Duke Energy

DUKE ENERGY CORPORATION

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VIA HAND DELIVERY

November 10, 2010

RECEIVED
NOV 10 2010
PUBLIC SERVICE
COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Blvd
Frankfort, KY 40601

Re: Case No. 2010-00203

Dear Mr. Derouen:

Enclosed please find an original and twelve copies of the *Responses of Duke Energy Kentucky, Inc. to Midwest Independent Transmission Systems Operator, Inc.'s Post-Hearing Data Requests* in the above captioned case.

Please date-stamp the extra two copies of the filing and return to me in the enclosed envelope.

Sincerely,

Kristen Cocanougher

Kristen Cocanougher

cc: Parties of record

379549

<u>VERIFICATION</u>

State of Ohio)
)
County of Hamilton)

The undersigned, William Don Wathen Jr., being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as General Manager Duke Energy & Vice President Rates-Ohio & Kentucky; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing information request, and that the matters set forth in the foregoing response to information request are true and accurate to the best of my knowledge, information and belief after reasonable inquiry.

Don Wathen Jr
William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen Jr. on this 5th day of November 2010.

Anita M. Schafer
NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2014

378508

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, G. Robert Burner Jr., being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Director, Transmission and Portfolio Optimization that on behalf of Duke Energy Kentucky, Inc. says that I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

G. Robert Burner Jr.

G. Robert Burner Jr., Affiant

Subscribed and sworn to before me by G. Robert Burner Jr. on this 4 day of November, 2010.

RITA G KALE
NOTARY
PUBLIC
CATAWBA CO., NORTH CAROLINA

Rita G Kale

NOTARY PUBLIC

My Commission Expires: 6/17/12

378548

VERIFICATION

State of North Carolina)
)
County of Mecklenburg)

The undersigned, James B. Gainer, being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Vice President of Federal Government and Regulatory Affairs; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the response to the foregoing information request; and that the matters set forth in the foregoing response to information request is true and accurate to the best of my knowledge, information and belief after reasonable inquiry.

James B. Gainer, Affiant

Subscribed and sworn to before me by James B. Gainer on this 4th day of November, 2010.

GAYLE H. WEBBER
NOTARY
PUBLIC
UNION COUNTY, N. C.

Gayle H. Webber
NOTARY PUBLIC

My Commission Expires: 09/13/11

378528

TABLE OF CONTENTS

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-001
(POST HEARING
DATA REQUEST)

REQUEST:

Please indicate where the $85,905 monthly ASM margins was credited back to customers in Duke Energy Kentucky's October 29, 2010 Rider PSM filing.

RESPONSE:

The adjustment was calculated in Schedule 5 and incorporated into Schedule 3 of the PSM filing made on October 29, 2010. See Post Hearing Attachment MISO-DR-01-001 for the details of the calculation.

PERSON RESPONSIBLE: William Don Wathen Jr.

DUKE ENERGY KENTUCKY
OFF-SYSTEM SALES SCHEDULE
PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2009

Schedule 3

e NO.	Description		Total TFS-2010-00417	Adjustment	Total TFS-2010-00656
1	**Off-System Sales Revenue**				
2	Asset Energy	(+)	$13,177,221	$0	$13,177,221
3	Non-Asset Energy	(+)	0	0	0
4	Bilateral Sales	(+)	216	0	216
5	Hedges	(+)	0	0	0
6	MISO RSG Make Whole Payments	(+)	4,196,943	0	4,196,943
7	Capacity	(+)	710,240	(837) (c)	709,403
9	Ancillary Services Market	(+)	170,604	**85,905** (d)	256,509
10	Sub-Total Revenues		$18,255,224	$85,068	$18,340,292
11	**Variable Costs Allocable to Off-System Sales**				
12	Bilateral Purchases	(+)	0	0	0
13	Fuel Cost	(+)	15,574,064	0	15,574,064
14	Variable O&M Cost	(+)	968,569	0	968,569
,	SO_2 Cost	(+)	531,143	0	531,143
16	NO_x Cost	(+)	9,333	0	9,333
17	MISO Costs	(+)	61,732	0	61,732
18	Sub-Total Expenses		$17,144,841	$0	$17,144,841
19	Total Off-System Sales Margin (Line 7 - Line 15)	(+)	$1,110,383	$85,068	$1,195,451
20	Allocated to Customers (guaranteed 100% of first $1.0 million) [(a)]	(-)	1,000,000		1,000,000
21	Sub-Total	(+)	$110,383	$85,068	$195,451
22	Percentage Allocated to Customers (50% of margins > $1.0 million) [(a)]		50.00%	50.00%	50.00%
23	Remainder Allocated to Customers (Line 18 x Line 19)		$55,192	$42,534	$97,726
24	Total Allocated to Customers (Line 17 + Line 20) [(b)]	(+)	$1,055,192	$42,534	$1,097,726
25	Net Margins on Sales of Emission Allowances	(+)	21,640	0	21,640
26	Prior Period Carryforward [(b)]	(+)	(644,627)	0	(644,627)
27	Amount Credited to Customers in 2009	(-)	453,277	-	453,277
28	Remaining PSM Credit Due to Customers at 12/31/09		(21,072)	42,534	21,462

Note: [(a)] Per provisions included in the Commission's Order dated December 5, 2003, in Case No. 2003-00252.

[(b)] Incremental change from prior filing is due to MISO resettlements.

[(c)] Adjustment for the cost of brokerage fees associated with the capacity sales.

[(d)] Adjustment for eliminating the months in 2009 that the ASM costs exceeded the ASM revenues.

SCHEDULE 5

DUKE ENERGY KENTUCKY
ANCILLARY SERVICES MARKET
PERIOD: YEAR TO DATE - DECEMBER 31, 2009

Line No.	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
1	DA Spinning	$25,945	$8,179	$6,450	$8,769	$3,111	$6,184	$5,646	$1,121	$2,455	$12,395	$8,343	$16,267	$104,865
2	RT Regulation	$19,186	$13,123	$17,193	$17,610	$35,546	$40,058	$1,746	$16,655	$4,487	$3,341	$2,440	$583	$171,968
3	RT Spinning	$59,974	$67,544	$24,197	$32,429	$87,804	$62,379	$11,973	$17,190	$14,111	$15,733	$13,111	$44,650	$451,095
4	RT Supplemental	$0	$0	$0	$0	$0	$0	$0	$0	$6,004	$1,607	$0	$67,041	$74,652
5	MISO Net Reg Adj Amt	($208)	($501)	$488	($939)	$1,524	($2,824)	($26)	($558)	$58	$87	$16	$923	($1,960)
6	MISO Reg Dist	($58,626)	($33,427)	($35,039)	($29,950)	($29,068)	($29,548)	($27,831)	($27,942)	($22,413)	($29,129)	($22,458)	($31,087)	($376,518)
7	MISO Reg Penalty	($1,558)	($960)	($1,400)	($1,101)	($1,232)	($2,556)	($696)	($858)	($722)	($588)	($833)	($332)	($12,836)
8	MISO Spin Dist	($39,015)	($23,764)	($13,844)	($16,000)	($13,765)	($19,446)	($14,440)	($14,224)	($12,099)	($23,823)	($13,376)	($18,046)	($221,842)
9	MISO Supp Dist	($1,406)	($1,288)	($1,317)	($1,319)	($1,447)	($1,514)	($1,562)	($1,708)	($2,116)	($2,566)	($1,184)	($1,393)	($18,820)
10	MISO Res Dep Penalty	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Total per TFS-2010-00417	$4,292	$28,906	($3,272)	$9,499	$82,473	$52,733	($25,190)	($10,324)	($10,235)	($22,943)	($13,941)	$78,606	$170,604
12	Total per TFS-2010-00656	$4,292	$28,906	$0	$9,499	$82,473	$52,733	$0	$0	$0	$0	$0	$78,606	$256,509
													Adjustment	$85,905

Note: Per the Commission Order dated January 30, 2009, in Case No 2008-00489

MISO-DR-01-002
(POST HEARING
DATA REQUEST)

REQUEST:

How did Duke Energy Kentucky calculate the 15-17% figures, as discussed in Page 8 of your pre-filed Direct Testimony?

RESPONSE:

See Post Hearing Attachment MISO-DR-01-002 which summarizes the monthly peak demands for Duke Energy Ohio and Duke Energy Kentucky. The 15% to 17% range represents the different results using the 1 CP method versus the 12 CP method. In either case, the allocation factor represents the share of Duke Energy Kentucky's peak load at the time Duke Energy Kentucky and Duke Energy Ohio peaked together.

The data in the Attachment is included in the formula rate filed with the Midwest ISO under the approved Attachment O in its Transmission and Energy Markets Tariff (TEMT).

PERSON RESPONSIBLE: William Don Wathen Jr.

2009 MONTHLY PEAKS IN MEGAWATTS

Duke Energy Ohio	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
Final System Input	3,523,000	3,402,000	3,099,000	2,736,000	3,010,000	3,949,000	3,156,000	3,594,000	2,597,000	1,847,000	1,863,000	2,258,000	35,034,000	2,919,500
Add:														
Customer Choice Load	100,000	81,000	73,000	106,000	129,000	276,000	327,000	377,000	622,000	724,000	912,000	1,001,000	4,728,000	394,000
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal	100,000	81,000	73,000	106,000	129,000	276,000	327,000	377,000	622,000	724,000	912,000	1,001,000	4,728,000	394,000
DE-Ohio Peak Demand including Customer Choice Load	3,623,000	3,483,000	3,172,000	2,842,000	3,139,000	4,225,000	3,483,000	3,971,000	3,219,000	2,571,000	2,775,000	3,259,000	39,762,000	3,313,500

Duke Energy Kentucky	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
inal System Input	756,000	720,000	645,000	594,000	626,000	767,000	736,000	799,000	673,000	498,000	557,000	676,000	8,047,000	670,583
DE-Kentucky Pricing Zone Peak Demand	756,000	720,000	645,000	594,000	626,000	767,000	736,000	799,000	673,000	498,000	557,000	676,000	8,047,000	670,583
Sum of DE-Ohio and DE-Kentucky Load	4,379,000	4,203,000	3,817,000	3,436,000	3,765,000	4,992,000 MAX CP	4,219,000	4,770,000	3,892,000	3,069,000	3,332,000	3,935,000	47,809,000	3,984,083

Duke Energy Kentucky Share of Total
Based on Highest CP (1 CP) → **15.4%**

Duke Energy Kentucky Share of Total
Based on Average of 12 CPs for the year → **16.8%**

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-003
(POST HEARING
DATA REQUEST)

REQUEST:

How did Duke Energy Kentucky calculate the $72 million figure, as discussed in Page 8 of your pre-filed Direct Testimony? (corrected to $72 million from $77 million at the November 3, 2010 hearing) Please provide a schedule showing the calculation. Also, provide an updated estimate of the MISO MTEPP costs estimated to be allocated to Duke Energy Kentucky upon its leaving MISO as was described at the Hearing lowering the estimate from $44 to $36 million.

RESPONSE:

The components of the $72 million estimate are as follows:

- $45 million for NPV of allocated share of estimated MTEP costs
- $18.5 million for estimated MISO exit fees
- $7 million for estimated hold harmless payments
- $1 million for estimated EMS upgrades
- $0.5 million for estimated legal fees

The $45 million estimate for MTEP costs was derived by estimating Duke Energy Midwest's (i.e. Indiana, Ohio, and Kentucky) total responsibility to be $72 million. Duke Energy Ohio/Kentucky's share of the $72 million was assumed to be 50% or $36 million based on eligible MTEP projects through 2009. Approximately $4 million was added for new projects assumed to be approved for 2010 and another $4 million was added for 2011 projects bringing the total estimate, rounded, to $45 million.

Since the time of the initial filing, the $45 million estimate for the NPV of Duke Energy Ohio and Kentucky's share of MTEP costs has been revised to $36 million principally because there has been a change in the Midwest ISO allocation methodology (energy vs. peak load). The difference between the $45 million and the $36 million is due to the impact of the allocation difference.

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-004
(POST HEARING
DATA REQUEST)

REQUEST:

Please produce a copy of the FERC Transmission Planning and Cost Allocation Notice of Proposed Rulemaking Comments as requested at the Hearing.

RESPONSE:

See Post-Hearing Attachment MISO-DR-01-004.

PERSON RESPONSIBLE: James B. Gainer

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities	)))	Docket No. RM10-23-000

COMMENTS OF DUKE ENERGY CORPORATION

Pursuant to the June 17, 2010 Notice of Proposed Rulemaking ("NOPR")[1] and the August 10, 2010 Notice Extending Comment Period issued by the Federal Energy Regulatory Commission ("Commission" or "FERC"), Duke Energy Corporation ("Duke") hereby submits these Comments in the above-referenced docket. Duke's Comments reflect its unique perspective as an organization that serves as the ultimate parent entity to: companies that own transmission in an organized market;[2] a company that owns transmission and provides transmission service under a vertically-integrated structure;[3] companies that are active in constructing and purchasing generation to meet

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[1] 131 FERC ¶ 61,253 (2010).

[2] Duke Energy Indiana, Inc. ("DEI"), Duke Energy Kentucky, Inc. ("DEK"), and Duke Energy Ohio, Inc. ("DEO") are transmission owners that currently participate in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). DEK and DEO have proposed moving to the PJM Interconnection, LLC. *See* Dkt. Nos. ER10-1562, ER10-2254.

[3] Duke Energy Carolinas, LLC ("DEC" or "Duke Carolinas")) is a transmission provider and not a participant in an ISO. DEC is not a signatory to the NOPR Comments of the Ad Hoc Coalition of Southeastern Utilities, but notes that such comments provide an accurate picture of the unique nature of transmission planning in the Southeast, a region with limited renewable resources, historically robust transmission systems, and state commissions that opted to retain vertical integration, all factors that may impact the manner in which a Final Rule is implemented. By granting regions sufficient flexibility and recognizing existing regional processes, as requested in Duke's comments, the Commission should be able to mitigate concerns expressed in the Ad Hoc

the needs of their retail customers in both retail choice and non-choice states; a company that is a partner in Pioneer Transmission, LLC, a joint venture that has proposed to construct an extra high-voltage ("EHV") transmission project that will span two different regional transmission organizations ("RTOs"); and companies that own merchant generation, with a focus on renewable generation.

I. INTRODUCTION

Duke supports the Commission's efforts to advance regional and inter-regional transmission planning and cost-allocation. As the Nation's aging generation fleet is replaced with new low-carbon and no-carbon resources, the grid must be expanded to keep pace. The Order No. 890 planning requirements substantially advanced the process, but, as the NOPR recognizes, significant work remains to be done, especially in the area of inter-regional planning. Duke agrees that the type of tariff reforms contemplated in the NOPR are essential to support the development of a 21st century grid that can accommodate ever-growing demand, the retirement of older generating resources, and compliance with state and federal requirements to interconnect renewable resources. By and large, Duke's comments recommend clarifications intended to alleviate many of the concerns that have been expressed about the NOPR's potential reach.

First and foremost, Duke recommends that the Commission make unambiguous that the tariff reforms ultimately adopted will apply *only* to regional and inter-regional projects, and that the Commission does not intend to expand the planning processes

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Coalition's comments that the Commission is seeking to discard, rather than refine, regional planning processes already in place in the Southeast.

currently used to develop local projects. In the comments and technical conferences leading up to the NOPR, industry participants consistently focused on the need to enhance the processes and cost-allocation rules for large-scale projects that span entire regions or multiple regions. There was no substantial concern over how utilities plan and develop their local systems, and no groundswell of support for opening those processes to third-party developers.

Along these lines, the Commission should make clear that its policy on the reasonableness of rights of first refusal in tariffs or other transmission agreements is limited to regional and inter-regional projects. An unequivocal statement by the Commission that it has no intention of applying its right of first refusal ("ROFR") policies to local projects will go a long way toward eliminating the need to debate jurisdictional boundaries and the Commission's authority to oversee local planning. Local planning requirements are directly linked to local obligations to serve retail customers and OATT obligations to meet discrete interconnection and transmission requests that are not placed on non-utility market participants that seek to develop transmission projects. Conversely, as the OATT does not, and should not, impose any obligation to develop regional and inter-regional projects, utilities should have no basis to claim a first-call right to build regional and inter-regional projects proposed by others.

Second, the Commission should recognize that, in accordance with Order No. 890, many regions already have in place consensus-driven, Commission-approved planning processes. While some of those processes may need minor adjustments to comply with the Final Rule, there is no reason for the industry and the Commission to dedicate substantial time and resources to reinventing the wheel – especially in regions where the stakeholders continue to agree that the processes in place are viable. Although the NOPR confirms that the Commission has approved many regional planning processes, there are passages that suggest otherwise and imply that the Final Rule may require changes to meet the Order No. 890 planning principles. This ambiguity should be addressed.

Third, the Final Rule should make unambiguous that the public policy aspect of regional and inter-regional planning refers only to those transmission projects driven by the need to comply with state and/or federal laws, rules, and/or regulations. Compliance with renewable portfolio standards is an example of a policy driver that should be accounted for in the regional and inter-regional planning processes. A purely aspirational goal advanced by a given set of stakeholders is not.

Duke agrees that the Commission must tackle the cost-allocation issue. The question of who pays and how much is the linchpin of the regional and inter-regional planning processes. Without clear rules in place in every region within the Commission's jurisdiction, innovative projects designed to span multiple pricing zones or multiple regions simply cannot advance beyond the design stage. That does not mean that the Commission must adopt a one-size-fits-all approach; the Commission should endorse regional and inter-regional flexibility. But if the regions cannot agree on the rules, the Commission must step in and fill the void.

II. PARTICIPATION IN THE REGIONAL PLANNING PROCESS: The Commission should recognize that Order No. 890 resulted in the creation of regional planning processes and the Final Rule should not require additional layers of planning processes.

A. Regional Planning Processes Have Been Both Required and Approved

In the NOPR, the Commission proposes that each transmission provider[4] participate in a regional planning process that produces a regional transmission plan and that meets the following transmission planning principles established in Order No. 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies. NOPR at P 50. Transmission providers, however, already have filed and obtained approval of regional transmission planning processes that meet the *nine* principles of Order No. 890. Order No. 890:

> *required* each public utility transmission provider to have a coordinated, open, and transparent *regional transmission planning* process that addresses the following nine principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[5]

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[4] Throughout the NOPR, the Commission uses the term "public utility transmission provider." Duke has shortened it to "transmission provider" for the sake of brevity and is not implying that non-public utility (*i.e.*, non-jurisdictional) transmission providers are subject to the Final Rule. Throughout the pleading, including in quotations from the NOPR and FERC orders, Duke has hyphenated the terms "inter-regional", "intra-regional", and "non-incumbent" as it makes them easier to read.

[5] *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042 at P 53 (2010) (emphasis added).

These regional processes already have been approved.[6] Indeed, the Commission acknowledges that "the existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these requirements." NOPR at P 53. Duke wholeheartedly agrees.

The NOPR, however, engenders confusion by suggesting in places that the *requirement* for having a regional planning process is an entirely new concept.[7] Adding to this lack of clarity, the NOPR seems to conflate local planning with planning for a region served by a single transmission provider:

> By "local" transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual service territory or footprint pursuant to the requirements of Order No. 890.

NOPR at P 64 n.77. Read literally, this passage suggests that every ISO or RTO regional planning process already filed and approved should be viewed as "local" in nature.[8] This result certainly cannot be what FERC intended. In fact, the Order No. 890 planning processes adopted by the Midwest ISO and North Carolina Transmission Planning Collaborative ("NCTPC") are properly recognized as regional planning processes.

[6] Duke's operating companies each participate in existing Commission-approved regional planning processes.

[7] "Although the explicit requirement for a public utility transmission provider to participate in a regional transmission planning process that complies with the Order No. 890 transmission planning principles identified above would be new . . . ." NOPR at P 53.

[8] For example, the Midwest ISO is a transmission provider responsible for conducting the planning process within its footprint "pursuant to the requirements of Order No. 890." *Id.*

Midwest Indep. Trans. Sys. Operator, Inc., 123 FERC ¶ 61,164 (2008) (describing Midwest ISO as a region throughout); *Duke Energy Carolinas, LLC*, 124 FERC ¶ 61,267 at P 4 (2008) (describing the "Carolina region").

Pursuant to Order No. 890, the local planning process concept was understood to apply primarily to transmission owners ("TOs") participating in RTOs and ISOs; it was not understood to refer to a single transmission provider, such as an RTO. The Commission provided TOs the option to file a separate Order No. 890-compliant local planning process *or* have the RTO file a regional process that ensured that any planning that occurred on a single TO-system basis was sufficiently open and transparent. The Commission described the local planning process as follows:

> In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. This is important because, in many cases, RTO planning processes may focus principally on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners.... To ensure full compliance, individual transmission owners must, *to the extent that they perform transmission planning within an RTO or ISO,* comply with the Final Rule as well....[9]

Similarly, the Staff's Whitepaper discussing the scope of Order No. 890's Attachment K requirements indicated that transmission providers could "develop local and/*or* regional

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[9] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 440 (2007), *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,261 (2008), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) ("Order No. 890").

transmission plans."[10] Staff confirms that Order No. 890 did not impose on individual TOs or individual transmission providers the obligation to include separate, Order No. 890-compliant local planning processes in their tariffs. As Staff explained: "*if* separate processes are used for local planning and regional planning, Attachment K should clearly identify those processes."[11]

In contrast to the Staff Whitepaper, and dozens of accepted Attachment Ks, the NOPR appears to require that every transmission provider, but not every TO (the entities for whom the local concept originally was created), have two separate planning processes – a local planning process that follows Order No. 890's nine principles, and a (new) regional planning process that follows seven of the nine principles. This appears to be based on the misperception that the Order No. 890 Attachment K filings did not in fact require regional planning processes that meet all nine principles.

For example, the Commission suggests, in Paragraph 47 of the NOPR, that it "did not require each regional transmission planning process to comply with each of the nine transmission planning principles established in Order No. 890." But the only citation is to *Entergy Services, Inc.*, 124 FERC ¶ 61,268 at P 104 (2008), which is inapposite. That case involved the issue of whether the nine Order No. 890 planning principles applied to

[10] *Preventing Undue Discrimination and Preference in Transmission Service*, Staff White Paper at 3, Dkt Nos. RM05-17, *et al.* (Aug. 2, 2007) (emphasis added).

[11] *Id.* at 14 (emphasis added). DEC, for example, did not file a separate planning process for its individual service territory or footprint that incorporated the nine planning principles of Order No. 890. Rather, DEC filed a regional planning process that covered the footprint of the members of the NCTPC. *Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc.*, Transmittal Letter of Joint Compliance Filing for Order No. 890 Attachment K at 2, Dkt. Nos. OA08-50-003 and OA08-51-003 (Dec. 17, 2008).

an *inter-regional transmission planning process (the SIRPP)*, rather than various regional processes in the Southeast. A commenter in the Entergy docket had asked that the Commission apply the nine principles to the SIRPP. Entergy responded that the SIRPP performed inter-regional coordination,[12] and that it never was intended to be a part of any regional planning process.[13]

To address these inconsistencies, the Commission should clarify that the nine planning principles of Order No. 890 continue to apply to regional planning processes. Duke recognizes that, as a result of the Final Rule, some limited modifications may be required, even to regional planning processes that already have been approved.

B. New Requirements Should Not Be Imposed on Local Planning Processes

In recognizing that regional planning processes have been approved, the Commission should not disturb the approved local planning processes. To alleviate concerns over redundancy, the Commission should clarify that there is no requirement for an entirely separate local planning process. That is, as suggested by the Staff Whitepaper, regional and local planning processes can be merged into a single process.

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[12] For example, Entergy told FERC that "For inter-regional planning, Entergy and the ICT participate in the SIRPP . . . ." Answer of Entergy Services, Inc. at 5, Dkt. No. OA08-59-004 (Mar. 17, 2009). Likewise, Southern explained that its filing contained "an inter-regional transmission planning process, referred to as the Southeast Inter-Regional Participation Process ("SIRPP"), for the evaluation of inter-regional economic transmission planning requests." Requests for Clarification, or in the Alternative Rehearing of Southern Company Services, Inc.; The City of Dalton; and Georgia Transmission Corporation at 1 n.1, Dkt. No. OA08-37-003 (Jul. 20, 2009). Duke and Progress explained that the SIRPP was "the inter-regional economic coordination process in which they participate." Transmittal Letter, *supra* n.11 at 2.

[13] Likewise, SERC does not engage in regional planning and is not a means for any Southeastern transmission provider to meet its regional planning obligations. Rather, SERC and SIRPP provide vehicles for inter-regional *coordination*, which also was required by Order No. 890.

As it has done to date, the Commission should allow flexibility within regions as to how local planning is performed to prevent stakeholders, TOs, and transmission providers from being overwhelmed by process and meetings. For example, if a transmission provider in a region performs five regional economic planning studies annually, each TO in the region should not be compelled to perform an additional set of five local economic studies. Similarly, just as is the case today, the Commission should not compel that a single TO or transmission provider craft a separate local transmission plan under the Order No. 890 planning process; rather, a regional plan that includes local projects should remain acceptable.

C. Duke Supports the Proposal for a Regional Transmission Plan

The requirement that a *regional* plan be produced through a *regional* planning process is a new requirement that Duke supports. Duke's operating companies already are compliant.[14] Duke also supports the Commission's position that the proposed planning obligations "do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers." NOPR at P 51 n.59 (internal citation omitted). The Commission should further recognize that transmission plans are not static; they evolve as underlying assumptions change.

[14] Both the Midwest ISO and NCTPC produce regional transmission plans. Again, Duke understands that there may be some confusion as whether SIRPP/SERC is a region – it is not and has never been proposed by any transmission provider to be a region.

III. PUBLIC POLICY DRIVEN PROJECTS: The Commission should narrow the requirement to take public policy into account and allow flexible approaches to implementation.

The NOPR observes that when choosing whether to include a proposed transmission project in its local or regional transmission plan, a "transmission provider has no explicit obligation under Order No. 890 or the *pro forma* OATT to evaluate the project based on its potential to facilitate the achievement of public policy requirements established by state or federal laws or regulations." NOPR at P 58.[15] The NOPR thus proposes that "each public utility transmission provider [] amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations *that may drive transmission needs*." NOPR at P 64 (emphasis added).

Importantly, the NOPR does not propose to require rules specifying that every conceivable public policy be taken into account in the planning process. Rather, the Commission specifies that planning processes must take into account those laws or regulations that drive the need for more transmission. For example, state and federal renewable portfolio standards ("RPS") and regulatory obligations to reduce carbon emissions could drive the need for transmission by requiring the addition of new facilities to reach location-constrained renewable resources. The retirement of older, higher-carbon generating units could drive the need for transmission, as power flows change.

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[15] While it is true that the obligation may not be explicit in the OATT, transmission providers already must abide by applicable laws and regulations in performing planning. That is, if a law or regulation drives the need for a transmission project, such project would have to be included in a transmission plan.

The Commission also proposes to require each "transmission provider to specify in its OATT the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations." *Id.* at P 66. This proposal reflects the Commission's intention to limit the requirement to public policies that drive the need for transmission and thus Duke supports it.

A. The Public Policies Taken Into Account Should Be Limited to Laws and Regulations and Not Set By Stakeholder Votes

As indicated, Duke has no objection to the requirement to amend the OATT to include an explanation of how public policies that are laws and regulations will be taken into account. The Commission also suggests, however, that, after consulting with customers and other stakeholders, the transmission provider may amend the OATT planning process to allow additional public policy objectives that drive transmission needs, but that are not required by state or federal laws or regulations, to be taken into account. *See* NOPR at P 64. The Commission should clarify that, even if a majority of stakeholders support this latter type of OATT amendment, transmission providers are not obligated to adopt such a proposal. Allowing stakeholders to demand that the transmission provider adopt a planning process, whereunder various public policies that do not rise to the level of laws or regulations will be considered, is unnecessary and potentially detrimental to orderly and productive planning processes. Such a process, once adopted, could unnecessarily complicate the planning process and consume valuable time and resources. Numerous disagreements about what is a public policy and then disputes as to how such policies should be addressed in the transmission planning process could arise. The Commission should clarify that a planning process is just and reasonable even if it requires the transmission provider to take into account only these public policies reflected in laws and regulations already adopted or enacted.

B. Implementation of the Policy Must Be Flexible

The Commission also specifically seeks comment on:

- how planning criteria based on public policy requirements should be formulated, including whether it is more appropriate to use flexible criteria instead of "bright line" metrics when determining which projects are to be included in the regional transmission plan;
- whether the use of flexible criteria would provide undue discretion as to whether a project is included in a regional transmission plan; and
- whether the use of "bright line" metrics may inappropriately result in alternating inclusion and exclusion of a single project over successive planning cycles and therefore create inappropriate disruptions in long-term transmission planning.

NOPR at P 70.

The Commission should clarify that planning criteria based on public policy requirements should be formulated in a flexible manner. For example, a *requirement* that bright-line metrics be used in all cases to determine which projects are included in the regional transmission plan is not appropriate, as it incorrectly assumes that a top-down approach to transmission planning will be adopted in every region. Indeed, there may be no need to adopt any new, specific planning criteria based on public policy requirements, as long as a transmission provider can demonstrate that the requisite public policies are already taken into account by the planning participants' adherence to public policy requirements.

Duke suggests that the Commission expressly recognize that a bottom-up approach to transmission planning is one appropriate way to ensure that public policy is taken into account. For example, if four out of six load serving entities ("LSEs") in a region are subject to RPS and all four also are subject to integrated resource planning, one would expect that the transmission provider would take the RPS laws into account as a result of the LSEs' integrated resource planning efforts, without having to craft new planning criteria. In other words, the integrated resource planning results, which include compliance with RPS, would be rolled into the regional planning process as a result of LSEs putting forth proposals to address their specific needs, as driven by public policies. In contrast, other transmission providers may take public policies into account through top-down planning. For example, the CAISO's Location Constrained Resource Interconnection Facility ("LCRI")[16] concept reflects a top-down approach to meeting the public policy goals of the state and the Commission through rules that facilitate the construction of facilities to interconnect location-constrained resources.

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[16] The LCRI is the strategy for planning and recovering the costs of transmission serving multiple generators that are "location-constrained", or distant from California energy consumers, due to the nature of their fuel (*e.g.*, wind, solar). Under the LCRI concept, each location-constrained generator pays its share of transmission facilities on a per-MW basis. The cost of transmission capacity not initially subscribed by generators is recovered in general transmission rates until additional new generators come online and pay for that capacity.

IV. OPPORTUNITIES FOR UNDUE DISCRIMINATION AGAINST NON-INCUMBENT TRANSMISSION DEVELOPERS: The Commission should focus on policies that will spur regional and inter-regional transmission projects and avoid the ROFR controversy by issuing appropriate clarifications.

FERC proposes to eliminate from any tariff or agreement provisions that establish a ROFR such that incumbent transmission owners and independent transmission developers receive similar treatment in the planning process and have comparable rights to construct and own facilities they sponsor – while being consistent with local or state laws and regulations. NOPR at P 89. Duke supports the elimination of the ROFR as it applies to regional and inter-regional projects coupled with the elimination of any tariff obligation to build such projects.

A. Duke Supports Elimination of the ROFR for Regional and Inter-Regional Projects

Duke supports a policy that allows any party proposing a regional or inter-regional transmission project that ultimately is approved as part of a regional transmission expansion plan to construct and own the transmission project, and to receive a regulated return on the investment subject to the applicable regional cost allocation. As discussed below, that party also should be required to meet the appropriate financial, operational, siting, and reliability requirements set forth by FERC, NERC, state, or any other regulatory body with authority over transmission ownership, construction and operations.

Duke stresses that the elimination of the ROFR should be strictly limited to "regional and inter-regional projects." This appears to be the Commission's intent, as the NOPR indicates that "[n]either incumbent nor non-incumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a *regional transmission planning process*." NOPR at P 89 (emphasis added). That the elimination of the ROFR applies only to regional transmission planning, and not to local planning, is further confirmed in Paragraph 96 ("when a project proposed by a non-incumbent transmission developer is included in a *regional transmission plan*, that developer must have an opportunity comparable to that of an incumbent transmission owner to recover the costs associated with developing the project and constructing the transmission facility." (Emphasis added). Duke understands that the Commission does not intend to apply its ROFR policies to local projects. And local projects may include more than merely the repair or replacement of existing facilities mentioned in Paragraph 97 of the NOPR[17]; they may include, for example, a request for a new delivery point or new interconnection, as well as other OATT service requests.

While commenters may challenge the Commission's authority to eliminate the ROFR, Duke expects that many of the concerns will center on the concern that the Commission seeks to apply the Final Rule to local transmission projects and/or that ROFRs are necessary adjuncts to the obligation to build local facilities.[18] The Commission should expressly confirm that the ROFR concept will remain in place for local projects, *i.e.*, those not resulting from regional planning and whose costs are not

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[17] Indeed, the need for tower change outs and reconductoring may be identified as a result of operations and maintenance activities rather than as a result of a local planning process.

[18] Duke understands that any obligation to build is not absolute, in that facilities for which siting approvals are required but not obtained cannot be built.

widely allocated. The Commission also should confirm that the elimination of the ROFR for regional/inter-regional projects may be coupled with tariff provisions that make clear that there is no regulatory obligation to build such projects.

At the state level, a state-regulated utility typically has an obligation to build transmission that arises out of its duty to serve all customers in its service area ("duty to serve"). At the federal level, a *transmission provider* has an obligation to build facilities necessary for service requested under the OATT[19] and a *transmitting utility* (an entity that owns, operates, or controls transmission) has an obligation under Federal Power Act Sections 210-212 to provide transmission service ("OATT-FPA obligation").[20] The FPA obligation is limited in that a TO/transmission provider must provide service on its existing transmission system or enlarge that system; there is no obligation to provide service on other systems. Given that ISOs and RTOs do not construct transmission, they typically *contractually* require each member TO to build facilities that the ISO/RTO otherwise would be required to build under the OATT-FPA obligation. This contractual obligation typically is limited to facilities located in each TO's own service territory.[21] It is against this background that the following issues raised in the NOPR should be addressed:

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[19] Indeed, there is no provision in OATT Parts II and III that allows other entities to build such facilities, nor is one being proposed.

[20] *See* FPA §§ 210(a)(1)(D), 211(a), 16 U.S.C. §§ 824i(a)(1)(D), 824j(a) (2006).

[21] Such a contractual obligation to build arguably is a reflection of both the state-imposed duty to serve and the FPA Sections 210-212 obligation that the incumbent TO would have in any event.

> How the proposed reforms affect the rights, obligations and responsibilities of incumbent and non-incumbent transmission providers;
>
> The relationship or lack of relationship between ROFR and obligation to build;
>
> Is it appropriate to maintain a federal ROFR in the OATT or other documents; and
>
> Is it appropriate to retain an obligation to build for an incumbent TO while removing the federal ROFR.

NOPR at PP 101.

The starting point in this discussion should be the recognition that entities with state-imposed duties to serve are not similarly-situated to transmission developers who have no such obligations, and that transmission providers and transmitting utilities with OATT-FPA obligations to build are not similarly-situated to potential TOs with no such obligations. These obligations all apply to local facilities and, as noted, the Commission does not propose to eliminate the ROFR for facilities that are identified in local planning processes. A contractual ROFR that applies to local projects should not be objectionable, as it reflects a duty to serve/OATT-FPA obligation to build local projects that is not imposed on transmission developers that lack such obligations. In contrast, to the extent that there is an obligation to construct regional projects, that obligation arises out of contract (*i.e.*, TO agreements).[22] If the Commission enables parties to agree to eliminate this *contractual obligation* in conjunction with elimination of the ROFR, it will achieve

[22] Thus, as to the question, "Is it appropriate to maintain a federal ROFR in the OATT?", Duke assumes that the NOPR is referring to ISO or RTO agreements, as the Commission did not propose to modify Parts II and III of the OATT.

parity and address claims of discrimination.[23] This approach ensures that needed local transmission facilities are constructed while at the same time establishes an open, competitive process for developing regional projects.

This approach raises the question of what happens if the regional planning process identifies a potential project that would address reliability concerns and that would span two or more service areas, but no entity volunteers to build it and no entity has a contractual obligation to build it. In that case, the individual TOs can comply with relevant Reliability Standards and address the reliability issue through other means, such as adding local generation, relying upon demand response or installing local transmission facilities.

Finally, Duke recognizes that in RTO/ISO regions, the line distinguishing regional from local projects may be blurry, as some projects will have regional and local characteristics.[24] For this reason, Duke recommends that the Commission adopt rules that are sufficiently flexible to enable each region to develop an approach for determining which types of projects are subject to regional cost allocation methodologies and for which there should be no ROFR. Region-specific criteria and rebuttable presumptions could be used make such determinations. For example, characteristics that could indicate a project is local might include one or more of the following:

- The project physically is located within the service area of (a) a single non-RTO/ISO Transmission Provider; (b) a single

[23] An OATT Attachment K (or its equivalent) should not include a ROFR for regional projects.

[24] In contrast, an inter-regional project may be easier to identify.

RTO/ISO Transmission Owner; or (c) two or more RTO/ISO Transmission Owners located in a single RTO/ISO Zone[25];

- The project is needed to address discrete, local reliability concerns, local load growth, or a request under the OATT for transmission service or generation interconnection; or

- The project voltage is below 345 kV.

Characteristics that indicate a project is regional might include:

- The project physically is located in (a) the footprint of at least two non-RTO/ISO Transmission Providers; or (b) the footprint of at least two RTO/ISO Transmission Owners in different zones;

- The project is designed to address reliability concerns in multiple systems or alleviate constraints that will reduce congestion costs in multiple systems or pricing zones;

- The project is designed as a large overlay to enable multiple load-serving entities to meet public policy requirements, such as state or federal renewable energy standards; or

- The project voltage is 345 kV or above.

B. TO Qualification Criteria

The Commission proposes that transmission providers revise their OATTs to ensure that the regional planning process has appropriate qualification criteria for determining an entity's eligibility to propose a regional project. NOPR at P 90. The Commission proposes that the OATTs should describe the regional process by which incumbent and non-incumbent sponsors will be selected to construct and own a proposed facility. *Id.* at P 93. Duke agrees that it would not be unduly discriminatory or

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[25] Often, a RTO/ISO Zone consists of a public utility TO and several other TOs that were historically transmission dependent on the public utility TO but own some integrated facilities. For example, a new interconnection point between DEI and Wabash Valley Power Association, Inc. at 161 kV could be an example of a local project that involves multiple TOs.

preferential to include appropriate qualification criteria for potential TOs to demonstrate that they have the necessary financial and technical expertise to develop, construct, own, and, if applicable, and maintain facilities for the life of the project. Duke supports strict eligibility criteria under which the project sponsor must demonstrate that it meets all the eligibility requirements, including state laws, to own and operate the transmission facilities it proposes to build.

It is also crucial that incumbent TOs not be forced to register with NERC as Transmission Operators or Owners for non-incumbent TOs' projects.[26] While incumbent TOs (and others) may agree contractually to take on such NERC Reliability Standard obligations for others (*e.g.*, under a joint registration agreement), they should not be subject to claims of undue discrimination if they choose not to assume that role for all third-party developers. The service of providing "Reliability Standard-compliance services" to third parties is not, and should not be treated as, FERC-jurisdictional. If the Commission believes otherwise, that should be stated expressly in the Final Rule so that TOs can decide whether to offer such service on a fully-informed basis. Likewise, the Commission should clarify that an incumbent TO will not be required to provide O&M service for a non-incumbent's facilities, but may voluntarily provide such services at its discretion.

[26] ISOs/RTOs often share responsibility to abide by various Transmission Operator Reliability Standards with TOs. An ISO/RTO should share responsibility with TOs on the same basis for non-incumbents and incumbents alike.

C. Proposal Form Requirement for Regional Projects

The Commission proposes that each transmission provider revise its OATT to include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process. NOPR at P 91. It also proposes that each proposal be submitted by a date certain. *Id.* As long as the requirement is limited to regional projects, Duke does not object generally to the development of a form to be used by project sponsors to propose regional projects and assumes that this form also will apply to incumbent TOs. Requiring a form for local projects that are installed outside of the regional planning process is unnecessary. Inter-regional project sponsors presumably will complete the form for all appropriate regions.

The nature of the form is crucial to prevent queue flooding by project sponsors, an issue that has a parallel in the interconnection process. Duke envisions a form that demonstrates that the project sponsor has already performed sufficient preliminary technical analysis and has gathered sufficient information that would permit meaningful evaluation in the planning process. That is, a mere statement that a sponsor proposes to increase capacity of an interconnection is not sufficient.

D. Evaluation Process for Regional Projects

FERC proposes to require each transmission provider to participate in a regional planning process that evaluates proposals through an open process. NOPR at P 92. As discussed, Duke considers Order No. 890 to have imposed this requirement and Duke has met its obligations through the Midwest ISO and NCTPC. Each transmission provider also will be required to describe in its OATT the process used to evaluate proposed projects for inclusion in the regional transmission plan. *Id.* Again, this is not a new requirement, as the Duke operating companies already accomplish this through participation in the Midwest ISO or the NCTPC. To avoid confusion, the Commission should acknowledge that most, if not all, FERC-approved existing regional planning processes meet these requirements.

E. ROFR and Modified Regional Projects

The Commission proposes that, if the regional planning process results in modifications to certain proposed projects, the transmission provider may determine which of those projects is most similar to the project originally included in the plan. The selected sponsor would then have the right, consistent with state or local laws or regulations, to construct and own the facilities. NOPR at P 94. If a proposed project is not included in a regional plan and if the project's sponsor resubmits that proposal in a future transmission planning cycle, that sponsor would have the right to develop that project even if one or more substantially similar projects are proposed by others in a future transmission planning cycle. *Id.* at P 95. A defined period of time should be established for this right. *Id.* Duke has no objection to these general policies, which it assumes also apply to inter-regional projects, but notes that the challenge will be implementation.

For example, developing criteria to determine whether a proposed project is a "modification" that will trigger the rights of the original sponsor or whether a proposed project is sufficiently different to be considered a new project will be difficult, and may engender disputes. The Commission should clarify how cost comes into play in determining if projects are similar, particularly if a competing sponsor is willing to limit cost recovery to a fixed amount over the life of the facility. Similarly, a region should be permitted to provide that a proposal for a certain voltage will not be considered substantially similar to an earlier proposal for a different voltage.

F. Non-Incumbent Cost Recovery

The NOPR states that if an incumbent transmission project developer may recover the cost of a project selected through a regional cost allocation method, a non-incumbent transmission project developer must enjoy that same eligibility. NOPR at P 96. This is an important right for non-incumbents, but guidance on mechanisms to recover costs should be provided for transmission providers in non-ISO/RTO regions. In ISOs/RTOs, there are existing mechanisms, as the non-incumbent TO can become a member TO, turn control of the relevant facilities over to the ISO/RTO, and have the ISO/RTO allocate costs per the regional OATT.

No such mechanism exists in non-ISO/RTO regions, as non-incumbent TOs likely will not be network customers eligible for OATT Section 30.9 credits. In these regions, the proposal raises the issue of who will take transmission service from the non-incumbent TO and under what tariff or agreement will such service be taken. Including the costs of a non-incumbent TO's facilities in the OATT rates of each relevant transmission provider (and then having the transmission provider distribute transmission revenues among itself and the non-incumbent TOs) does not resolve the issue because native load customers do not pay for service under the OATT. (There also may be wholesale customers that do not pay OATT rates, but instead take grandfathered transmission service.) If the Commission intends that the transmission provider (on behalf of its native load) and other LSEs take transmission service from the non-incumbent TO, each such entity would be left to recover those costs from its respective retail customers. At least for state-regulated LSEs, this approach raises cost trapping concerns, as well as potential problems resulting from regulatory lag.

The Commission should clarify that if regional stakeholders cannot agree on a cost recovery approach that the Commission will address the issue in a manner that takes into account the existing regulatory structure and ensures that costs are not trapped.

G. Merchant Transmission

The Commission does not propose to require a transmission developer that does not seek to use the regional cost allocation process to participate in the regional transmission planning process, although such a developer would be required to comply with all reliability requirements applicable to facilities in the region. NOPR at P 99. Such developers are not prohibited from participating, and Duke believes that they should be strongly encouraged to participate in the regional transmission planning process.

V. INTER-REGIONAL COORDINATION: Duke generally supports the Commission's positions on inter-regional coordination.

The Commission proposes to require each transmission provider through its regional planning process to coordinate with transmission providers in each neighboring region, and to reflect such coordination in inter-regional planning agreements. NOPR at P 114. Transmission providers may create and enter into multilateral inter-regional transmission planning agreements to fulfill these requirements. *Id.* at P 115. Duke supports these requirements, assuming sufficient time is provided for implementation. The Commission proposes to require the inter-regional transmission planning agreements to be submitted to the Commission no later than one year after the effective date of the Final Rule issued in this proceeding. *Id.* at P 120. Experience in the regions confirms that time period is extremely short. The Commission should provide two years to submit inter-regional agreements, given the number of parties that may be involved.[27]

As to the Duke Midwest operating companies, the Midwest ISO is the entity currently responsible for inter-regional agreements.[28] In the Southeast, Duke envisions that an entity such as the SIRPP would be one vehicle for ensuring that each transmission provider has an inter-regional agreement with each neighboring region; this could be accomplished through a single inter-regional transmission planning agreement among the SIRPP member transmission providers. As to transmission providers that are not SIRPP members but neighbor one or more SIRPP members, a separate inter-regional agreement would be acceptable. For example, because PJM is not in the SIRPP footprint, DEC and PJM would enter into an inter-regional transmission planning agreement. Other neighboring transmission providers on the southern PJM border might also join such an agreement.

[27] In some regions, such as the Midwest ISO, inter-regional transmission planning agreements already exist with some neighbors. Such agreements may require some refinements to fully meet the rule and also can provide models for future agreements. But, the existence of such agreements does not mean that one year is sufficient in that larger regions such as the Midwest ISO have a large number of neighboring regions.

[28] Assuming that the Commission approves the DEK and DEO proposal to move to PJM, PJM will assume this responsibility.

The Commission plans to require that inter-regional transmission planning agreements include a detailed description of the process for coordination between transmission providers in neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as inter-regional facilities that are not proposed but that could address transmission needs more efficiently than separate intra-regional facilities. NOPR at P 116. FERC also proposes that an inter-regional transmission planning agreement include:

- a commitment to coordinate and share the results of respective regional transmission plans to identify possible inter-regional facilities that could address transmission needs more efficiently than separate intra-regional facilities;
- an agreement to exchange at least annually planning data and information;
- a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions; and
- a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

Id. at P 117. Again, such proposals are largely unobjectionable, and many are in place today, although the Commission should clarify that relative to the inter-regional planning process, information can be maintained on an existing transmission provider or regional planning website. The Midwest ISO, for example, need not have a separate website for each inter-regional planning process.

The Commission proposes that the sponsor of a project that would be located in two transmission planning regions first propose its project in each region's transmission planning process, and that such submission trigger a procedure under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed project. *Id.* at P 118. FERC "proposes that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed project." *Id.* This approach will be cumbersome. Duke assumes that the Commission intends that only one joint inter-regional study will be performed, regardless of the number of regions that are crossed. Requiring multiple studies would be an inefficient use of resources. Inter-regional projects would be identified as such when submitted by the sponsor to each planning region. The planning regions would then have a process to review individual inter-regional requests, as well as regional requests, in order to determine the most efficient and effective projects to meet both regional and inter-regional needs.

The Commission's proposal – that "inclusion of the inter-regional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an inter-regional cost allocation method that satisfies the cost allocation principles" (*id.*) – is a logical approach, subject to the "usual caveat" that inclusion in the plan does not mean that the project will necessarily be constructed.

Duke questions the need to apply the inter-regional planning agreement where, for example, a generator interconnection request or transmission service request happens to impact a utility in a neighboring region. Today, such issues are readily addressed by the affected system agreement process under the LGIP and by cooperation among neighbors. Upgrades required on one system due to an OATT service request on another system should not be subject to inter-regional cost allocation. Such an approach would be inefficient and unwieldy. Duke thus seeks clarification that where studies for a specific generator interconnection or transmission service request indicate that there will be impacts on a transmission owner in a neighboring region, such impacts continue to be addressed under the existing generation or transmission interconnection arrangements.

VI. COST ALLOCATION: Duke supports flexibility in the development of regional and inter-regional cost allocation methodologies that reflect the widespread benefits of EHV transmission.

Duke fully endorses the Commission's conclusion that the broad regional and inter-regional planning requirements envisioned under the NOPR need to be accompanied by rules that specify how the costs of new regional and inter-regional projects will be allocated to transmission customers. NOPR at PP 155-63. Duke's experience to date has been that the question of who will pay for new infrastructure rears its head from the earliest moment that a project is proposed. Absent clear pricing guidelines that do more than merely restate general cost allocation principles, regional and inter-regional transmission projects will have trouble getting out of the starting gate. Deciding cost allocation on a case-by-case approach with no guideposts invariably leads to arguments, and ultimately protracted litigation, about who benefits and by how much. All the while, needed infrastructure projects are stalled. Duke therefore agrees with the NOPR's conclusion that it is imperative that each transmission provider's OATT include regional and inter-regional cost-allocation rules, or at least specific guidelines in order to move beyond this stumbling block. *Id.* at P 159-60.

Duke further agrees that the cost allocation cases discussed in the NOPR set out the appropriate framework for cost allocation. The consistent theme is that, while the Commission must consider who benefits when deciding who pays, the Commission is not bound to adopt rules that mete out the costs to a mathematical certainty. Indeed, in *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009), the most recent appellate case to address cost allocation for new transmission facilities, the court made clear that benefits need not be quantified to the "last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." The *Illinois Commerce* court relied upon the D.C. Circuit's determination in *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004), also cited in the NOPR (at P 147 n.162), that courts "have never required a ratemaking agency to allocate costs with exacting precision." Consistent with the case law and the NOPR's first proposed allocation principle, Duke agrees that regional and inter-regional cost allocation methodologies need only ensure that costs allocated to customers across a regional or multiple regions be "at least roughly commensurate" with the benefits likely to be achieved by those customers. Duke agrees with the Commission's important recognition that benefits can be achieved "at present or in a likely future scenario." NOPR at P 174.

Duke further agrees that regional and inter-regional planning and cost allocation go hand-in-hand and, therefore, regional and inter-regional cost allocation should apply only to projects that have been approved through the applicable regional or inter-regional planning processes. A successful allocation methodology requires that customers have confidence that they will obtain meaningful benefits from projects, even if the projects are physically located on other systems or other pricing zones. The only way to build that confidence is to ensure that projects eligible for regional and inter-regional cost allocation have been carefully scrutinized through an open and transparent planning process that uses metrics that already have been agreed to by the stakeholders.[29]

With that introduction, Duke sets out three guideposts that should underlie the Commission's final regional cost allocation rules. First, Duke supports the Commission's proposal to allow flexibility, both across the regions and within a region. It is inevitable that planning regions across the country will differ in size and scope, as well as in the way planning is done (*e.g.*, ISO/RTO regions versus non-ISO/RTO regions). Under these circumstances, there is no reason for the Commission to adopt a one-size-fits-all methodology, and below Duke discusses alternatives that could be adopted by particular regions. Second, the Commission should leave undisturbed those regional and/or inter-regional cost allocations that previously were approved by the Commission. Finally, Duke believes that benefit analyses should recognize the integrated nature of the grid and the long-term system benefits that inure to customers throughout the region when carefully planned, large-scale projects are added to the grid.

A. Regional Flexibility Is Crucial

To be sure, the easiest cost-allocation methodologies to implement would be ones that uniformly allocate all new transmission costs across the entire region, whether the allocation is based on monthly peak loads ($/kW) or hourly transmission usage ($/kWh).

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[29] Linking cost allocation to the formal, regional planning process will not, however, restrict two or more parties in a region from collaborating on a multi-system project and agreeing to a project-specific allocation of costs among themselves.

But Duke does not support a one-size fits-all approach. Regions should have the flexibility to adopt methodologies that broadly allocate costs based on other factors.

For example, a region could adopt a rebuttable presumption that a project qualifies for region-wide allocation if it meets certain minimum criteria, such as (i) the size of investment; (ii) voltage level (*e.g.*, 345 kV and above); or (iii) a minimum benefit-cost ratio (*e.g.*, 1.1-to-1). Under this inclusionary approach, parties challenging the regional allocation for projects that meet the selected criteria would bear the burden of demonstrating why such an allocation is unreasonable. A variation would be to adopt an exclusionary approach under which regional cost allocation would not be available to certain projects, such as (i) reliability upgrades that address violations in discrete areas of the region; (ii) upgrades needed to accommodate transmission and/or interconnection requests on discrete systems; (iii) economic upgrades that do not meet energy cost/lower LMP benefit thresholds (*e.g.*, less than 1.25-to-1) or do not benefit a minimum number of pricing zones or TO systems; or (iv) public policy overlays that are not capable of delivering significant amounts of renewable power to a minimum number of pricing zones or TO systems.

Another variation would be a hybrid model, under which a certain percentage of a project's cost would be allocated across the entire region and the remaining percentage would be allocated more locally. This model could be used for all regional projects or those that do not meet regional standards, such as those discussed immediately above. The policy justification would be that projects that make it through the regional planning process bring some level of benefits to the entire region and over time become vital parts of the region's comprehensive, integrated grid. This approach addresses the free riding problem that potentially arises from assessing benefits by looking only to a snapshot of flow distribution a year or two after a project is placed in service.

Duke further recommends that the Commission accommodate similar flexibility for inter-regional cost allocation methodologies. Again, while allocating costs between regions based on objective metrics such as peak load or dollars invested in each region may be relatively easy to implement, these allocations may not be equitable in all situations. For example, for projects primarily located in one region that bring substantially more benefits to that region, a regional load-ratio sharing system may not make sense. Duke believes that a case-by-case approach may work better for inter-regional allocation, as that enables the regions to assess such metrics as (i) the size of the project investment in each region; (ii) the number and type of reliability violations resolved in each region; (iii) the energy savings in each region; and (iv) the amount of renewable energy that can be delivered from one region to the other (*i.e.*, an inter-regional overlay project may deliver most of the renewable energy into one region and, because of transmission limitations, lesser amounts of energy into the neighboring region).

B. Regions Should Be Permitted to Retain Cost Allocation Methodologies that Already Have Been Approved

Certain regions already have adopted cost allocation methodologies for various types of regional projects. For example, the Midwest ISO market participants adopted allocation methodologies for reliability projects ("RECB I") and economic upgrades

("RECB II"). Those proposals reflected substantial stakeholder deliberation and ultimately were approved by the Commission.[30] Likewise, the Commission recently approved the regional cost allocation methodology adopted in the SPP region.[31]

In each of these cases, the RTOs and their stakeholders committed substantial time and resources to the development of these methodologies. Likewise, the Commission dedicated resources to carefully scrutinize the methodologies and weigh the concerns raised by those who may not have agreed with each of the elements of those methodologies. If the consensus in a region is that the current methodologies meet the standards of the Final Rule, at least for the types of projects covered by those methodologies, that region need not start from scratch. Parties challenging the appropriateness of existing Commission-approved methodologies should bear a heavy burden of showing why those methodologies are inconsistent with the Final Rule.

C. Regional Projects Generally Provide Regional Benefits

The argument supporting a region-wide allocation of the cost of regional projects rests on the notion that a well-designed project will bring long-term benefits to customers across the entire region. Duke believes that it is important that regions develop benefit metrics that recognize that large-scale EHV facilities typically have service lives of up to forty years, and that the use of the network invariably will change over that time as the network itself expands and adapts to growing load and changing technologies. This is

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[30] *Midwest Indep. Trans. Sys. Operator, Inc.*, 114 FERC ¶ 61,106, *order on reh'g*, 117 FERC ¶ 61,241 (2006); *Midwest Indep. Trans. Sys. Operator, Inc.*, 118 FERC ¶ 61,209, *order on reh'g*, 120 FERC ¶ 61,080 (2007).

[31] *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010), *reh'g pending*.

especially the case when facilities are proposed as part of a larger, more expansive project that ultimately may extend benefits across the entire region. Duke believes that a thorough and comprehensive evaluation of the benefits of large-scale regional projects can support the Seventh Circuit's standard that costs allocated be "at least roughly commensurate" with benefits received.

The starting point for evaluating benefits should be the recognition that facilities approved in the regional planning process ultimately will become integrated into the larger network that serves to maintain overall system reliability and facilitate the delivery of lower-cost resources and renewable energy throughout the region. The benefits of regional projects will become more pronounced as older, less efficient generating resources located close to load centers are replaced by more distant low-carbon and no-carbon resources. In other words, a project's full range of benefits may not be fully realized until the grid is further expanded and the project is operated as part of a comprehensive, integrated network.

Moreover, the addition of a comprehensively-planned package of integrated regional projects often can displace the need to construct numerous smaller projects that otherwise would be constructed throughout the region. Similarly, an EHV project may displace the need for multiple projects that otherwise would be needed to accommodate discrete interconnection requests. Replacing numerous disparate projects with a single comprehensive project ultimately can reduce overall costs and minimize environmental disruption.

In addition, a highly integrated regional network that can effectively and reliably deliver large amounts of energy from no-carbon and low-carbon resources will become increasingly important as more and more states, and perhaps the federal government, adopt RPS. Transmission projects that enable large amounts of renewable energy to be delivered from resource-rich areas of the region to distant load centers in the region can substantially reduce the cost of meeting RPS obligations.

Regional benefits analysis can include other metrics. For example, EHV projects can reduce the cost of meeting resource requirements through lower reserve margins resulting from wider access to generating capacity. This is important in regions that have adopted capacity requirements with corresponding market rules under which capacity must be capable of being delivered across the region. EHV projects also can accommodate a broader geographic scope of generating resources, which is important as regions develop more and more intermittent renewable resources, such as wind and solar generation.

In addition to considering generation resource-related benefits, regional benefit analyses could factor in enhanced operability, such as the unloading of underlying lower-voltage networks. This flexibility can be helpful when performing routine service maintenance on the lower-voltage lines and when interconnecting new resources. Enhanced flexibility also provides a margin for the uncertainties inherent in future operations, such as the unexpected loss of transmission corridors or baseload generators.

Benefit metrics could also include reduced transmission losses, which is important in organized markets in which customers are assessed marginal loss charges. Benefits analyses also could include cost advantages that large-scale regional projects often have over a collection of smaller projects. For example, the amount of right-of-way required for a single 500 or 765 kV circuit often is less than the total right-of-way required for the larger number 230 or 345 kV circuits that would be needed to deliver an equivalent amount of power.

VII. COMMUNICATIONS

Communications regarding this matter should be addressed to the following:

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VIII. CONCLUSION

Wherefore, Duke requests that the Commission consider these comments and issue the clarifications sought above.

Respectfully submitted,

/s/

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September 29, 2010

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-005
(POST HEARING
DATA REQUEST)

REQUEST:

Please describe the components of the $3 million to cover PJM's integration costs.

RESPONSE:

The components of the $3M PJM integration costs are as follows.

Estimated Integration Costs

	Est. Expense	Est. Capital
Operations	$500,000	$300,000
Markets	$400,000	$300,000
Planning	$100,000	$100,000
IT Infrastructure	$200,000	$200,000
Audit Prep/Execution	$100,000	
Legal Fees	$300,000	
Project Management	$400,000	
Training	$100,000	
TOTAL	$2,100,000	$900,000

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Duke Energy Ohio and Kentucky pay $2.1 million expense and PJM stakeholders pay $900,000 capital expense. This is set forth in the Agreement to Implement Expansion of PJM Region for Duke Energy Ohio and Duke Energy Kentucky attached to the Direct Testimony of James B. Gainer.

PERSON RESPONSIBLE: G. R. Burner

MISO-DR-01-006
(POST HEARING
DATA REQUEST)

REQUEST:

Is the $3 million PJM integration cost part of the $72 million?

RESPONSE:

No. The $3 million represents the PJM Integration costs as is set forth in the Agreement to Implement Expansion of PJM Region for Duke Energy Ohio and Duke Energy Kentucky attached to the Direct Testimony of James B. Gainer. The $72 Million was the estimated aggregate level of Midwest ISO exit costs for Duke Energy Ohio and Kentucky (exit fee, MTEPP, misc. costs [e.g. hold harmless, EMS upgrades, etc.]).

PERSON RESPONSIBLE: G. R. Burner

MISO-DR-01-007
(POST HEARING
DATA REQUEST)

REQUEST:

Is the $3 million PJM integration cost an allocation between Ohio and Kentucky?

RESPONSE:

PJM estimated integration cost of $3 million is the total for both Ohio and Kentucky as is reflected in the "Agreement to Implement Expansion of PJM Region for Duke Energy Ohio and Duke Energy Kentucky" attached to the Direct Testimony of James B. Gainer (Article 4.2). Duke Energy Kentucky's share will be the 15-17% discussed in testimony or approximately $450,000. Duke Energy Kentucky committed that it would not seek to recover these PJM-related integration costs from customers and will thus hold customers harmless for those costs.

PERSON RESPONSIBLE: G. R. Burner

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-008
(POST HEARING
DATA REQUEST)

REQUEST:

Please describe the components of the $27 million estimated integration cost.

RESPONSE:

Estimated $27 million exit fee/expenses comprised of:

- $18.5 million for estimated MISO exit fees
- $7 million for estimated hold harmless payments
- $1 million for estimated EMS upgrades
- $0.5 million for estimated legal fees

The $27 million exit fee/expenses estimate is part of the total aggregate $72 million Midwest ISO exit costs (excluding the $45 million estimated MTEP obligation) as discussed in testimony. The $27 million is separate from the $3 million in PJM integration costs set forth in the PJM Expansion Agreement. Since these costs (excluding the MTEP) are one-time costs associated with the withdrawal from Midwest ISO, the Company considers all of them as part of the cost of "integration." In referencing the $27 million, the Company was trying to distinguish these one-time costs from the MTEP obligation, which is still to be determined in terms of the actual level and duration over which the Company would be required to pay the obligation. As was clarified at the hearing, Duke Energy Kentucky will not be responsible for the hold harmless amounts, the EMS upgrades, or the legal fees included in the $27 million calculation. Therefore, Duke Energy Kentucky's total integration costs related to the MISO exit (non MTEP and not including the $3 million PJM expansion) will be limited to an allocation of only the final Midwest ISO exit fee. In any event, Duke Energy Kentucky committed that it would not seek to recover any of the "integration" costs (i.e., those from MISO and the $3 million in PJM integration costs) from its customers. Treatment of transmission expansion costs (MTEP and RTEPP) will be addressed in a future rate case proceeding. Duke Energy Kentucky committed that it would not seek to double recover for transmission expansion for overlapping periods.

PERSON RESPONSIBLE: G. R. Burner

Duke Energy Kentucky
Case No. 2010-00203
MISO Post Hearing Data Requests
Date Received: November 4, 2010

MISO-DR-01-009
(POST HEARING
DATA REQUEST)

REQUEST:

Is the $27 million estimated integration cost part of the $72 million? Is it a MISO cost or a PJM cost?

RESPONSE:

The $27 million estimated integration cost is part of the $72 million charge and is comprised of the MISO exit fee, customer hold harmless, EMS upgrades, and legal fees as shown in MISO-DR-01-008 Post Hearing Data Request.

PERSON RESPONSIBLE: G. R. Burner

MISO-DR-01-010
(POST HEARING
DATA REQUEST)

REQUEST:

Is the $27 million estimated integration cost an allocation between Ohio and Kentucky?

RESPONSE:

Please see response to MISO-DR-01-008 Post Hearing Data Request for an explanation of the $27 million cost components. As clarified at the hearing, of the total $27 million, Duke Energy Kentucky will only be allocated a portion of the final exit fee component (estimated $18.5M). In either event, in its testimony, Duke Energy Kentucky committed that it would not seek to recover any of the $27 million "integration" costs from its customers.

PERSON RESPONSIBLE: G. R. Burner