh	
LMP	Forward zonal LMPs with basis adjustment to node	
Outages	None, accounted for in output profile	

Deviations from standard values allowed in unit-specific exception requests with supporting documentation

Battery Storage Resource-Specific Parameters

Parameter	Standard Value (in-service units)	Notes
Max Capacity	Nameplate MW	Modeled with Nameplate MW and MWh of storage
Round Trip Efficiency	Efficiency Factor	The current approved value for the unit's cost-based offers, as stored in MIRA
State of Charge (Max / Min)	Required by market seller	
Forced & Maintenance Outages	None at this time, to be determined	

Deviations from standard values allowed in unit-specific exception requests with supporting documentation

Stakeholder Process

2020

July

August

July 30
Updated proposal and discussion

August 5
Compliance filing due

Stakeholder Feedback and Input

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