Fifth Review of the Variable Resource Requirement Curve

GROSS CONE AND E&AS DRAFT RESULTS

PRESENTED BY

Samuel Newell

Michael Hagerty

Travis Carless

PRESENTED TO

PJM Market Implementation Committee

DECEMBER 8, 2021

Brattle

Agenda

Preliminary Gross CONE Summary

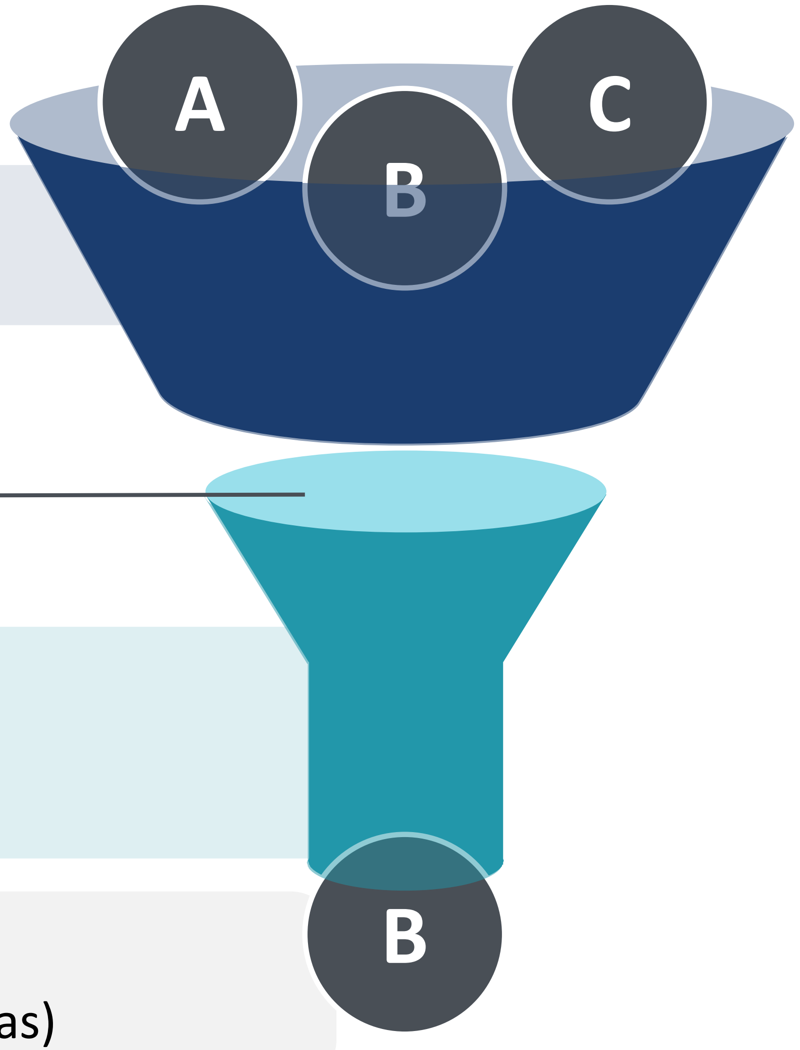
Preliminary Gross CONE Detailed Analysis

Net E&AS Offset Approach Review

Preliminary Gross CONE Summary

Review of Screening Analysis

Screening Analysis: Apply criteria to all candidate technologies



SHORT LIST PROPOSED TECHNOLOGIES
(CC, CT, and 4-Hour Battery Storage)

Detailed Analysis: Conduct detailed analysis of Net CONE for proposed technologies; re-apply selection criteria

Recommend Reference Technology
(or technologies if appropriate for different areas)

Updated CONE Analysis

Based on results from the screening analysis, we performed a bottom-up cost analysis for the Gas CT (1x0 7HA.02) and the Gas CC (1x1 7HA.02 with duct firing)

There are at least 3 areas of uncertainty that have a significant impact on the CONE results:

- **CC Configuration:** Recent market trends indicate an increasing preference for 1x1 CCs, but 1x1 CC capital and fixed O&M costs are higher than 2x1 CCs and have higher Net CONE
- **Economic Life:** Industry experience over the past decade has demonstrated that the economic life of gas turbines are longer with plants operating for 25 – 40 years based on the scope of costs included in our analysis; and long-term analyses indicate ongoing need for and value of dispatchable capacity even as renewable penetration increases
- **Commodity Prices:** Prices have recently risen and been more volatile than past reviews increasing the uncertainty of estimating costs for a new plant with a May 2026 COD

Other assumptions (e.g., cost recovery path and ATWACC) impact CONE, but based on our analysis these assumptions are less uncertain and less impactful to CONE

Preliminary Gross CONE Estimates

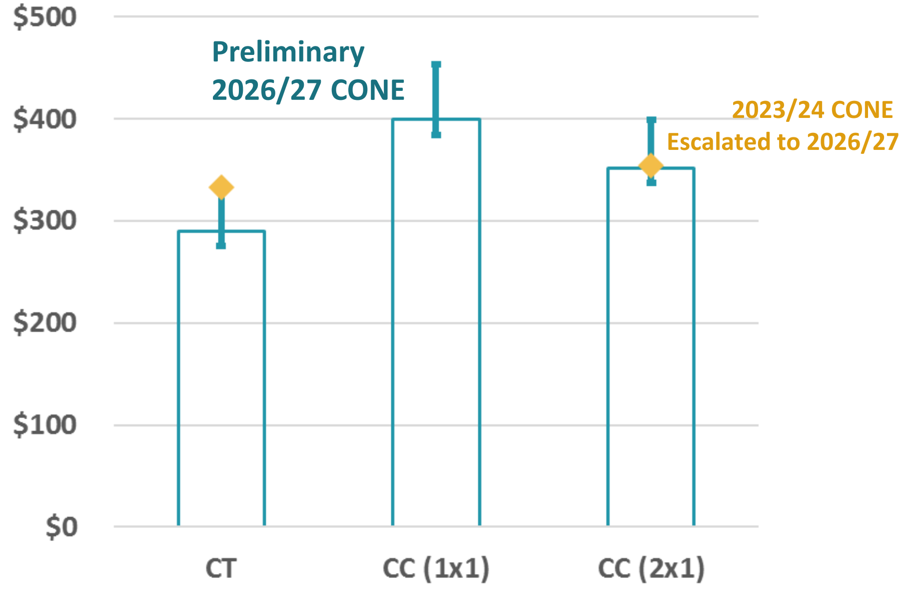
We developed a range of Gas CT and 1x1 CC CONE values, as well as an indicative 2x1 CC CONE, to understand the impact of key uncertainties on CONE values

- **CT CONE:** Base CONE of **$289/MW-day** is 13% lower than escalated 23/24 CONE due to longer economic life (range: $275-332/MW-day)
- **1x1 CC CONE:** Base CONE of **$400/MW-day** is 14% above escalated 23/24 CONE primarily due to higher per-kW capital costs, offset somewhat by longer economic life (range: $384-454/MW-day)
- **2x1 CC CONE**: Base CONE of **$352/MW-day**, 12% below 1x1 due to economies of scale of larger plant (range: $337-400/MW-day)

Increasing economic life to 30 years reduces CONE by $37-44/ICAP MW-day, while shifting CC from 1x1 to 2x1 reduces CONE by about $50/MW-day

- Range of EPC cost escalation assumptions have smaller ($5-9/MW-day) impact on CONE values

Preliminary Rest of RTO 2026/27 CONE Estimates
(2026$/ICAP MW-Day)



Preliminary CONE Assumptions

Case	Economic Life	EPC Cost Escalation (labor, materials, equipment)
Low	35 years	Fixed nominally for 2 years and then escalate at long-term rates
Base	30 years	Fixed in real terms for 5 years
High	20 years	Escalate at long-term rates for 5 years

Impact of Updated CONE Estimates on Net CONE

We calculated *indicative* Net CONE values to benchmark the preliminary CONE values to recent market results

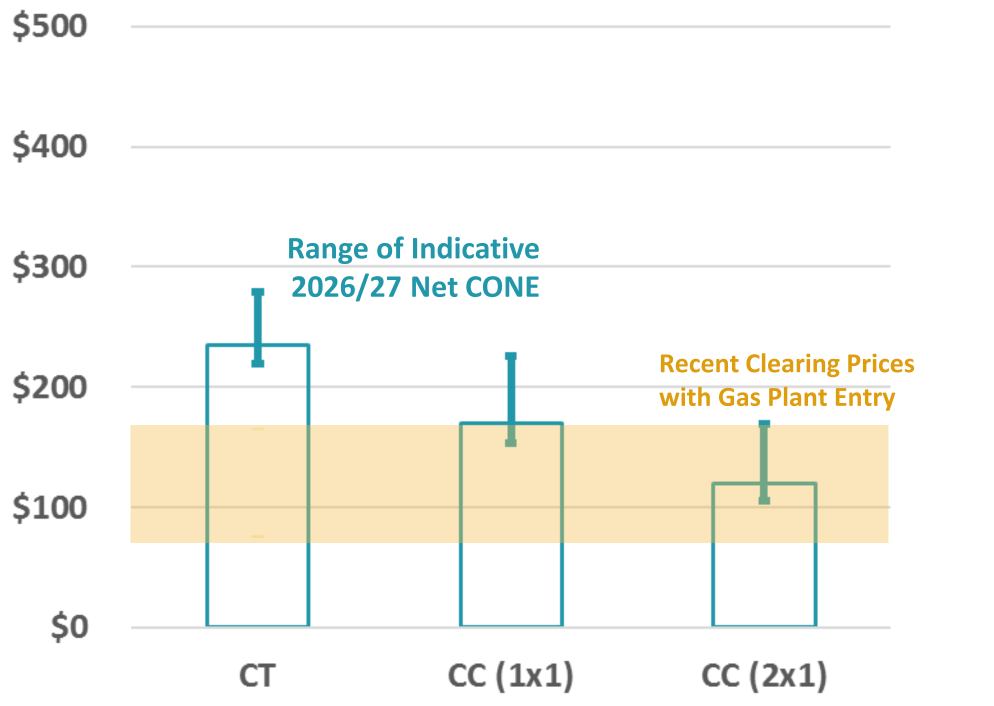
- *CONE*: preliminary CONE values from previous slide
- *E&AS*: 2023/24 E&AS revenue offsets grossed up by 10% based on 2023 and 2026 gas & electricity futures

The 2x1 CC Net CONE range of $105-169/MW-day best aligns with recent clearing prices which attracted new gas entry

- 1x1 CC is at the upper end of the range of recent clearing prices if an operating life of at least 30 years is assumed
- CT is $55-114/MW-day above recent clearing prices

Benchmarking preliminary Net CONE values to recent clearing prices support the adoption of a CC with a longer economic life for setting Net CONE

Indicative Rest of RTO 2026/27 Net CONE Estimates
(2026$/UCAP MW-Day)



Note: Indicative E&AS revenues grossed up 10% from 2023/24 E&AS values to reflect changes in Henry Hub and Western Hub futures prices.

Preliminary Gas CT and 1x1 CC CONE Values

				Simple Cycle				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs										
[1]	Overnight	*$m*		$332	$315	$320	$324	$650	$581	$606	$625
[2]	Installed (inc. IDC)	*$m*		$347	$329	$334	$338	$708	$633	$660	$681
[3]	First Year FOM	*$m/yr*		$5	$9	$6	$5	$19	$35	$20	$17
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**	**593**	**596**	**580**	**575**
	Unitized Costs										
[5]	Overnight	*$/kW*	= [1] / [4]	$920	$867	$906	$925	$1,096	$975	$1,045	$1,088
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$961	$906	$947	$967	$1,194	$1,062	$1,138	$1,185
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$17	$24	$19	$16	$40	$62	$38	$37
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.5%**	**7.5%**	**7.4%**	**7.5%**	**7.5%**	**7.5%**
[9]	Effective Charge Rate	*%*		9.6%	9.6%	9.6%	9.6%	10.3%	10.2%	10.3%	10.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$105,000**	**$107,000**	**$105,600**	**$104,700**	**$152,700**	**$162,100**	**$145,900**	**$148,800**
	Prior Auction CONE										
[11]	PJM 2023/24 CONE	*$/MW-yr*		$115,314	$116,598	$111,814	$111,737	$126,139	$129,968	$119,120	$121,672
[12]	Escalated to 2026/27	*$/MW-yr*	$= [11] \times (1 + 0.028)^3$	$125,300	$126,700	$121,500	$121,400	$137,000	$141,200	$129,400	$132,200
	Difference between Updated CONE and Escalated Prior Auction CONE										
[13]	Escalated to 2026/27	*$/MW-yr*	= [10] - [12]	($20,300)	($19,700)	($15,900)	($16,700)	$15,700	$20,900	$16,500	$16,600
[14]	Escalated to 2026/27	*%*	= [13] / [12]	-16%	-16%	-13%	-14%	11%	15%	13%	13%

Preliminary Reference Technology Recommendations

- Based on the preliminary CONE values, we recommend switching to a CC as the technology that best meets the reference technology screening criteria, subject to evidence that combined cycle plants can be built in all locations
- There is evidence of 1x1 currently being the preferred configuration for new CCs in PJM, which we are weighing against substantial recent additions of 2x1s and their lower Net CONE
- We will revisit the evidence both ways as we finalize recommendations
- We are developing a top-down CONE value for standalone 4-hour battery storage that we will present at a future stakeholder meeting, in case gas plants are infeasible to be built[1]

[1] See Appendix Slides 30 and 31 for basis of selecting standalone battery storage as the non-emitting technology

Preliminary Gross CONE Detailed Analysis

Gas CT and CC Detailed Specifications

- Most significant difference is switching from a 2x1 to a 1x1 CC due to recent trend towards smaller units
- Reduces CC capacity from 1,150 MW to about 590 MW
- Other specifications consistent with 2018 CONE study, including locations within each CONE Area

Characteristic	Combustion Turbine	Combined Cycle
Site Type	Greenfield	Greenfield
Turbine Model	GE 7HA.02	GE 7HA.02
Configuration	1x0	**1x1**
Power Augmentation	Evaporative Cooling, no inlet chillers	Evaporative Cooling, no inlet chillers
CC Cooling System	---	Cooling Towers
Fuel Supply	Dual Fuel	Dual Fuel, except SWMAAC (firm gas)
Environmental Controls	Dry Low NOx burners, SCR and CO Catalyst	Dry Low NOx burners, SCR and CO Catalyst
Net ISO Rating	350 – 363 MW	Without Duct Firing: 513 – 531 MW **With Duct Firing: 575 – 596 MW**
Net ISO Heat Rate (HHV)	9,304 – 9,320 Btu/kWh	Without Duct Firing: 6,274 – 6,291 Btu/kWh With Duct Firing: 6,501 – 6,521 Btu/kWh

Developers Building 1x1 CCs over 2x1 CCs

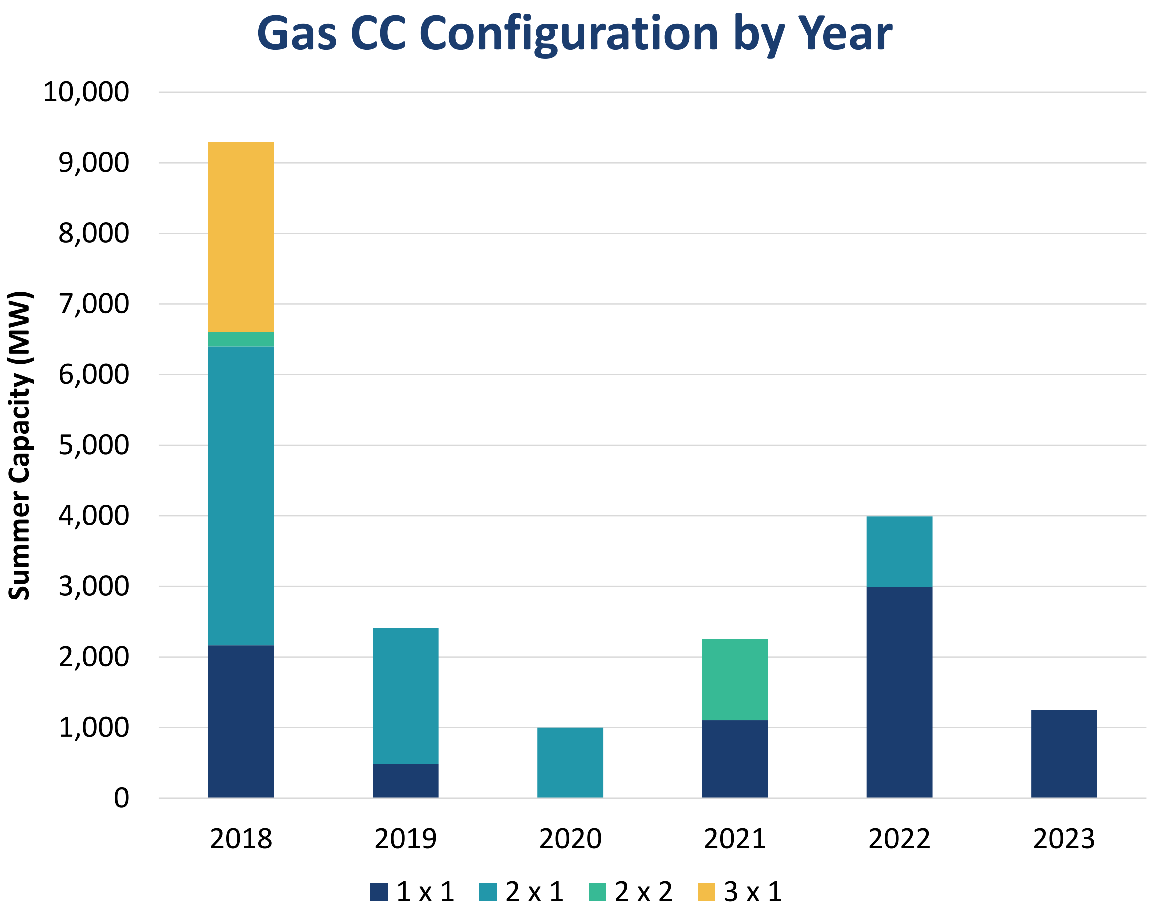
New Gas CCs are shifting away from larger 2x1 units (>700 MW) specified in the 2018 CONE Study to smaller and more flexible 1x1 units (<700 MW)

- Since 2018, 2x1 and 1x1 CCs have each added about 8 GW of new merchant capacity in PJM
- Majority of units built in 2021 or are currently under construction are 1x1 units (5.3 GW vs 1.0 GW of 2x1)
- All 1x1 CCs being built in PJM with multiple trains

Developers are shifting towards 1x1 CCs despite higher levelized costs due to greater operational flexibility

- 1x1 CC able to startup faster due to a smaller steam turbine that requires less thermal soak time
- 1x1 single shaft arrangement offers better part-load efficiency since steam turbine matches CT on shared shaft

NYISO and ISO-NE both base their CC Net CONE estimates on a 1x1 CC with 7HA turbines



Sources and Notes: Ventyx Energy Velocity Suite, Accessed August 2021. Includes operational or units under construction (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

Gas CT and CC Cost Recovery Path

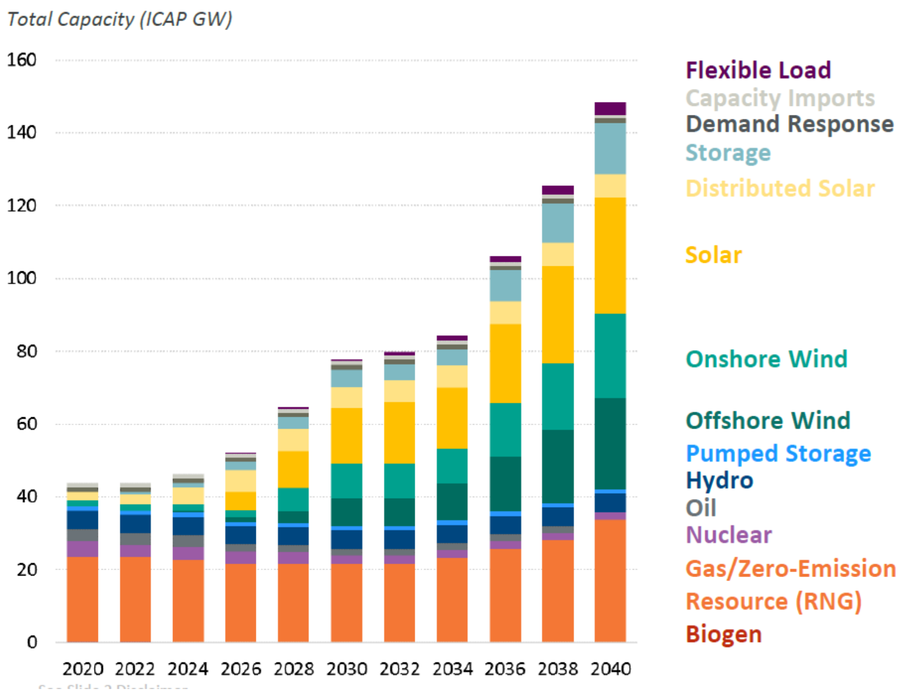
We recommend estimating CONE for the Gas CT and CC assuming their net revenues remain constant in nominal terms over its economic life (“level-nominal”)

- Public studies (e.g., Princeton Net Zero America, DOE Solar Futures, NYISO Grid Evolution) and our internal modeling of the future generation resource mix necessary to achieve decarbonization targets **demonstrate an on-going need for dispatchable gas-fired resources**
- Continued gas-fired generation entry indicates that cost recovery path will be based on **long-term outlook of gas-fired capacity costs**, although revenues may shift to more heavily rely on capacity payments
- Long-term trends in turbine costs per kW show that **costs have on average remained flat in nominal terms** over past 20 years

Princeton Net Zero America Findings:

- “New natural gas fired capacity is added in all scenarios except E+RE+.”
- “To meet firm capacity needs in the 100% renewable E+RE+ scenario, ~590 GW of new combustion turbine and combined cycle power plants are deployed and by 2050 are fired entirely with zero-carbon synthetic gas.”

NYISO Projected Capacity through 2040



Source: Princeton Net Zero America study; NYISO Grid Evolution study

Gas CC and CT Economic Life

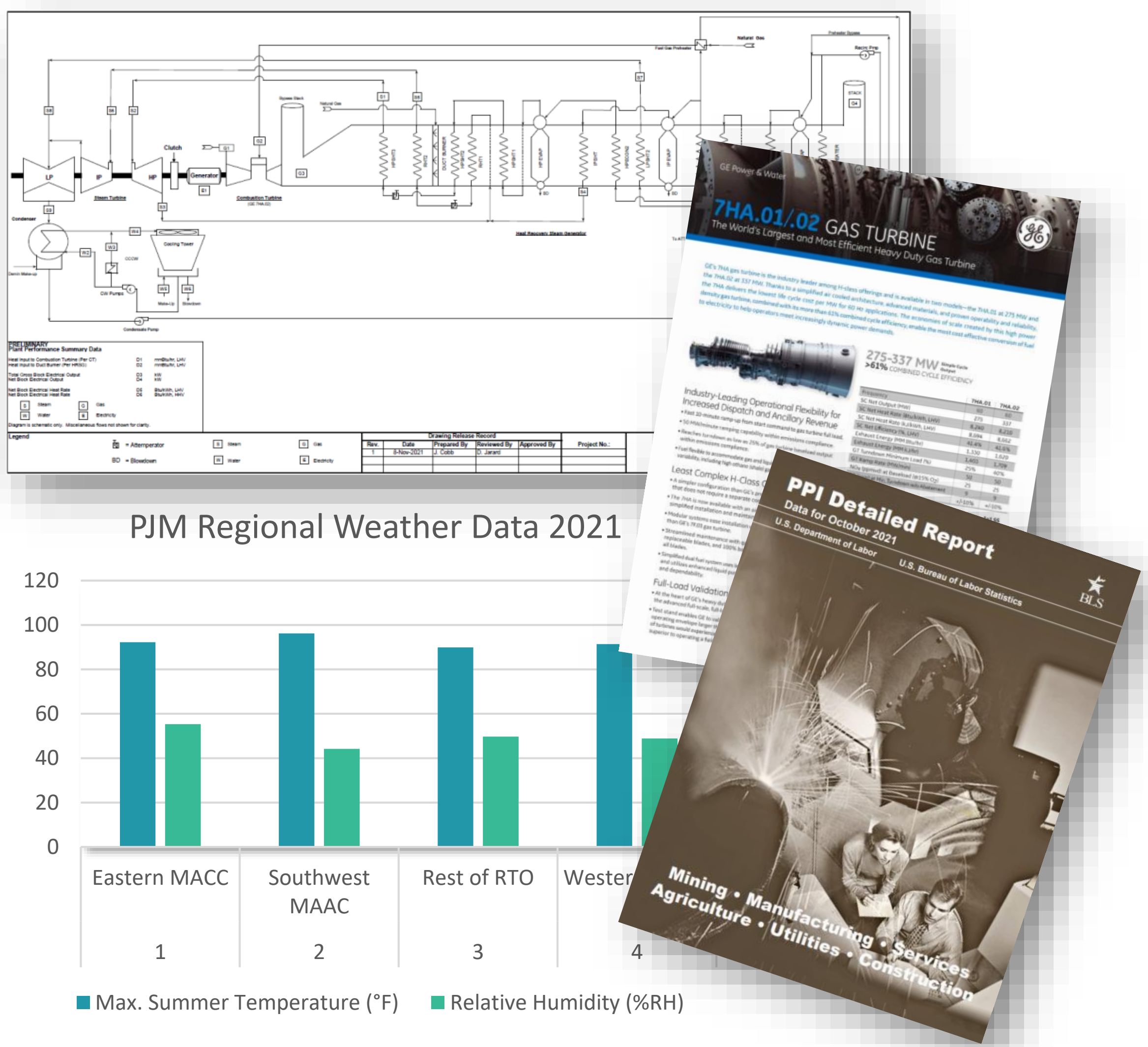
We recommend increasing the economic life of Gas CT and CCs from 20 years to 30 years

- Industry has gained significant experience over the past 10-15 years in operating gas turbines for longer periods of time
- The long-term service agreement (LTSA) costs included in the O&M costs are expected to cover all costs necessary to maintain unit performance for over 30 years, but does not include capital projects or major equipment replacement that may be necessary to further extend the life
- IMM recommends 35 years based on MOPR submissions
- Longer economic life is consistent the long-term need for dispatchable, non-energy-limited capacity
- Longer economic life also “calibrates” Net CONE downward to be closer to recent clearing prices that attracted new gas-fired capacity

Approach to Estimating Gas CT and CC Costs

Bottom-Up Approach (Inputs)

- Detailed technical specifications developed for complete CT and CC installations
- Regional weather data updated and averaged to provide representative climate conditions in each zone: EMAAC, SWMAAC, WMAAC, and Rest of RTO*
- Heat balances prepared to size balance-of-plant (BOP) equipment and establish performance expectations for CTs and CCs in each of the four established zones
- Major equipment cost data obtained from OEM budgetary quotes or recent Sargent & Lundy project data
- U.S. Bureau of Labor Statistics data used to establish representative labor rates for each zone

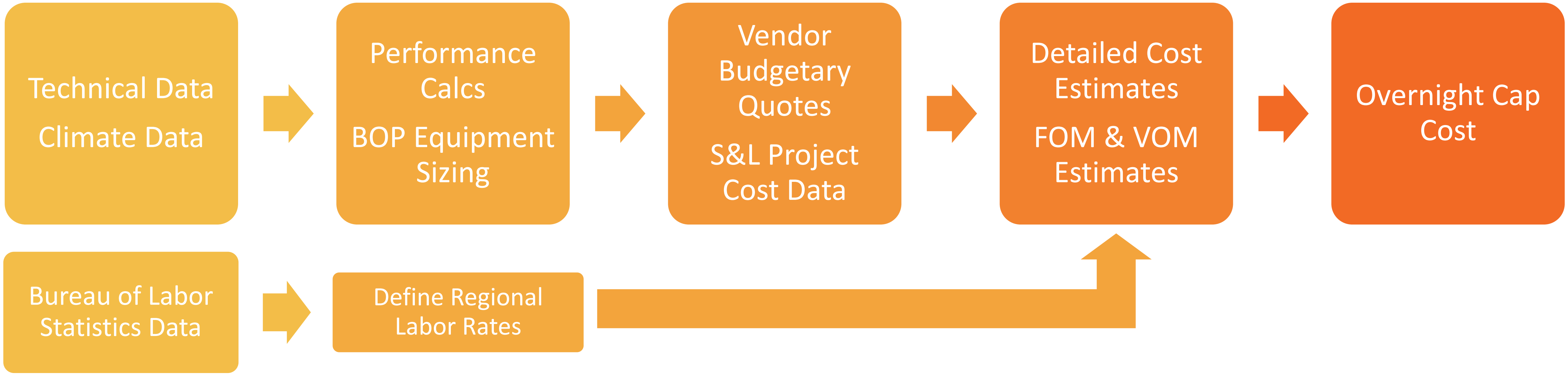


*EMAAC, SWMAAC, and WMAAC represent the Eastern, Southwest, and Western mid-Atlantic regions, Rest of RTO captures the areas not included in these regions

Approach to Estimating Gas CT and CC Costs

Bottom-Up Approach (Methods and Outputs)

- BLS labor material costs and labor rates used to establish construction costs in each zone
- Fixed and Variable Operation and Maintenance (FOM and VOM) costs determined for installations in each zone
- Owner Furnished Equipment, EPC Costs (e.g. BOP equipment, materials, and labor), and Non-EPC Costs (e.g. project development, mobilization, and owner's contingency) combined to establish Overnight Capital Cost (OCC)



Gas CT and Gas CC Capital Costs

Capital costs are 10% higher for Gas CT and 34% higher for 1x1 CC compared to the unadjusted costs from 2018 CONE study on a per-kW basis

- Gas CT capital costs increase at about the projected rate of inflation with modest shifts in costs across components
- Significantly higher 1x1 CC capital costs per kW are driven by higher EPC costs (i.e., labor, equipment, and materials costs) due to the smaller capacity
- Assume 1x1 CC built on site with second 1x1 block, such that some costs (e.g., gas interconnection costs) are shared by both blocks

Indicative 2x1 CC capital costs of $920/kW is 12% lower than 1x1 CC based on the 2020 EIA generation cost study

Rest of RTO 2026/27 Capital Cost Estimates
(nominal $)

	Updated Gas CT		Change from 2018 Study	Updated Gas 1x1 CC		Change from 2018 Study
	million $	*$/kW*	*$/kW*	*million $*	*$/kW*	*$/kW*
Owner Furnished Equipment	**$113**	**$321**	**$31**	**$152**	**$261**	**$19**
Gas Turbines	$78	$222	$8	$78	$134	-$19
HRSG / SCR	$35	$99	$22	$39	$67	$18
Steam Turbines	$0	$0	$0	$35	$61	$19
EPC Costs	**$125**	**$355**	**$10**	**$365**	**$629**	**$204**
Equipment	$25	$72	-$11	$62	$107	$37
Construction Labor	$36	$101	$6	$136	$234	$87
Other Labor	$15	$41	$4	$32	$55	$8
Materials	$8	$23	$4	$46	$79	$33
EPC Contractor Fee	$20	$56	$3	$43	$74	$18
EPC Contingency	$22	$61	$4	$47	$81	$20
Non-EPC Costs	**$81**	**$230**	**$43**	**$90**	**$155**	**$40**
Development & Start Up Costs	$15	$43	$5	$27	$47	$16
Electrical Interconnection	$7	$21	-$1	$12	$21	-$1
Gas Interconnection	$41	$117	$33	$23	$39	$14
Other Costs (Land, Inventories, etc.)	$17	$49	$6	$27	$47	$11
Total Capital Costs	**$320**	**$906**	**$84**	**$606**	**$1,045**	**$263**

Source: EIA, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020.

Gas CT and Gas CC Fixed O&M Costs

- Fixed O&M costs are 5% higher for Gas CT and 57% higher for Gas CC compared to the unadjusted costs from 2018 CONE study on a per-kW basis
- The largest fixed O&M costs for Gas CC are from labor and maintenance and minor repairs

Rest of RTO 2026/27 Fixed O&M Estimates

(nominal $)

	Updated Gas CT		Change from 2018 Study	Updated Gas 1x1 CC		Change from 2018 Study
	million $	*$/kW*	*$/kW*	*million $*	*$/kW*	*$/kW*
Fixed O&M Cost	**$6.3**	**$18.0**	**$0.9**	**$20.0**	**$34.4**	**$12.5**
LTSA	$0.3	$0.9	$0.2	$0.4	$0.8	$0.3
Labor	$0.8	$2.2	-$0.1	$4.2	$7.2	$3.3
Maintenance and Minor Repairs	$0.5	$1.3	$0.0	$5.3	$9.1	$4.4
Administrative and General	$0.2	$0.6	$0.0	$1.0	$1.8	$0.8
Asset Management	$0.4	$1.1	$0.0	$0.6	$1.0	-$0.1
Property Taxes	$2.2	$6.3	$0.4	$4.7	$8.1	$2.1
Insurance	$1.9	$5.4	$0.5	$3.6	$6.3	$1.6
Firm Gas Contract	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Working Capital	$0.0	$0.1	$0.0	$0.1	$0.1	$0.0

Note: Major maintenance costs are split between fixed O&M (LTSA fixed costs), shown here, and variable O&M (major maintenance costs incurred based on operating hours or starts), shown on the next slide.

Gas CT and Gas CC Variable O&M Costs

- Variable O&M costs are about 3x higher for Gas CT and about 2x higher for Gas CC compared to the unadjusted costs from 2018 CONE study on a per-MWh basis
- CT major maintenance costs by starts are 13% lower compared to the unadjusted costs from 2018 CONE study O&M costs

Rest of RTO 2026/27 Variable O&M Estimates

(nominal $)

	Updated Gas CT	Change from 2018 Study	Updated Gas 1x1 CC	Change from 2018 Study
Variable O&M Costs ($/MWh)	**$3.1**	**$2.2**	**$4.2**	**$2.1**
Major Maintenance - Hours ($/MWh)	$0.0	$0.0	$2.2	$0.8
Consumables, Waste Disposal, Other VOM ($/MWh)	$3.1	$2.2	$2.0	$1.3
Major Maintenance - Starts ($/Factored Start, Per Turbine)	**$20,249**	**-$3,215**	**$0**	**$0**

Cost of Capital Recommendation

We recommend a 7.5% merchant generation ATWACC

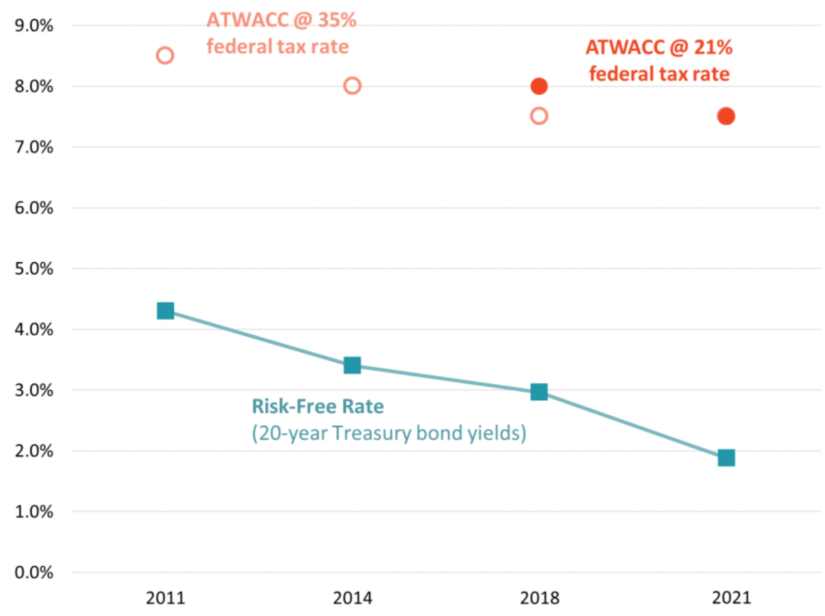
- Estimated ATWACC of three publicly-traded companies with merchant exposure (Vistra, NRG, and AES)
- No additional reference points, such as from recent fairness opinions, available to include in our analysis
- Selected ATWACC at higher end of range to reflect higher risks of a pure-play merchant investment

ATWACC has declined at a slower rate than the risk-free rate over past decade, such that the spread between risk-free rate and merchant ATWACC has increased

Cost of capital compensates investors for systematic (non-diversifiable) risk from constructing and operating a plant

- Uncertainty regarding the gas-fired plant’s economic life or cost recovery path does not affect the ATWACC, but should be considered in the levelization assumptions (see previous slides)

Recommended PJM CONE ATWACC



ATWACC Components

Component	Value
Debt Rate	55%
Cost of Debt	4.2%
Return on Equity	13.0%
Effective Tax Rate	28.1%
ATWACC	**7.5%**

Updated Merchant Generation ATWACC

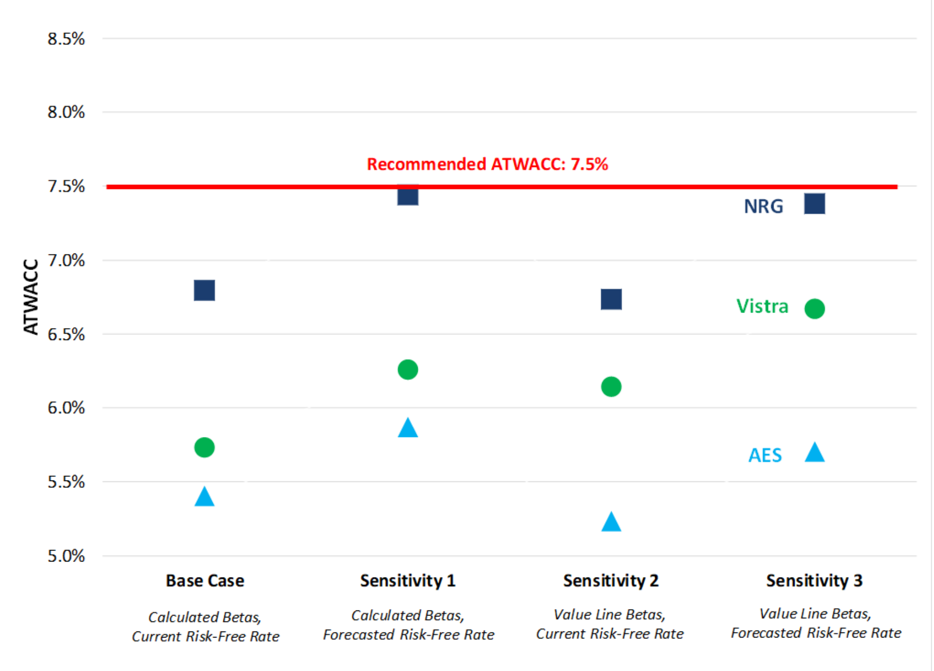
Estimated ATWACC for publicly-traded generation companies ranges from 5.2% to 7.5%

- Sensitivities test ATWACC under alternative risk-free rate assumptions and sources of company betas
- Rely more heavily on NRG and Vistra due to larger share of their business exposed to wholesale prices (including both merchant generation and competitive retail)

Fairness opinions identified in past studies ranged from 5.75% to 7.7%

Review of recent analyst reports did not identify any concerns related to ESG funds or decarbonization targets impacting near-term access to capital

ATWACCs of Publicly-Traded Generation Companies



2019 Business Mix of NRG and Vistra

Company	Retail	Generation
[1]	[2]	[3]
NRG	38%	62%
Vistra	8%	92%

Other Financial Assumptions

- **Bonus Depreciation**: Decreases from 100% in 2022 to 20% in 2026
- **Inflation**: Assume 2.0% inflation based on the latest long-term inflation estimates projected by Cleveland Fed and Blue Chip Economic Indicators, which are in the range of 1.8 – 2.0%

Net E&AS Offset Approach Review

Forward-Looking E&AS Recommendations

We reviewed four aspects of the forward-looking E&AS approach requested by PJM to be completed during the Quadrennial Review:

- **Electric Hub Mapping**: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices
- **Natural Gas Hub Mapping**: Switch EKPC gas hub from Columbia-App TCO to Michcon; otherwise current gas hub mapping supported by recent prices
- **Ancillary Service Prices**: Recommend scaling historical hourly sync and non-sync reserve prices by forward energy prices, similar to regulation, but only if forward energy prices exceed historical prices
- **EE Wholesale Energy Savings**: Recommend updating EE Net CONE assumptions based on most recent program data available for ComEd, PPL, and BG&E; have not identified any additional utility programs to include in the sample

Electricity Hub Mapping

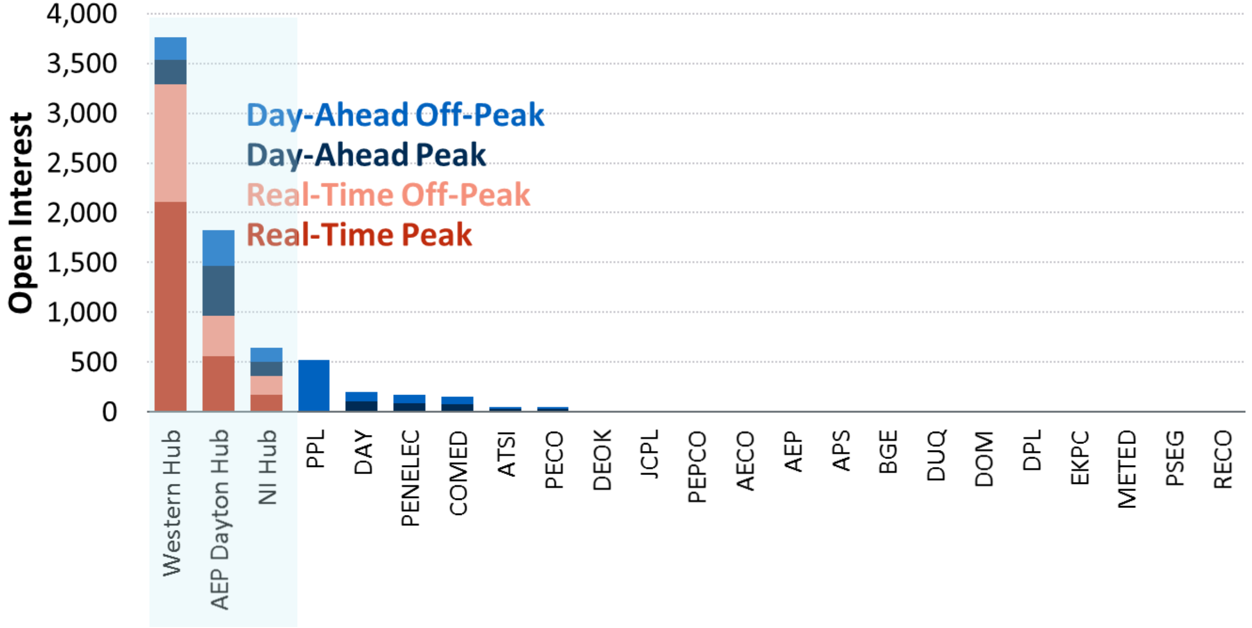
Updated trading data for futures products across PJM continue to show significantly more open interest at trading hubs than zones

- Note: PPL has open interest similar to NI Hub but only for DA off-peak products

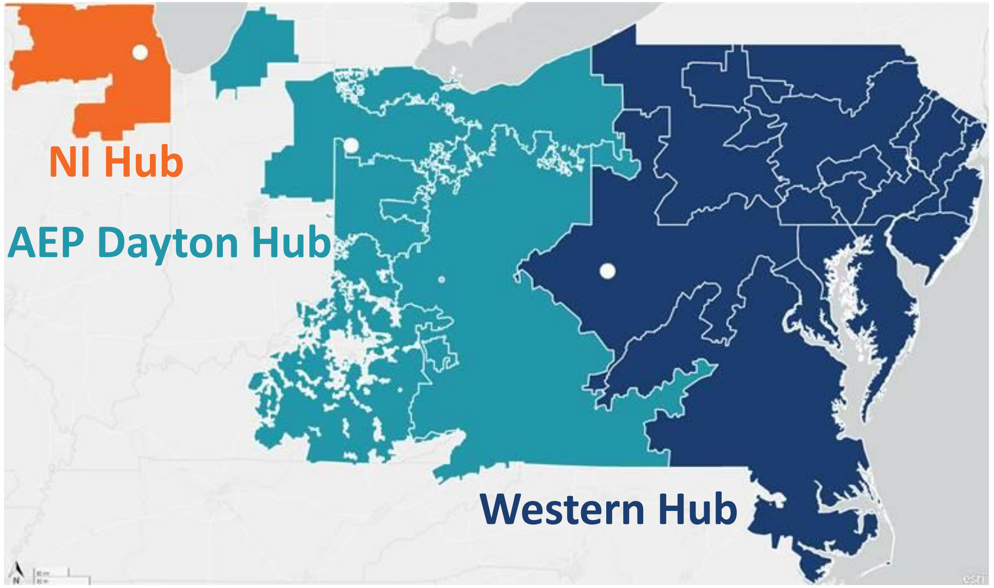
Historical 2019 to 2021 zonal prices continue to correlate closely with current hub mapping

- Prices converged across the hubs such that some zones are slightly more correlated with more distant hubs
- Recommend maintaining current mapping in case greater price differentials occur before next review

Monthly Average Open Interest at PJM Electricity Hubs and Zones for 2025



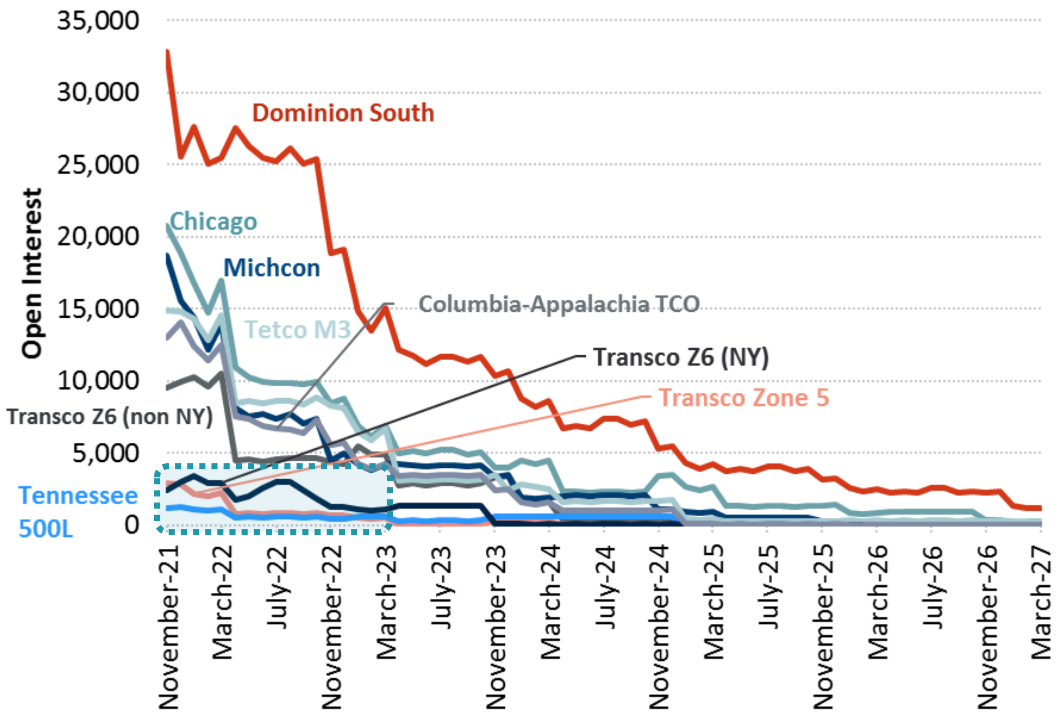
Electricity Futures Zonal Mapping of Trading Hubs

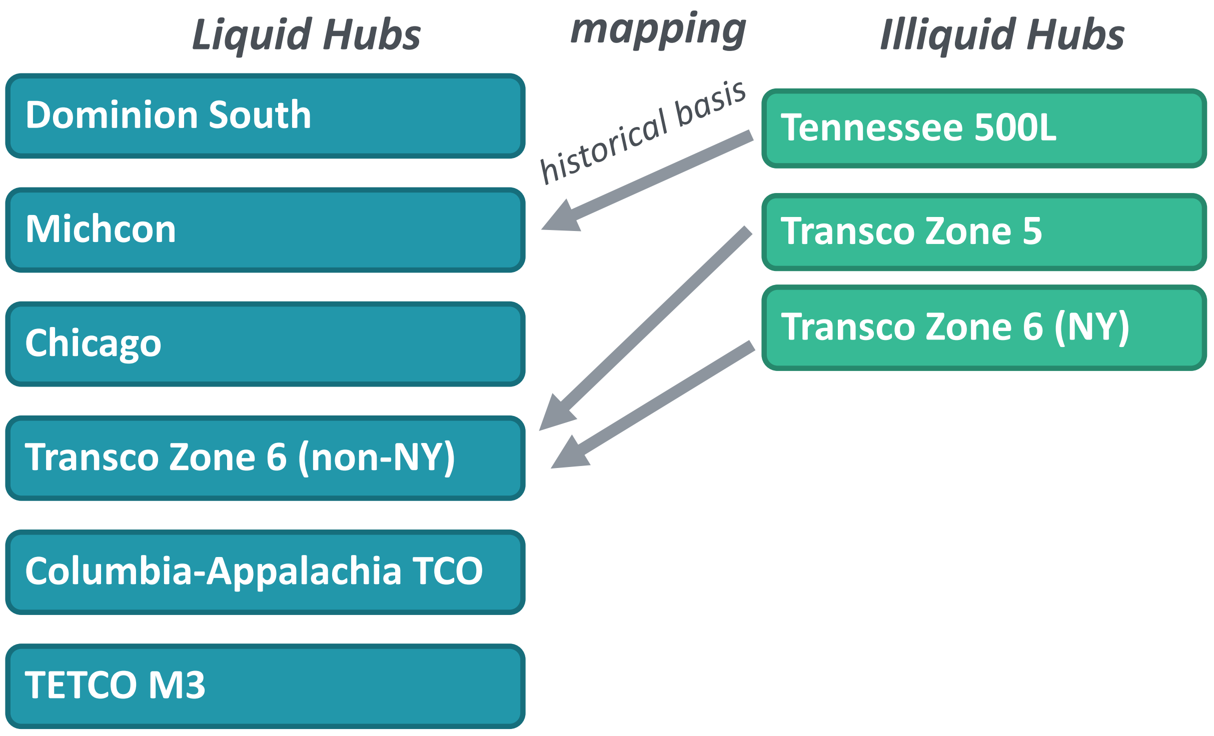


Natural Gas Hub Mapping

Due to the lower level of open interest at three hubs, we recommend mapping Tennessee 500L to Michcon (instead of Columbia-App TCO) for EKPC gas plants and keeping Transco Zone 5 and Zone 6 (NY) mapped to Zone 6 (non-NY)

Monthly Open Interest at PJM Gas Hubs through 2027

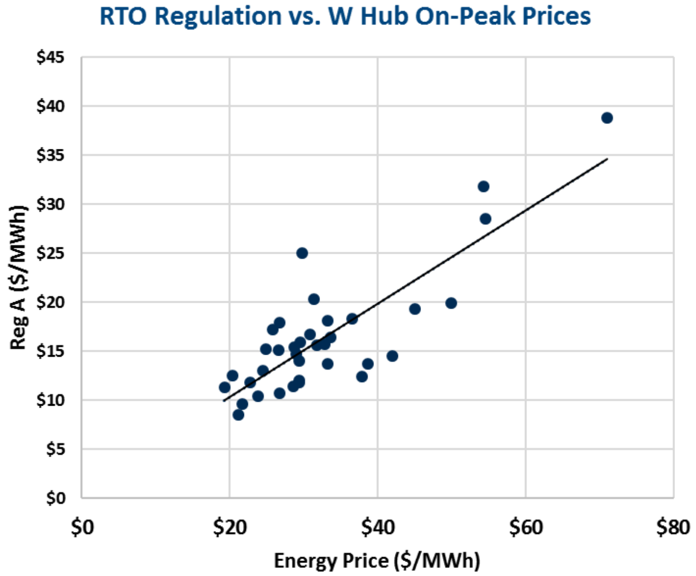


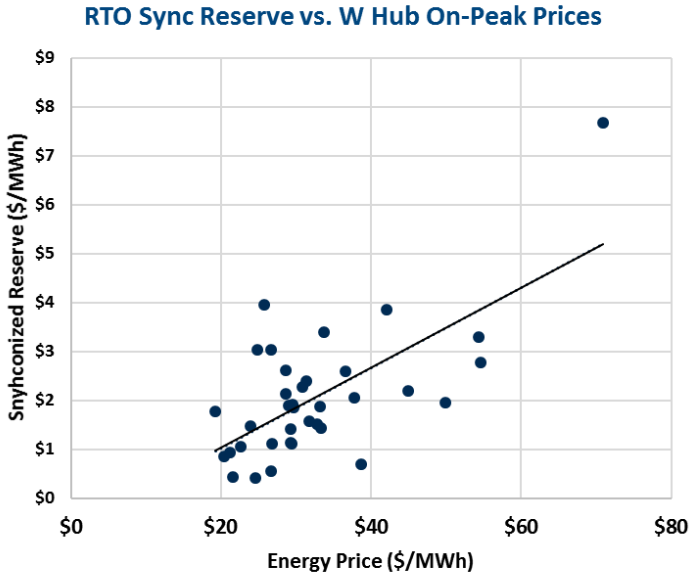


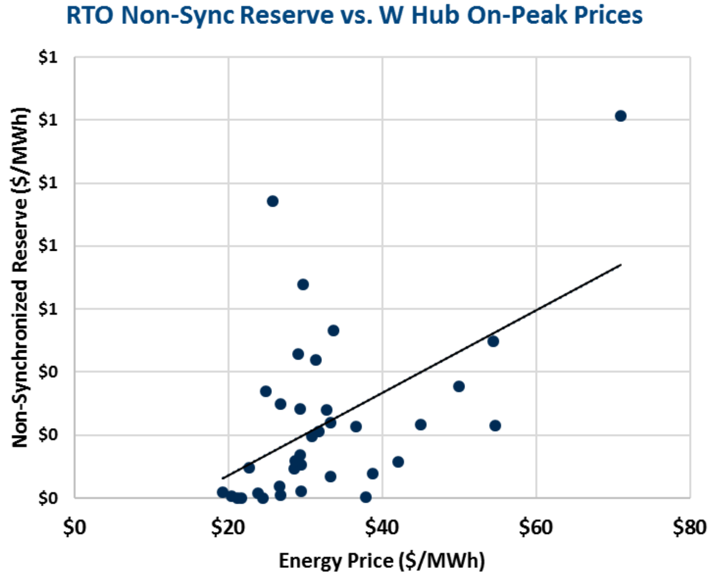
Ancillary Service Prices

Reviewed whether a historical or forward-looking approach is justified for setting ancillary service prices

- **Regulation**: Energy prices and regulation prices continue to be highly correlated (left figure); maintain current approach of scaling historical hourly regulation prices by the change in hourly energy prices
- **Sync and Non-Sync Reserves**: As 3-year-forward energy prices now exceed historical prices, we recommend that PJM scale historical sync and non-sync reserve by energy prices similar to regulation, but only when forward-looking energy prices exceed historical prices







Updated EE Net CONE Assumptions

Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts

- Current sample includes the largest utilities in each state that provides sufficient detail for the analysis
- Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample

We will update the EE Net CONE analysis based on the available data and share results next stakeholder meeting

Stakeholder Input to Inform the Quadrennial Review

Provide initial input on draft results by **December 23** to
Melissa.Pilong@pjm.com or Gary.Helm@pjm.com

2021

August 6th

Overview and VRR Curve Presentation

August 17th

CONE and E&AS Offset Presentation

October 8th

Reference Technology Presentation

December 8th

Draft Results Presentation

2022

February

Near-Final Results Presentation

May

VRR Curve and CONE Reports

October

Filing date for VRR parameters (2026/27 thru 2029/30)

Milestones for Stakeholder Input

Dec 23

Contact Information

Sam Newell

PRINCIPAL | BOSTON

Sam.Newell@brattle.com

+1 (617) 234-5725

Travis Carless

ASSOCIATE | BOSTON

Travis.Carless@brattle.com

+1 (617) 234-5268

Michael Hagerty

SENIOR ASSOCIATE | WASHINGTON DC

Michael.Hagerty@brattle.com

+1 (202) 419-3323

Appendix Slides

Non-Emitting Technologies Considered

We recommend standalone 4-hour battery storage as the non-emitting technology due to the lower uncertainty in accurately estimating its Net CONE value compared to tracking solar PV and hybrid solar PV

We considered the following uncertainties in estimating Net CONE for each of non-emitting technology

- *Standalone 4-hour battery storage* E&AS revenues are uncertain due to the current reliance on regulation revenues for the majority of its revenue, which may decline in the future as the relatively thin regulation market is saturated with fast-responding resources, like battery storage.
- *Tracking solar PV* ELCC values are uncertain as they will decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV resources currently depend on RECs for entry, which are both uncertain and limit the responsiveness of solar PV resources to enter the market due to rising capacity prices.
- *Hybrid solar PV plus battery storage resources* are uncertain for similar reasons as standalone battery storage and solar PV in terms of the future regulation revenues, ELCC value, and dependence on RECs for entry, and add the uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

Screening Analysis of Technologies

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes** (may be unable to build in certain LDAs)	**Yes** (significant recent entry; lowest 2023/24 Net CONE)	**Highest**
Gas CT	**Yes** (may be unable to build in certain LDAs)	**Unclear** (few recently built; highest 2023/24 Net CONE among candidates)	**High** (greater E&AS uncertainty than Gas CC)
4-Hour Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; 2023/24 Net CONE second lowest)	**Low** (uncertain future AS revenues; falling costs)
Tracking Solar PV	**Yes**	**Unclear** (limited evidence of entry without RECs; 2023/24 Net CONE similar to CT)	**Low** (REC-dependence; falling costs; highly uncertain ELCC)
Hybrid Solar PV plus Battery Storage	**Yes**	**Unclear** (limited evidence of entry without RECs; no 2023/24 Net CONE)	**Low** (REC-dependence; falling costs; uncertain future AS revenues; highly uncertain ELCC; broad range of configurations)

Cost Escalation and Economic Life Cost Impact

Cost Escalation and Economic Life Cost Impact

	Rest of RTO Gross CONE (2026$/ICAP MW-Day)			
	CT	Difference from CT Base Scenario	CC (1x1)	Difference from CC (1x1) Base Scenario
30-Year Economic Life w/ EPC Escalation Fixed in Real Terms for 5 Years				
Base	$289	-	$400	-
Economic Life Sensitivity w/ EPC Escalation Fixed in Real Terms for 5 Years				
20 Years	$326	$37	$443	$44
35 Years	$281	-$8	$390	-$10
EPC Escalation Sensitivity w/ 30-Year Economic Life				
Escalate at Long-Term Rates for 5 Years	$294	$5	$409	$9
Fixed 2 Years, then Escalate at Long-Term I	$283	-$6	$393	-$7

Recent CC Merchant Entry

CC Entry Since 2018

CT x ST	Capacity (MW)	Merchant Unregulated	Regulated
1 x 1	7,994	14	0
2 x 1	8,163	9	0
3 x 1	2,682	1	1
2 x 2	1,362	2	0

CC Entry Since 2021

CT x ST	Capacity (MW)	Merchant Unregulated	Regulated
1 x 1	5,345	9	0
2 x 1	1,000	1	0
3 x 1	0	0	0
2 x 2	1,152	1	0

Construction Labor Costs

		EMAAC	SWMAAC	Rest of RTO	WMAAC
CT Plant					
2021 Construction Labor Hours	hours	261,496	239,508	248,531	261,560
2021 Weighted Average Crew Rates	$	131.48	113.00	117.44	117.20
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	$	$40,568,600	$29,772,100	$32,689,000	$36,171,800
2021 Construction Labor Costs	$/kW	112	82	93	103
CC Plant					
2021 Construction Labor Hours	hours	947,597	880,019	900,575	947,597
2021 Weighted Average Crew Rates	$	138.35	122.56	124.75	124.60
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	$	$154,697,400	$118,643,800	$125,828,100	$139,320,000
2021 Construction Labor Costs	$/kW	293	223	243	272

Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width (inches)	Pipeline Length (miles)	Pipeline Cost (service year $m)	Pipeline Cost (2021$m)	Pipeline Cost ($m/mile)	Meter Station (Y/N)	Station Cost (service year $m)	Station Cost (2021$m)
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y		$0.0
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$6.7**			**$4.0**

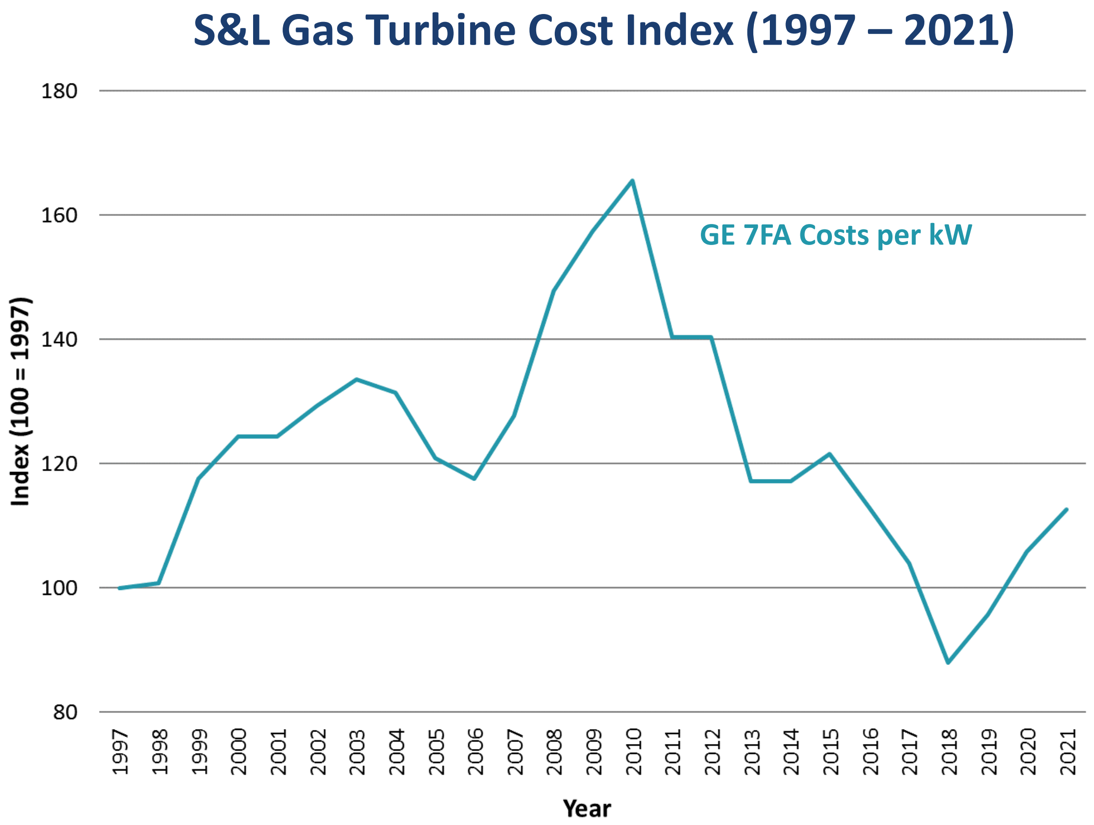
ATWACC Details

ATWACCs of Publicly-Traded Generation Companies (Base Case)

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,213	$18,664	1.16	10.3%	38%	3.3%	5.4%
NRG Energy Inc	BB+	$9,994	$8,984	1.17	10.3%	53%	3.9%	6.8%
Vistra Corp	BB	$8,251	$10,748	1.02	9.3%	43%	4.2%	5.7%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 9/30/2021, millions USD.
[4]: Computed 3-year weekly betas based on stock price returns and index returns. These calculations omits all weekly stock price returns where they deviated from weekly index returns by more than 8%.
[5]: RFR (1.88%) + [4] × MERP (7.25%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on S&P Credit Rating for NPI and Company Cost of Debt for other companies.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Long-Term Gas Turbine Cost Index

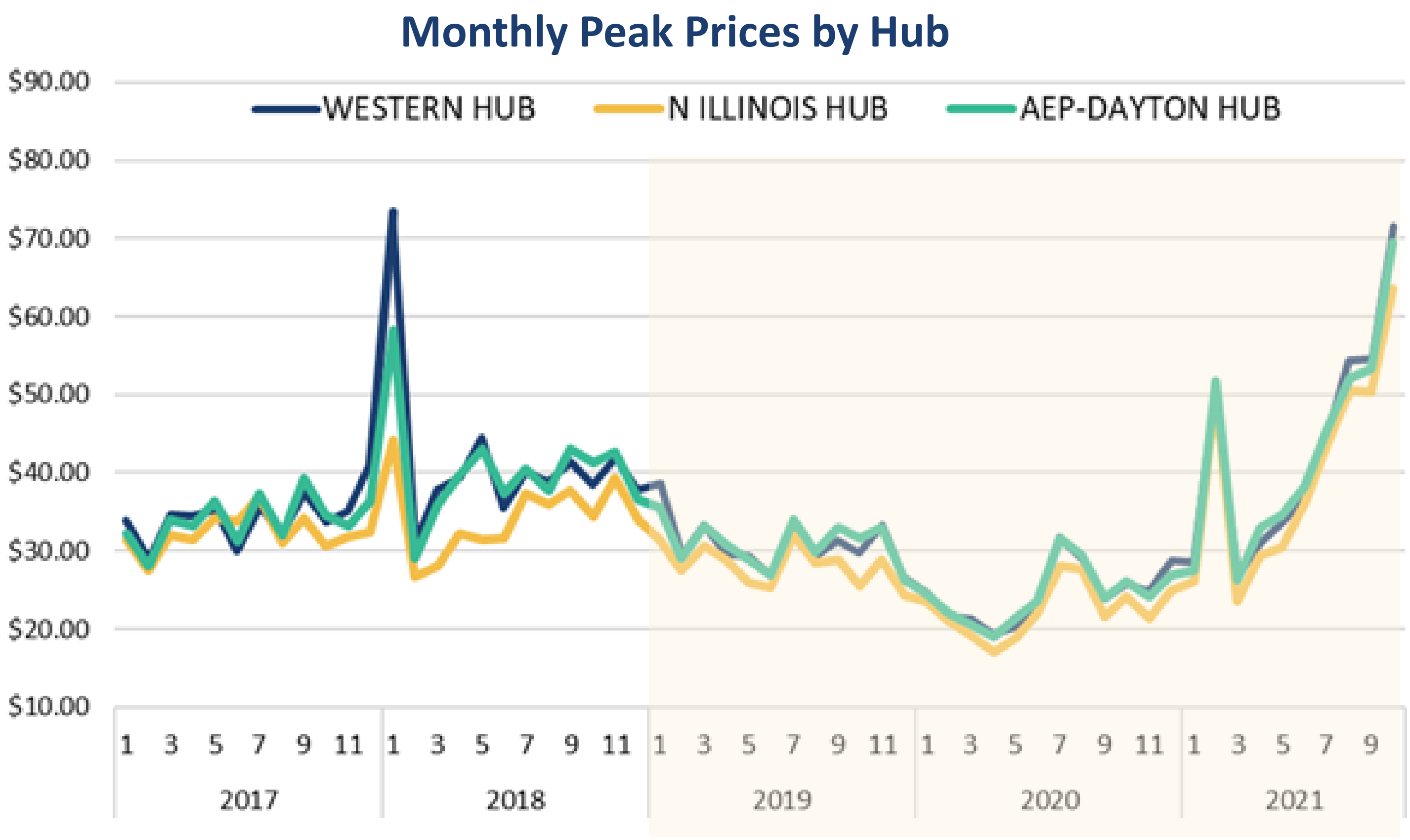


Source: S&L project database.

Energy Hub Correlation Analysis

	COMED	AEP	ATSI	DAY	DEOK	DUQ	EKPC	APS	DOM	PEPCO	BGE	DPL	PENELEC	PPL	METED	PECO	AECO	PSEG	JCPL	RECO
Western Hub	0.99	0.995	0.9970	0.992	0.986	0.993	0.993	0.997	0.987	0.9953	0.984	0.907	0.995	0.986	0.983	0.934	0.937	0.939	0.959	0.930
N. Illinois Hub	1.00	0.992	0.9881	0.991	0.983	0.984	0.992	0.985	0.976	0.9848	0.975	0.906	0.986	0.979	0.972	0.937	0.936	0.933	0.954	0.937
AEP-Dayton Hub	0.99	1.000	0.9966	0.998	0.993	0.995	0.998	0.994	0.988	0.9946	0.986	0.891	0.986	0.975	0.970	0.920	0.921	0.921	0.944	0.920

Prices Have Converged across Trading Hubs



Gas Hub Correlation Analysis

Zone	Tennessee 500L Correlation
Michcon	0.984
Columbia-Appalachia TCO	0.967
Dominion South	0.868
Chicago	0.555
TETCO M3	0.543
Transco Zone 5	0.485
Transco Zone 6 (non NY)	0.485
Tennessee Zone 4 300L	0.432

Comparison of Historical Zonal Prices to Hub Futures Prices

		Day-Ahead	
Hub	Zone	2019-21 Average	2025/26 Futures
N. Illinois	COMED	$25.58	$33.93
AEP-Dayton	AEP	$28.40	$36.48
	ATSI	$28.41	$36.48
	DAY	$29.87	$36.48
	DEOK	$29.06	$36.48
	DUQ	$28.15	$36.48
	EKPC	$28.25	$36.48
Western Hub	APS	$28.40	$38.38
	DOM	$29.96	$38.38
	PEPCO	$30.34	$38.38
	BGE	$31.68	$38.38
	DPL	$26.54	$38.38
	PENELEC	$27.09	$38.38
	PPL	$24.87	$38.38
	METED	$26.61	$38.38
	PECO	$23.99	$38.38
	AECO	$24.37	$38.38
	PSEG	$24.93	$38.38
	JCPL	$24.58	$38.38
	RECO	$25.92	$38.38