Illinois Generation Retirement Study

PJM Interconnection

August 3, 2022

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Contents

Overview

PJM, a FERC-approved RTO, coordinates the movement of wholesale electricity across a high-voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM's footprint encompasses major U.S. load centers from the Atlantic Coast to the Illinois western border, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and the District of Columbia.

PJM's Regional Transmission Expansion Plan (RTEP) process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members with access to PJM's regional power markets as well as those of adjoining systems.

PJM's RTEP process spans state boundaries and in doing so gives PJM the ability to identify one optimal, comprehensive set of solutions to solve reliability criteria violations, operational performance issues and market efficiency constraints. Specific system enhancements are justified to meet local reliability requirements and deliver needed power to more distant load centers.

PJM's RTEP process, including that to evaluate deactivation of generation, encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability and short-circuit North American Electric Reliability Corporation (NERC) Standard TPL-001-4.[1] This study focuses on the thermal and reactive dimensions of Standard TPL-001-4.

Background

In PJM's role as a NERC regional planning authority, and in response to the recently passed Illinois law the Climate and Equitable Jobs Act (CEJA), PJM conducted a study to determine impacts to the transmission system resulting from anticipated generation retirements in Illinois through 2045. CEJA mandates the scheduled phaseout of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. CEJA also allows for the opportunity to create reliability safety measures[2] and further directs Illinois government to create a working group to collaborate with PJM and MISO starting in 2025 so as to analyze reliability impacts based on this retirement schedule. Further, CEJA contemplates and incentivizes the construction of a significant quantity of renewable resources.

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1 NERC standard that establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies; TPL-001-4.

2 See PJM Reliability Guidance: https://www.pjm.com/-/media/committees-groups/committees/oc/postings/illinois-ceja-reliability-guidance.ashx.

Scope

While generation retirements could occur in Illinois for reasons other than CEJA (e.g., economic factors, federal EPA regulations), the scenarios studied were based upon the two significant target deadlines in CEJA for phasing out fossil generation: 2030 and 2045. Thus, PJM's study encompassed analysis of two study scenarios, 2030 and 2031–2045, as part of identifying overall reliability criteria violations and developing high-level solutions and cost estimates.

The study includes in its modeling: (i) units that will be leaving the system as a result of already issued retirement notices; (ii) phaseout requirements as set forth in CEJA; and (iii) generation additions based on the current PJM generation interconnection queue.

The study does not include in its modeling renewable generation that is expected to be added to the system in the future as contemplated and incentivized under CEJA.

The difference between the 2030 case and the 2031–2045 case was the increased expected deactivations in the latter case. Load and the replacement generation remained consistent between the two scenarios to ensure violations were attributable to the deactivations.

PJM conducted its standard set of planning reliability studies tests, including generation deliverability, N-1, N-1-1 thermal and voltage drop analyses.3

The study does not include the MISO Long-Range Transmission Plan (LRTP) Tranche 1 project portfolio or the ongoing additional LRTP study work MISO is performing that includes the Illinois area. PJM adopted a number of assumptions that may be updated when PJM, MISO and impacted transmission owners conduct a more rigorous Illinois deactivation reliability study analysis in late 2022/early 2023. PJM monitored MISO facilities along the PJM/MISO seam and coordinated with the most heavily impacted MISO transmission owner (NIPSCO) to review results and provide required high-level transmission solutions and attendant high-level cost estimates. While MISO participated in model development with PJM, MISO indicated that its own timeline for conducting a detailed study of its own system and identification of additional upgrade costs would likely be late 2022 or early 2023.

To establish the timing of affected generation units' expected deactivation, MISO and PJM analyzed each generating unit's publically available emissions data; published heat rate; and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones to understand CEJA criteria impacts.

PJM did not attempt to estimate early retirements due to current CEJA operational limits on natural gas-fired generation.

Modeled PJM replacement generation was based on generation interconnection queue projects with executed Interconnection Service Agreements (ISAs) or Facilities Study Agreements through Jan. 7, 2022, in Queue AF1.

3 Descriptions of study methodologies can be found in PJM Manual 14B.

Further Framing

This is a very initial snapshot of the system based upon what PJM knows today, and PJM will iterate on this analysis over time. The timing of deactivations in Illinois, as well as in the rest of the PJM region, and the impact of replacement generation from PJM's interconnection queue will impact future study results.

PJM notes it is not proposing fixes for PJM RTEP projects based on this study.

The cost estimates identified in this study will not actually be charged to consumers today; as the system evolves with retirements and additions, PJM will have a better sense of the necessary transmission that will be needed to alleviate any reliability violations.

New generation located at the same points where units are retiring, or in similarly favorable locations, could decrease the transmission cost estimates outlined in our findings. At the same time, there is the risk of an acceleration of upgrades if existing generators retire earlier than modeled.

In addition, PJM will combine this analysis with an analysis from MISO to determine whether any interregional transmission planning can assist in optimizing the systems to further reduce costs in the PJM (and MISO) footprint.

PJM will iterate on this study as we gain more clarity on renewable build out through the Illinois Renewable Energy Access Plan (REAP) and the projects that enter our queue. Currently, PJM's generation interconnection queue consists of approximately 200,000 MW, of which approximately 95% is solar, wind or hybrid; we expect this trend to continue.

Summary of Findings

PJM identified several transmission upgrades that will be needed as Illinois generation retires or is phased out. Initial estimated costs for transmission upgrades are approximately $700 million by 2030 and an additional $1.3 billion by 2045. For reliability reasons, PJM may need to request that certain units operate beyond their desired deactivation dates pursuant to Part V of the PJM Tariff.

Detailed takeaways include the following:

The study identified 69 upgrades to the 138 kV system dispersed over the PJM footprint that accounted for 82% of the thermal upgrade costs; sixteen 345 kV upgrades accounted for 18% of the costs.

The overall study yielded a total upgrade solution cost estimate of $2 billion, or $0.7 billion and $1.3 billion, respectively, for the 2030 and 2031–2045 study scenarios.

(a) Grid upgrades to solve thermal-based reliability criteria violations account for 64%, or $1.3 billion, of the upgrade cost estimate and are almost evenly split between the 2030 and 2031–2045 study scenarios. Fifteen percent of this total is for thermal-based upgrades in ComEd; 85% is for upgrades across the rest of the PJM Western subregion.

(b) Grid upgrades to solve voltage-based reliability criteria violations account for 36%, or $718 million, of the upgrade costs. Unlike thermal violations, which tend to be more linearly aligned with megawatt impacts, voltage violations are nonlinear.

The Illinois fossil resource deactivations create the need to import a substantial amount of remote replacement power to serve load. The PJM interconnection queue provided 14,848 MW dispersed across the footprint, which were applied to both the 2030 and 2031–2045 cases. The studies in the 2030 and 2031–2045 cases show significant east-to-west power-flow increases on the PJM grid, particularly in the Western subregion. These increased flows primarily impact ComEd, FirstEnergy, Duquesne, AEP and NIPSCO (MISO) zones.

(c) The increased east-to-west imports caused numerous, significant thermal-based reliability criteria violations in both the 2030 and 2031–2045 scenarios.

(d) The 2030 study case analysis identified the initial onset of system voltage instability issues in Illinois.

(e) The 2031–2045 study case analysis identified significant voltage stability concerns in Illinois and surrounding states that, if not resolved with system upgrades, could lead to blackouts driven by voltage collapse.

Because Illinois includes parts of both the PJM and MISO footprints, future coordinated interregional studies and solutions are recommended to ensure cost-effective and optimized solutions.

To address the voltage instability concerns, ComEd and NIPSCO proposed static volt-amp reactive compensators (SVCs) and synchronous condensers to replace the megavolt amperes reactive (MVAR) capabilities lost from the deactivation of the generating units that had provided that reactive support at a $525 million and $193 million cost estimate for the SVCs, respectively. With the onset of voltage instability observed in the 2030 scenario, PJM assumed 10% of that cost would be incurred prior to 2030 with the remainder needed after 2030.

Study Assumptions

Base Cases

PJM and MISO agreed to use the 2021-series Multiregional Modeling Working Group (MMWG) 2031 study year power-flow case adjusted for updated loads, anticipated baseline upgrade updates, deactivation estimates and replacement generation for both 2030 and 2045. MISO provided PJM modifications to the MMWG case to reflect generation retirements. PJM then incorporated into that case its own system model from the last completed five-year RTEP summer case – the 2021-series 2026 summer case – with load scaled as shown in **Table 1**, below.

Table 1. Illinois Generation Retirement Study Load Levels

Year	PJM	MISO

2030	2026 scaled to 2031	MMWG 2031
2031–2045		

Publically available data were applied to the deactivation requirement criteria. Deactivations were modeled totaling the following power reductions as shown below in **Table 2**.

Table 2. PJM's Illinois Generation Retirement Study Deactivation Levels

Year	PJM (MW)	MISO (MW)	Illinois Total (MW)
Estimated Illinois for 2030 Case	9,661	1,933	**11,594**
Estimated Illinois for 2031–2045 Case	14,888*	8,003*	**22,891***

* Cumulative and includes all anticipated Illinois CEJA deactivations

Given the level of deactivations, replacement power – shown in **Table 3** – was met with output from generators in its interconnection queue that had either an executed Interconnection Service Agreement, or a generator Facilities Study Agreement, as of Jan. 7, 2022, in Queue AF1. PJM applied a commercial probability of 57% to the requested Capacity Interconnection Rights for those Facilities Study Agreement projects.

Table 3. PJM Illinois Generation Retirement Study Replacement Capacity (as of Jan. 7, 2022, in Queue AF1)[4]

Year	PJM (MW)	MISO (MW)	Total (MW)
ISA	6,315	N/A	6,315
Facilities Study (57% CP x CIRs)	8,533	7,240*	15,773
Total	**14,848**	**7,240**	**22,088**

* MISO provided value and does not constitute 57% CP x CIRs

Detailed Findings

As indicated above, PJM conducted two generation retirement studies – one each for the 2030 and 2031–2045 study cases – using its established set of PJM RTEP deactivation analyses. **Table 4** quantifies the estimated cost for each transmission owner zone to solve identified thermal-based reliability criteria in each study year. **0** quantifies the estimated cost for each transmission owner zone to solve identified voltage-based reliability criteria violations in each study case. The longest duration for upgrade completion for was 60 months.

4 Based on requested CIRs using PJM's current process, which does not include Effective Load Carrying Capacity (ELCC)

Transmission owners reviewed and confirmed the identified violations. Where a violation was identified, the transmission owner either provided existing planned upgrades or provided a proposed upgrade solution. For proposed solutions, transmission owners provided high-level cost-per-mile and duration estimates. Existing planned upgrades were excluded from this report, since they will be completed prior to the scenario timing, and the costs are already accounted for in the respective regional expansion plans.

Under PJM's existing RTEP process, once an official retirement notification is received, PJM engages in an intensive process with affected transmission owners to identify transmission network reliability upgrade solutions and attendant estimated costs and in-service dates. If needed, PJM would also develop interim operating procedures until such upgrades were in place.

Solutions and Cost Estimates To Solve Thermal-Based Violations

	2030	2031–2045
ComEd	ComEd estimated approximately $100 M of upgrades are required to address thermal overloads. Most of that cost estimate is associated with a new 138 kV transmission line from Haumesser to West Dekalb to Glidden.	ComEd identified an additional $160 M in thermal upgrades.

	2030	2031–2045
AEP	AEP estimated approximately $63.5 M of upgrades to solve thermal overloads. Almost 80% of that cost would be to rebuild the AltaVista to Otter to Johnson Mountain to New London 138 kV line.	AEP estimated $178 M of upgrades to solve thermal overloads. Approximately 85% of that cost was for a proposed new Segreto-Cook 345 kV line and to rebuild the West End Fostoria to Woodville 138 kV line.

	2030	2031–2045
FirstEnergy	FirstEnergy estimated $320 M in upgrades to address the thermal violations caused by an increase in east-to-west power flow. Approximately 60% of that estimate derives from reconductoring five 138 kV circuits: two between Leroy Center and Mayfield and three from Charleroi to Union Junction, Westraver and Yukon.	FirstEnergy estimated $180 M in upgrades to address thermal violations. Over 80% of this estimate would be to conductor the following 138 kV lines: Mitchell to Shepler Hill Junction, Peters to Union Junction, Yukon to Smithton, Leroy Center to Mayfield, and Richland to Lockwood (AEP).

Duquesne	The Duquesne area had the same thermal issues identified in both the 2030 and 2031–2045 study cases. The proposed 2030 fixes also resolve the 2031–2045 study case reliability criteria violations. Duquesne identified upgrades with an estimated cost of $180 M. Most of that estimated cost is for new 138 kV facilities, including a new Elrama substation, two new ties and one new transmission line. Additionally, approximately 35 circuit miles of 138 kV reconductor is required.

MISO (NIPSCO)	Based on PJM’s analyses, NIPSCO identified $125 M of upgrades are needed to address thermal-based reliability criteria violations.

Table 4. PJM Illinois Generation Retirement Study Cost Estimates To Solve Thermal-Based Reliability Criteria Violations

TO	2030 Thermal Upgrades ($M)	2031–2045 Thermal Upgrades ($M)	Overall Thermal Upgrades ($M)
ComEd	98.00	161.50	259.50
FE	320.00	180.00	500.00
DLCO	180.00	0	180.00
AEP	63.55	178.10	241.58
NIPSCO	0	125.40	125.00
Total	**661.75**	**644.33**	**1,306.08**

Solutions and Cost Estimates To Solve Voltage Violations

ComEd

The onset of voltage stability issues was identified in the 2030 study case. However, more widespread voltage stability violations were identified in the 2031–2045 study case N-1-1 voltage analyses. The primary causes are: (1) the lack of reactive support in the ComEd area driven by loss of reactive capability from deactivated generators; and (2) increased power imports into Illinois required to serve load.

In particular, PJM notes that the two lines comprising the East Frankfort-Olive 345 kV would have to support power delivery of 1,730 MW into ComEd in the 2031–2045 study case. Each of the two lines in the corridor consumes about 500 MVAR.

Widespread voltage collapse was observed for many N-1-1 contingencies involving east/west tie line flows and/or large generator contingencies. This is indicative of the need for additional transmission system expansion – reinforcements to existing lines or construction of new lines – on east-west transmission paths between ComEd and AEP.

The generator reactive capabilities modeled in study year 2045 totaled 4,324 MVAR. If actual generation deactivation notices were received, ComEd indicates its voltage stability and dynamic recovery criteria would be triggered. ComEd estimates that if all this lost reactive capability was replaced with SVCs, using an estimate of $0.12 million per MVAR, it would yield an estimated cost of $525 million. Due to the short time frame to develop and evaluate the results of the studies, a more optimal combination of upgrades to address the voltage issues would likely include a combination of new transmission and SVCs, especially in consideration of reliability criteria violation issues that span multiple transmission owner zones.

For purposes of this study, PJM assumed 10% of overall MVAR replacement would be needed in 2030 and the remaining needed in the 2031–2045 study case.

AEP

AEP concurred with ComEd's proposed solution for replacement reactive power devices. AEP also agreed that further study would be needed to ensure the proper balance of transmission and reactive power upgrades.

MISO (NIPSCO)

Based on PJM's study results, NIPSCO estimates $193 million of synchronous condensers would be required to solve voltage-based reliability criteria violations. NIPSCO concurs with PJM that MISO and PJM interregional coordination will be required to properly address voltage issues. Similar to that for ComEd, PJM assumed about 10% of the overall MVAR capability replacement would be needed in 2030, and the remaining needed in the 2031–2045 study case.

Table 5. PJM Illinois Generation Retirement Study Cost Estimates To Solve Voltage-Based Reliability Criteria Violations

TO	2030 Voltage Upgrades ($M)	2031–2045 Voltage Upgrades ($M)	Overall Voltage Upgrades ($M)
ComEd	52.5	472.5	525.0
NIPSCO	19.3	173.7	193.0
Total	**71.8**	**646.2**	**718.0**

Overall Upgrade Cost Estimates

The thermal-based and voltage-based upgrade cost estimates discussed above are enumerated in **Table 6,** below.

Table 6. PJM Illinois Generation Retirement Study Total Estimated Upgrade Costs by Study Year

TO	Thermal Upgrades		Voltage Upgrades		Overall Upgrades ($M)
	2030 ($M)	2031–2045 ($M)	2030 ($M)	2031–2045 ($M)	
ComEd	98.00	161.50	52.50	472.50	784.50
FE	320.00	180.00	0	0	500.00
DLCO	180.00	0	0	0	180.00
AEP	63.75	178.83	0	0	241.58
NIPSCO	0	125.00	19.30	173.70	318.0
Total	**661.75**	**644.33**	**71.80**	**646.20**	**2,024.02**

Appendix

Table 7. Facility Study Queues

Queue name	CIRS	CIRSx0.57	Fuel Type	TO Zone
AB1-087	341.00	194.37	Natural Gas	AEP
AB1-087	243.60	138.85	Natural Gas	AEP
AB1-088	341.00	194.37	Natural Gas	AEP
AB1-088	243.60	138.85	Natural Gas	AEP
AC2-015	119.70	68.23	Solar	AEP
AD2-063	90.00	51.30	Solar	DVP
AE1-058	261.20	148.88	Hydro	PPL
AE1-058	261.20	148.88	Hydro	PPL
AE1-059	261.40	149.00	Hydro	PPL
AE1-059	261.40	149.00	Hydro	PPL
AE1-068	255.70	145.75	Solar	DVP
AE1-068	255.70	145.75	Solar	DVP
AE1-069	192.74	109.86	Solar	DVP
AE1-069	214.16	122.07	Solar	DVP
AE1-072	99.00	56.43	Solar	DVP
AE1-085	50.00	28.50	Solar	DVP
AE1-092	96.00	54.72	Solar	DAY
AE1-128	72.00	41.04	Solar	PENELEC
AE1-153	89.00	50.73	Solar	DVP
AE1-155	76.00	43.32	Solar	DVP
AE1-206	171.00	97.47	Solar	DVP
AE1-238	225.00	128.25	Wind	JCP&L
AE1-246	81.00	46.17	Solar	EKPC
AC1-008	19.20	10.94	Nuclear	PENELEC
AC1-033	13.10	7.47	Wind	CE
AC1-053	26.00	14.82	Wind	CE
AC1-086	123.70	70.51	Solar	DVP
AC1-101	19.00	10.83	Solar	AEP
AC1-102	38.00	21.66	Solar	AEP
AC1-167	33.60	19.15	Solar	AEP
AC1-168	10.20	5.81	Wind	CE
AC1-171	10.30	5.87	Wind	CE
AC1-188	46.60	26.56	Solar	AEP
AC1-190	35.00	19.95	Solar	DP&L
AC1-194	48.00	27.36	Solar	AEP
AC1-194	47.50	27.08	Solar	AEP
AC2-017	11.10	6.33	Nuclear	BGE
AC2-023	26.50	15.11	Solar	DP&L
AC2-029	26.60	15.16	Solar	AEP

Queue name	CIRS	CIRSx0.57	Fuel Type	TO Zone
AC2-044	7.60	4.33	Solar	AEP
AC2-048	22.80	13.00	Solar	AEP
AC2-060	64.00	36.48	Solar	AEP
AC2-061	58.10	33.12	Solar	DEO&K
AC2-084	53.60	30.55	Solar	DVP
AC2-090	38.00	21.66	Solar	AEP
AC2-141	168.20	95.87	Solar	DVP
AC2-154	19.00	10.83	Solar	CE
AC2-157	38.00	21.66	Solar	AEP
AC2-157	38.00	21.66	Solar	AEP
AC2-157	62.80	35.80	Solar	AEP
AC2-157	62.80	35.80	Solar	AEP
AD1-013	15.40	8.78	Solar	CE
AD1-022	77.70	44.29	Solar	DVP
AD1-022	42.30	24.11	Solar	DVP
AD1-025	94.20	53.69	Solar	DVP
AD1-031	26.60	15.16	Solar	CE
AD1-039	56.35	32.12	Natural Gas	CE
AD1-043	45.60	25.99	Solar	AEP
AD1-056	61.30	34.94	Solar	DVP
AD1-056	32.70	18.64	Solar	DVP
AD1-070	36.00	20.52	Solar	AEP
AD1-073	13.20	7.52	Solar	AEP
AD1-074	320.70	182.80	Solar	DVP
AD1-074	163.30	93.08	Solar	DVP
AD1-088	75.20	42.86	Solar	DVP
AD1-098	57.80	32.95	Solar	CE
AD1-100	150.00	85.50	Wind	CE
AD1-102	23.40	13.34	Wind	AEP
AD1-103	19.66	11.20	Wind	ATSI
AD1-103	25.74	14.67	Wind	ATSI
AD1-105	45.43	25.90	Solar	DVP
AD1-106	22.80	13.00	Solar	AEP
AD1-115	19.00	10.83	Solar	DVP
AD1-116	7.60	4.33	Solar	CE
AD1-118	70.00	39.90	Natural Gas	ATSI
AD1-128	57.00	32.49	Solar	AEP
AD1-133	180.00	102.60	Solar	CE
AD1-148	49.00	27.93	Wind	CE
AD1-151	90.00	51.30	Solar	DVP
AD1-152	48.00	27.36	Solar	DVP
AD1-161	30.20	17.21	Solar	AEP

Queue name	CIRS	CIRSx0.57	Fuel Type	TO Zone
AD2-007	4.50	2.57	Solar	DVP
AD2-008	16.40	9.35	Solar	DVP
AD2-014	22.40	12.77	Solar	AEP
AD2-020	61.90	35.28	Solar	AEP
AD2-022	60.00	34.20	Solar	AEP
AD2-023	35.00	19.95	Solar	AEP
AD2-031	19.00	10.83	Solar	DAY
AD2-033	78.00	44.46	Solar	DVP
AD2-038	19.50	11.12	Wind	CE
AD2-046	54.80	31.24	Solar	DVP
AD2-047	34.00	19.38	Wind	CE
AD2-051	52.40	29.87	Solar	DVP
AD2-059	0.24	0.14	Storage	DP&L
AD2-060	20.00	11.40	Solar	CE
AD2-062	53.50	30.50	Solar	AP
AD2-066	69.60	39.67	Solar	CE
AD2-067	57.00	32.49	Solar	AEP
AD2-071	67.00	38.19	Solar	AEP
AD2-074	32.68	18.63	Solar	DVP
AD2-075	145.00	82.65	Natural Gas	AEP
AD2-077	100.00	57.00	Storage	PPL
AD2-086	138.00	78.66	Solar	AEP
AD2-091	50.00	28.50	Storage	AEP
AD2-092	105.00	59.85	Solar	AEP
AD2-096	50.00	28.50	Storage	AEP
AD2-100	126.00	71.82	Solar	CE
AD2-102	120.00	68.40	Solar	CE
AD2-131	8.30	4.73	Storage	CE
AD2-134	22.90	13.05	Wind	CE
AD2-136	46.80	26.68	Wind	AEP
AD2-157	42.00	23.94	Solar	AP
AD2-162	73.81	42.07	Solar	AEP
AD2-178	72.00	41.04	Solar	AEP
AD2-179	60.00	34.20	Solar	AEP
AD2-214	40.80	23.26	Solar	CE
AE1-001	7.10	4.05	Nuclear	BGE
AE1-020	229.30	130.70	Wind	JCP&L
AE1-040	31.60	18.01	Solar	DAY
AE1-051	10.00	5.70	Storage	PPL
AE1-052	10.00	5.70	Storage	AP
AE1-056	38.80	22.12	Solar	DVP
AE1-062	10.00	5.70	Storage	AE

Queue name	CIRS	CIRSx0.57	Fuel Type	TO Zone
AE1-064	67.30	38.36	Solar	AEP
AE1-079	13.50	7.70	Solar	ATSI
AE1-090	21.56	12.29	Solar	AEP
AE1-091	46.93	26.75	Solar	AEP
AE1-093	42.00	23.94	Storage	AEP
AE1-102	15.60	8.89	Solar	AEP
AE1-103	21.00	11.97	Solar	DVP
AE1-105	1,235.00	703.95	Natural Gas	AP
AE1-107	31.00	17.67	Solar	DP&L
AE1-108	89.70	51.13	Solar	DVP
AE1-113	66.00	37.62	Wind	CE
AE1-115	10.00	5.70	Storage	AE
AE1-117	48.00	27.36	Wind	DP&L
AE1-138	13.20	7.52	Solar	METED
AE1-139	39.00	22.23	Solar	METED
AE1-144	80.20	45.71	Solar	EKPC
AE1-146	81.80	46.63	Solar	AEP
AE1-148	54.00	30.78	Solar	DVP
AE1-149	60.00	34.20	Solar	DVP
AE1-157	77.80	44.35	Solar	DVP
AE1-158	79.40	45.26	Solar	DVP
AE1-161	20.00	11.40	Storage	AE
AE1-163	49.00	27.93	Wind	CE
AE1-170	63.00	35.91	Solar	AEP
AE1-172	44.80	25.54	Wind	CE
AE1-179	35.00	19.95	Solar	AE
AE1-181	27.00	15.39	Solar	PPL
AE1-190	60.00	34.20	Solar	DVP
AE1-190	40.00	22.80	Solar	DVP
AE1-207	67.20	38.30	Solar	AEP
AE1-208	55.00	31.35	Solar	AEP
AE1-209	13.00	7.41	Wind	AEP
AE1-210	13.00	7.41	Wind	AEP
AE1-212	59.00	33.63	Solar	AEP
AE1-225	9.40	5.36	Solar	PPL
AE1-227	30.69	17.49	Solar	AEP
AE1-229	89.00	50.73	Solar	AE
AE1-237	13.50	7.70	Solar	ATSI
AE1-240	29.00	16.53	Solar	AE
AE1-245	19.50	11.12	Wind	AEP
AE1-250	90.00	51.30	Solar	AEP
AE2-001	12.00	6.84	Solar	AP

Queue name	CIRS	CIRSx0.57	Fuel Type	TO Zone
AE2-071	21.00	11.97	Solar	EKPC
AE2-148	397.30	226.46	Solar	DAY
AE2-282	43.90	25.02	Solar	ATSI
AE2-308	110.00	62.70	Solar	EKPC
AF1-086	20.54	11.71	Wind	PENELEC
AF1-123	267.50	152.48	Wind	DVP
AF1-124	267.50	152.48	Wind	DVP
AF1-125	267.50	152.48	Wind	DVP
AF1-130	133.90	76.32	Solar	AEP
AF1-141	62.80	35.80	Solar	AEP
AF1-162	60.00	34.20	Storage	AEP
AF1-164	195.00	111.15	Solar	AEP
AF1-215	180.00	102.60	Solar	AEP
AF1-233	150.60	85.84	Solar	EKPC

Table 8. ISA Queue Assumptions

Queue Name	CIRs	Fuel	TO
AB2-070	26.00	Wind	CE
AB2-100	33.50	Solar	DVP
AB2-100	33.50	Solar	DVP
AC2-111	30.40	Solar	AEP
AD1-061	7.60	Solar	AP
AD1-083	60.10	Solar	AP
AD1-155	37.20	Solar	AP
AD2-076	18.62	Solar	DP&L
AD2-085	19.40	Solar	DVP
AD2-115	13.00	Solar	METED
AD2-116	13.00	Solar	METED
AD2-158	46.50	Solar	AP
AD2-160	32.80	Solar	DVP
AD2-163	60.35	Solar	ATSI
AD2-163	60.35	Solar	ATSI
AD2-180	15.08	Wind	AP
AE1-084	50.00	Solar	DVP
AE1-087	16.41	Storage	DP&L
AE1-101	99.90	Solar	AP
AE1-101	49.90	Solar	AP
AE1-104	60.50	Wind	AE
AE1-104	60.50	Wind	AE

Queue Name	CIRs	Fuel	TO
AE1-129	47.00	Solar	METED
AE1-185	12.60	Solar	METED
AE1-196	13.00	Solar	METED
AE1-226	9.40	Solar	PPL
AE2-042	46.80	Solar	PPL
AE2-126	12.00	Solar	PENELEC
AE2-129	12.00	Solar	PENELEC
AE2-249	8.10	Solar	PENELEC
AE2-253	69.57	Solar	DVP
AE2-254	50.00	Solar	EKPC
AF1-006	20.00	Solar	PENELEC
AF1-039	9.00	Solar	PENELEC
AF1-217	12.00	Solar	PENELEC
AF1-249	14.00	Solar	DEO&K
AF1-287	12.00	Solar	PENELEC
AF2-057	20.00	Storage	DVP
AF2-144	10.20	Solar	DVP
AF2-265	8.60	Solar	PENELEC
AF2-367	12.00	Hydro	DLCO
AF2-368	9.50	Hydro	DLCO
AA1-146	190.00	Natural Gas	CE
AA2-030	157.00	Natural Gas	CE
AB2-036	34.90	Solar	DP&L
AB2-135	29.90	Solar	DP&L
AB2-136	24.80	Solar	DP&L
AC1-001	33.93	Solar	AEP
AC1-074	56.00	Solar	EKPC
AC1-078	66.00	Solar	ATSI
AC1-083	38.00	Solar	AEP
AC1-174	38.00	Solar	AEP
AC1-175	38.00	Solar	AEP
AC1-216	54.80	Solar	DVP
AC2-012	57.00	Solar	DVP
AC2-059	62.50	Solar	AEP
AC2-123	44.60	Solar	AEP
AC2-165	57.00	Solar	DVP
AC2-185	15.20	Solar	DP&L
AC2-186	3.80	Solar	DP&L

Queue Name	CIRs	Fuel	TO
AC2-187	7.60	Solar	DP&L
AC2-188	7.60	Solar	DP&L
AC2-195	62.10	Solar	ATSI
AD1-101	19.00	Solar	AEP
AD1-119	19.00	Solar	AEP
AD1-125	10.43	Wind	AP
AD1-125	1.33	Wind	AP
AD2-016	63.00	Solar	AEP
AD2-073	13.32	Solar	DVP
AD2-079	12.00	Solar	AEP
AD2-172	21.00	Solar	CE
AE1-109	2.90	Solar	AP
AE1-109	2.90	Solar	AP
AE1-109	2.90	Solar	AP
AE2-035	21.00	Solar	CE
AE2-224	60.00	Solar	PENELEC
AF1-174	12.00	Solar	PECO
AF1-227	112.25	Solar	AEP
AF1-227	81.07	Solar	AEP
AF1-227	1.68	Solar	AEP
AB2-085	54.40	Solar	AEP
AB2-102	225.00	Natural Gas	AE
AC1-082	29.00	Solar	AEP
AC1-110	15.00	Natural Gas	CE
AC1-189	53.40	Solar	DVP
AC1-191	53.40	Solar	DVP
AD1-082	43.30	Solar	DVP
AD1-087	48.30	Solar	DVP
AD1-140	95.80	Solar	ATSI
AD2-048	46.70	Solar	EKPC
AD2-093	135.00	Solar	AEP
AE1-044	111.80	Solar	DVP
AE1-071	62.10	Solar	PENELEC
AE1-100	41.90	Solar	AEP
AE2-029	30.00	Solar	DVP
AE2-206	41.58	Solar	DAY
AE2-218	106.00	Solar	DAY
AE2-221	180.00	Solar	DAY

Queue Name	CIRs	Fuel	TO
AE2-290	60.00	Solar	AEP
AE2-297	91.50	Solar	AEP
AE2-303	45.00	Solar	DAY
AE2-342	26.80	Solar	DAY
AF1-147	60.00	Solar	DVP
AC1-103	557.90	Natural Gas	AEP
AA1-111	463.00	Natural Gas	PENELEC
AB2-037	202.00	Solar	DP&L
AD2-055	35.00	Natural Gas	PENELEC
AE2-285	30.00	Solar	ATSI
AB1-089	243.60	Natural Gas	CE
AB1-089	341.00	Natural Gas	CE