

Duke Integration White Paper

Version 6.0

[The purpose of this whitepaper is to provide the best current information to the PJM stakeholders regarding how PJM intends to integrate Duke. The term “Duke” is used throughout this paper and specifically refers to the entities that are being integrated into PJM, namely, Duke Energy—Ohio, Inc. and Duke Energy—Kentucky, Inc. The whitepaper should be viewed as a draft proposal as some of it will require approvals by FERC, NERC, and applicable stakeholder processes. Any proposed exception to current PJM Tariff or PJM agreement provisions will be noted accordingly and will require FERC approval. This whitepaper will be a living document likely up until the time Duke integrates into PJM on January 1, 2012.]

Revision History

Version	Date Posted	Revision Description
1	08/20/2010	Initial distribution
2	8/24/2010	Corrected reference to the special FTR allocation only being one round
3	9/8/2010	Updated FRR plan opt-out dates within Reliability Pricing Model Integration section Added Balancing Operating Reserve regions and DASR Ancillary Service Area to table on page 5
4	9/27/2010	Updated list of interface pricing points in Interface Pricing section
5	10/24/2011	Updated the name of the Duke zone to the DEOK zone. Added LSE Account Set Up and Billing Line Item Transfers section. Added Schedule 9-FERC Exemption section.
6	1/20/2012	Added sections on Transmission Enhancement Charge Billing and MTEP Project Cost Recovery Billing.

Duke Integration White Paper

TABLE OF CONTENTS

<u>INTRODUCTION</u>	5
<u>OVERVIEW</u>	5
<u>TRANSFER OF BALANCING AREA</u>	7
DECERTIFICATION OF DUKE FROM MISO	7
CERTIFICATION PROCESS FOR PJM	7
PJM COORDINATION WITH NEIGHBORING TRANSMISSION OPERATORS AND BALANCING AREAS.....	7
NERC COMPLIANCE REGISTRY	7
<u>REACTIVE POWER, VOLTAGE SCHEDULING COORDINATION (RTO/LOCAL CONTROL CENTER)</u>	7
VOLTAGE OPERATING CRITERIA AND GUIDELINES.....	7
VOLTAGE COORDINATION	9
BULK POWER CAPACITORS.....	9
<u>SYSTEM OPERATOR CERTIFICATION AND TRAINING REQUIREMENTS</u>	9
SYSTEM OPERATOR CERTIFICATION REQUIREMENTS	10
INITIAL SYSTEM OPERATOR TRAINING REQUIREMENTS	10
<u>REAL-TIME OPERATIONS</u>	11
AUTOMATIC GENERATION CONTROL (“AGC”).....	11
OUTAGE COORDINATION	11
GENERAL PRINCIPLES	11
SCHEDULING TRANSMISSION OUTAGE REQUESTS	12
REQUIREMENTS	12
SCHEDULING & TRACKING TRANSMISSION RATING CHANGES	13
GENERATION.....	14
OUTAGE REPORTING OVERVIEW.....	14
PLANNED OUTAGES	14
MAINTENANCE OUTAGES.....	14
UNPLANNED OUTAGES.....	15
REACTIVE OUTAGE REPORTING.....	15
VOLTAGE REGULATOR & GOVERNOR OUTAGE REPORTING.....	15
MVAR CAPABILITY ADJUSTMENT REPORTING	15
SPECIALIZED EDART REPORTING	16
INSTANTANEOUS RESERVE CHECK (IRC) OVERVIEW.....	16
ADDITIONAL EDART REPORTING.....	16
<u>EMERGENCY PROCEDURES</u>	17
SYNCHRONIZATION OF PROCEDURES	17
SYSTEM RESTORATION.....	17
<u>CONGESTION MANAGEMENT PROCESS</u>	17
<u>EXCHANGE DATA FOR LOAD FLOW STUDIES</u>	18
<u>LOAD SHEDDING</u>	18
<u>DEMAND RESPONSE</u>	18
<u>PLANNING</u>	19
<u>MARKETS</u>	19
EMARKET AND UDS	19

Duke Integration White Paper

INTERFACE PRICING	20
SYNCHRONIZED RESERVE ZONE/REGULATION ZONE	21
BLACK START	21
FINANCIAL TRANSMISSION RIGHTS	21
SERVICE ON THE MISO OASIS	22
<u>RELIABILITY PRICING MODEL INTEGRATION</u>	23
RESERVE MARGIN ANALYSIS.....	23
OBLIGATION DETERMINATION	23
OBLIGATION COMPLIANCE	24
RPM TRANSITION	25
<u>ETOOOL CHANGES</u>	26
<u>MARKET MONITORING DATA REQUIREMENTS</u>	28
<u>SCHEDULING AND TAGGING/OASIS</u>	28
INTERNAL ENERGY SCHEDULING (FINANCIAL)	28
EXTERNAL ENERGY SCHEDULING	29
EXTERNAL TRANSACTION TIMING REQUIREMENTS.....	29
RAMP LIMITS	30
ENTERING RAMP RESERVATIONS	30
ENTERING SCHEDULES	31
ENTERING REAL-TIME WITH PRICE SCHEDULES.....	31
ENTERING TWO-SETTLEMENT SCHEDULES	32
TRANSACTION VALIDATIONS, VERIFICATION AND CHECKOUT	32
TRANSMISSION SERVICE (ATC CALCULATION)	35
TRANSMISSION SERVICE (OASIS)	35
CONVERSION OF SERVICE	35
<u>BILLING AND SETTLEMENT</u>	35
<u>METER CHECKOUT</u>	38
<u>PARTICIPANT READINESS/TRAINING DEVELOPMENT</u>	38
PARTICIPANT READINESS.....	38
TRAINING DELIVERY	38
<u>REFERENCE DOCUMENTS</u>	40
<u>CONTACT INFORMATION</u>	40
APPENDIX A: <u>GLOSSARY OF ACRONYMS</u>	41
APPENDIX B: <u>FTR ALLOCATION PROCEDURE</u>	45
APPENDIX C: <u>RAMP EXAMPLES</u>	47
APPENDIX D: <u>PJM MEMBERSHIP GUIDE</u>	50
APPENDIX E: <u>CONVERSION OF SERVICE IN THE DUKE ZONE</u>	52
APPENDIX F: <u>INTERFACE PRICING POINTS</u>	54
APPENDIX G: <u>PJM INTERFACE DEFINITION METHODOLOGY</u>	55

Duke Integration White Paper

Introduction

PJM Interconnection will integrate the transmission assets of Duke Energy—Ohio, Inc. and Duke Energy—Kentucky, Inc. (“Duke”), the unregulated and selected regulated generation assets of Duke Energy and other generation owners within the above footprint, and a number of the distribution affiliates of Duke Energy¹ and other load serving entities into PJM’s, operations, planning, wholesale energy markets, capacity markets and ancillary service markets. Upon integration, the Duke zone² will merge into the PJM RTO and become part of the PJM Balancing Authority. This new PJM transmission zone will be referred to as the Duke Energy Ohio and Kentucky (“DEOK”) Zone.

This Whitepaper is for informational purposes only and does not modify any of the rights and obligations of PJM and its Members under the PJM Manuals, PJM Tariff and applicable FERC approved agreements or FERC regulations and NERC Reliability Standards unless such changes are submitted and accepted by the FERC and/or approved by the applicable PJM stakeholder processes. In the event of a conflict between this Whitepaper and the terms and conditions of the PJM Tariff, FERC approved agreements, PJM Manuals, FERC regulations and NERC Reliability Standards, the terms and conditions of the PJM Tariff, FERC approved agreements, PJM Manuals, FERC regulations and NERC Reliability Standards shall control. Moreover, several of the integration proposals contained in this Whitepaper will require filing with and acceptance by the FERC including but not limited Appendix E: Conversion of Service in the DEOK Zone. Therefore, the processes and procedures set forth herein will not be implemented until such FERC acceptance is obtained and they may be modified as directed by the FERC.

Unless otherwise provided herein, all defined terms in this document are as defined in the PJM Tariff, applicable FERC approved agreements or PJM Manuals.

Overview

The PJM RTO has a single energy market and a single economic dispatch. There will be three Synchronized Reserve Zones and one Regulation Zone run across the PJM RTO, making up the Ancillary Service Areas. Each Control Zone (i.e. PJM Mid Atlantic, Allegheny Power (AP), DEOK, Dayton, AEP, Duquesne, Dominion, and Commonwealth Edison (CE)) will be assigned to one and only one Ancillary Service Area.

Below is a summary of changes for the DUKE Market Implementation:

Items	Market Implementation Configuration
Balancing Authority Area	ONE

¹ Duke Energy—Ohio, Inc. and Duke Energy—Kentucky, Inc.

² The DEOK zone is the DEOK Local Balancing Authority Area, a term used in the Agreement between the Midwest ISO and Midwest ISO Balancing Authorities.

Duke Integration White Paper

Control Zones	NINE (CE, AEP, Dayton, PJM Mid-Atlantic, AP, Duquesne, Dominion, ATSI, DEOK)
Area Control Error (ACE)	ONE
Ancillary Service Area (Regulation Zone)	ONE
Ancillary Service Area (Synchronized Reserve)	THREE (PJM Mid-Atlantic, AP/Dayton/AEP/Duquesne/CE/ATSI/DEOK, and Dominion)
Ancillary Service Area (Day Ahead Scheduling Reserve)	ONE Market (includes RFC and DOM reserve requirements)
Energy Market	ONE
Day Ahead Operating Reserve Billing Region	ONE
Balancing Operating Reserve Billing Region	THREE (RTO, East, West – DEOK will be included in the RTO and West regions)
Capacity (RPM)	ONE Market / 25 LDAs (The DEOK zone will be an LDA)
Black Start	ONE
Load Management	TWENTY
PJM Load Response	ONE
Schedules/Tagging	ONE
OASIS node	ONE
eSuite	ONE
Accounting & Settlements	ONE
Inadvertent Calculations	ONE

Transfer of Balancing Area

Decertification of Duke from MISO

Prior to PJM integration, Duke is a MISO Local Balancing Authority Area (LBA), and its load and resources. On the date of Duke's integration into PJM, which is expected to be January 1, 2012 at 00:00 Midnight, Duke will cease to be a LBA in MISO, and the Duke load and resources, will be included in the PJM Balancing Area.

PJM will be the Balancing Authority used for transmission service and tags involving Duke beginning at midnight, the day of Market Integration (January 1, 2012). Duke will be removed as a Balancing Authority in TSIN at 12:01a.m the day *after* Market Integration (January 2, 2012).

Certification Process for PJM

PJM will be requesting NERC certification for the addition of the Duke area load and resources to the PJM Balancing Area. This process will include the naming of a certification team by NERC, review of relevant documentation, site visits to PJM and Duke, and a decision being rendered by NERC. We expect that the certification process could take approximately six months and is required to be complete by the integration date.

PJM Coordination with Neighboring Transmission Operators and Balancing Areas

PJM will coordinate with neighboring Transmission Operators and Balancing Authorities, particularly MISO to ensure a smooth transition, especially on the day of the integration. Seeing that Duke is already a member of RFC, no other changes or approvals will be necessary from a Regional Reliability Organization perspective.

NERC Compliance Registry

PJM is registered as a BA, IA, PA, RC, TOP, TP, RP, and TSP. Most of the existing PJM transmissions owning members are registered at Transmission Owners (TOs). Duke and is presently registered as a TOP, TP, and TO in MISO. Duke will have to decide if they prefer to maintain their TOP and TP registration prior to the integration date. Upon integration, PJM will become the RC, BA, IA, PA, RP and the TP and TOP for Duke, in the event Duke does not register as the TOP and TP.

Reactive Power, Voltage Scheduling Coordination (RTO/Local Control Center)

Voltage Operating Criteria and Guidelines

PJM will operate the facilities that are under PJM's operational control such that no PJM monitored facility will violate normal voltage limits on a continuous basis and that no monitored facility will violate emergency voltage limits following any simulated facility malfunction or failure.

Duke Integration White Paper

If a limit violation develops, PJM will direct the operation so that the system is returned to within normal continuous voltage limits under system normal conditions and the system is to be returned to within emergency voltage limits for the simulated loss of the next most severe contingency. Corrective action should begin as soon as a violation is observed and the violation corrected within 30-minutes.

PJM operation requires that actions should be taken on a pre-contingency basis in order to assure reliable operations after a malfunction or failure happens. Some examples of possible pre-contingency actions include pre-arranged approved switching of capacitors or reactors, Phase Angle Regulator tap adjustments (PARs), redispatch, and transaction curtailment. These actions can be used pre-contingency to control post-contingency operation so as not to exceed emergency ratings on a simulated basis. These pre-contingency options are considered by PJM's Reliability Engineer for inclusion in the day-ahead reliability analysis.

Voltage Drop limits are utilized to prevent voltage instability, which could result in system voltage collapse. Voltage Drop Violation limits will be evaluated by PJM based on studied system voltage characteristics. For voltage equipment levels below 500 kV, the transmission owner can recommend changes to the voltage drop limits over a range of values depending on local transmission system characteristics.

Load dump limits are provided to aid the system operator in identifying the speed necessary to relieve constraints. Operation at a load dump limit should not result in any facility tripping or voltage collapse when actually operated at that value for at least 15 minutes.

PJM has a number of IROLs on its system and all are related to wide area voltage control. (See list below from PJM Manual M-37, Reliability Coordination.) In addition to the procedures listed above, PJM has a Transfer Limit Calculator (TLC) which calculates voltage collapse points in real time and provides MW transfer limits which provide safe operating margins to ensure reliable operations at all times.

Transfer Limit / Thermal Rating	Reportable IROL Violation
Eastern Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
Central Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
5004/5005 Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
Western Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
AP South Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
Bedington – Black Oak Reactive Transfer Interface	Flow exceeds Last Convergent Case Limit for 30 minutes (T_v)
AEP-DOM Reactive Transfer Limit	Flow exceeds Last Convergent Case Limit for 30 Minutes (T_v)
Kammer 765/500kV Xfmr. Thermal Rating	Post-contingency Simulated Flows exceed the Load Dump Limit for 30 Minutes (T_v)

Belmont #5 765/500 kV Xfmr Thermal Rating Post-contingency Simulated Flows exceed the Load Dump Limit for 30 Minutes (Tv)

Voltage Coordination

PJM is responsible for the overall coordination of the bulk power voltage scheduling. In general, since voltage schedules have a significant effect on local voltages, PJM authorizes the Local Control Center (LCC)³ to establish and adjust voltage schedules, when operating within the overall PJM voltage control methodology. If the generator or the LCC desired voltage schedule impacts the overall PJM economic/reliable operation, then PJM shall exercise its operational control and direct changes to the generation voltage/reactive schedules, capacitor/reactor schedule/status, and transformer LTC operation for the overall reliable/economic operation of PJM.

Under most situations, the local Transmission Owner will establish and coordinate voltage schedules for all generators within that LCC zone. The typical LCC desired generating station voltage schedules should be communicated to the PJM dispatcher. By September of 2010, Duke will either share its voltage scheduling methodology and schedules or agree to the default schedules found in PJM's Manual M-3. Voltage Schedules will be integrated into the PJM Generation Performance Monitor tool which is used to track a generator adherence to voltage schedules.

PJM performs the following actions to correct high voltage conditions:

- The PJM dispatcher requests that switchable capacitors be disconnected and switchable reactors be connected.
- The PJM dispatcher requests LCC operators to direct all generators, synchronous condensers and SVCs within their zone to absorb reactive power.
- The PJM dispatcher requests neighboring Balancing Authorities to assist in reducing voltage.
- The PJM dispatcher requests the LCC operators to open effective EHV circuits.

Bulk Power Capacitors

Operation of the PJM RTO is coordinated in an attempt to minimize capacitor switching operation and transformer tap changes. PJM coordinates all switching of the 230 kV, 345 kV and 500 kV capacitors with the LCC to assist the system for actual or post-contingency situations. Capacitors should be kept in service whenever they are beneficial to the PJM RTO transfer capability or reliability and should generally not be switched automatically at a predetermined time of day, or by operating voltage except as noted in PJM Manual M-3. Local conditions may require some deviations.

System Operator Certification and Training Requirements

³ The LCC for the Duke area will be located at the Duke control center in Cincinnati, OH.

System Operator Certification Requirements

PJM System Operator Certification ensures PJM, LCC and Market Operation Center (MOC) operators have a baseline level of knowledge, awareness and familiarity with applicable PJM procedures, tools, tasks, and related power system operation theory in accordance with and in support of applicable NERC and regional standards during normal, emergency and restoration operational conditions. This certification supplements NERC Certification requirements by focusing on the details of PJM procedures, tools and tasks required for safe, reliable system operation.

All generation and transmission system operators must be PJM certified if they:

- Operate on the PJM RTO systems
- Communicate directly with any PJM control center and
- Perform daily operations-related functions at the direction of the PJM System Operators during normal, emergency and/or system restoration states.

As of January 1, 2012, all LCC operators must be PJM certified prior to operating on the PJM system. All MOC operators have a maximum of 12 months to become certified after they begin operating on the PJM RTO systems. During this 12 month period, if the operator is operating on the system and not PJM-certified, they must work under direct supervision of a PJM Certified operator, either in person or via an on-call arrangement.

Operators must complete and pass the applicable PJM Generation Exam or PJM Transmission Exam in order to attain certification. Passing a PJM certification exam is the only way for an individual to achieve initial PJM System Operator Certification. In addition, transmission operators will be required to maintain or acquire NERC certification as of the integration date.

Initial System Operator Training Requirements

Minimum training requirements have been established for Local Control Center (LCC) operators and MOC operators. MOC Generation System Operators are defined as System Operators who participate in the real time operations of the PJM system by dispatching generation and performing other generation-related real time duties of a MOC.

The following initial training requirements must be met by LCC and MOC operators integrating into PJM:

- Successfully complete the following PJM sponsored training within one year of participating in PJM real time operations:
 - MOC operators: Generation 101, 201, 301 and Operations 101 course series, or the Generation track of the PJM Interconnection Training Program (ITP). These courses are the equivalent of the MOC training program that will be held in the Duke footprint prior to integration.
 - LCC operators: Transmission 101 and Operations 101 course series, or the Standard track of the PJM Interconnection Training Program (ITP). These courses are the equivalent of the LCC training program that will be held in the Duke footprint prior to integration.

Duke Integration White Paper

- Successfully complete the Generation track (for MOC operators) or the Standard track (for LCC operators) of the ITP or equivalent within two years of participating in real-time PJM operations. The ITP is typically offered twice yearly and is typically delivered at a location near PJM's offices.

Experienced system operators are exempt from the requirement to complete the ITP program within two years of participating in real-time PJM operations. An experienced system operator is defined as an individual who has two or more years of prior experience participating in real time operations before assignment of PJM real time duties.

Completion of a course is measured by receipt of a certificate of completion for the course. Strongly recommended is successful completion of the ITP Standard or Generation Track within the first year of participating in PJM system operations. Also recommended is completion of the System Dynamics Extended Training Class following completion of the ITP. Further details on initial and ongoing system operator training requirements are included in Manual 40: Certification and Training Requirements.

Real-Time Operations

Automatic Generation Control (“AGC”)

PJM economically dispatches the PJM RTO as a single security constrained solution. There is one RTO schedule that is distributed to the entire PJM footprint via the economic dispatch and the Generation Transfer construct. The individual control zone calculations will provide regulation signals for all generator fleets in each respective zone (of which Duke will be a separate and distinct zone) and these signals will be sent to the generation fleet owners in the zone. PJM will provide the control zones with Control Zone Regulation Assist (“CZRA”) capability by sending the Generation Transfer (“GT”) for each zone. Further details are available in the AGC Market Integration White Paper.

Outage Coordination

General Principles

Transmission Owners have the right and obligation to maintain and repair their transmission system facilities. PJM approves all Reportable Transmission Facility outages prior to removal of the equipment from service. PJM will coordinate scheduled outages of all Reportable Transmission Facilities with planned generation outages that are submitted to PJM and may affect PJM RTO operation. For purposes of scheduling, Reportable Transmission Facilities include, but are not limited to, lines, transformers, phase angle regulators, buses, breakers, disconnects, bulk power capacitors, reactors, and all related equipment above 100kV.

PJM maintains a list of Reportable Transmission Facilities. Each Transmission Owner submits the tentative dates of all transmission outages of Reportable Transmission Facilities to PJM as far in advance as possible.

Duke Integration White Paper

Procedures and timelines are established for the scheduling, coordinating, requesting, studying, approving, and notifying of the transmission outage to/by the appropriate Transmission Owner and PJM. Under certain conditions such as extreme weather, peak load, heightened homeland security, etc. PJM will evaluate the need to operate the Power Grid in a more conservative manner. Actions that may be taken in these special circumstances include, but are not limited to, canceling or rescheduling outages and returning outaged equipment to service.

Scheduling Transmission Outage Requests

Each Transmission Owner shall submit the tentative dates of all planned transmission outages of Reportable Transmission Facilities to PJM via Electronic Dispatcher Applications and Reporting Tool (eDART) as far in advance as possible and update PJM at least monthly. For transmission outages exceeding five days, the TO shall use reasonable efforts to submit the planned outage schedule via eDART one year in advance but no later than the first of the month six months in advance of the requested start date along with a minimum of monthly updates. PJM maintains a planned transmission outage schedule for a period of at least the next 13 months. The planned transmission outage schedule is posted, subject to change, on the PJM Open Access Same-time Information System (OASIS). Planned transmission outages are given priority based on the date of submission. All planned transmission outages will be posted on OASIS within 20 minutes of Transmission Owner submittal of the outage through the PJM eDART system, with further updates as new information is provided in eDART. PJM periodically reviews all submissions of planned transmission outages and considers the effect of proposed transmission outages upon the integrated operation of the transmission system using established operating reliability criteria, as described within Sections 2 and 3 of this manual. Advance notification assures that the outage is reflected in both the ATC analysis and the FTR Auction. Outages scheduled for the following Planning year (i.e. June 1 – May 31) exceeding 30 days in duration are to be submitted via eDART by February 1 for use in the annual FTR auction. For example, outages scheduled to begin between June 1, 2009 and May 31, 2010 should be submitted by February 1, 2009. Estimated start and stop dates are acceptable. Duke should begin to submit dates for planned transmission outages starting in September 2010 in parallel with its present responsibilities in MISO.

Requirements

The Transmission Owner is required to submit all outage requests in excess of 5 days in duration by the 1st of the month six months in advance of the start of the outage. The Transmission Owner is required to submit all other outage requests by the 1st of the Month prior to the Month of the requested start date of the outage. Recognizing that this may not always be possible, the following table illustrates the five different time frames in which an Outage Request can be submitted and the different Actions PJM can take.

Request Submitted	Ticket Received Status	PJM Actions
By the 1st of the Month six months prior to start of the outage (Outages > 5days)	On Time	The outage will be approved, provided it does not jeopardize system reliability
After the 1 st of the Month 6	Late	The outage may be

Duke Integration White Paper

months prior to the start of the outage (Outages > 5days)		cancelled if it causes congestion requiring off-cost operations
By the 1 st of the Month prior to the Month of the outage	“On Time”	The outage will be approved, provided it does not jeopardize system reliability
After the 1st of the Month prior to the Month of the outage start, and before 8 am three business days before the start of the outage	“Late”	The outage may be cancelled if it causes congestion requiring off-cost operations
After 8 am three business days before the start of the outage	“Past Deadline”	Only Emergency or Exception requests (i.e. a generator tripped and the TO request to perform maintenance on the generator tie-line facilities while the unit is out of service) will be considered.

More detailed explanation of the Outage Coordination process can be found in PJM Manual M-03 (Transmission Operations), Section 4 (Reportable Transmission Facility Outages).

Scheduling & Tracking Transmission Rating Changes

In addition to transmission outage reporting Transmission Owners will update and verify facility ratings via the eDART – Transmission Equipment Ratings Monitor (“TERM”) application as soon as possible. Section 2 Thermal Operating Guidelines of the Transmission Operations Manual (M03) describes how actual and simulated equipment flows are compared to Normal, Emergency and Load Dump equipment ratings to assess system security. Transmission Owners (TOs) are responsible for providing the equipment ratings used in this analysis. TOs use TERM to monitor and update equipment (line and transformer) ratings used by PJM.

Recognizing that many factors affect thermal equipment ratings, both PJM’s EMS and the TERM system are designed to accept multiple ratings for monitored equipment. These multiple rating sets permit Transmission Owners to model equipment capability as a function of temperature (indexed to 95, 86, 77, 68, 59, 50, 41 and 32 degrees Fahrenheit) and to recognize the influence of solar heating during daytime versus nighttime operation. The PJM ratings system also allows Transmission Owners to model progressive and appropriate increases in the risk of equipment loss-of-life to respond to various operating conditions (Normal, Emergency or Load Dump. Normal ratings are also known as continuous ratings.) All ratings are submitted in MVA.

Duke Integration White Paper

The ratings submitted by Transmission Owners are subject to PJM review and approval. It is recommended that TOs review ratings seasonally, in conjunction with Model Updates, to ensure and maintain accuracy.

To ensure fair and equitable operation of market systems, by FERC order, PJM is required to provide an auditable record of ratings changes. TERM is designed to provide this audit trail.

Generation

Outage Reporting Overview

PJM is responsible for coordinating and approving requests for outages of generation facilities, as necessary, for the reliable operation of the PJM RTO. PJM maintains records of outages and outage requests for these facilities. Generation outages fall into the following three categories:

- planned
- maintenance
- unplanned

The general procedure begins with the PJM Members requesting outages via the eDART tool. PJM may either accept or reject a specific outage request. It is important to emphasize that PJM does not “schedule” when outages should take place. PJM only accepts/rejects the requests for outages. PJM only rejects outage requests when they affect the reliability of the PJM RTO. It is the responsibility of each PJM Member to determine its own best schedule of outages. Outage requests are honored by PJM on a first come-first serve basis.

Planned Outages

Planned Outages are scheduled by the PJM Members well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections, testing, and nuclear re-fueling are typical Planned Outages. Characteristically, Planned Outages usually occur during those seasons of the year when the peak demand on the power system is lowest. Planned Outages have flexible start dates, have a predetermined duration, last for several weeks, and occur only once or twice a year.

Maintenance Outages

A Maintenance Outage is an outage that may be deferred beyond the next weekend but requires that the Capacity Resource be removed from service before the next Planned Outage. Characteristically, these Maintenance Outages may occur throughout the year, have flexible start dates, are much shorter than Planned Outages, and have a predetermined duration established at the start of the outage. The duration of a Maintenance Outage is generally unlimited except during the PJM Peak Period Maintenance Season, which is defined as those weeks containing the 24th through 36th Wednesday of the calendar year. Each such week shall begin on a Monday,

Duke Integration White Paper

and approved Maintenance Outages will be limited to a maximum duration of 9 consecutive days, 5 weekdays plus the included weekends.

More detailed explanation of the Outage Coordination process can be found in PJM Manual M-10 (Pre-Scheduling Operations), Section 2 (Outage Reporting).

Unplanned Outages

Market Sellers that own or control a Capacity Resource whether or not PJM RTO Scheduled are expected to advise PJM of a Capacity Resource Unplanned Outage suffered or anticipated to be suffered by the resource as promptly as possible. They are expected to provide PJM with the expected date and time that the Capacity Resource is available, and to submit a record of the events and circumstances giving rise to the Unplanned Outage to PJM.

Reactive Outage Reporting

In addition to the MW (real power) outages, certain other generator data must be submitted to PJM pertaining to unit reactive values. These are for Voltage Regulator Outages, Governor Outages and MVAR Capability Adjustments. This reporting is handled in the eDART - Generator Ticket application.

Voltage Regulator & Governor Outage Reporting

Whenever a PJM unit's automatic voltage regulation (AVR) status is off (or is planned to be off), the unit's owner or operator must immediately enter a ticket via eDART. For real-time changes, the unit's owner or operator should also notify the PJM PD and the respective LCC by phone.

If a unit's governor status is off (or is planned to be off), the unit's owner or operator must immediately enter a ticket via eDART. For real-time changes, the unit's owner or operator should also notify the PJM PD and the respective LCC by phone.

MVAR Capability Adjustment Reporting

MVAR Capability Adjustments are reported in two instances. Whenever a PJM unit's reactive capability is reduced (or is planned to be reduced) for any reason, the unit's owner or operator must immediately enter a ticket via eDART. For real-time changes, the unit's owner or operator should also notify the PJM Power Dispatcher (PD) and the respective Local Control Center (LCC) by phone. Whenever a PJM unit's actual reactive output has reached a limit which is less than the unit's normal specified capability for any reason, the unit's owner or operator must immediately enter a ticket via eDART and notify the PJM PD and the respective LCC by phone. Generators should also identify the reason for any reduction in reactive capability and mitigation plan for restoring the capability.

Generating Unit Reactive Power is a primary method of providing voltage support on the PJM system. A lack of deliverable Generating Unit Reactive Power, which is relied upon to be available based on reported Reactive Capability, can result in PJM system reliability problems including voltage collapse. Whereas, proper reporting can result in controlled measures, such as generation adjustment in lieu of unanticipated load shedding to address inadequate Reactive Power Reserves.

Duke Integration White Paper

The PJM EMS Real-Time and Study Network Applications, Seasonal PJM Operating Studies, and PJM Planning Studies use Continuous Unit Reactive Capability Curves for actual pre-contingency steady-state analysis and for simulated post-contingency security analysis.

The Generating Unit Reactive Capability determination should recognize any constraints caused by system voltages, unit transformer tap position setting, temperature, operating conditions and restrictions, station auxiliary equipment, generator terminal bus voltage limitations, and auxiliary bus voltages limitations. There may be different limiting conditions for either leading or lagging reactive capability.

Generating Unit Reactive Capability is a measurement of the reactive power able to be delivered by a generating unit to the bulk power transmission system, and is defined by the MW versus MVAR points of a generator capability curve. To help maintain a reliable transmission system, each Generation Owner/Operator must provide capability curve information to PJM via eDART as soon as the information is available. The LCC for the Transmission Zone where the unit is located is automatically notified via eDART, as well as any other LCC with eDART authority to receive automatic notification for the unit. For real-time changes, each Generation Owner should also notify PJM and the respective LCC via phone.

Specialized eDART Reporting

Instantaneous Reserve Check (IRC) Overview

PJM is responsible for monitoring the reserves for the PJM RTO. Periodically, the PJM dispatcher takes an IRC to determine if adequate reserves exist to meet the PJM Reserve Requirements. An IRC may be taken more frequently if system conditions dictate. When the PJM Generation dispatcher requests an IRC, generation member dispatchers report the information via eDART within 15 minutes of the All-Call notice for members to report. Through this PJM can verify that the Contingency Reserves meet VACAR standards. PJM operators can verify these values using EMS displays. Duke will provide PJM with real time reserve values via ICCP links in addition to the IRC process.

Additional eDART Reporting

A Supplemental Status Report (“SSR”) or Minimum Generation (“MinGen”) will be requested by PJM as needed. SSRs are called if it appears there is insufficient generation to meet the load. An example of this may be the summer periods when load may be higher than normal. The MinGen data is requested when there is a fear of over-generation for the valley load period of the day. The following outlines what steps need to be followed when the above mentioned reports are requested.

- SSR data – The company responsible for submitting generator tickets on the unit are also responsible for submitting the following values to PJM when an SSR is called: Status Report application, Resource Limited Units, On-Cost and Max Emergency Generation totals.
- MinGen data – When a MinGen *alert* is called, each company reports the amount of generation that can safely be reduced. When a MinGen *event* is called, PJM determines the required percent reduction for each company and communicated that percentage.

Duke Integration White Paper

Each company must reduce their generation output by the percentage of the reported reducible generation requested by PJM. When the event has concluded each company will report the final actual amount that was reduced during the event.

Emergency Procedures

Synchronization of Procedures

PJM will work with Duke to integrate operational procedures into PJM manuals and processes.

System Restoration

Duke will need to provide its system restoration plans to PJM by September 2010 for incorporation into the PJM System Restoration Manual M-36. Duke generator and transmission owners will be included as part of the PJM Restoration Drill and will need to submit data for the Restoration Drill whenever a Restoration Drill is called. Restoration drills typically will be held with FE and other personnel each Fall beginning in 2010. PJM will coordinate the updated PJM Restoration Plan both internally and externally before the RFC certification.

Congestion Management Process

As indicated previously, the inclusion of Duke into the PJM RTO will result in the transfer of their current control obligations and responsibilities to the PJM RTO. As such, the Duke Control Zone will utilize the current PJM Congestion Management Process (i.e., Locational Marginal Pricing through the Day-Ahead and Real-Time markets, the NERC Transmission Loading Relief (“TLR”) procedure, and the Congestion Management Coordinated Methodology (“CM2”) process. For more information on the CM2 process, please see the PJM Tariff or the MISO-PJM Joint Operating Agreement.

Integration of Duke will result in several significant changes with regard to CM2:

Transmission Facilities currently under the MISO OATT will become facilities under the PJM RTO OATT.

Several new Coordinated Flowgates (and associated Reciprocal Coordinated Flowgates) will be defined based on the tests described in the PJM Tariff.

New Marginal Zones for the new Duke Control Zone will be developed. This new Marginal Zone will be combined with the existing 30 Marginal Zones. The Marginal Zones are used to determine PJM Import and Export Marginal Zone Weighting Factors, which will be sent to the NERC IDC.

PJM has implemented a Post Contingency Congestion Management program. This program provides the requirements for PJM to operate a Transmission Owner's facilities on a post contingency basis. (Normally, PJM operates on a pre-contingency basis, meaning that PJM will initiate congestion management steps prior to the actual contingency occurring if the emergency rating is exceeded.) Duke will need to review their operational philosophy and determine if they would like to become participants in the program. In order to become participants, facilities will need to be specifically identified and pre-studied for conformance to the program requirements.

Duke Integration White Paper

In order to have any facilities managed on a post-contingency basis, Duke needs to identify such facilities by September 2011.

Exchange Data for Load Flow Studies

In order to adequately perform studies of the PJM system, certain modeling data is required from both transmission and generation owners. PJM Manual M-05 "Power System Application Data" provides guidelines for the power system data that is required for regional planning studies. For a higher level overview of data requirements, refer to Attachment D of Manual M14B.

Load Shedding

PJM modified the existing PJM EMS load dump calculator to institute changes to the Operating Agreement set forth in Schedule 1, Section 1.7.11 stating that "... the Office of Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone." Only Manual Load Dump requests for capacity deficiencies are addressed. A load dump request will only be initiated when all other emergency actions have been taken as identified in the PJM Emergency Procedures Manual (Manual 13).

The load dump calculation determines which Control Zone(s) is short based on real-time load and energy values from PJM EMS and capacity values received daily from the Capacity Adequacy Planning Department. Real-time energy values are used as a surrogate for available capacity because in a capacity shortage situation available capacity and energy should be close to equal. As set forth in Manual 13, all generation should be loaded to full capacity prior to implementing any load dump, therefore actual real-time energy output will be used to identify deficient Control Zones. Since most of the values used in the load dump calculation are real-time dynamic numbers, the calculation is performed in the PJM EMS. Load Serving Entities ("LSEs") are able to designate within eRPM that capacity resources are being used to serve load in a specific Control Zone. Similarly EES users are able to specify that an external energy schedule is designated for a specific Control Zone. Resources that are not designated for a specific Control Zone are considered an RTO resource for load dump calculation purposes and allocated across all Control Zones according to load ratio share. Only Control Zones that are determined to be deficient are assigned a share of a load dump request initiated due to RTO capacity deficiencies.

Demand Response

Duke utility customers will have the opportunity to participate as a demand resource in the Energy, Reliability Pricing Model (capacity) and Ancillary Service markets under the PJM market rules as defined by the OATT/OA and supporting manuals. Please note the provisions of Order 719A issued 7/16, 2009 and Order issued on 9/14/09 in Docket No. ER09-701-000 et al. require PJM to include in eligibility requirements for participation in load response opportunities the decision of the relevant electric retail regulatory authority (RERRA). Specifically, PJM must accept the registrations of end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year unless the RERRA prohibits participation by such customers. Conversely, PJM may not accept the registrations of end-use customers of

Duke Integration White Paper

an electric distribution company that distributed 4 million MWh or less in the previous fiscal year unless the RERRA permits participation by such customers. Both orders are posted on the PJM website (www. pjm.com) under Documents on the FERC Orders page.

Planning

RTEP Process

The PJM planning process activities, culminating in PJM's annual Regional Transmission Expansion Plan, constitute PJM's single, Order No. 890 compliant, transmission planning process. All PJM Open Access Transmission Tariff (OATT) facilities are planned through and included in this open, fully participatory, and transparent process. In the case of the Duke integration, all bulk electric system (BES) facilities and any other facility that Duke turns over to PJM for operational control will be subject to and included in the various analyses associated with the RTEP process. Such inclusion will begin such that the 2012 RTEP will include all applicable Duke facilities.

The following are the key components of PJM's 15-year transmission planning process:

1. Baseline reliability analyses
2. Generation and transmission interconnection
3. Market efficiency analyses
4. Operational performance issue reviews and accompanying analyses
5. The final RTEP Plan

Duke and other entities in the Duke footprint will be expected to provide to PJM all necessary information about their facilities to enable their inclusion into the RTEP process.

Generation Interconnection

PJM's robust energy market has attracted numerous requests from generator and transmission developers for interconnections with the Transmission System. These generator and transmission Interconnection Requests constitute a significant driver of regional transmission expansion needs. To the degree that there are existing generation interconnection requests within the Duke footprint, those projects will be incorporated into the PJM queue process as explained in the PJM Manuals.

Markets

eMarket and UDS

One day-ahead market will be cleared for the PJM RTO. The timeline for clearing the market and posting the results will remain the same based on Eastern Prevailing Time. The Generation Control Application ("GCA") that will replace the Unit Dispatch System ("UDS") requires a separate Load Forecast for each control zone.

Duke Integration White Paper

The Independent Market Monitor will propose specific market power mitigation measures that would be applied to the aggregate energy market if required.

Interface Pricing

Upon the integration of Duke into the PJM market, the points at which external energy transactions are priced (interface pricing points) will not change. The balancing areas directly connected to the expanded PJM market will be grouped as shown below, and only one OASIS source of an import/sink of an export will be available for each POR/POD. For example the OASIS POR/POD combination of POR- TVA and POD- MECS will have only one Source- SOUTHIMP and one Sink- MISO available. The mapping of all external balancing areas to these interface pricing points appears in Appendix F of this document.

CPLEIMP (qualifying imports from CPLE): Carolina Power & Light Company - East

CPLEEXP (qualifying exports to CPLE): Carolina Power & Light Company - East

DUKIMP (qualifying imports from DUK): Duke Energy Carolinas

DUKEXP (qualifying exports to DUK): Duke Energy Carolinas

LINDENVFT (qualifying exports to NYISO via the Linden VFT)

MISO

Alliant Energy - East

Alliant Energy - West

Ameren Services Company – Illinois

Cinergy Corporation

City Water Light & Power

Indianapolis Power & Light Company

MidAmerican Energy Company

Michigan Electric Coordinated System

Northern Indiana Public Service Company

Wisconsin Energy Corporation

NCMPAIMP (qualifying exports from NCMPA1 via DUK): Duke Energy Carolinas

NCMPAEXP (qualifying exports to NCMPA1 via DUK): Duke Energy Carolinas

NEPTUNE (qualifying exports to NYISO via the Neptune HVDC tie)

NYIS - New York Independent System Operator

OVEC - Ohio Valley Electric Corporation

SOUTHIMP / SOUTHEXP –

Carolina Power & Light Company - West

Duke Integration White Paper

East Kentucky Power Cooperative, Inc.

LGEE - E.ON U.S. Services Inc.

Tennessee Valley Authority

Synchronized Reserve Zone/Regulation Zone

Each Ancillary Service Area will have Synchronized Reserve Zone and Regulation Zone mechanisms separate from each other, but operated via the same market mechanism. PJM will select resources hourly to provide each service based on a co-optimization between energy, regulation and synchronized reserve. Assignments will be communicated to the unit owners/operators by eMKT or the appropriate dispatcher.

The Synchronized Reserve Zone will be arranged into 2 Zones and 1 Sub-Zone, designated based on the reserve sharing agreements and transfer constraints existing in the RTO. PJM participates in the Shared Activation Reserve program with NPCC. Dominion participates in the VACAR Reserve Sharing Group.

Reliability *First* Corporation Synchronized Reserve Zone: PJM RTO less Dominion

Southern Synchronized Reserve Zone: Dominion

Mid-Atlantic Synchronized Reserve Sub-Zone: PJM Mid-Atlantic Region plus parts of AEP and AP

The Regulation Zones will be a single regulation zone including the entire PJM footprint.

Black Start

The PJM Black Start mechanisms will be implemented in all Ancillary Areas. The required Black Start resources contained in the plan will be eligible for compensation under the PJM Tariff. Black Start units in each Ancillary Area will be subject to the same outage restrictions as Black Start units in the PJM Mid-Atlantic.

Financial Transmission Rights

Auction Revenue Rights (–ARRs”) or Financial Transmission Rights (–FTRs”) will be allocated to Network Service Customers and Firm Point-to-Point Transmission Customers for the DEOK Zone. Market Participants submit ARR requests for the planning period during the Annual ARR Allocation process. The Annual ARR Allocation is a two-stage allocation process designed to provide long-term certainty along with increased flexibility. The first stage of the allocation consists of two parts, Stage 1A and Stage 1B. In this first stage, Network Service Customers make ARR requests based on generation resources that historically served load in the DEOK Zone. Also in Stage 1, Firm Transmission Customers, which are deemed as Qualifying Transmission Customers, can make ARR requests based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Firm Point-to-Point Transmission Service during the historical reference year.

The second stage, Stage 2, is a three-round allocation procedure that allows market participants to adjust their hedging paths on an annual basis. In every round of the three-round allocation

Duke Integration White Paper

process, the Network Customer's ARR requests are limited to one third of the Network customer's peak load remaining unallocated after the Stage 1 allocation process. All ARR requests must pass a Simultaneous Feasibility Test in both stages.

For a transitional period, Network Service Users and those Firm Transmission Customers that receive, and pay for, that take service that sinks or sources, in DEOK Zone, at their election, may receive a direct allocation of FTRs instead of an allocation of ARRs. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the DEOK Zone into the PJM Interchange Energy Market. The election of a direct FTR Allocation shall be made prior to the commencement of each Annual FTR Auction.

1. Network Service Users and Firm Transmission Customers in the DEOK Zone that elect not to receive direct allocations of FTRs, may receive allocations of ARRs. Network Service Users and Firm Transmission Customers in the DEOK Zone must choose to receive either an FTR Allocation or an ARR Allocation. A Network Service User or Firm Transmission Customer cannot choose to receive both an FTR Allocation and an ARR Allocation.
2. All FTR requests in the DEOK Zone made during these transition periods will be subject to the same allocation procedures as those set forth in the Annual ARR Allocation process. As part of the integration of DEOK Zone into the PJM Market, PJM will identify the set of eligible FTR sources for the Stage 1 allocation process based on historic and contractual delivery patterns.
3. These FTR requests must satisfy the same requirements as the Annual ARR requests. The Annual FTR Allocation process for the DEOK Zone will be conducted simultaneously with the Annual ARR Allocation process for the other zones to ensure Simultaneous Feasibility of all rights.

A Special FTR Allocation will be conducted for the DEOK Zone since the integration date is not on the first of June. This special allocation of FTRs will cover the period of time between the implementation of the DEOK Zone on January 1, 2012 and the next Annual ARR Allocation in which the DEOK Zone actually integrates into PJM (ARRs effective for June 1, 2012). This FTR Allocation will be for FTRs and not ARRs. Requests for this special allocation can be made by Network Service Customers based on generation resources that historically served load in the DEOK Zone. Firm Transmission Customers, which are deemed as Qualifying Transmission Customers, can make FTR requests based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Firm Point-to-Point Transmission Service during the historical reference year. This special FTR allocation will be conducted approximately three months before the DEOK Zone integrates into PJM.

Service on the MISO OASIS

Firm P-T-P transmission service that sources in Duke and sinks in the current PJM footprint or that source in the current PJM footprint and sink in Duke will be converted to Network service upon the Duke integration. Participants owning such service may nominate ARRs/FTRs for the portion of the path that is converted from the MISO OASIS to the PJM OASIS, and these nominations will be evaluated in Stage 2 of the allocation for the Duke integration. For example, the owner of Firm P-T-P service with a source in Duke and a sink in PJM will be eligible to

Duke Integration White Paper

nominate an ARR/FTR from the source in Duke in order to complete the path from ultimate source to ultimate sink.

Because Duke is part of the MISO Balance Authority prior to moving to the PJM market, additional consideration may be required on a case-by-case basis for existing contracts for delivery of energy between Duke and the rest of the MISO Balance Authority. Grandfathered reservations from MISO to Duke that are listed on the MISO OASIS will be converted to the appropriate grandfathered, point-to-point or network service.

Reliability Pricing Model Integration

Capacity Resources and LSEs in the Duke footprint will participate in the PJM RPM capacity program. RPM is a 3-year forward auction based program. PJM will ready Duke to participate in the 2014-2015 Base Residual Auction to be held in May of 2011. An interim Fixed Resource Requirement Plan (“FRR”) will be put in place to obtain Capacity Resources for the 2 ½ delivery years prior to 2014-2015.

Reserve Margin Analysis

The reliability study analysis performed by PJM staff calculated 15.5% for 2011/2012, 15.4% for 2012/2013 and 15.3% for 2013/2014 Installed Reserve Margin (“IRM”) for the RTO. These IRM values are equivalent to Forecast Pool Requirements (“FPR”) of 1.0833 for 2011/2012, 1.0815 for 2012/2013 and 1.0804 for 2013/2014 Delivery Years. The FPR values will be used to calculate the Preliminary Zonal Unforced Capacity Obligations for the DEOK Zone. The IRM and FPR for 2014/2015 will be determined and posted by February 1, 2011 in advance of the 2014/2015 Base Residual Auction.

Results from reliability studies indicate the reserve margin required for a one day in ten year loss of load expectation. PJM reliability studies use a probabilistic model that considers, among other factors, the characteristics of the loads, the probability of load forecast error, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, and the effects of interconnections to other regions. See PJM Manual 20 for further details.

The IRM is then converted to the “unforced” reserve margin or FPR based on the following equation:

$$\text{FPR} = (1 + \text{IRM}) * (1 - \text{PJM average EFORD})$$

For example, for 2012/2013, at 15.4% IRM and 6.28% PJM average EFORD, the FPR is:

$$\text{FPR} = (1 + 0.154) * (1 - 0.0628) = 1.0815$$

Obligation Determination

The 2011/2012, 2012/2013 and 2013/2014 Preliminary Peak Load Forecast for the Duke Control Zone will be performed by PJM with input from Duke and other load serving entities. The PJM FPR of 1.0833 for the 2011/2012 Delivery Year, 1.0815 for the 2012/2013 Delivery Year and 1.0804 for the 2013/2014 Delivery Year is applied to the Preliminary Peak Load Forecast to

Duke Integration White Paper

determine the Preliminary Zonal UCAP Obligation for the Delivery Year. PJM plans to post the 2011/2012 Final Zonal UCAP Obligation for the 2011/2012 Delivery Year in January 2011. PJM also plans to post the 2012/2013 and 2013/2014 Preliminary Zonal UCAP Obligation for the DEOK Zone by January 1, 2011. The Final Zonal UCAP Obligation for the 2012/2013 DY and 2013/2014 DY will be posted in January 2012 and January 2013, respectively. The Final Zonal UCAP Obligations for each DY may reflect changes in zonal peak load forecast for the DEOK Zone and IRM for the respective DY. Each LSE's allocation of the zone's Final UCAP Obligation will be based on its Obligation Peak Load share of the zone. Each LSE's Obligation Peak Load will be updated daily to reflect load shifts between LSEs. For the 2011/2012, 2012/2013 and 2013/2014 Delivery Years, an LSE's daily Obligation Peak Load is then multiplied by the Final Zonal FRR Scaling Factor and FPR to determine its unforced capacity obligation for a particular day. The Final Zonal FRR Scaling Factors to determine the LSE Obligations for 2011/2012, 2012/2013 and 2013/2014 will be posted in January 2011, January 2012 and January 2013 respectively, based on the zonal weather normalized peak load for the summer prior to actual Delivery Year. See PJM Manual 18 for further details.

Starting with the 2014/2015 Delivery Years, the unforced capacity obligation for the DEOK Zone will be determined as a result of the 2014/2015 Delivery Year Base Residual Auction and Incremental Auctions in accordance with PJM Manual 18.

Obligation Compliance

Duke will be added to the current PJM RPM construct and therefore adhere to the same rules for qualifying capacity. The final unforced capacity value of a generating resource is equal to its net dependable summer rating reduced by its EFORD for 12-months ending September 30 prior to the Delivery Year. Generator planned and maintenance outages over the summer interval are subject to PJM approval. Capacity Resources must pass the deliverability test within the construct. The list of deliverable generators in the DEOK Zone will be available on the PJM website. New system resources must enter the Regional Transmission Expansion Planning Process (RTEP) to obtain the injection rights necessary to be considered a Capacity Resource.

To qualify an external resource (one outside of the PJM CA), an LSE must have firm transmission service from the source to the PJM border and across the border into PJM (this latter service is at zero cost but Available Transfer Capability ("ATC") must be available to accommodate it). All external purchases of capacity must be from a specific and identified unit or collection of units. Firm energy liquidated damages contracts do not qualify as Capacity Resources. Monthly reporting of GADS outage data is required in preparation for integration. See PJM Manual 18.

PJM will review the list of behind-the-meter generation to ensure consistency with PJM's Behind the Meter Generation Business rules. Please see the reference section for a link to those rules.

Capacity obligations may be satisfied through self-supply, bilateral arrangements, Demand Resources, and Energy Efficiency Resources. All of these methods are subject to the same rules and procedures that currently apply to the PJM RPM and FRR Entities. For the 2011/2012,

Duke Integration White Paper

2012/2013 and 2013/2014 Delivery Years, obligation compliance is tracked on a daily basis. PJM will verify that there is enough unforced capacity committed in the out-of-time FRR Capacity Plans to satisfy the daily unforced capacity obligations of the DEOK Zone. Starting with the 2014/2015 Delivery Year, LSEs in the DEOK Zone will be assessed a Daily Unforced Capacity Obligation and all LSEs that have not elected the FRR Alternative will be required to pay the Daily Locational Reliability Charge for the DEOK Zone under the RPM construct.

RPM Transition

The PJM RPM capacity market will be expanded to include the DEOK Zone. The DEOK Zone will be included in the May 2011 BRA for the 2014/2015 Delivery Year and all market rules effective as of that time will apply to the DEOK Zone.

For the second half of the 2011/2012 Delivery Year (January 1, 2012 – May 31, 2012) and the 2012/2013 and 2013/2014 Delivery Years, a transition plan will be required for the DEOK Zone. To fulfill the RPM capacity requirements for these three transition years, Duke will submit to PJM an out-of-time FRR plan for each of the referenced Delivery Years by December 15, 2011 (FRR plan submission timelines are tentative subject to further discussion). The capacity resources included in these FRR plans will be required to cover the capacity requirement for the entire DEOK Zone, with the exception of such requirement associated with any LSEs that choose to, and meet all other requirements to, model their load as separate RPM Zone/Areas within the DEOK Zone. LSEs that meet such requirements and choose to be modeled as separate RPM Zone/Areas will be considered an FRR Entity for 2011/12, 2012/2013 and 2013/2014 Delivery Years and allowed to submit their own out-of-time FRR plans by December 15, 2011. LSEs that choose to model their load as a separate area in the DEOK Zone must provide written election to Duke no later than March 31, 2011.

Duke's FRR Capacity Plans and any LSE that has opted to submit FRR Capacity Plans for an area in the DEOK Zone for the 2011/2012, 2012/2013 and 2013/2014 Delivery Years must submit their out-of-time FRR Capacity Plans in the eRPM system no later than December 15, 2011. Failure to commit enough unforced capacity in their FRR Capacity Plan to satisfy the FRR Entity's Preliminary Unforced Capacity Obligation for the Delivery Year upon initial submission will result in an FRR Commitment Insufficiency Charge for the remaining term of the FRR Plan. The FRR Commitment Insufficiency Charge in the DEOK Zone is equal to two times the RTO Cost of New Entry (\$/MW-year) times the shortage of unforced capacity resources in meeting the obligation. FRR Commitment Insufficiency Charges are allocated on a pro-rata basis to all other LSEs (includes RPM LSEs and FRR Entities that have met their daily unforced capacity obligations) in the RTO based on their daily unforced obligations.

Prior to the start of the Delivery Year, FRR Entities may need to procure and commit additional resources to their FRR plan to meet an increase in the Final Zonal UCAP Obligation and any decreases in the unforced capacity value of committed resources in their FRR Capacity Plan to avoid Daily FRR Capacity Resource Deficiency Charges during the 2011/2012, 2012/2013 and 2013/2014 Delivery Years. Failure to commit enough unforced capacity in their FRR Capacity Plan to satisfy the FRR Entity's Final Daily Unforced Capacity Obligation will result in a Daily

Duke Integration White Paper

FRR Capacity Resource Deficiency Charge. The Daily FRR Capacity Resource Deficiency Charge is equal to the FRR Capacity Resource Deficiency Charge Rate times the daily MW shortfall. The FRR Capacity Resource Deficiency Charge Rate for the DEOK Zone is 1.2 times the capacity resource clearing price resulting from all RPM Auctions for the Delivery Year for the LDA encompassing the DEOK Zone, weight-averaged for the Delivery year based on the prices established and the quantities cleared in such auctions. Daily FRR Capacity Resource Deficiency Charges are allocated on a pro-rata basis to the LSEs in the RTO that were charged a RPM Locational Reliability Charge. The allocation is based on the RPM LSE's daily unforced capacity obligation.

Upon the start of the Delivery Year, the EFORD that will be used to evaluate the amount of UCAP committed to an FRR Plan for a given generation resource will be the Final EFORD, which includes forced outage data for the October through September period prior to the Delivery Year. The Final EFORDs for the 2011/2012, 2012/2013 and 2013/2014 Delivery Years will include data from 10/1/2009 through 9/30/2010, from 10/1/2010 through 9/30/2011 and from 10/1/2011 through 9/30/2012 respectively. To the extent that a generation resource's Final EFORD is greater than the EFORD used at the time the FRR plan was submitted, the FRR Entity will be required to provide replacement capacity prior to the start of the Delivery Year in order to avoid the application of the Daily FRR Capacity Resource Deficiency Charge to the FRR Entity. Similarly, for Demand Resources and Energy Efficiency Resources, if the Final DR Factor or FPR for the Delivery Year decrease resulting in less UCAP being available on the resource than what was submitted in the FRR Plan, then the FRR Entity must provide replacement capacity in order to avoid application of the FRR Capacity Resource Deficiency Charge.

Capacity Resources submitted as part of Duke's FRR plans will be subject to the same performance requirements as any other FRR Capacity Resource. Any non-performance by resources submitted as part of Duke's FRR plans will result in the associated penalties applied to Duke as the FRR Entity. In the case of LSEs that have submitted an FRR Capacity Plan for an area in the DEOK Zone, these LSEs will also be considered FRR Entities. Any non-performance by resources submitted as part of that FRR Entity's FRR plans will result in the associated penalties applied to the FRR Entity. Details regarding resource performance assessments, associated penalties, and allocation of penalties are provided in Manual 18, Capacity Market Manual.

eTool Changes

The following changes are expected for the PJM eTools, as a result of the market integration activities:

CAM – No Changes

eSuite Messages - No Changes

eSchedules –

-No system changes

-Pricing Point additions for source / sink list must be made no later than 1 week prior to integration

Duke Integration White Paper

eRPM – pending analysis to support transitional FRR Plans.

eFTR – No Changes

eMKT – No Changes

eGADS / eFuel – No Changes/

eDart -

- The Peak Summary Report will show net interchange for the new control zone.
- The Peak Summary Report will also be enhanced to show the detailed peak summary data by control zone.

eLRS - No system changes just need to add new EDC(s).

eMTR –

- eMTR Sandbox modeling should be complete at least one month prior to a given integration. All Gen owners should verify that their generation is modeled in the sandbox

eData -

The following user interface changes will also be made:

- Cities will be added to the Temperature displays;
- States will be added to the LMP Contour map;
- New zones will be added to the Instantaneous Reserve Check display, the Load Chart, and Dispatch Lambda;
- New preferences will be allowed for the LMP chart;
- New pricing points will be added to the tie flows;
- New locations will be added for the Reactive Transfer Interfaces.

EES -

- New Customers with a NERC Acronym that is different from their PJM Acronym will need to contact PJM to have them mapped to each other in EES (By having a mapping of acronyms, it would avoid the need for the market participant to have to do a FRP approval every time they submit a tag).

OASIS -

- No system changes
- Pricing Point additions for source / sink list must be made no later than 1 week prior to integration

Emergency Procedures - No Changes

MSRS – No system changes; potential report changes / additions pending further analysis of special cases

Market Monitoring Data Requirements

For Each Generating Unit – Supplied By Owner; from ALL marketers:

1. Unit Data
 - a. List of generating units including summer installed capacity, manufacturer of turbine, type of unit (i.e. steam, combustion turbine, combined cycle, hydro etc.). Where applicable specify whether the unit is supercritical or sub-critical.
 - b. Primary, back-up and supplemental fuel
 - c. Full load actual heat rate
 - d. Commercial operation date
2. Cost Based Offers
 - a. All cost-based offers (start-up, no load, ancillary services and energy) as outlined in Manual M-15 Cost Development Guidelines (CDTF). Cost based data requested for all units regardless of construction date.
3. Unit Ancillary Services Capability
 - a. Regulation Capability (Y/N). Provide the regulation range (+/- MW) and MW/min ramping capability within this range.
 - b. Spin Capability (Y/N) and quantity. (Includes condensing)
 - c. Black Start Capability (Y/N) and quantity. Specify whether the unit has load-rejection capability.
4. Ownership Status
 - a. Specify whether or not the resource is currently committed to a power purchase agreement (PPA).
 - b. If committed to a PPA, provide a brief summary of the contract details including counterparty, start/end date, products (energy, capacity etc.) and pricing.
 - c. Provide a copy of each power purchase agreement. Notify the PJM Independent Market Monitor (Monitoring Analytics) if additional confidentiality agreements need to be executed to facilitate the release of this information.

Items 1, 3 and 4 above must be submitted to the Independent Market Monitor 180 days prior to the anticipated integration date. These items need only be submitted once to the Independent Market Monitor unless otherwise requested by PJM. Cost based offers, item 2 above, must be submitted to the Independent Market Monitor 45 days prior to the anticipated integration date. Future submittals of cost based bids will be in accordance with eMKT requirements unless otherwise requested by PJM.

Scheduling and Tagging/OASIS

Internal Energy Scheduling (Financial)

Internal bilateral energy transactions are made between two parties using the eSchedules application. Transactions include load and generation interchange adjustment modeling, and implicit internal spot market schedules. For an internal bilateral transaction to be valid, it must

be approved by both parties. eSchedules energy transactions are financial in nature and do not result in the physical flow of energy. Power Marketers, Load Serving Entities, and Generation Owners use eSchedules. eSchedules allows for hourly increments to be transacted.

External Energy Scheduling

Market participants that wish to transact energy into, out-of or through the PJM RTO are required to make their requests to PJM via the NERC E-Tagging system. This system interfaces with PJM's Enhanced Energy Scheduler (EES) software to create an interface that both PJM Market Participants as well as PJM Transaction Coordinators can use to evaluate and manage external transactions that affect the PJM RTO.

An important aspect of scheduling external transactions in PJM is finding a start and end time to transact energy while respecting the PJM ramp limits imposed for security (see "Ramp Limits" section for additional information on PJM's ramp limits). PJM allows market participants to reserve ramp in advance of completing their transactions via the EES application. This is an optional step in making external transaction requests, as the NERC E-Tag serves as the actual request for scheduling in PJM.

In cases where the NERC E-tag does not have the required fields to request a PJM market specific transaction (e.g. dispatchable, two-settlement etc.) the EES application will be used in concert with the NERC E-tag (see "Entering Dispatchable Schedules" and "Entering Two-settlement transactions" sections).

Regional Through and Out Rate (RTOR) Elimination will apply to any new or converted reservations between PJM and MISO as a result of the Duke integration.

New short-term transmission service can be requested at any time. The model used for ATC calculations will be updated for new short-term service requests, April 1, 2011 two calendar months prior to integration.

External Transaction Timing Requirements

The following timing requirements are imposed by PJM for the submission of ramp reservations:

1. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions.
2. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration.
3. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) one day prior to start time.

Ramp reservations expire if they are not used. The following timing requirements are imposed on ramp reservations that are not scheduled against:

- If the reservation is submitted 1 hour prior to the start of the schedule or less, the reservation will be held in "Pending Tag" status for 10 minutes.
- If the reservation is submitted more than 1 hour, but less than 4 hours prior to the start of the schedule, the reservation will be held in "Pending Tag" status for 15 minutes.

Duke Integration White Paper

- Reservations that are less than 24 hours in duration and submitted 4 or more hours prior to the start of the schedule will be held in —Pending Tag status for 90 minutes.
- Reservations made on a day-ahead basis will expire at 1430 EPT, one day prior to the start of the schedule. Note that a ramp reservation will not be —split into separate days, so if a ramp reservation is made for multiple days, and not scheduled against, and if the start time for the multi-day reservation is the next day, the entire reservation will expire.

The following timing requirements are imposed by PJM for the submission of Schedules. Schedules are submitted to PJM by submitting a valid NERC Tag. (The schedule is considered submitted when the NERC Tag is received by the PJM Tag Approval Service, not when it is submitted by the market participant’s Tag Agent software):

1. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions.
2. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration.
3. For a schedule to be included in PJM’s Day-Ahead checkout process, they must be implemented by 1400 (EPT) one day prior to start of schedule.
4. Schedules utilizing the Real-Time with Price option must be submitted prior to 1200 noon (EPT) day prior to start time.
5. Schedules utilizing FIRM Point-To-Point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions submitted after 1000 (EPT) on day prior will be accommodated if practicable.

The following timing requirements are imposed by PJM for the submission of Two-Settlement Transactions:

1. All Two-Settlement transactions must be submitted by 1200 noon (EPT) one day prior to start time.

Ramp Limits

PJM validates all external transaction requests against a net interchange ramp. The ramp limit is configurable by PJM dispatch based on operating conditions. There are two separate ramps that are evaluated, a PJM Net Interchange Ramp, and a New York Independent System Operator (—NYISO”) Interchange Ramp. Future ramp limits are in the process of being studied.

PJM Variable Ramp

At no time, can the difference in the net interchange be greater than the ramp designated by the PJM dispatch at any given 15 -minute interval. Ramp room is allocated on a first come, first serve basis. Refer to Appendix C for a ramp example to see how the ramp is calculated for any given 15 - minute interval.

Entering Ramp Reservations

Each PJM Member Company that is authorized to do business in PJM’s energy market is given an EES account. It is in the EES application that ramp reservations are made.

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Ramp reservations are an optional step in scheduling transactions in PJM. A ramp reservation can be made to “hold” ramp room while market participants complete their scheduling responsibilities. Ramp reservations are then associated on the NERC Tag when the market participant wishes to submit the schedule. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Market Participants generally use Ramp reservations to ensure their ability to schedule prior to purchasing transmission or making other potentially cost affecting decisions.

To make a ramp reservation, the market participant enters the EES application, and navigates to the “Reserve Ramp” screen. On this screen, the market participant enters the path for which they are interested in transacting energy, their energy profile and any other unique information that may apply to a schedule (i.e. special exceptions, notes, outside ID’s, internal naming conventions etc.). Upon submission of a ramp reservation, PJM validates the information against ramp availability. If it passes the current ramp limits, the ramp reservation will pass, and will move into a status of “Pending Tag”. At this point, the market participant is holding a valid reservation that can then be associated on a NERC Tag for scheduling.

Entering Schedules

Market participants enter schedules in PJM by submitting a valid NERC Tag. As noted in the previous section, if the market participant holds a ramp reservation in the status of “Pending Tag”, they can associate the ramp reservation on the NERC Tag. This is done by placing the ramp reservation in the “miscellaneous” column on the PJM Transmission Provider line, of the “Physical Path” portion of the NERC Tag.

If no ramp reservation was made prior to scheduling, a NERC Tag can be submitted without a reservation. NERC Tags that are submitted without a ramp reservation will automatically have a ramp reservation created that matches the energy profile and path of the NERC Tag. This newly created reservation will be evaluated against ramp, and an approval or denial will be made based on the validation. If there is enough ramp room, PJM will continue with other validations (See “Transaction Verification and Checkout”). If all validations pass, an approval message will be sent to the NERC Tag, and upon implementation of the NERC Tag, the transaction will be scheduled by PJM.

Because of the nature of NERC tagging, it is possible for the market participant who enters a NERC tag to not be consistent with the market participants listed for each TP segment on a particular tag. In this instance, the Financially Responsible Party (“FRP”) entering the tag is effectively acting on behalf of other market participants that are listed. Because PJM will now be identifying a NERC tag as a market participant’s schedule, it will be necessary for those market participants who have had a tag entered on their behalf to acknowledge this tag through the EES.

Entering Real-Time with Price Schedules

Real-Time with Price schedules differ from other schedules in that an action must be made in EES in addition to the submission of a NERC Tag. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES using the “Real-Time with Price” tab in the notebook section of the ramp reservation screen. In addition to the information entered for a Real-Time schedule, market participants are also required to enter a price associated with each energy block. Upon submission, the Real-Time with Price request will

automatically move to the ~~“Pending Tag”~~ status, as Real-Time with Price schedules do not hold ramp.

Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. This is done by placing the ramp reservation in the ~~“miscellaneous”~~ column on the PJM Transmission Provider line, of the ~~“Physical Path”~~ portion of the NERC Tag. For Real-Time with Price schedules, the NERC Tag energy profile must match the ramp reservation exactly in order for the tag to be approved.

Entering Two-Settlement Schedules

Market participants can submit two settlement schedules to the eMarket application through EES. These schedules do not require a NERC tag, as they are only financial obligations, and are not considered physical schedules for actual flow. Two settlement schedules are submitted using the ~~“Two Settlement”~~ tab in the notepad section of the ramp reservation screen.

Two settlement schedules must have an OASIS reservation associated upon submission. The market participant must then choose a pricing point or points for which they wish their bid to be evaluated (import pricing point for an import, export pricing point for an export or both import and export pricing points for wheels).

In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. The option to choose fixed, dispatchable and congestion are also displayed in the notepad section. The type ~~“fixed”~~ acts as a price taker, ~~“dispatchable”~~ sets a floor or ceiling price criteria for acceptance and ~~“congestion”~~ sets the maximum amount of congestion the market participant is willing to pay for acceptance in the two settlement market from an amount of \$-50 to \$50. Graphing energy is done the same way as a Real-Time or Real-Time with Price request.

Transaction Validations, Verification and Checkout

Transactions must pass specific validations and evaluations prior to being scheduled. The following validations and evaluation and checkout procedures are done for Real-Time Schedules to ensure accurate information and reliable scheduling in PJM.

- Validations

On submission, the following validations are performed on ramp reservations:

1. Path Identified
2. Stop time after start time
3. Energy Profile Identified
4. Price associated with Energy Profile (only applicable for Real-Time with Price)
5. Ramp Availability (not applicable for Real-Time with Price)
6. Timing Requirements are met for submission deadlines

On submission, the following validations are performed on NERC Tags:

Duke Integration White Paper

1. Syntax validation (See NERC Tagging Policy for complete list of syntax validations for NERC Tags)
2. Path on NERC Tag matches ramp reservation (if identified) and OASIS path
3. Timing requirements are met for submission deadlines
4. PJM Loss type must be financial (FIN)
5. Ramp availability (if no ramp reservation is identified)
6. OASIS validation for valid OASIS, valid path, instantaneous capacity, total capacity, date-time, priority and vertical stacking (not allowed)
7. Token and Value fields (in miscellaneous column) have valid inputs
8. FRP check

On submission, the following validations are performed for Two Settlement requests:

1. Path identified
 2. Timing requirements are met for submission deadlines
 3. OASIS validation for valid OASIS, ensure that the reservation is willing to pay congestion, and that the reservation is valid for period covered by the two settlement contract
 4. Pricing point(s) have been identified
 5. Stop time is after start time
 6. Energy profile is identified
 7. Price is associated for energy profile (for dispatchable option only)
 8. Congestion amount is identified for energy profile (for up-to congestion option only)
- Real-Time Evaluation and Check-Out

If all validations pass on a Real-Time schedule, PJM will approve the tag. Once the tag is approved by all parties associated on the tag and the status of the tag becomes “IMPLEMENTED”, the schedule will be ready for the Balancing Area to Balancing Area Checkout. This checkout is done by phoning the neighboring balancing area to verify all interchange schedules match. PJM also has the ability to verify interchange schedules electronically via the “Balancing Area Checkout” function in EES. If during the Balancing Area to Balancing Area checkout, both parties agree to the interchange on the NERC Tag, the schedule will flow.

The following list identifies all Neighboring Balancing Areas that PJM will check out with after the Duke integration:

1. CPLE
2. CPLW
3. DUK

Duke Integration White Paper

4. EKPC
 5. MECS-MISO BA
 6. NYISO
 7. OVEC
 8. TVA
 9. ALTE- MISO BA
 10. ALTW- MISO BA
 11. AMIL- MISO BA
 12. CIN- MISO BA⁴
 13. CWLP – MISO BA
 14. IPL- MISO BA
 15. LGEE- MISO BA
 16. NIPS- MISO BA
- Real Time with Price Evaluation and Check-Out

Real-Time with Price schedules are verified differently than Real-Time schedules. Real-Time with Price schedules are evaluated hourly to determine if they will be loaded or not for the upcoming hour. This evaluation is done by the PJM Generation Dispatcher. If the dispatcher feels that the economics for the schedule warrant the transaction to be loaded or unloaded, they will inform the transaction coordinator to load or unload the contract. This evaluation is based on a very conservative approach, and works similar to the way the generation dispatcher would call on or off generation. In addition to the economics of the transaction, the generation dispatcher may also take into consideration the ramp availability for the loading or unloading of the schedule. Since Real-Time with Price schedules do not hold ramp room, there may be times where the economics warrant a schedule to be loaded, but due to security issues related to ramp, the schedule will not be called on to flow. Once a Real-Time with Price schedule has been called on to flow, a reload request will be issued by the PJM Transaction Coordinator. If all external parties approve the reload request, and it passes the Balancing Area to Balancing Area checkout process, the schedule will flow.
 - Two Settlement Evaluation and Checkout

For Two Settlement scheduling, EES serves only as an interface to the eMarket application. Two Settlement transactions are evaluated by the PJM Markets Department, and the results are fed back to EES to allow market participants to view the results. There is no Checkout performed on two-settlement schedules, as they are considered financially binding transactions, not physical schedules.

⁴ Prior to Duke's integration into PJM, the Cinergy BA is comprised of Duke Energy – Indiana, Duke Energy – Ohio and Duke Energy – Kentucky. Following Duke's integration into PJM, the Cinergy BA will be comprised of Duke Energy – Indiana.

Transmission Service (ATC calculation)

A process and associated software for calculating the PJM Available Transfer Capability (–ATC”) derived from component Available Flowgate Capability (–AFC”) values has been implemented by PJM. The Path ATC values are uploaded to the OASIS. While the basic engine has been in service since April 2003, the driver files that define various system attributes have been updated to reflect the various stages of evolution of the PJM market. Changes will be required to fully integrate Duke into the calculations by modifying the import and export definition to include the resources within Duke.

Transmission Service (OASIS)

All external transaction requests, with the exception of import spot market transactions, require a CONFIRMED transmission reservation from the PJM OASIS. PJM offers several transmission product types, such as hourly, daily, weekly, monthly, yearly, on and off-peak, non-firm, firm and network transmission. PJM also offers the opportunity to state whether or not the market participant is willing to pay congestion.

On some occasions, due to PJM ramp rules, market participants are required to shift their energy requests. If the market participant shifts their energy up to one hour in either direction, they are not required to purchase additional transmission. Likewise, if the market participant chooses to fix their ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded. For graphical representations of these scenarios, refer to C.

Conversion of Service

Transmission service currently provided by MISO does not correspond exactly to the transmission service that is available on the PJM OASIS but are very close as a result of the Joint and Common market initiative. Differences include variations in product definitions as well as additions of new Locational Marginal Pricing (–LMP”) pricing points.

All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery, and path. Additional detail on conversion of service and Parallel Operations can be found in the Conversion of Service Appendix (Please see Appendix E.).

Billing and Settlement

The Weekly and Monthly billing process/cycles is in effect.

A Weekly Billing Statement will be issued each Tuesday for month-to-date activity through the previous Wednesday for a specified subset of PJM billing line items. Payments will be due by noon on the third business day following issuance. Disbursements will be made by 5pm on the fourth business day following issuance. Note that monthly billing statements will continue to be issued and will be financially settled on the same dates as the following month’s first weekly billing statement.

LSE Account Set Up and Billing Line Item Transfers

All Competitive Retail Electric Suppliers and POLR load suppliers in the DEOK zone will need to establish a separate PJM sub-account for their load in this zone in order to facilitate the settlement of certain billing line items that will remain the responsibility of Duke Energy Ohio as the utility, rather than the LSE. The account chosen to house the LSE's DEOK zone load may be an existing sub-account or a newly created sub-account, but may not have load for any other transmission zones in it.

A tentative inventory of the line items for which Duke Energy Ohio will be responsible is available on the DEOK integration web page: <http://www.pjm.com/markets-and-operations/market-integration/~media/markets-ops/duke-integration/deok-billing-line-item-transfer-inventory.ashx>

This preliminary list of billing line items for which Duke Energy Ohio will be responsible is based on a settlement agreement rider between Duke Energy Ohio, the Ohio Public Utilities Commission and interveners in that proceeding and is subject to change based on further settlement discussions. Under these billing arrangements, the load for impacted LSEs will still reside with the LSEs and the LSE will see all billing associated with that load on their settlement reports. However, 100% of the charges for the selected billing line items will be directly transferred to Duke Energy Ohio via the use of a billing line item transfer. That billing line item transfer will cause those charges to appear on Duke Energy Ohio's billing statements rather than those of the LSEs.

In order to initiate billing line item transfers for load-related billing line items, the LSE's account from which the charges are being transferred must contain only load within the DEOK zone. This is because PJM billing line item transfers move 100% of a given billing line item from the '_Transfer From' account to the '_Transfer To' account. Therefore, since the charges will be transferred from the LSE back to the utility, loads in different transmission zones cannot be comingled in a sub-account from which load-related charges will be transferred.

This account set up pertains to Network Service Peak Load, capacity Peak Load Contribution and real-time load-related billing. All such activity for the DEOK zone must reside in an isolated account.

Existing PJM members may use CAM Form B to request the creation of additional sub-accounts: <http://www.pjm.com/about-pjm/member-services/~media/about-pjm/member-services/membership-assistant/customer-account-manager-designation-form.ashx>

Schedule 9-FERC Exemption

PJM as a public utility and the Transmission Provider under the PJM Open Access Transmission Tariff is subject to annual charges assessed by FERC in accordance with Part 382 of FERC's regulations. Schedule 9-FERC of the PJM tariff recovers PJM's payments to FERC for the FERC annual charge. FERC assesses its annual charge to PJM and other public utilities based on their total megawatt-hours of transmission of electric energy in interstate commerce. Accordingly, the charge

Duke Integration White Paper

under Schedule 9-FERC is assessed on all MWh of transmission provided by PJM. PJM provides this service to customers using Point-to-Point and Network Integration Transmission Service under this Tariff.

As FERC will utilize transmission volumes from 2011 for the 2012 FERC Annual Charge, the Midwest ISO's 2012 annual charge will include the DEOK zone's transmission volumes and PJM's 2012 annual charge will not. The Midwest ISO will bill Duke Energy Ohio and Duke Energy Kentucky directly for the 2012 FERC Annual Charge assessed to the Midwest ISO for the Companies' 2011 transmission volumes. If PJM started assessing this fee to transmission customers in the DEOK zone as soon as the DEOK zone integrated, transmission customers in the DEOK zone would have to pay a disproportionate share of the annual assessment. To ensure that transmission customers in the DEOK zone are not over- or under-assessed their share of the annual FERC fees, subject to FERC approval, PJM will waive Schedule 9-FERC charges to transmission customers in the DEOK Zone. This waiver will cover the period beginning with the planned integration date of January 1, 2012 and expire on September 30, 2012.

Transmission Enhancement Charge Billing

All network customers and merchant transmission owners pay PJM transmission owners for PJM required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. These costs are collected through Transmission Enhancement Charges on the PJM billing statement.

Because the DEOK integration is occurring on January 1, 2012 and DEOK will not have been a PJM Zone during the peak load measurement period prescribed by section (b)(i)(A) of Schedule 12 which is used to determine cost responsibility for required transmission enhancements, the DEOK zone will not be assigned cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities during 2012. Network transmission customers in the DEOK zone therefore will not see Transmission Enhancement Charges on their PJM billing statement until the January 2013 billing period.

MTEP Project Cost Recovery Billing

Following the integration of DEOK into the PJM footprint, the DEOK zone will maintain responsibility for a share of the costs of transmission projects approved under MISO's Transmission Expansion Plan (MTEP) prior to DEOK's departure from MISO. MISO will bill such costs to PJM, on behalf of the DEOK zone. PJM will then pass those charges on to DEOK zone LSEs via the MTEP Project Cost Recovery Charge on the monthly PJM billing statement. These legacy MTEP charges will be allocated to DEOK zone LSEs on an NSPL ratio share basis. Additional information on the calculation of MTEP charges and the distribution of MTEP revenues can be found in Attachment JJ to the PJM OATT.

Note: MTEP Project Cost Recovery Charges assessed to retail LSEs are subject to billing line item transfers as outlined in the "LSE Account Set Up and Billing Line Item Transfers" section above; therefore, these charges will not show up on retail LSEs' billing statements.

Meter Checkout

The generator and tie-line meter data checkout process via eMTR will follow current PJM business rules. The PJM accounting deadline is Noon next business day (3pm on Mondays and after holidays, all times Eastern Prevailing Time). All submitted data is considered final at this time (end-of-month corrections are allowed). Please see the Reference section for a link to the eMTR Deadline, File Format and Training Documentation.

Participant Readiness/Training Development

PJM has developed a comprehensive approach to assist PJM market customers with the integration of Duke into the PJM footprint. This approach consists of two parallel and complimentary efforts: Participant Readiness and Training Delivery.

Participant Readiness

The Participant Readiness approach consists of a proactive effort to reach out to Duke-related customers and work with them to prepare them for integration. This includes distribution of relevant information, references to white papers and other PJM resources to provide details, requirements, and a customized checklist for each customer which highlights the major topics that need to be covered to prepare for integration.

To facilitate this process, PJM has established client manager teams that will work with the various customer bases (i.e. Generation Owners, Load servers, etc.) to conduct meetings, recommend training, and monitor progress. Status of each company and overall readiness progress for all participants will be tracked and reported as part of the market implementation. Periodic roundtable discussions, conference calls, and in person visits will also be held to monitor status and progress and to provide a forum for information sharing and issues discussion.

The tools to support the readiness effort include:

- Participant Readiness Checklists
- Client Manager Meetings

A membership guide describing the high-level requirements for membership according to business activity has been included as an appendix: Appendix D: PJM Membership Guide.

Training Delivery

A comprehensive training schedule will be developed centered around four core programs:

- LSE - Load Serving Entity training focuses on the processes and applications relevant to load servers.
- MOC – Market Operations training targets generators who will need to understand the scheduling, operation and dispatch of generation and ancillary services within PJM, as well as other PJM specific business rules and applications.
- LCC – Local Control Center training covers the roles and responsibilities of LCC operators operating within the PJM RTO.

Duke Integration White Paper

- TO – Training will also be provided to the TO staff related to the various model and transmission planning and protection related functions for Duke facilities.

Training on other topics will be developed and delivered based on needs that are identified. Training courses will be available in the Duke footprint, as well as in other locations throughout the PJM footprint and online.

Operational personnel targeted for PJM Certification will be identified and a company Training Liaison designated. This group will need to individually schedule their tests and earn their PJM credential (Generation or Transmission) prior to integration.

If necessary, a training course for existing PJM members will be developed to provide an overview of changes and highlight specific business rule and application changes related to Market Integration. Please see the Reference Documents section for the link to the courses offered and instructions for registering.

Reference Documents

Markets Training - Annual FTR Auction 2009/2010

<http://www.pjm.com/training/~/media/training/special-events/ip-arr-ftr-wkshop/09-10-arr-ftr-training.ashx>

PJM Capacity Market Manual, M18

<http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx>

eRPM User Guide

<http://www.pjm.com/markets-and-operations/etools/~/media/markets-ops/rpm/erpm-user-guide-v1.ashx>

RPM Schedule

<http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20080319-rpm-auction-schedule.ashx>

PJM Regional Practices

<http://www.pjm.com/markets-and-operations/etools/oasis.aspx>

eMeter Deadline, File Format, and Training Documentation

<http://www.pjm.com/markets-and-operations/etools/emtr.aspx>

Training Web Site

<http://www.pjm.com/training.aspx>

Behind the Meter Business Rules (Manual 14D - Appendix A)

<http://www.pjm.com/documents/~/media/documents/manuals/m14d.ashx>

PJM Manual 05 Power System Application Data

<http://www.pjm.com/documents/~/media/documents/manuals/m05.ashx>

Guide to Billing, Weekly Billing Implementation Summary, June 2009 - May 2010 Weekly Billing Calendar

<http://www.pjm.com/markets-and-operations/market-settlements/guides-forms.aspx>

Contact Information

Please direct all questions and comments regarding this document to Frank Koza at kozaf@pjm.com.

Appendix A: Glossary of Acronyms

ACE	Area Control Error
AEP	American Electric Power
AGC	Automatic Generation Control
ARR	Annual Auction Revenue Right
AFC	Available Flowgate Capability
ATC	Available Transfer Capability
BA	Balancing (Authority) Area
ComEd	Commonwealth Edison
CPS	Control Performance Standard
CM2	Congestion Management Coordinated Methodology
CZRA	Control Zone Regulation Assist
DP&L	Dayton Power and Light Company
eDART	Electronic Dispatcher Applications and Reporting Tool
ECAR	East Central Area Reliability (NERC)
EES	Enhanced Energy Scheduler
eGADS	Generator Availability Data System
EMS	Energy Management System
EPT	Eastern Prevailing Time
FTR	Financial Transmission Right
FRP	Financial Responsible Party
GCA	Generating Control Area
GMS	Generation Management System

Duke Integration White Paper

GTO	Generation Transfer Optimizer
GT	Generation Transfer
ICAP	Installed Capacity
IDC	Interchange Distribution Calculator
IRC	Instantaneous Reserve Check
IRM	Installed Reserve Margin
JOA	Joint Operating Agreement
LCA	Load Control Area
LCC	Local Control Center
LD	Liquidated Damages
LMP	Locational Marginal Pricing
LSE	Load Serving Entity
MIL	Mandatory Interruptible Load
MISO	Midwest Independent System Operator
MOC	Market Operations Committee
NCA	Neighboring Control Area
ND	Network Designated
NND	Network Non – Designated
NERC	North American Electric Reliability Council
NYISO	New York Independent System Operator
NI CA	Northern Illinois Control Area
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
OC	Operating Committee

Duke Integration White Paper

PD	Power Dispatcher
PGT	Pathway Generation Transfer
POD	Point of Delivery
POR	Point of Receipt
PJM CA	PJM Balancing Area
PTP	Point – To – Point
RAA	Reliability Assurance Agreement
RPM	Reliability Pricing Model
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SA	Security Analysis
SDX	System Data Exchange
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous Feasibility Test
SPP	Southwest Power Pool
SSR	Supplemental Status Report
TERM	Transmission Equipment Ratings Monitor
TLR	Transmission Line-Load Relief
TO	Transmission Owner
TVA	Tennessee Valley Authority
UCAP	Uninstalled Capacity
UDS	Unit Dispatch System
VSTLF	Very Short Term Load Forecast

Duke Integration White Paper

XIC

External Installed Capacity

Appendix B: FTR Allocation Procedure

Background

Previously under the PJM market rules, FTRs were allocated to Network and Firm Point-to-point Transmission customers on an annual basis using a rule based approach. A single round FTR Auction was held on a monthly basis to allow Market Participants to purchase FTRs from residual system capability or from sale offers submitted by FTR holders. Beginning with the 2004 planning period, in addition to the continuing monthly FTR auctions, PJM replaced the annual FTR allocation procedure with an annual FTR Auction mechanism in order to create a more robust FTR Market in PJM. In its order accepting the annual FTR auction for filing, the FERC required PJM to provide a two-year transition period during which participants in integration areas may elect to either participate in the annual FTR auction or, in the alternative, choose to have FTRs allocated directly to them. The purpose of this document is to specify the process by which initial FTR allocations will take place for integration areas.

DUKE Integration Transition Issues and Proposed Resolutions

Conversion of Firm Point-to-Point Transmission Service

Since FTRs may be allocated to Firm Point-to-Point (–PTP”) transmission service customers, the topic of transmission service conversion is relevant to the subject of FTR allocations. Firm Point-to-Point (–PTP”) transmission service with Point of Delivery (–POD”) and Point of Receipt (–POR”) that will, following the PJM market integration, within the PJM footprint will be converted to a comparable PJM product. Conversion to PJM Network Service means that the holder would stop paying the entity from which the service was originally purchased as of the implementation date of the associated integration, and deliver energy within the PJM footprint without Point to Point (–PTP”) transmission. The transmission customer would be charged for Network service based on peak load, consistent with the provisions in the PJM Tariff. If the customer chooses to maintain the PTP service, then the customer would pay the appropriate zonal Firm PTP transmission rate, and would have the option to nominate an FTR with the same POD and POR as that of the PTP reservation.

Actual conversion of existing reservations along with applications for new transmission service for the expanded PJM footprint will be handled through the PJM Transmission Department and the PJM OASIS.

Redirects of Firm Transmission Service

Upon integration of the PJM footprint and implementation of the expanded OASIS, PJM transmission customers will be allowed to redirect Firm transmission service, subject to ATC availability on the requested path. (Note: redirect requests on the PJM OASIS must be submitted as pre-confirmed.) Upon requesting a redirect of Firm transmission service, the participant will have the option of requesting an FTR on the redirected path. If no such request is made, the participant will retain any existing FTR on the original path. If the participant does request an FTR on the redirected path, PJM will conduct a feasibility analysis on the request, the new FTR will be granted to the extent it is feasible for the length of the redirect, and any FTR associated

Duke Integration White Paper

with the original reservation will be relinquished for the time period of the redirect. If no FTRs (i.e. – 0 MW) are available on the redirected path, the requestor will have the option of retaining the FTR on the original path. Note that if the participant takes an FTR on the redirected path (thereby relinquishing the FTR on the original path) and then terminates the redirect prior to the scheduled date, the original FTR may no longer be feasible until the original term of the redirect has expired.

Monthly FTR Auctions

As each new zone is added into the PJM market, the monthly FTR auction model will be updated to accommodate FTR purchases and sales that have source and/or sink points in the new zones. Addition of the new zones to the monthly FTR auction model will take place beginning with the first monthly auction that occurs following actual integration of each new zone.

Load Shifts in the New Zones

Once the initial or annual ARR allocations are completed in the new zone, ARRs will be reassigned as Network Load changes from one Network Service user to another. ARRs will be reassigned on a proportional basis from the Network Service users losing the load to the Network Service users gaining the load. Similarly, any FTRs that are directly allocated to participants in lieu of their participation in the annual FTR auction will also be reassigned as Network Load shifts between load serving entities.

Appendix C: Ramp Examples

NYISO 500 MW Ramp

PJM also monitors a ± 500 MW ramp with the NY ISO. At no time can the difference in the interchange between NY and PJM be greater than ± 500 MW at any 15-minute interval. Ramp room for NY transactions is allocated on a first come, first serve basis. NY transactions submitted to PJM will be evaluated against both the PJM ramp and the NY ISO ramp.

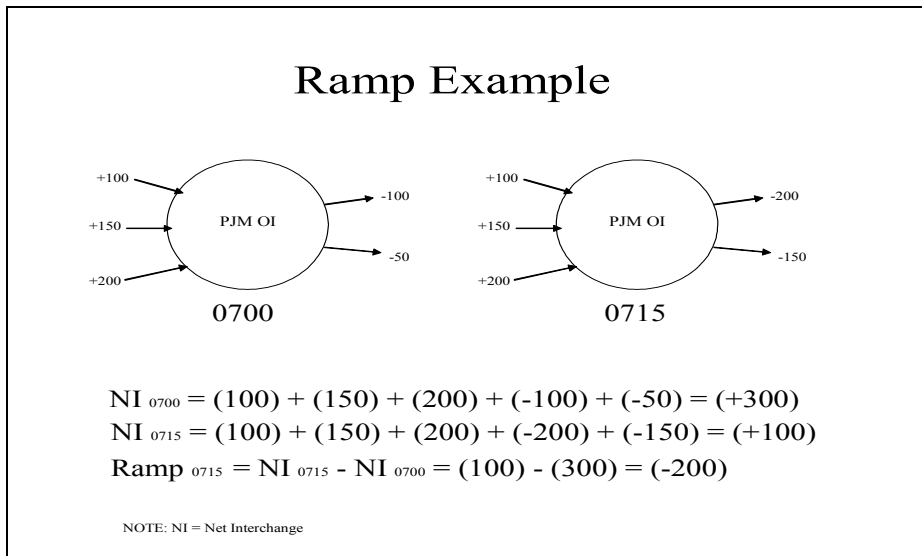


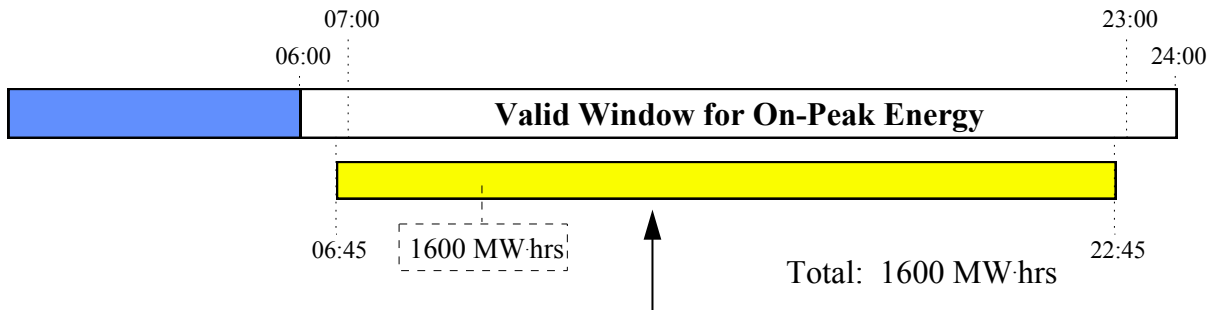
Exhibit A: Example Ramp Calculation

The current PJM ramp limits are shown in Exhibit B.

Time	Ramp In	Ramp Out
0000-0500 (M-F)	1000	1000
0500-2400 (M-F)	1000	1000
0000-2400 (S & Su)	1000	1000

Exhibit B: Example Ramp Calculation

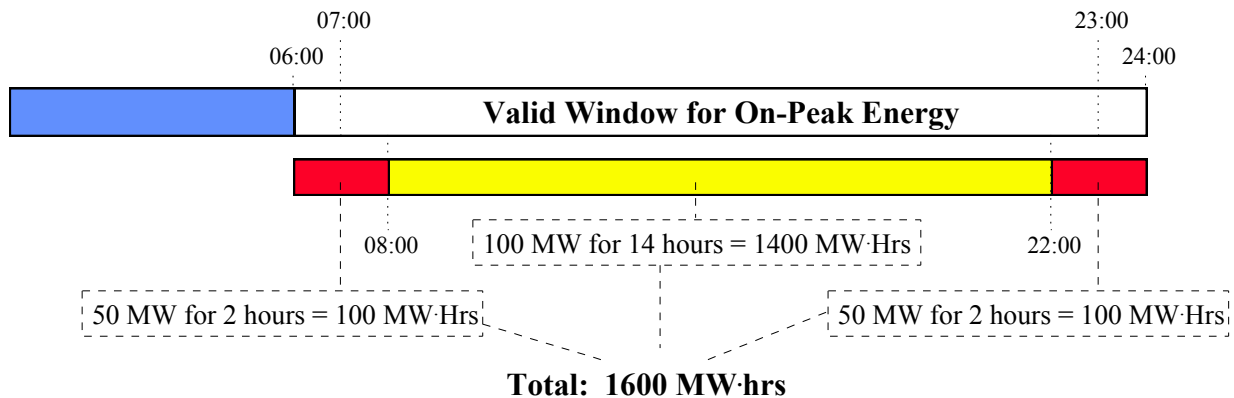
On-Peak Monday-Friday



Example of Valid Energy Schedule using a 100MW Capacity
On-Peak Transmission Service Reservation
Over 16 Hour Period

Exhibit C: On-Peak Transmission Service Over 16 Hour Period Example

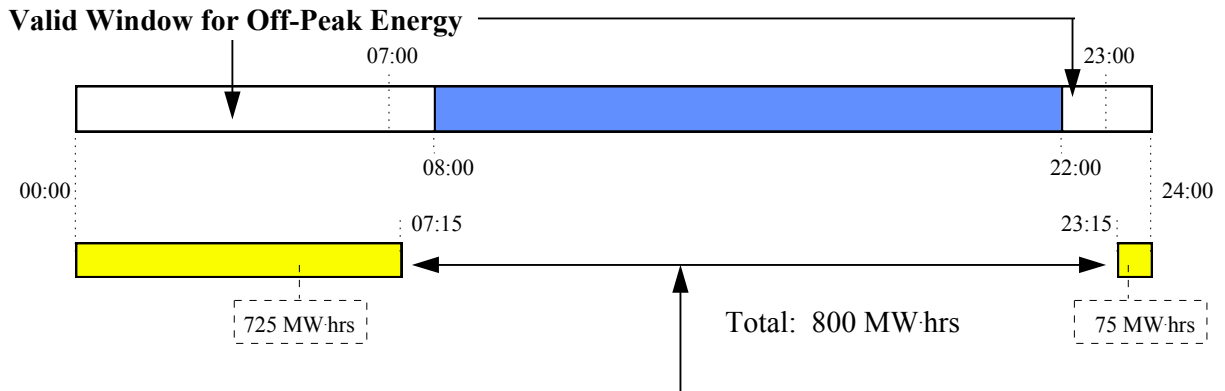
On-Peak Monday-Friday



Example of Valid Energy Schedule using a 100MW Capacity
On-Peak Transmission Service Reservation
Over 18 Hour Period

Exhibit D: On-Peak Transmission Service Over 18 Hour Period Example

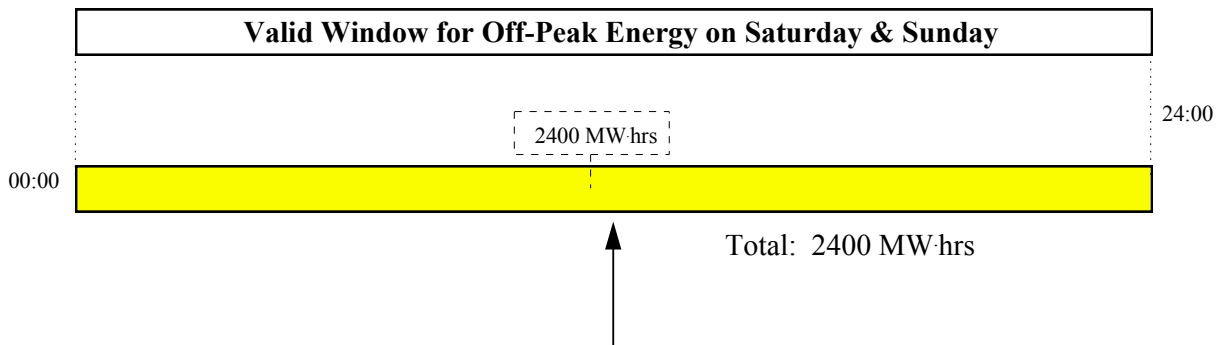
Off-Peak Monday-Friday



Example of Valid Energy Schedule using a 100MW Capacity
Off-Peak Transmission Service Reservation

Exhibit E: Off-Peak Monday-Friday Transmission Service Example

Off-Peak Saturday & Sunday



Example of Valid Energy Schedule using a 100MW Capacity
Off-Peak Transmission Service Reservation

Exhibit F: Off-Peak Saturday-Sunday Transmission Service Example

Appendix D: PJM Membership Guide

(DRAFT)

Business Activity	Membership Required	Comments
Reserve Point to Point Transmission Service	<ul style="list-style-type: none"> • Transmission Service Customer • No membership fees • Credit Required • May receive ARR/FTRs for amount of Firm PTP service reserved 	<ul style="list-style-type: none"> • PTP or Network Service required for dynamic generation schedules. • Congestion may be charged on transmission reservation
Energy Market Participant	<ul style="list-style-type: none"> • Membership Required • Annual \$5000 fee • \$1500 one-time Application Fee (waived for new DEOK Zone members from integration upon approval of FERC) • Affiliate groups pay only one fee per group 	
Load Serving Entity (Retail Load Aggregator)	<ul style="list-style-type: none"> • Membership Required • May nominate ARR/FTRs to amount of Network Service Peak Load 	<ul style="list-style-type: none"> • Must be signatory to RAA • Must have Att. F-1 agreement for network transmission service
Load Serving Entity (Wholesale Municipal, Cooperative, EDC)	<ul style="list-style-type: none"> • Membership Required • May nominate ARR/FTRs to amount of Network Service Peak Load 	<ul style="list-style-type: none"> • Must be signatory to RAA • Must have Att. F Agreement for network transmission service
Generation Owner	Membership Required if selling energy to PJM Market	<ul style="list-style-type: none"> • Must file revenue requirement with FERC to receive reactive supply payments • Must submit black start revenue

Duke Integration White Paper

		requirements to PJM to receive black start payments
End Use Customer	Membership Optional	Voting privileges only
Curtailed Service Provider	<ul style="list-style-type: none">• Membership Required• May be Special member is only participating in RT energy market	

Appendix E: Conversion of Service in the DEOK Zone

Reservations purchased on the MISO OASIS nodes prior to the integration of the DEOK Zones shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the MISO tariff pending prior to the integration of the DEOK Zone shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

For service with an export from the DEOK Zone and an import to the remainder of the PJM Region (or vice-versa), the transmission service cannot be converted into a single reservation under this Tariff. Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the MISO tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery, and path.
2. All Duke reservations must select Source and Sink LMP pricing points, where applicable, willing to pay through (or not), a new product if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the Duke integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM's judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All converted service will be placed on the PJM OASIS no later than 30 days prior to the Duke integration start date.
3. All Duke import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS: Spot market, Non-Firm Point-to-Point, Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.
4. All existing Duke extended transmission requests (i.e. monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from April 1 to June 1 will be converted to two individual monthly requests, April 1 to May 1, and May 1 to June 1; and a daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

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5. Sliding monthly service (i.e. monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.
6. Sliding weekly service (i.e. weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.
7. Transmission service that is not currently confirmed on the MISO OASIS node and is in an active state such as ~~–Received~~”, ~~–Queued~~” or ~~–Study~~” will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.
8. All ~~–Grandfathered~~” requests that exist on the MISO OASIS node will require a reservation on the PJM OASIS node.
9. To facilitate the OASIS transition, from one month prior to the Duke integration start date until such integration start date, requests for service that are active on or after such integration start date should be made on both the MISO and PJM OASIS nodes.
10. Reservations will be converted based on the priority of the product.
11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (e.g., reliability issues, etc.). In this case, reservations will be reviewed on a case-by-case basis. In the event that any path may be oversubscribed, Transmission service that is not currently confirmed on the MISO OASIS node and is in an active state such as ~~–Received~~”, ~~–Queued~~” or ~~–Study~~” will be granted to each market participant on a pro-rata basis.
12. Converted Point-to-Point transmission service reservations that intersect with or begin after the integration commencement date will be posted to the PJM OASIS web page on a weekly basis. The web page will distinguish between the original Duke reservations and the new PJM OASIS reservation.
13. An Interconnection request pending under the Duke OATT at the time of the integration of the DEOK Zone shall be assigned the same priority date under this Tariff as such request had under the MISO OATT immediately prior to such integration. All such interconnection requests will be integrated into PJM’s existing Interconnection Queue(s), effective on the Duke integration start date and will be subject to the generation interconnection procedures under Parts IV and VI of this Tariff.

Appendix F: Interface Pricing Points

Mapping of External Balancing Areas to Interface Pricing Points, Post-Duke Integration

All external balancing areas in a group are mapped to one pricing point relative to the expanded PJM BA.

Please refer to the current Pricing Point guide on the EES web page.

<http://www.pjm.com/markets-and-operations/etools/ees.aspx>

<http://www.pjm.com/markets-and-operations/etools/~media/etools/ees/pricing-point-guide.ashx>

Appendix G: PJM Interface Definition Methodology

For transactions that either source or sink outside of the PJM footprint, a means to price the transactions at the PJM border is required. A set of proxy buses are used to create this border price, referred to as an interface price. The challenge is creating an interface price that is made up of proxy buses, or external pricing points, that not only accurately represents the tie line flows between the two areas, but also produces the correct pricing signals.

The first step in this process is to identify all adjacent balancing areas. These will serve as the basis for interface prices. The abbreviation of the adjacent balancing area is used as the name for the interface price. For example, in determining the interface prices for the ComEd integration, the MidAmerican Energy Company is adjacent to the Northern Illinois balancing area. The abbreviation of the MidAmerican Energy Company together with the "NI" designation to indicate its association with the Northern Illinois balancing area, MECNI, was used as the name for that interface price.

Using standard power flow analysis tools, transactions to and from each external balancing area are simulated in order to obtain distribution factor data. This distribution factor data is then analyzed to determine through which adjacent balancing area the majority of flow will occur. By calculating the correlation coefficient of the external area distribution factor with the distribution factor for each of the adjacent balancing areas, the association of an external balancing area with one of the adjacent balancing areas can be determined.

The distribution factor analysis may show that certain adjacent balancing areas have very similar effects on the ties between them and PJM. If this similarity is observed, then the adjacent balancing areas can be "combined" to use a common definition. The definition can be external pricing points from just one adjacent balancing area or a combination of external pricing points in both of the adjacent balancing areas. The analysis for the ComEd integration showed that certain adjacent balancing areas showed very similar effects to other adjacent balancing areas. The MidAmerican Energy Company, MEC, and Alliant Gas & Electric West, ALTW, is an example where the definition for each interface is the same and composed of a combination of external pricing points from both adjacent balancing areas. Furthermore, the analysis for the AEP and Dayton integration showed a great deal of adjacent balancing areas having very similar effects on the ties between the adjacent balancing area and PJM. Because of the large number of adjacent balancing areas and the amount of adjacent balancing areas that showed similar effects on the PJM ties, single interface pricing points were created that represented several adjacent balancing areas. The external pricing points from each adjacent balancing area in these grouping were used to define the interface price. The Southwest interface price is an example of this single interface price used to represent several adjacent balancing areas.

If a transaction from an external balancing area results in similar tie line flows on multiple interfaces, but not interfaces that share the same interface price definition, then additional analysis is needed to determine if an additional interface is needed that is not one of the adjacent balancing areas. This similar tie line flow situation is evident when the correlation coefficients of an external balancing area are similar to one or more adjacent balancing areas. This additional interface would model the combined effect of transactions from the external area across the

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various PJM tie lines as seen in the correlation coefficient analysis. An example of this situation exists in the Ontario Independent Electric System Operator (IESO) interface.