KyPSC Case No. 2022-00372
TABLE OF CONTENTS

STAFF-DR-04-001

REQUEST:

Refer to the Application, Schedule L, page 9 of 16, which states that, for Rate NSU, text is added and deleted to cancel the pending termination of the tariff sheet in favor of a replacement of all old lighting technology with LED as fixtures fail. Also refer to Duke Kentucky's response to Commission Staff's Third Request for Information (Staff's Third Request), Item 7, in which Duke Kentucky confirms that Rate NSU will terminate on December 31, 2026. Reconcile the information in Schedule L with confirmation that Rate NSU will terminate on December 31, 2026.

RESPONSE:

The information on Schedule L, page 9 of 16, regarding Rate NSU was incorrectly copied. The Company confirms that the information provided on the Rate NSU tariff sheet as well as the information in STAFF-DR-03-007 is accurate and Rate NSU will terminate on December 31, 2026.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-002

REQUEST:

Refer to the Application, Schedule L-1, page 164 of 189, Local Government Fee, and pages 185–186 of 189, Rider ILIC, Incremental Local Investment Charge. For the expanded costs to be recovered from customers in the Local Government Fee tariff and for the costs to be recovered under Rider ILIC, explain how Duke Kentucky has historically recovered those costs.

RESPONSE:

Historically if the Company were to incur costs related to its location/relocation of facilities in the municipal ROW and it is for a city project under their police power (e.g. road widening), the Company will incur the costs to relocate its facilities and capitalize them on the balance sheet. These costs would be recovered from customers in a base rate case proceeding. If the Company were to incur costs at a location with a private easement or other property right, the municipal would be responsible for the costs related to relocating those facilities. The Company would incur the cost but then collect contribution in aid of construction (CIAC) from the customer and record that as a credit to the costs the Company incurred and recorded on their balance sheet. Similarly, costs for temporary relocations of existing utility facilities, installed in compliance with the NESC, that were necessitated *not* by the Company's work, but were necessary to accommodate the City or individual customers and their contractors working on customer-owned property, would historically be borne by the customer.

As a result, there would be no costs to recover from customers in a base rate case proceeding. This would remain unchanged.

The costs contemplated through Rider ILIC are for situations where a municipality is directing the Company to take some action by ordinance, or some other act under its police power, that is requiring the Company to incur incremental costs, specific to its operation in that municipality with respect to how the Company otherwise designs, locates, relocates, (temporary or permanently) or maintains it equipment in a manner that is specific to that municipality, such as undergrounding of electric distribution networks that are currently overhead. The Company is proposing that under Rider ILIC, if a municipality is directing the Company to take such an action by franchise fee or other ordinance, that it would not otherwise be obligated to take, including attempting to push cost responsibility upon the utility, that the Company would bring that matter to the Commission for a determination whether those costs should be capitalized and recovered as normal rate making or should be assessed specifically under Rider ILIC within that municipality. By way of example, see ABS-5, Sections:

- 6-incorporating other municipal ordinances as a condition of the franchise;
- 16 (d)-requiring all existing overhead facilities relocated underground within 3 years;
- 16(e)(2), authorizing the government to order relocations whereby due to proximity, the government determines the equipment is "interfering with the property owner's respective use of their property…"
- 16(e)(3)- to assist installation of facilities by another party at the other party's cost, except, for relocations resulting from redevelopment and construction of a City-owned property, which shall include ownership by Industrial Revenue

Bond and/or similar economic incentive issued by applicable state law. The intention is that the City would require the Company to bear those cost for City-owned property.

- 16(e)(4)- requiring the Company to place facilities underground at no cost to the Government, if the Government determines in its sole discretion that the facilities cause a public safety concern… See the Whereas clauses of ABS-4 where the City has pre-determined that "location of electric utility lines has interfered with property owner use and enjoyment of property…" and "public necessity and convenience mandates locating of all electric utility lines underground for aesthetic, safety, and development reasons."

The theory for recovery of costs under Rider ILIC is identical to that of how franchise fees are treated, except for that the Company is asking the Commission for approval as to whether to socialize the costs to all customers or charge only the customers in the municipality that is directing the Company to take action.

PERSON RESPONSIBLE: Sarah E. Lawler
Dominic "Nick" J. Melillo
Amy B. Spiller

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-003

REQUEST:

Refer to the Direct Testimony of Amy B. Spiller, page 27, line 18 through page 28, line 2 and page 30, line 14 through page 31, line 13.

a. For the calendar years 2018 through 2022, the base period, and the forecasted test period, provide the costs of incremental system investments required pursuant to a local ordinance or franchise.

b. For the forecasted test period, confirm that all costs of incremental system investments required pursuant to a local ordinance or franchise have been removed from base rates. If confirmed, explain how the costs were excluded. If this cannot be confirmed, explain why these costs were not excluded.

c. Explain any other steps Duke Kentucky has taken to address the franchise or locality investment costs with each municipality Duke Kentucky has taken issue with, including but not limited to filing a legal action in state court.

RESPONSE:

a. To date, the Company has not been required to make incremental system investments that were required pursuant to a local ordinance or franchise akin to what is contemplated in the Ordinance included as Attachment ABS-5. However, pursuant to various franchises and ordinances throughout its service territory, the Company is required to do many activities including obtain permits, design its facilities in particular ways, perform vegetation management in specific manner and time, and relocate facilities in the road right of way at the direction of a municipality for public works projects such as road widening. Additionally, the Company tries to work with municipalities with respect to its facility designs including the addition of incremental decorative fencing, lighting, or additional vegetation if desired as part of the permitting process. Where the Company has a private easement, the municipality must pay for any city-ordered relocations. In situations where the Company is in the road right of way at the consent of the municipality pursuant to a franchise or common law right, the Company typically must pay for municipal-ordered relocations.

Below is a figure depicting facility relocations for the period requested that shows investments broken into reimbursable (where the customer was required to pay) and non-reimbursable (where the Company was obligated to relocate the facilities without reimbursement). The Company is not able to break out temporary relocations as it does not track that separately across its territory.

Process CB - Description	2022	2021	2020	2019	2018	Grand Total
Highway Nonreimb Total	$ 1,264,472.20	$ 1,808,011.08	$ 4,359,028.27	$ 2,016,693.88	$ 633,448.32	$ 10,081,653.75
Highway Reimbursable Total	$ (74,281.85)	$ 27,187.00	$ 797,588.30	$ 872,996.91	$ 183,347.25	$ 1,806,837.61
Grand Total	**$ 1,190,190.35**	**$ 1,835,198.08**	**$ 5,156,616.57**	**$ 2,889,690.79**	**$ 816,795.57**	**$ 11,888,491.36**

b. See response to part (a). Investments that were reimbursed/paid for by municipalities are removed from rate base and are treated as CIAC. Other investments that were non-reimbursable and performed at the direction of a municipality pursuant to its authority to control its right of way and for public improvement, such as relocations for road widening, are capitalized.

c. Historically, the Company has not initiated litigation against municipalities with any degree of regularity. Rather, given the constructive, collaborative relationships that it maintains with municipalities, Duke Energy Kentucky is typically able to negotiate appropriate franchises and ordinances that affect its operations. However, the ability to amicably resolve matters concerning potential local regulation has become more challenging. Municipalities seeking to support economic development within their geographic borders are continually advancing criteria that conflicts with well-settled practices.

By way of example, hoping to remove perceived obstacles to attracting new and expanding businesses, municipalities are demanding that existing overhead facilities be placed underground or relocated, at no cost to the municipality or its residents. Municipalities are increasingly attempting to transfer the obligations of business owners and/or their contractors to make worksites compliant with OSHA guidelines upon the utility. The Company has had numerous discussions and disagreements with municipalities over who bears responsibility for costs to either permanently or temporarily relocating utility infrastructure otherwise installed compliant with the NESC, prior to the City or a customer engaging in construction-related activities on city-owned or customer-owned premises that would cause their contractors or workers to enter into power zones along Duke Energy Kentucky's electric delivery facilities. In such instances, municipalities are demanding that the Company, and not the customer or the city requesting the facilities to be temporary relocated, to bear the costs of the City or a customer's contractor's compliance with OSHA, that otherwise prohibit unqualified workers from entering into wire/power clearance zones. See Attachment ABS-5, Section 16, (e)(2)

In general, municipalities are increasingly flexing their statutory authority to control the Company's occupation of the municipal right-of way, becoming less willing to negotiate with the Company, and insisting the Company pay for these incremental costs and investments the government is demanding the Company undertake, particularly as it relates to rights set forth in Kentucky law (KRS 96.050(9)). Having a process like the ILIC proposed would make it clear to these municipalities that these desired relocation/undergrounding/ incremental costs would, if not paid for by the municipality themselves, could be passed on to their constituents as they would be receiving the benefit of those investments vis a vis all other customers.

In the past, the Company has challenged attempts to require the Company to collect 911 fees on behalf of the municipality. Duke Energy Kentucky's predecessor, Union Light Heat and Power Company previously challenged the municipality's right to force a utility to underground facilities. The challenge was decided in the favor of the municipality. See *Benzinger v. Union Light Heat & Power Co*. 293 Ky 747. "So in this case we hold that in the light of the wording of the involved statute, and in view of the upsetting effect it would have on long continued exercise of authority by municipalities in promoting local self-government, the enactment of the statute under consideration was not a preemption of the field of municipal authority over its public streets, alleys and property so as to deny to it the right to choose for itself the method or manner of encumbering or placing burdens on such public owned property over which it has exclusive jurisdiction."

PERSON RESPONSIBLE: Amy B. Spiller – a., c.
Dominic "Nick" J. Melillo – a., b.

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-004

REQUEST:

Refer to the Direct Testimony of Sarah E. Lawler page 14.

a. Provide a complete sample of Duke Kentucky's Fuel Adjustment Clause (FAC) rate sheet filings as if the proposed twelve-month average was approved for the expense months of July 2021 through October 2022.

b. Explain how the proposed change to the FAC would impact Duke Kentucky's FAC rate sheet calculations for Schedule 4, Final Fuel Cost Schedule; Schedule 5, Over or (Under) Recovery Schedule; and Schedule 6, Regional Transmission Organization Resettlements.

c. If the Commission were to approve the 12-month average calculation change to its FAC as proposed by Duke Kentucky, explain how Duke Kentucky would implement the change and roll in any under or over recoveries from prior FAC rates.

RESPONSE:

a. Please see STAFF-DR-04-004 Attachments 1 through 16 for the monthly FAC filings for July 2021 through October 2022.

b. Please see STAFF-DR-04-004 Attachments 1 through 16.

   i. Schedule 4 will always be reconciling one specific expense month. Schedule 4 reconciles the previous expense month estimate to actuals. In the next month's filing, the twelve-month rolling average will incorporate the actuals. For example, in the filing for July expense month, Schedule 4 will reconcile June actuals to the estimate included in the previous month's filing. Then in the filing for the August expense month, the rolling twelve-month average calculation on Schedule 2 will show actuals for June that tie to Schedule 4 in the July expense month filing. For clarity, the headers on Schedule 2 in all of STAFF-DR-04-004 Attachments state the Schedule the dollar amounts are from for each expense month.

ii. Schedule 5: In the first and second months that the Company transitions to the rolling 12-month average, the values that are being trued-up on Schedule 5 will represent one expense month. In the third month of the transition and going forward, the values that are being trued-up on Schedule 5 will represent a rolling twelve-month average. See headers on Schedule 5 in all of STAFF-DR-04-004 Attachments for clarity.

iii. Schedule 6 will always be reconciling one specific expense month. In the next month's filing, the twelve-month rolling average on Schedule 2 will incorporate the reconciled actuals. For example, in July expense month, Schedule 6 will reconcile March actuals to the true-up of March's current month fuel costs to any changes due to RTO Resettlements. Then in the filing for the August expense month, the rolling twelve-month average calculation on Schedule 2 will show actuals for March that tie to Schedule 6 in the July expense month filing.

See headers on Schedule 2 in all of STAFF-DR-04-004 Attachments for clarity.

c. See response to (b)ii.

PERSON RESPONSIBLE: Sarah E. Lawler

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **July 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 7,700,921.23		
2	Sales S_m (Schedule 3, Line C)	÷	322,349,654		0.023890
3	Base Fuel Rate (F_b/S_b) per PSC Order in Case No. 2017-00005			(-)	0.023837
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.000053

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: July 2021

		Dollars ($)	2020 August Schedule 6 Dollars ($)	2020 September Schedule 6 Dollars ($)	2020 October Schedule 6 Dollars ($)	2020 November Schedule 6 Dollars ($)	2020 December Schedule 6 Dollars ($)	2021 January Schedule 6 Dollars ($)	2021 February Schedule 6 Dollars ($)	2021 March Schedule 4 Dollars ($)	2021 April Schedule 4 Dollars ($)	2021 May Schedule 4 Dollars ($)	2021 June Schedule 2 Dollars ($)	2021 July Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 5,481,439.67	7,864,886.15	3,688,942.84	0.00	1,617,603.79	7,791,500.94	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.92	5,488,966.20	7,332,974.66	6,938,910.36
Oil Burned	(+)	186,149.61	83,126.20	77,029.31	68,951.63	157,233.99	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68
Gas Burned	(+)	242,780.35	343,251.89	67,819.00	342,000.00	(956.45)	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80
Net Fuel Related RTO Billing Line Items	(-)	(248,501.57)	(215,834.51)	(118,866.11)	327,287.77	(22,088.98)	(117,547.28)	(339,091.75)	(354,752.34)	(1,304,255.87)	(397,342.29)	(317,802.57)	(123,940.46)	2,215.60
Fuel (assigned cost during Forced Outage[a])	(+)	144,357.73	0.00	0.00	0.00	51,016.98	0.00	875,049.67	0.00	31,777.40	203,939.79	0.00	46,770.49	523,738.44
Fuel (substitute cost during Forced Outage[a])	(-)	12,803.45	0.00	0.00	0.00	0.00	0.00	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	79,535.91
Sub-Total		$ 6,290,425.47	8,507,098.75	3,952,657.26	83,663.86	1,846,987.29	8,419,228.94	7,300,889.72	8,824,527.23	7,928,253.11	6,085,733.04	6,557,008.26	8,039,112.41	7,939,945.77
B. Purchases														
Economy Purchases	(+)	$ 2,619,715.42	723,080.72	2,855,765.23	7,492,180.64	5,729,404.27	443,619.15	3,210,276.30	507,451.49	674,897.18	2,404,417.83	2,814,015.83	1,005,228.79	3,576,247.61
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	223,361.59	0.00	0.00	0.00	52,901.22	0.00	1,213,596.94	0.00	37,694.70	295,541.22	0.00	91,953.92	988,651.04
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 2,396,353.83	723,080.72	2,855,765.23	7,492,180.64	5,676,503.05	443,619.15	1,996,679.36	507,451.49	637,202.48	2,108,876.61	2,814,015.83	913,274.87	2,587,596.57
C. Non-Native Sales Fuel Costs	(-)	$ 688,670.89	583,614.76	168,036.35	1,247.03	62,267.78	1,496,784.74	937,792.87	1,238,860.64	693,296.52	1,115,398.00	1,130,208.10	572,429.64	264,114.29
D. Total Fuel Costs (A + B - C)	(+)	$ 7,998,108.41	$8,646,564.71	$6,640,386.14	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,872,159.07	$7,079,211.65	$8,240,815.99	$8,379,957.64	$10,263,428.05
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 222,056.83												
F. Adjustment indicating the difference in actual fuel cost for the month of June 2021 and the estimated cost orginally reported $8,262,218.92 (actual) - $8,379,957.64 (estimate)	(+)	($117,738.72)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ 42,608.37												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 7,700,921.23	$8,646,564.71	$6,640,386.14	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,872,159.07	$7,079,211.65	$8,240,815.99	$8,379,957.64	$10,263,428.05

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: July 2021

		kWh	2020 August kWh	2020 September kWh	2020 October kWh	2020 November kWh	2020 December kWh	2021 January kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh
A. Generation (Net)	(+)	271,225,700	383,949,900	193,020,200	7,895,000	67,256,800	397,619,000	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000
Purchases Including Interchange-In	(+)	98,274,323	32,882,984	148,571,491	287,603,347	227,121,151	19,688,766	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280
Sub-Total		369,500,023	416,832,884	341,591,691	295,498,347	294,377,951	417,307,766	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	28,261,285	22,121,020	7,305,480	27,010	4,596,700	63,903,460	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460
System Losses [(a)]	(+)	18,889,084	26,445,695	22,062,890	18,910,166	18,546,000	22,264,471	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591
Sub-Total		47,150,369	48,566,715	29,368,370	18,937,176	23,142,700	86,167,931	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051
C. Total Sales (A - B)		322,349,654	368,266,169	312,223,321	276,561,171	271,235,251	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: June 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	7,332,974.87
Oil Burned	(+)	208,007.20
Gas Burned	(+)	327,419.60
Net Fuel Related RTO Billing Line Items	(-)	(6,334.99)
Fuel (assigned cost during Forced Outage[a])	(+)	46,770.49
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		7,921,507.15
B. Purchases		
Economy Purchases	(+)	1,010,807.63
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	91,953.92
Less purchases above highest cost units	(-)	0.00
Sub-Total		918,853.71
C. Non-Native Sales Fuel Costs	(-)	578,141.94
D. Total Fuel Costs (A + B - C)		$8,262,218.92

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Expense Month: May 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.003264
2	Retail kWh Billed at Above Rate	(x)		373,437,338
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	1,218,899.47
4	kWh Used to Determine Last FAC Rate Billed	(+)		305,405,220
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			305,405,220
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	996,842.64
8	Over or (Under) (Line 3 - Line 7)		$	222,056.83
9	Total Sales (Schedule 3, Line C)	(-)		389,302,229
10	Kentucky Jurisdictional Sales	(÷)		389,302,229
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	222,056.83
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	222,056.83

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: March 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,489,966.27
Oil Burned	(+)		118,040.26
Gas Burned	(+)		(21,000.00)
Net Fuel Related RTO Billing Line Items	(-)		(1,291,401.06)
Fuel (assigned cost during Forced Outage[a])	(+)		31,259.18
Fuel (substitute cost during Forced Outage[a])	(-)		(5,213.31)
Sub-Total		$	7,914,880.08
B. Purchases			
Economy Purchases	(+)	$	723,925.85
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		36,985.48
Less purchases above highest cost units	(-)		-
Sub-Total		$	686,940.37
C. Non-Native Sales Fuel Costs	(-)		$687,053.01
D. Total Fuel Costs (A + B - C)		$	7,914,767.44
E. Total Fuel Costs Previously Reported	(-)	$	7,872,159.07
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	42,608.37

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **August 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 7,668,323.93		
2	Sales S_m (Schedule 3, Line C)	÷	325,022,287		0.023593
3	Base Fuel Rate (F_b/S_b) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				(0.001808)

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: August 2021		Dollars ($)	2020 September Schedule 6 Dollars ($)	2020 October Schedule 6 Dollars ($)	2020 November Schedule 6 Dollars ($)	2020 December Schedule 6 Dollars ($)	2021 January Schedule 6 Dollars ($)	2021 February Schedule 6 Dollars ($)	2021 March Schedule 6 Dollars ($)	2021 April Schedule 4 Dollars ($)	2021 May Schedule 4 Dollars ($)	2021 June Schedule 4 Dollars ($)	2021 July Schedule 2 Dollars ($)	2021 August Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 5,335,502.24	3,688,942.84	0.00	1,617,603.79	7,791,500.94	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.92	5,488,966.20	7,332,974.87	6,938,910.36	6,113,636.83
Oil Burned	(+)	189,706.18	77,029.31	68,951.63	157,233.99	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03
Gas Burned	(+)	279,885.19	67,819.00	342,000.00	(956.45)	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00
Net Fuel Related RTO Billing Line Items	(-)	(235,580.97)	(118,866.11)	327,287.77	(22,088.98)	(117,547.28)	(339,091.75)	(354,752.34)	(1,291,401.06)	(397,342.29)	(317,802.57)	(6,334.99)	2,215.60	(191,247.65)
Fuel (assigned cost during Forced Outage[a])	(+)	295,898.13	0.00	0.00	51,016.98	0.00	875,049.67	0.00	31,259.18	203,939.79	0.00	46,770.49	523,738.44	1,819,003.00
Fuel (substitute cost during Forced Outage[a])	(-)	12,803.45	0.00	0.00	0.00	0.00	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	79,535.91	0.00
Sub-Total		$ 6,323,769.26	3,952,657.26	83,663.86	1,846,987.29	8,419,228.94	7,300,889.72	8,824,527.23	7,914,880.08	6,085,733.04	6,557,008.26	7,921,507.15	7,939,945.77	9,038,202.51
B. Purchases														
Economy Purchases	(+)	$ 2,993,571.10	2,855,765.23	7,492,180.64	5,729,404.27	443,619.15	3,210,276.30	507,451.49	723,925.85	2,404,417.83	2,814,015.83	1,010,807.63	3,576,247.61	5,154,741.36
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	520,085.52	0.00	0.00	52,901.22	0.00	1,213,596.94	0.00	36,985.48	295,541.22	0.00	91,953.92	988,651.04	3,561,396.39
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 2,473,485.58	2,855,765.23	7,492,180.64	5,676,503.05	443,619.15	1,996,679.36	507,451.49	686,940.37	2,108,876.61	2,814,015.83	918,853.71	2,587,596.57	1,593,344.97
C. Non-Native Sales Fuel Costs	(-)	$ 684,967.98	168,036.35	1,247.03	62,267.78	1,496,784.74	937,792.87	1,238,860.64	687,053.01	1,115,398.00	1,130,208.10	578,141.94	264,114.29	539,710.96
D. Total Fuel Costs (A + B - C)	(+)	$ 8,112,286.87	$6,640,386.14	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,079,211.65	$8,240,815.99	$8,262,218.92	$10,263,428.05	$10,091,836.52
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (8,368.81)												
F. Adjustment indicating the difference in actual fuel cost for the month of July 2021 and the estimated cost orginally reported $9,848,865.42 (actual) - $10,263,428.05 (estimate)	(+)	($414,562.63)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (37,769.12)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 7,668,323.93	$6,640,386.14	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,079,211.65	$8,240,815.99	$8,262,218.92	$10,263,428.05	$10,091,836.52

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: August 2021

		kWh	2020 September kWh	2020 October kWh	2020 November kWh	2020 December kWh	2021 January kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh
A. Generation (Net)	(+)	266,240,292	193,020,200	7,895,000	67,256,800	397,619,000	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000
Purchases Including Interchange-In	(+)	105,243,722	148,571,491	287,603,347	227,121,151	19,688,766	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780
Sub-Total		371,484,014	341,591,691	295,498,347	294,377,951	417,307,766	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	28,020,584	7,305,480	27,010	4,596,700	63,903,460	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610
System Losses [(a)]	(+)	18,441,143	22,062,890	18,910,166	18,546,000	22,264,471	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409
Sub-Total		46,461,727	29,368,370	18,937,176	23,142,700	86,167,931	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019
C. Total Sales (A - B)		325,022,287	312,223,321	276,561,171	271,235,251	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: July 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	6,938,910.49
Oil Burned	(+)	172,053.68
Gas Burned	(+)	386,994.80
Net Fuel Related RTO Billing Line Items	(-)	115,874.65
Fuel (assigned cost during Forced Outage[a])	(+)	525,674.54
Fuel (substitute cost during Forced Outage[a])	(-)	43,150.77
Sub-Total		7,864,608.09
B. Purchases		
Economy Purchases	(+)	3,252,703.26
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	983,836.41
Less purchases above highest cost units	(-)	0.00
Sub-Total		2,268,866.85
C. Non-Native Sales Fuel Costs	(-)	284,609.52
D. Total Fuel Costs (A + B - C)		$9,848,865.42

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Expense Month: June 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		(0.000807)
2	Retail kWh Billed at Above Rate	(x)		369,568,986
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	(298,242.17)
4	kWh Used to Determine Last FAC Rate Billed	(+)		359,198,707
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			359,198,707
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	(289,873.36)
8	Over or (Under) (Line 3 - Line 7)		$	(8,368.81)
9	Total Sales (Schedule 3, Line C)	(-)		400,337,761
10	Kentucky Jurisdictional Sales	(÷)		400,337,761
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(8,368.81)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(8,368.81)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: April 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	5,331,139.95
Oil Burned	(+)		94,300.56
Gas Burned	(+)		84,650.00
Net Fuel Related RTO Billing Line Items	(-)		(401,095.03)
Fuel (assigned cost during Forced Outage[a])	(+)		198,176.59
Fuel (substitute cost during Forced Outage[a])	(-)		25,639.52
Sub-Total		$	6,083,722.61
B. Purchases			
Economy Purchases	(+)	$	2,377,791.28
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		286,050.21
Less purchases above highest cost units	(-)		-
Sub-Total		$	2,091,741.07
C. Non-Native Sales Fuel Costs	(-)		$1,134,021.15
D. Total Fuel Costs (A + B - C)		$	7,041,442.53
E. Total Fuel Costs Previously Reported	(-)	$	7,079,211.65
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(37,769.12)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[(a)])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **September 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 8,397,637.22		
2	Sales S_m (Schedule 3, Line C)	÷	326,505,171		0.025720
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.000319

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: September 2021			2020 October Schedule 6	2020 November Schedule 6	2020 December Schedule 6	2021 January Schedule 6	2021 February Schedule 6	2021 March Schedule 6	2021 April Schedule 6	2021 May Schedule 4	2021 June Schedule 4	2021 July Schedule 4	2021 August Schedule 2	2021 September Schedule 2
		Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 5,098,321.06	0.00	1,617,603.79	7,791,500.94	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.95	5,488,966.20	7,332,974.87	6,938,910.49	6,113,636.83	842,768.46
Oil Burned	(+)	198,007.46	68,951.63	157,233.99	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74
Gas Burned	(+)	286,633.61	342,000.00	(956.45)	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00
Net Fuel Related RTO Billing Line Items	(-)	(226,340.97)	327,287.77	(22,088.98)	(117,547.28)	(339,091.75)	(354,752.34)	(1,291,401.06)	(401,095.03)	(317,802.57)	(6,334.99)	115,874.65	(191,247.65)	(117,892.39)
Fuel (assigned cost during Forced Outage[a])	(+)	384,348.89	0.00	51,016.98	0.00	875,049.67	0.00	31,259.18	198,176.59	0.00	46,770.49	525,674.54	1,819,003.00	1,065,236.21
Fuel (substitute cost during Forced Outage[a])	(-)	10,257.33	0.00	0.00	0.00	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	5,831.76
Sub-Total		$ 6,183,394.65	83,663.86	1,846,987.29	8,419,228.94	7,300,889.72	8,824,527.23	7,914,880.08	6,083,722.61	6,557,008.26	7,921,507.15	7,864,608.09	9,038,202.51	2,345,510.04
B. Purchases														
Economy Purchases	(+)	$ 3,890,672.42	7,492,180.64	5,729,404.27	443,619.15	3,210,276.30	507,451.49	723,925.85	2,377,791.28	2,814,015.83	1,010,807.63	3,252,703.26	5,154,741.36	13,971,151.97
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	668,181.30	0.00	52,901.22	0.00	1,213,596.94	0.00	36,985.48	286,050.21	0.00	91,953.92	983,836.41	3,561,396.39	1,791,455.04
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 3,222,491.12	7,492,180.64	5,676,503.05	443,619.15	1,996,679.36	507,451.49	686,940.37	2,091,741.07	2,814,015.83	918,853.71	2,268,866.85	1,593,344.97	12,179,696.93
C. Non-Native Sales Fuel Costs	(-)	$ 681,899.09	1,247.03	62,267.78	1,496,784.74	937,792.87	1,238,860.64	687,053.01	1,134,021.15	1,130,208.10	578,141.94	284,609.52	539,710.96	92,091.35
D. Total Fuel Costs (A + B - C)	(+)	$ 8,723,986.68	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,240,815.99	$8,262,218.92	$9,848,865.42	$10,091,836.52	$14,433,115.62
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (325.33)												
F. Adjustment indicating the difference in actual fuel cost for the month of August 2021 and the estimated cost orginally reported $9,820,408.10 (actual) - $10,091,836.52 (estimate)	(+)	($271,428.42)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (55,246.37)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 8,397,637.22	$7,574,597.47	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,240,815.99	$8,262,218.92	$9,848,865.42	$10,091,836.52	$14,433,115.62

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: September 2021

		kWh	2020 October kWh	2020 November kWh	2020 December kWh	2021 January kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh
A. Generation (Net)	(+)	255,373,775	7,895,000	67,256,800	397,619,000	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000
Purchases Including Interchange-In	(+)	116,996,509	287,603,347	227,121,151	19,688,766	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930
Sub-Total		372,370,284	295,498,347	294,377,951	417,307,766	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	27,875,913	27,010	4,596,700	63,903,460	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430
System Losses [(a)]	(+)	17,989,199	18,910,166	18,546,000	22,264,471	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560
Sub-Total		45,865,112	18,937,176	23,142,700	86,167,931	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990
C. Total Sales (A - B)		326,505,171	276,561,171	271,235,251	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: August 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	6,113,635.94
Oil Burned	(+)	125,805.03
Gas Burned	(+)	788,510.00
Net Fuel Related RTO Billing Line Items	(-)	(50,645.68)
Fuel (assigned cost during Forced Outage[a])	(+)	1,815,898.52
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		8,894,495.17
B. Purchases		
Economy Purchases	(+)	5,044,812.15
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	3,559,458.48
Less purchases above highest cost units	(-)	0.00
Sub-Total		1,485,353.67
C. Non-Native Sales Fuel Costs	(-)	559,440.74
D. Total Fuel Costs (A + B - C)		$9,820,408.10

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: July 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.000053
2	Retail kWh Billed at Above Rate	(x)		316,211,405
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	16,759.20
4	kWh Used to Determine Last FAC Rate Billed	(+)		322,349,654
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			322,349,654
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	17,084.53
8	Over or (Under) (Line 3 - Line 7)		$	(325.33)
9	Total Sales (Schedule 3, Line C)	(-)		326,505,171
10	Kentucky Jurisdictional Sales	(÷)		326,505,171
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(325.33)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(325.33)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: May 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	5,488,966.19
Oil Burned	(+)		199,289.49
Gas Burned	(+)		550,950.00
Net Fuel Related RTO Billing Line Items	(-)		(315,120.03)
Fuel (assigned cost during Forced Outage[a])	(+)		-
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	6,554,325.71
B. Purchases			
Economy Purchases	(+)	$	2,783,637.97
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	2,783,637.97
C. Non-Native Sales Fuel Costs	(-)		$1,152,394.06
D. Total Fuel Costs (A + B - C)		$	8,185,569.62
E. Total Fuel Costs Previously Reported	(-)	$	8,240,815.99
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(55,246.37)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	Updated in Exp Month: Month Year	Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **October 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 9,167,084.51		
2	Sales S_m (Schedule 3, Line C)	÷	328,241,861		0.027928
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.002527

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: October 2021

		Dollars ($)	2020 November Schedule 6 Dollars ($)	2020 December Schedule 6 Dollars ($)	2021 January Schedule 6 Dollars ($)	2021 February Schedule 6 Dollars ($)	2021 March Schedule 6 Dollars ($)	2021 April Schedule 6 Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 4 Dollars ($)	2021 July Schedule 4 Dollars ($)	2021 August Schedule 4 Dollars ($)	2021 September Schedule 2 Dollars ($)	2021 October Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 5,071,144.09	1,617,603.79	7,791,500.94	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.95	5,488,966.19	7,332,974.87	6,938,910.49	6,113,635.94	842,768.46	(326,122.68)
Oil Burned	(+)	192,261.50	157,233.99	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00
Gas Burned	(+)	282,433.61	(956.45)	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00
Net Fuel Related RTO Billing Line Items	(-)	(239,339.39)	(22,088.98)	(117,547.28)	(339,091.75)	(354,752.34)	(1,291,401.06)	(401,095.03)	(315,120.03)	(6,334.99)	115,874.65	(50,645.68)	(117,892.39)	28,022.26
Fuel (assigned cost during Forced Outage[a])	(+)	384,090.18	51,016.98	0.00	875,049.67	0.00	31,259.18	198,176.59	0.00	46,770.49	525,674.54	1,815,898.52	1,065,236.21	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	10,257.33	0.00	0.00	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	5,831.76	0.00
Sub-Total		$ 6,159,011.42	1,846,987.29	8,419,228.94	7,300,889.72	8,824,527.23	7,914,880.08	6,083,722.61	6,554,325.71	7,921,507.15	7,864,608.09	8,894,495.17	2,345,510.04	(62,544.94)
B. Purchases														
Economy Purchases	(+)	$ 4,529,623.17	5,729,404.27	443,619.15	3,210,276.30	507,451.49	723,925.85	2,377,791.28	2,783,637.97	1,010,807.63	3,252,703.26	5,044,812.15	13,971,151.97	15,299,896.68
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	668,019.81	52,901.22	0.00	1,213,596.94	0.00	36,985.48	286,050.21	0.00	91,953.92	983,836.41	3,559,458.48	1,791,455.04	0.00
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 3,861,603.36	5,676,503.05	443,619.15	1,996,679.36	507,451.49	686,940.37	2,091,741.07	2,783,637.97	918,853.71	2,268,866.85	1,485,353.67	12,179,696.93	15,299,896.68
C. Non-Native Sales Fuel Costs	(-)	$ 682,754.21	62,267.78	1,496,784.74	937,792.87	1,238,860.64	687,053.01	1,134,021.15	1,152,394.06	578,141.94	284,609.52	559,440.74	92,091.35	(30,407.30)
D. Total Fuel Costs (A + B - C)	(+)	$ 9,337,860.57	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,262,218.92	$9,848,865.42	$9,820,408.10	$14,433,115.62	$15,267,759.04
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 37,999.55												
F. Adjustment indicating the difference in actual fuel cost for the month of September 2021 and the estimated cost orginally reported $14,374,048.55 (actual) - $14,433,115.62 (estimate)	(+)	($59,067.07)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (73,709.44)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 9,167,084.51	$7,461,222.56	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,262,218.92	$9,848,865.42	$9,820,408.10	$14,433,115.62	$15,267,759.04

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: October 2021

		kWh	2020 November kWh	2020 December kWh	2021 January kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh
A. Generation (Net)	(+)	254,815,692	67,256,800	397,619,000	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000
Purchases Including Interchange-In	(+)	118,908,193	227,121,151	19,688,766	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560
Sub-Total		373,723,885	294,377,951	417,307,766	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	27,873,663	4,596,700	63,903,460	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-
System Losses [(a)]	(+)	17,608,361	18,546,000	22,264,471	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112
Sub-Total		45,482,024	23,142,700	86,167,931	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112
C. Total Sales (A - B)		328,241,861	271,235,251	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: September 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	842,768.01
Oil Burned	(+)	176,644.74
Gas Burned	(+)	148,800.00
Net Fuel Related RTO Billing Line Items	(-)	(77,427.16)
Fuel (assigned cost during Forced Outage[a])	(+)	1,065,236.21
Fuel (substitute cost during Forced Outage[a])	(-)	19,668.51
Sub-Total		2,291,207.61
B. Purchases		
Economy Purchases	(+)	13,966,387.29
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	1,791,455.04
Less purchases above highest cost units	(-)	0.00
Sub-Total		12,174,932.25
C. Non-Native Sales Fuel Costs	(-)	92,091.31
D. Total Fuel Costs (A + B - C)		$14,374,048.55

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: August 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		(0.001808)
2	Retail kWh Billed at Above Rate	(x)		304,004,834
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	(549,640.74)
4	kWh Used to Determine Last FAC Rate Billed	(+)		325,022,287
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			325,022,287
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	(587,640.29)
8	Over or (Under) (Line 3 - Line 7)		$	37,999.55
9	Total Sales (Schedule 3, Line C)	(-)		328,241,861
10	Kentucky Jurisdictional Sales	(÷)		328,241,861
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	37,999.55
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	37,999.55

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: June 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	7,332,974.88
Oil Burned	(+)		208,007.20
Gas Burned	(+)		327,419.60
Net Fuel Related RTO Billing Line Items	(-)		(8,696.93)
Fuel (assigned cost during Forced Outage[a])	(+)		46,701.10
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	7,923,799.71
B. Purchases			
Economy Purchases	(+)	$	958,342.84
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		91,956.78
Less purchases above highest cost units	(-)		-
Sub-Total		$	866,386.06
C. Non-Native Sales Fuel Costs	(-)		$601,676.29
D. Total Fuel Costs (A + B - C)		$	8,188,509.48
E. Total Fuel Costs Previously Reported	(-)		$8,262,218.92
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(73,709.44)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **November 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 10,233,363.52		
2	Sales S_m (Schedule 3, Line C)	÷	330,630,088		0.030951
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.005550

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

Schedule 2

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: November 2021		Dollars ($)	2020 December Schedule 6 Dollars ($)	2020 January Schedule 6 Dollars ($)	2020 February Schedule 6 Dollars ($)	2021 March Schedule 6 Dollars ($)	2021 April Schedule 6 Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 4 Dollars ($)	2021 August Schedule 4 Dollars ($)	2021 September Schedule 4 Dollars ($)	2021 October Schedule 2 Dollars ($)	2021 November Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,936,343.74	7,791,500.94	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.95	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.01	(326,122.68)	0.00
Oil Burned	(+)	186,579.49	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.95
Gas Burned	(+)	326,705.21	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80
Net Fuel Related RTO Billing Line Items	(-)	(209,588.53)	(117,547.28)	(339,091.75)	(354,752.34)	(1,291,401.06)	(401,095.03)	(315,120.03)	(8,696.93)	115,874.65	(50,645.68)	(77,427.16)	28,022.26	296,817.97
Fuel (assigned cost during Forced Outage[a])	(+)	379,832.98	0.00	875,049.67	0.00	31,259.18	198,176.59	0.00	46,701.10	525,674.54	1,815,898.52	1,065,236.21	0.00	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	11,410.40	0.00	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	19,668.51	0.00	0.00
Sub-Total		$ 6,027,639.56	8,419,228.94	7,300,889.72	8,824,527.23	7,914,880.08	6,083,722.61	6,554,325.71	7,923,799.71	7,864,608.09	8,894,495.17	2,291,207.61	(62,544.94)	322,534.78
B. Purchases														
Economy Purchases	(+)	$ 5,582,350.90	443,619.15	3,210,276.30	507,451.49	723,925.85	2,377,791.28	2,783,637.97	958,342.84	3,252,703.26	5,044,812.15	13,966,387.29	15,299,896.68	18,419,366.54
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	663,611.61	0.00	1,213,596.94	0.00	36,985.48	286,050.21	0.00	91,956.78	983,836.41	3,559,458.48	1,791,455.04	0.00	0.00
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 4,918,739.29	443,619.15	1,996,679.36	507,451.49	686,940.37	2,091,741.07	2,783,637.97	866,386.06	2,268,866.85	1,485,353.67	12,174,932.25	15,299,896.68	18,419,366.54
C. Non-Native Sales Fuel Costs	(-)	$ 679,526.42	1,496,784.74	937,792.87	1,238,860.64	687,053.01	1,134,021.15	1,152,394.06	601,676.29	284,609.52	559,440.74	92,091.31	(30,407.30)	0.00
D. Total Fuel Costs (A + B - C)	(+)	$ 10,266,852.43	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,848,865.42	$9,820,408.10	$14,374,048.55	$15,267,759.04	$18,741,901.32
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (15,021.24)												
F. Adjustment indicating the difference in actual fuel cost for the month of October 2021 and the estimated cost orginally reported $15,281,149.44 (actual) - $15,267,759.04 (estimate)	(+)	$13,390.40												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (61,900.54)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 10,233,363.52	$7,366,063.35	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,848,865.42	$9,820,408.10	$14,374,048.55	$15,267,759.04	$18,741,901.32

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: November 2021

		kWh	2020 December kWh	2020 January kWh	2020 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh
A. Generation (Net)	(+)	249,872,958	397,619,000	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000
Purchases Including Interchange-In	(+)	125,460,816	19,688,766	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619
Sub-Total		375,333,774	417,307,766	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	27,490,604	63,903,460	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-
System Losses [(a)]	(+)	17,213,082	22,264,471	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651
Sub-Total		44,703,686	86,167,931	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651
C. Total Sales (A - B)		330,630,088	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: October 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	(326,122.67)
Oil Burned	(+)	0.00
Gas Burned	(+)	291,600.00
Net Fuel Related RTO Billing Line Items	(-)	34,423.07
Fuel (assigned cost during Forced Outage[a])	(+)	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		(68,945.74)
B. Purchases		
Economy Purchases	(+)	15,319,687.88
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00
Less purchases above highest cost units	(-)	0.00
Sub-Total		15,319,687.88
C. Non-Native Sales Fuel Costs	(-)	(30,407.30)
D. Total Fuel Costs (A + B - C)		$15,281,149.44

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: September 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.000319
2	Retail kWh Billed at Above Rate	(x)		279,416,637
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	89,133.91
4	kWh Used to Determine Last FAC Rate Billed	(+)		326,505,171
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			326,505,171
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	104,155.15
8	Over or (Under) (Line 3 - Line 7)		$	(15,021.24)
9	Total Sales (Schedule 3, Line C)	(-)		330,630,088
10	Kentucky Jurisdictional Sales	(÷)		330,630,088
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(15,021.24)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(15,021.24)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: July 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,938,910.49
Oil Burned	(+)		172,053.68
Gas Burned	(+)		386,994.80
Net Fuel Related RTO Billing Line Items	(-)		107,490.13
Fuel (assigned cost during Forced Outage[(a)])	(+)		524,128.57
Fuel (substitute cost during Forced Outage[(a)])	(-)		43,150.77
Sub-Total		$	7,871,446.64
B. Purchases			
Economy Purchases	(+)	$	3,193,160.07
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[(a)])	(-)		980,721.31
Less purchases above highest cost units	(-)		-
Sub-Total		$	2,212,438.76
C. Non-Native Sales Fuel Costs	(-)		$296,920.52
D. Total Fuel Costs (A + B - C)		$	9,786,964.88
E. Total Fuel Costs Previously Reported	(-)		$9,848,865.42
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(61,900.54)

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **December 2021**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 11,093,772.84		
2	Sales S_m (Schedule 3, Line C)	÷	329,619,875		0.033656
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.008255

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: December 2021		**Dollars ($)**	**2021 January Schedule 6 Dollars ($)**	**2021 February Schedule 6 Dollars ($)**	**2021 March Schedule 6 Dollars ($)**	**2021 April Schedule 6 Dollars ($)**	**2021 May Schedule 6 Dollars ($)**	**2021 June Schedule 6 Dollars ($)**	**2021 July Schedule 6 Dollars ($)**	**2021 August Schedule 4 Dollars ($)**	**2021 September Schedule 4 Dollars ($)**	**2021 October Schedule 4 Dollars ($)**	**2021 November Schedule 2 Dollars ($)**	**2021 December Schedule 2 Dollars ($)**
A. Company Generation														
Coal Burned	(+)	$ 4,375,051.62	5,716,136.94	7,516,247.92	6,489,966.27	5,331,139.95	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.01	(326,122.67)	0.00	1,055,995.53
Oil Burned	(+)	210,833.34	378,940.63	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.95	454,576.85
Gas Burned	(+)	296,755.93	45,350.00	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)
Net Fuel Related RTO Billing Line Items	(-)	(219,865.37)	(339,091.75)	(354,752.34)	(1,291,401.06)	(401,095.03)	(315,120.03)	(8,696.93)	107,490.13	(50,645.68)	(77,427.16)	34,423.07	296,817.97	(238,885.63)
Fuel (assigned cost during Forced Outage[a])	(+)	389,874.28	875,049.67	0.00	31,259.18	198,176.59	0.00	46,701.10	524,128.57	1,815,898.52	1,065,236.21	0.00	0.00	122,041.50
Fuel (substitute cost during Forced Outage[a])	(-)	11,410.40	53,679.27	0.00	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	19,668.51	0.00	0.00	0.00
Sub-Total		$ 5,480,970.14	7,300,889.72	8,824,527.23	7,914,880.08	6,083,722.61	6,554,325.71	7,923,799.71	7,871,446.64	8,894,495.17	2,291,207.61	(68,945.74)	322,534.78	1,858,758.11
B. Purchases														
Economy Purchases	(+)	$ 6,919,287.02	3,210,276.30	507,451.49	723,925.85	2,377,791.28	2,783,637.97	958,342.84	3,193,160.07	5,044,812.15	13,966,387.29	15,319,687.88	18,419,366.54	16,526,604.64
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	678,786.10	1,213,596.94	0.00	36,985.48	286,050.21	0.00	91,956.78	980,721.31	3,559,458.48	1,791,455.04	0.00	0.00	185,208.96
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 6,240,500.92	1,996,679.36	507,451.49	686,940.37	2,091,741.07	2,783,637.97	866,386.06	2,212,438.76	1,485,353.67	12,174,932.25	15,319,687.88	18,419,366.54	16,341,395.68
C. Non-Native Sales Fuel Costs	(-)	$ 561,661.35	937,792.87	1,238,860.64	687,053.01	1,134,021.15	1,152,394.06	601,676.29	296,920.52	559,440.74	92,091.31	(30,407.30)	0.00	70,092.95
D. Total Fuel Costs (A + B - C)	(+)	$ 11,159,809.71	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,820,408.10	$14,374,048.55	$15,281,149.44	$18,741,901.32	$18,130,060.84
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 7,171.29												
F. Adjustment indicating the difference in actual fuel cost for the month of November 2021 and the estimated cost orginally reported $18,692,824.13 - $18,741,901.32 (actual) (estimate)	(+)	($49,077.19)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (9,788.38)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 11,093,772.84	$8,359,776.21	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,820,408.10	$14,374,048.55	$15,281,149.44	$18,741,901.32	$18,130,060.84

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: December 2021

		kWh	2021 January kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh
A. Generation (Net)	(+)	219,332,117	284,410,000	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900
Purchases Including Interchange-In	(+)	149,209,249	119,637,573	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964
Sub-Total		368,541,365	404,047,573	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	22,252,674	40,460,810	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300
System Losses [(a)]	(+)	16,668,816	17,815,751	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277
Sub-Total		38,921,490	58,276,561	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577
C. Total Sales (A - B)		329,619,875	345,771,012	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: November 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	0.00
Oil Burned	(+)	89,049.98
Gas Burned	(+)	530,302.80
Net Fuel Related RTO Billing Line Items	(-)	428,949.00
Fuel (assigned cost during Forced Outage[a])	(+)	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		190,403.78
B. Purchases		
Economy Purchases	(+)	18,502,420.35
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00
Less purchases above highest cost units	(-)	0.00
Sub-Total		18,502,420.35
C. Non-Native Sales Fuel Costs	(-)	0.00
D. Total Fuel Costs (A + B - C)		$18,692,824.13

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: October 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.002527
2	Retail kWh Billed at Above Rate	(x)		331,079,726
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	836,638.47
4	kWh Used to Determine Last FAC Rate Billed	(+)		328,241,861
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			328,241,861
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	829,467.18
8	Over or (Under) (Line 3 - Line 7)		$	7,171.29
9	Total Sales (Schedule 3, Line C)	(-)		329,619,875
10	Kentucky Jurisdictional Sales	(÷)		329,619,875
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	7,171.29
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	7,171.29

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: August 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,113,635.94
Oil Burned	(+)		125,805.03
Gas Burned	(+)		788,510.00
Net Fuel Related RTO Billing Line Items	(-)		(53,051.79)
Fuel (assigned cost during Forced Outage[a])	(+)		1,814,872.94
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	8,895,875.70
B. Purchases			
Economy Purchases	(+)	$	5,036,984.92
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		3,555,798.70
Less purchases above highest cost units	(-)		-
Sub-Total		$	1,481,186.22
C. Non-Native Sales Fuel Costs	(-)		$566,442.20
D. Total Fuel Costs (A + B - C)		$	9,810,619.72
E. Total Fuel Costs Previously Reported	(-)		$9,820,408.10
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(9,788.38)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **January 2022**

Line No.	Description		Amount	Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 11,214,384.80	
2	Sales S_m (Schedule 3, Line C)	÷	332,129,462	0.033765
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057		(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)			0.008364

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

Schedule 2

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: January 2022		Dollars ($)	2021 February Schedule 6 Dollars ($)	2021 March Schedule 6 Dollars ($)	2021 April Schedule 6 Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 4 Dollars ($)	2021 October Schedule 4 Dollars ($)	2021 November Schedule 4 Dollars ($)	2021 December Schedule 2 Dollars ($)	2022 January Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,521,778.00	7,516,247.92	6,489,966.27	5,331,139.95	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.01	(326,122.67)	0.00	1,055,995.53	7,476,853.43
Oil Burned	(+)	226,700.67	513,291.64	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.98	454,576.85	569,348.65
Gas Burned	(+)	381,892.20	440,235.33	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31
Net Fuel Related RTO Billing Line Items	(-)	(227,575.45)	(354,752.34)	(1,291,401.06)	(401,095.03)	(315,120.03)	(8,696.93)	107,490.13	(53,051.79)	(77,427.16)	34,423.07	428,949.00	(238,885.63)	(561,337.63)
Fuel (assigned cost during Forced Outage[(a)])	(+)	317,820.38	0.00	31,259.18	198,176.59	0.00	46,701.10	524,128.57	1,814,872.94	1,065,236.21	0.00	0.00	122,041.50	11,428.41
Fuel (substitute cost during Forced Outage[(a)])	(-)	6,937.12	0.00	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	19,668.51	0.00	0.00	0.00	0.00
Sub-Total		$ 5,668,829.57	8,824,527.23	7,914,880.08	6,083,722.61	6,554,325.71	7,923,799.71	7,871,446.64	8,895,875.70	2,291,207.61	(68,945.74)	190,403.78	1,858,758.11	9,685,953.43
B. Purchases														
Economy Purchases	(+)	$ 6,884,727.19	507,451.49	723,925.85	2,377,791.28	2,783,637.97	958,342.84	3,193,160.07	5,036,984.92	13,966,387.29	15,319,687.88	18,502,420.35	16,526,604.64	2,720,331.75
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	579,679.20	0.00	36,985.48	286,050.21	0.00	91,956.78	980,721.31	3,555,798.70	1,791,455.04	0.00	0.00	185,208.96	27,973.93
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 6,305,047.99	507,451.49	686,940.37	2,091,741.07	2,783,637.97	866,386.06	2,212,438.76	1,481,186.22	12,174,932.25	15,319,687.88	18,502,420.35	16,341,395.68	2,692,357.82
C. Non-Native Sales Fuel Costs	(-)	$ 581,683.38	1,238,860.64	687,053.01	1,134,021.15	1,152,394.06	601,676.29	296,920.52	566,442.20	92,091.31	(30,407.30)	0.00	70,092.95	1,171,055.69
D. Total Fuel Costs (A + B - C)	(+)	$ 11,392,194.19	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,374,048.55	$15,281,149.44	$18,692,824.13	$18,130,060.84	$11,207,255.56
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 114,698.90												
F. Adjustment indicating the difference in actual fuel cost for the month of December 2021 and the estimated cost orginally reported $18,144,424.15 (actual) - $18,130,060.84 (estimate)	(+)	$14,363.32												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (77,473.80)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 11,214,384.80	$8,093,118.08	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,374,048.55	$15,281,149.44	$18,692,824.13	$18,130,060.84	$11,207,255.56

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: January 2022

		kWh	2021 February kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh
A. Generation (Net)	(+)	225,283,533	363,795,000	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000
Purchases Including Interchange-In	(+)	144,159,953	15,706,182	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028
Sub-Total		369,443,487	379,501,182	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	20,515,903	32,851,850	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560
System Losses [(a)]	(+)	16,798,122	17,332,467	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420
Sub-Total		37,314,025	50,184,317	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980
C. Total Sales (A - B)		332,129,462	329,316,865	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: December 2021

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	1,055,995.12
Oil Burned	(+)	454,576.85
Gas Burned	(+)	(12,741.40)
Net Fuel Related RTO Billing Line Items	(-)	(206,493.97)
Fuel (assigned cost during Forced Outage[a])	(+)	125,383.02
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		1,829,707.56
B. Purchases		
Economy Purchases	(+)	16,541,419.82
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	193,066.92
Less purchases above highest cost units	(-)	0.00
Sub-Total		16,348,352.90
C. Non-Native Sales Fuel Costs	(-)	33,636.31
D. Total Fuel Costs (A + B - C)		$18,144,424.15

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: November 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.005550
2	Retail kWh Billed at Above Rate	(x)		351,296,556
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	1,949,695.89
4	kWh Used to Determine Last FAC Rate Billed	(+)		330,630,088
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			330,630,088
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	1,834,996.99
8	Over or (Under) (Line 3 - Line 7)		$	114,698.90
9	Total Sales (Schedule 3, Line C)	(-)		332,129,462
10	Kentucky Jurisdictional Sales	(÷)		332,129,462
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	114,698.90
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	114,698.90

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: September 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	842,768.00
Oil Burned	(+)		176,644.74
Gas Burned	(+)		148,800.00
Net Fuel Related RTO Billing Line Items	(-)		(76,866.82)
Fuel (assigned cost during Forced Outage[a])	(+)		1,060,259.05
Fuel (substitute cost during Forced Outage[a])	(-)		3,681.48
Sub-Total		$	2,301,657.13
B. Purchases			
Economy Purchases	(+)	$	13,871,945.59
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		1,782,944.50
Less purchases above highest cost units	(-)		-
Sub-Total		$	12,089,001.09
C. Non-Native Sales Fuel Costs	(-)		$94,083.47
D. Total Fuel Costs (A + B - C)		$	14,296,574.75
E. Total Fuel Costs Previously Reported	(-)		$14,374,048.55
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(77,473.80)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	Updated in Exp Month: Month Year	Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **February 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 11,534,734.66		
2	Sales S_m (Schedule 3, Line C)	÷	331,117,538		0.034836
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.009435

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: February 2022

		Dollars ($)	2021 March Schedule 6 Dollars ($)	2021 April Schedule 6 Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 4 Dollars ($)	2021 November Schedule 4 Dollars ($)	2021 December Schedule 4 Dollars ($)	2022 January Schedule 2 Dollars ($)	2022 February Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,429,963.96	6,489,966.27	5,331,139.95	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,853.43	6,414,479.92
Oil Burned	(+)	214,917.66	118,040.26	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.98	454,576.85	569,348.65	371,895.47
Gas Burned	(+)	347,330.93	(21,000.00)	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00
Net Fuel Related RTO Billing Line Items	(-)	(238,463.55)	(1,291,401.06)	(401,095.03)	(315,120.03)	(8,696.93)	107,490.13	(53,051.79)	(76,866.82)	34,423.07	428,949.00	(206,493.97)	(561,337.63)	(518,361.48)
Fuel (assigned cost during Forced Outage[a])	(+)	340,171.92	31,259.18	198,176.59	0.00	46,701.10	524,128.57	1,814,872.94	1,060,259.05	0.00	0.00	125,383.02	11,428.41	269,854.13
Fuel (substitute cost during Forced Outage[a])	(-)	5,604.87	(5,213.31)	25,639.52	0.00	0.00	43,150.77	0.00	3,681.48	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 5,565,243.13	7,914,880.08	6,083,722.61	6,554,325.71	7,923,799.71	7,871,446.64	8,895,875.70	2,301,657.13	(68,945.74)	190,403.78	1,829,707.56	9,685,953.43	7,600,091.00
B. Purchases														
Economy Purchases	(+)	$ 7,176,043.30	723,925.85	2,377,791.28	2,783,637.97	958,342.84	3,193,160.07	5,036,984.92	13,871,945.59	15,319,687.88	18,502,420.35	16,541,419.82	2,720,331.75	4,082,871.30
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	634,337.59	36,985.48	286,050.21	0.00	91,956.78	980,721.31	3,555,798.70	1,782,944.50	0.00	0.00	193,066.92	27,973.93	656,553.22
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 6,541,705.71	686,940.37	2,091,741.07	2,783,637.97	866,386.06	2,212,438.76	1,481,186.22	12,089,001.09	15,319,687.88	18,502,420.35	16,348,352.90	2,692,357.82	3,426,318.08
C. Non-Native Sales Fuel Costs	(-)	$ 507,968.59	687,053.01	1,134,021.15	1,152,394.06	601,676.29	296,920.52	566,442.20	94,083.47	(30,407.30)	0.00	33,636.31	1,171,055.69	388,747.71
D. Total Fuel Costs (A + B - C)	(+)	$ 11,598,980.26	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,281,149.44	$18,692,824.13	$18,144,424.15	$11,207,255.56	$10,637,661.37
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 150,730.59												
F. Adjustment indicating the difference in actual fuel cost for the month of January 2022 and the estimated cost orginally reported $11,413,623.84 (actual) - $11,207,255.56 (estimate)	(+)	$206,368.29												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (119,883.29)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 11,534,734.66	$7,914,767.44	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,281,149.44	$18,692,824.13	$18,144,424.15	$11,207,255.56	$10,637,661.37

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: February 2022

		kWh	2021 March kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh
A. Generation (Net)	(+)	217,672,908	327,538,000	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500
Purchases Including Interchange-In	(+)	149,319,330	28,454,217	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700
Sub-Total		366,992,238	355,992,217	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	19,100,520	37,896,970	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250
System Losses [(a)]	(+)	16,774,180	15,268,572	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166
Sub-Total		35,874,700	53,165,542	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416
C. Total Sales (A - B)		331,117,538	302,826,675	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: January 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	7,476,852.67
Oil Burned	(+)	569,348.65
Gas Burned	(+)	1,066,985.31
Net Fuel Related RTO Billing Line Items	(-)	(510,582.50)
Fuel (assigned cost during Forced Outage[a])	(+)	11,534.67
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		9,635,303.80
B. Purchases		
Economy Purchases	(+)	2,871,182.67
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	28,311.46
Less purchases above highest cost units	(-)	0.00
Sub-Total		2,842,871.21
C. Non-Native Sales Fuel Costs	(-)	1,064,551.17
D. Total Fuel Costs (A + B - C)		$11,413,623.84

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: December 2021

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.008255
2	Retail kWh Billed at Above Rate	(x)		347,879,183
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	2,871,742.66
4	kWh Used to Determine Last FAC Rate Billed	(+)		329,619,875
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			329,619,875
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	2,721,012.07
8	Over or (Under) (Line 3 - Line 7)		$	150,730.59
9	Total Sales (Schedule 3, Line C)	(-)		331,117,538
10	Kentucky Jurisdictional Sales	(÷)		331,117,538
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	150,730.59
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	150,730.59

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: October 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	(326,122.67)
Oil Burned	(+)		-
Gas Burned	(+)		291,600.00
Net Fuel Related RTO Billing Line Items	(-)		34,899.08
Fuel (assigned cost during Forced Outage[(a)])	(+)		-
Fuel (substitute cost during Forced Outage[(a)])	(-)		-
Sub-Total		$	(69,421.75)
B. Purchases			
Economy Purchases	(+)	$	15,200,280.60
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[(a)])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	15,200,280.60
C. Non-Native Sales Fuel Costs	(-)	$	(30,407.30)
D. Total Fuel Costs (A + B - C)		$	15,161,266.15
E. Total Fuel Costs Previously Reported	(-)		$15,281,149.44
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(119,883.29)

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **March 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 12,410,779.58		
2	Sales S_m (Schedule 3, Line C)	÷	331,868,476		0.037397
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.011996

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: March 2022		Dollars ($)	2021 April Schedule 6 Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 4 Dollars ($)	2021 December Schedule 4 Dollars ($)	2022 January Schedule 4 Dollars ($)	2022 February Schedule 2 Dollars ($)	2022 March Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,462,965.42	5,331,139.95	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.67	6,414,479.92	6,885,984.52
Oil Burned	(+)	217,975.36	94,300.56	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.98	454,576.85	569,348.65	371,895.47	154,732.62
Gas Burned	(+)	375,101.76	84,650.00	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00
Net Fuel Related RTO Billing Line Items	(-)	(128,788.16)	(401,095.03)	(315,120.03)	(8,696.93)	107,490.13	(53,051.79)	(76,866.82)	34,899.08	428,949.00	(206,493.97)	(510,582.50)	(518,361.48)	(26,527.61)
Fuel (assigned cost during Forced Outage[a])	(+)	337,575.84	198,176.59	0.00	46,701.10	524,128.57	1,814,872.94	1,060,259.05	0.00	0.00	125,383.02	11,534.67	269,854.13	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	6,039.31	25,639.52	0.00	0.00	43,150.77	0.00	3,681.48	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 5,516,367.22	6,083,722.61	6,554,325.71	7,923,799.71	7,871,446.64	8,895,875.70	2,301,657.13	(69,421.75)	190,403.78	1,829,707.56	9,635,303.80	7,600,091.00	7,379,494.75
B. Purchases														
Economy Purchases	(+)	$ 7,371,143.02	2,377,791.28	2,783,637.97	958,342.84	3,193,160.07	5,036,984.92	13,871,945.59	15,200,280.60	18,502,420.35	16,541,419.82	2,871,182.67	4,082,871.30	3,033,678.85
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	631,283.59	286,050.21	0.00	91,956.78	980,721.31	3,555,798.70	1,782,944.50	0.00	0.00	193,066.92	28,311.46	656,553.22	0.00
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 6,739,859.43	2,091,741.07	2,783,637.97	866,386.06	2,212,438.76	1,481,186.22	12,089,001.09	15,200,280.60	18,502,420.35	16,348,352.90	2,842,871.21	3,426,318.08	3,033,678.85
C. Non-Native Sales Fuel Costs	(-)	$ 486,796.39	1,134,021.15	1,152,394.06	601,676.29	296,920.52	566,442.20	94,083.47	(30,407.30)	0.00	33,636.31	1,064,551.17	388,747.71	539,491.12
D. Total Fuel Costs (A + B - C)	(+)	$ 11,769,430.26	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,692,824.13	$18,144,424.15	$11,413,623.84	$10,637,661.37	$9,873,682.48
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (633,648.83)												
F. Adjustment indicating the difference in actual fuel cost for the month of February 2022 and the estimated cost orginally reported $10,766,255.68 (actual) - $10,637,661.37 (estimate)	(+)	$128,594.31												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (120,893.82)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 12,410,779.58	$7,041,442.53	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,692,824.13	$18,144,424.15	$11,413,623.84	$10,637,661.37	$9,873,682.48

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: March 2022

		kWh	2021 April kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh
A. Generation (Net)	(+)	213,934,558	267,183,000	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800
Purchases Including Interchange-In	(+)	152,115,401	78,788,616	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070
Sub-Total		366,049,959	345,971,616	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	17,283,150	55,058,390	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530
System Losses [(a)]	(+)	16,898,333	13,963,835	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413
Sub-Total		34,181,483	69,022,225	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943
C. Total Sales (A - B)		331,868,476	276,949,391	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: February 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	6,414,479.82
Oil Burned	(+)	371,895.47
Gas Burned	(+)	25,500.00
Net Fuel Related RTO Billing Line Items	(-)	(487,306.05)
Fuel (assigned cost during Forced Outage[a])	(+)	274,592.15
Fuel (substitute cost during Forced Outage[a])	(-)	4,970.62
Sub-Total		7,568,802.87
B. Purchases		
Economy Purchases	(+)	4,172,339.13
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	656,553.22
Less purchases above highest cost units	(-)	0.00
Sub-Total		3,515,785.91
C. Non-Native Sales Fuel Costs	(-)	318,333.10
D. Total Fuel Costs (A + B - C)		$10,766,255.68

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: January 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.008364
2	Retail kWh Billed at Above Rate	(x)		256,370,396
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	2,144,281.99
4	kWh Used to Determine Last FAC Rate Billed	(+)		332,129,462
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			332,129,462
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	2,777,930.82
8	Over or (Under) (Line 3 - Line 7)		$	(633,648.83)
9	Total Sales (Schedule 3, Line C)	(-)		331,868,476
10	Kentucky Jurisdictional Sales	(÷)		331,868,476
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(633,648.83)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(633,648.83)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: November 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	-
Oil Burned	(+)		89,049.96
Gas Burned	(+)		530,302.80
Net Fuel Related RTO Billing Line Items	(-)		433,172.73
Fuel (assigned cost during Forced Outage[a])	(+)		-
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	186,180.03
B. Purchases			
Economy Purchases	(+)	$	18,385,750.28
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	18,385,750.28
C. Non-Native Sales Fuel Costs	(-)	$	-
D. Total Fuel Costs (A + B - C)		$	18,571,930.31
E. Total Fuel Costs Previously Reported	(-)		$18,692,824.13
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(120,893.82)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	Updated in Exp Month: Month Year	Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **April 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 13,578,016.74		
2	Sales S_m (Schedule 3, Line C)	÷	332,571,651		0.040827
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.015426

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: April 2022

		Dollars ($)	2021 May Schedule 6 Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 4 Dollars ($)	2022 January Schedule 4 Dollars ($)	2022 February Schedule 4 Dollars ($)	2022 March Schedule 2 Dollars ($)	2022 April Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,389,066.39	5,488,966.19	7,332,974.88	6,938,910.49	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.67	6,414,479.82	6,885,984.52	4,444,351.74
Oil Burned	(+)	225,502.40	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12
Gas Burned	(+)	392,222.14	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55
Net Fuel Related RTO Billing Line Items	(-)	(117,712.34)	(315,120.03)	(8,696.93)	107,490.13	(53,051.79)	(76,866.82)	34,899.08	433,172.73	(206,493.97)	(510,582.50)	(487,306.05)	(26,527.61)	(303,464.28)
Fuel (assigned cost during Forced Outage[(a)])	(+)	321,455.96	0.00	46,701.10	524,128.57	1,814,872.94	1,060,259.05	0.00	0.00	125,383.02	11,534.67	274,592.15	0.00	0.00
Fuel (substitute cost during Forced Outage[(a)])	(-)	4,316.91	0.00	0.00	43,150.77	0.00	3,681.48	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00
Sub-Total		$ 5,441,642.32	6,554,325.71	7,923,799.71	7,871,446.64	8,895,875.70	2,301,657.13	(69,421.75)	186,180.03	1,829,707.56	9,635,303.80	7,568,802.87	7,379,494.75	5,222,535.69
B. Purchases														
Economy Purchases	(+)	$ 7,961,347.38	2,783,637.97	958,342.84	3,193,160.07	5,036,984.92	13,871,945.59	15,200,280.60	18,385,750.28	16,541,419.82	2,871,182.67	4,172,339.13	3,033,678.85	9,487,445.85
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	607,446.07	0.00	91,956.78	980,721.31	3,555,798.70	1,782,944.50	0.00	0.00	193,066.92	28,311.46	656,553.22	0.00	0.00
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 7,353,901.31	2,783,637.97	866,386.06	2,212,438.76	1,481,186.22	12,089,001.09	15,200,280.60	18,385,750.28	16,348,352.90	2,842,871.21	3,515,785.91	3,033,678.85	9,487,445.85
C. Non-Native Sales Fuel Costs	(-)	$ 429,326.58	1,152,394.06	601,676.29	296,920.52	566,442.20	94,083.47	(30,407.30)	0.00	33,636.31	1,064,551.17	318,333.10	539,491.12	514,797.97
D. Total Fuel Costs (A + B - C)	(+)	$ 12,366,217.05	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,144,424.15	$11,413,623.84	$10,766,255.68	$9,873,682.48	$14,195,183.57
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (1,295,962.02)												
F. Adjustment indicating the difference in actual fuel cost for the month of March 2022 and the estimated cost orginally reported $9,851,818.07 (actual) - $9,873,682.48 (estimate)	(+)	($21,864.42)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (62,297.91)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 13,578,016.74	$8,185,569.62	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,144,424.15	$11,413,623.84	$10,766,255.68	$9,873,682.48	$14,195,183.57

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: April 2022

		kWh	2021 May kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh
A. Generation (Net)	(+)	206,449,725	267,283,500	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000
Purchases Including Interchange-In	(+)	156,958,191	94,838,657	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100
Sub-Total		363,407,916	362,122,157	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	13,744,033	41,654,980	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990
System Losses [(a)]	(+)	17,092,232	15,061,957	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618
Sub-Total		30,836,265	56,716,937	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608
C. Total Sales (A - B)		332,571,651	305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: March 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	6,885,984.78
Oil Burned	(+)	154,732.62
Gas Burned	(+)	312,250.00
Net Fuel Related RTO Billing Line Items	(-)	52,652.15
Fuel (assigned cost during Forced Outage[a])	(+)	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		7,300,315.25
B. Purchases		
Economy Purchases	(+)	3,089,413.56
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00
Less purchases above highest cost units	(-)	0.00
Sub-Total		3,089,413.56
C. Non-Native Sales Fuel Costs	(-)	537,910.74
D. Total Fuel Costs (A + B - C)		$9,851,818.07

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: February 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.009435
2	Retail kWh Billed at Above Rate	(x)		193,760,673
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	1,828,131.95
4	kWh Used to Determine Last FAC Rate Billed	(+)		331,117,538
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			331,117,538
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	3,124,093.97
8	Over or (Under) (Line 3 - Line 7)		$	(1,295,962.02)
9	Total Sales (Schedule 3, Line C)	(-)		332,571,651
10	Kentucky Jurisdictional Sales	(÷)		332,571,651
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(1,295,962.02)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(1,295,962.02)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: December 2021

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	1,055,995.12
Oil Burned	(+)		454,576.85
Gas Burned	(+)		(12,741.40)
Net Fuel Related RTO Billing Line Items	(-)		(206,177.84)
Fuel (assigned cost during Forced Outage[a])	(+)		123,617.55
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	1,827,625.96
B. Purchases			
Economy Purchases	(+)	$	16,480,073.26
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		190,400.08
Less purchases above highest cost units	(-)		-
Sub-Total		$	16,289,673.18
C. Non-Native Sales Fuel Costs	(-)	$	35,172.90
D. Total Fuel Costs (A + B - C)		$	18,082,126.24
E. Total Fuel Costs Previously Reported	(-)		$18,144,424.15
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(62,297.91)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **May 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 13,196,903.66		
2	Sales S_m (Schedule 3, Line C)	÷	333,761,940		0.039540
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.014139

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: May 2022

		Dollars ($)	2021 June Schedule 6 Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 6 Dollars ($)	2022 January Schedule 4 Dollars ($)	2022 February Schedule 4 Dollars ($)	2022 March Schedule 4 Dollars ($)	2022 April Schedule 2 Dollars ($)	2022 May Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,434,376.83	7,332,974.88	6,938,910.49	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.67	6,414,479.82	6,885,984.78	4,444,351.74	6,032,691.22
Oil Burned	(+)	257,583.96	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14
Gas Burned	(+)	346,327.85	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50
Net Fuel Related RTO Billing Line Items	(-)	(145,846.78)	(8,696.93)	107,490.13	(53,051.79)	(76,866.82)	34,899.08	433,172.73	(206,177.84)	(510,582.50)	(487,306.05)	52,652.15	(303,464.28)	(732,229.26)
Fuel (assigned cost during Forced Outage[a])	(+)	373,985.72	46,701.10	524,128.57	1,814,872.94	1,060,259.05	0.00	0.00	123,617.55	11,534.67	274,592.15	0.00	0.00	632,122.62
Fuel (substitute cost during Forced Outage[a])	(-)	4,316.91	0.00	43,150.77	0.00	3,681.48	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00	0.00
Sub-Total		$ 5,553,804.23	7,923,799.71	7,871,446.64	8,895,875.70	2,301,657.13	(69,421.75)	186,180.03	1,827,625.96	9,635,303.80	7,568,802.87	7,300,315.25	5,222,535.69	7,981,529.74
B. Purchases														
Economy Purchases	(+)	$ 8,257,572.79	958,342.84	3,193,160.07	5,036,984.92	13,871,945.59	15,200,280.60	18,385,750.28	16,480,073.26	2,871,182.67	4,172,339.13	3,089,413.56	9,487,445.85	6,343,954.70
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	771,945.43	91,956.78	980,721.31	3,555,798.70	1,782,944.50	0.00	0.00	190,400.08	28,311.46	656,553.22	0.00	0.00	1,976,659.13
Less purchases above highest cost units	(-)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		$ 7,485,627.36	866,386.06	2,212,438.76	1,481,186.22	12,089,001.09	15,200,280.60	18,385,750.28	16,289,673.18	2,842,871.21	3,515,785.91	3,089,413.56	9,487,445.85	4,367,295.57
C. Non-Native Sales Fuel Costs	(-)	$ 398,228.27	601,676.29	296,920.52	566,442.20	94,083.47	(30,407.30)	0.00	35,172.90	1,064,551.17	318,333.10	537,910.74	514,797.97	779,258.14
D. Total Fuel Costs (A + B - C)	(+)	$ 12,641,203.32	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,413,623.84	$10,766,255.68	$9,851,818.07	$14,195,183.57	$11,569,567.17
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (698,359.20)												
F. Adjustment indicating the difference in actual fuel cost for the month of April 2022 and the estimated cost orginally reported $14,257,043.53 - $14,195,183.57 (actual) (estimate)	(+)	$61,859.96												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (204,518.81)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 13,196,903.66	$8,188,509.48	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,413,623.84	$10,766,255.68	$9,851,818.07	$14,195,183.57	$11,569,567.17

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: May 2022

		kWh	2021 June kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh
A. Generation (Net)	(+)	207,664,017	368,441,000	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000
Purchases Including Interchange-In	(+)	156,855,701	32,087,606	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770
Sub-Total		364,519,717	400,528,606	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	13,310,399	22,822,290	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370
System Losses [(a)]	(+)	17,447,378	18,507,609	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707
Sub-Total		30,757,777	41,329,899	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077
C. Total Sales (A - B)		333,761,940	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: April 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	4,444,351.24
Oil Burned	(+)	184,625.12
Gas Burned	(+)	290,094.55
Net Fuel Related RTO Billing Line Items	(-)	(330,817.67)
Fuel (assigned cost during Forced Outage[a])	(+)	0.00
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		5,249,888.58
B. Purchases		
Economy Purchases	(+)	9,522,658.64
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00
Less purchases above highest cost units	(-)	0.00
Sub-Total		9,522,658.64
C. Non-Native Sales Fuel Costs	(-)	515,503.69
D. Total Fuel Costs (A + B - C)		$14,257,043.53

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: March 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.011996
2	Retail kWh Billed at Above Rate	(x)		273,652,471
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	3,282,735.04
4	kWh Used to Determine Last FAC Rate Billed	(+)		331,868,476
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			331,868,476
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	3,981,094.24
8	Over or (Under) (Line 3 - Line 7)		$	(698,359.20)
9	Total Sales (Schedule 3, Line C)	(-)		333,761,940
10	Kentucky Jurisdictional Sales	(÷)		333,761,940
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(698,359.20)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(698,359.20)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: January 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	7,476,852.69
Oil Burned	(+)		569,348.65
Gas Burned	(+)		1,066,985.31
Net Fuel Related RTO Billing Line Items	(-)		(591,448.66)
Fuel (assigned cost during Forced Outage[a])	(+)		11,241.72
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	9,715,877.03
B. Purchases			
Economy Purchases	(+)	$	2,806,649.29
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		27,556.86
Less purchases above highest cost units	(-)		-
Sub-Total		$	2,779,092.43
C. Non-Native Sales Fuel Costs	(-)	$	1,285,864.43
D. Total Fuel Costs (A + B - C)		$	11,209,105.03
E. Total Fuel Costs Previously Reported	(-)		$11,413,623.84
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(204,518.81)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	Updated in Exp Month: Month Year	Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **June 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 14,996,857.46		
2	Sales S_m (Schedule 3, Line C)	÷	333,920,900		0.044911
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.019510

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: June 2022

		Dollars ($)	2021 July Schedule 6 Dollars ($)	2021 August Schedule 6 Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 6 Dollars ($)	2022 January Schedule 6 Dollars ($)	2022 February Schedule 4 Dollars ($)	2022 March Schedule 4 Dollars ($)	2022 April Schedule 4 Dollars ($)	2022 May Schedule 2 Dollars ($)	2022 June Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,533,523.51	6,938,910.49	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.69	6,414,479.82	6,885,984.78	4,444,351.24	6,032,691.22	8,522,735.43
Oil Burned	(+)	260,449.73	172,053.68	125,805.03	176,644.74	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51
Gas Burned	(+)	393,459.55	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50	893,000.00
Net Fuel Related RTO Billing Line Items	(-)	(95,024.06)	107,490.13	(53,051.79)	(76,866.82)	34,899.08	433,172.73	(206,177.84)	(591,448.66)	(487,306.05)	52,652.15	(330,817.67)	(732,229.26)	709,395.33
Fuel (assigned cost during Forced Outage[a])	(+)	401,371.74	524,128.57	1,814,872.94	1,060,259.05	0.00	0.00	123,617.55	11,241.72	274,592.15	0.00	0.00	632,122.62	375,626.32
Fuel (substitute cost during Forced Outage[a])	(-)	4,316.91	43,150.77	0.00	3,681.48	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00	0.00	0.00
Sub-Total		$ 5,679,511.68	7,871,446.64	8,895,875.70	2,301,657.13	(69,421.75)	186,180.03	1,827,625.96	9,715,877.03	7,568,802.87	7,300,315.25	5,249,888.58	7,981,529.74	9,324,362.93
B. Purchases														
Economy Purchases	(+)	$ 8,567,469.08	3,193,160.07	5,036,984.92	13,871,945.59	15,200,280.60	18,385,750.28	16,480,073.26	2,806,649.29	4,172,339.13	3,089,413.56	9,522,658.64	6,343,954.70	4,706,418.95
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	865,265.51	980,721.31	3,555,798.70	1,782,944.50	0.00	0.00	190,400.08	27,556.86	656,553.22	0.00	0.00	1,976,659.13	1,212,552.28
Less purchases above highest cost units	(-)	528.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,336.76
Sub-Total		$ 7,701,675.51	2,212,438.76	1,481,186.22	12,089,001.09	15,200,280.60	18,385,750.28	16,289,673.18	2,779,092.43	3,515,785.91	3,089,413.56	9,522,658.64	4,367,295.57	3,487,529.91
C. Non-Native Sales Fuel Costs	(-)	$ 435,048.84	296,920.52	566,442.20	94,083.47	(30,407.30)	0.00	35,172.90	1,285,864.43	318,333.10	537,910.74	515,503.69	779,258.14	821,504.20
D. Total Fuel Costs (A + B - C)	(+)	$ 12,946,138.35	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,766,255.68	$9,851,818.07	$14,257,043.53	$11,569,567.17	$11,990,388.64
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (1,756,415.72)												
F. Adjustment indicating the difference in actual fuel cost for the month of May 2022 and the estimated cost orginally reported $11,916,076.48 - $11,569,567.17 (actual) (estimate)	(+)	$346,509.31												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (52,205.92)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 14,996,857.46	$9,786,964.88	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,766,255.68	$9,851,818.07	$14,257,043.53	$11,569,567.17	$11,990,388.64

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: June 2022

		kWh	2021 July kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh	2022 June kWh
A. Generation (Net)	(+)	207,772,392	326,317,000	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000	369,741,500
Purchases Including Interchange-In	(+)	157,728,504	93,911,280	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770	42,561,250
Sub-Total		365,500,896	420,228,280	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770	412,302,750
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	13,479,352	10,436,460	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370	24,849,720
System Losses [a]	(+)	18,100,644	20,489,591	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707	26,346,806
Sub-Total		31,579,996	30,926,051	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077	51,196,526
C. Total Sales (A - B)		333,920,900	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693	361,106,224

Note: [a] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: May 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	6,032,691.48
Oil Burned	(+)	584,268.14
Gas Burned	(+)	218.50
Net Fuel Related RTO Billing Line Items	(-)	(585,432.98)
Fuel (assigned cost during Forced Outage[(a)])	(+)	959,488.20
Fuel (substitute cost during Forced Outage[(a)])	(-)	0.00
Sub-Total		8,162,099.30
B. Purchases		
Economy Purchases	(+)	7,587,761.09
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	3,044,032.32
Less purchases above highest cost units	(-)	0.00
Sub-Total		4,543,728.77
C. Non-Native Sales Fuel Costs	(-)	789,751.59
D. Total Fuel Costs (A + B - C)		$11,916,076.48

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: April 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.015426
2	Retail kWh Billed at Above Rate	(x)		218,710,915
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	3,373,834.57
4	kWh Used to Determine Last FAC Rate Billed	(+)		332,571,651
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			332,571,651
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	5,130,250.29
8	Over or (Under) (Line 3 - Line 7)		$	(1,756,415.72)
9	Total Sales (Schedule 3, Line C)	(-)		333,920,900
10	Kentucky Jurisdictional Sales	(÷)		333,920,900
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(1,756,415.72)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(1,756,415.72)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: February 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,414,479.82
Oil Burned	(+)		371,895.47
Gas Burned	(+)		25,500.00
Net Fuel Related RTO Billing Line Items	(-)		(488,166.83)
Fuel (assigned cost during Forced Outage[(a)])	(+)		271,590.96
Fuel (substitute cost during Forced Outage[(a)])	(-)		4,970.62
Sub-Total		$	7,566,662.46
B. Purchases			
Economy Purchases	(+)	$	4,128,979.51
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[(a)])	(-)		649,303.60
Less purchases above highest cost units	(-)		-
Sub-Total		$	3,479,675.91
C. Non-Native Sales Fuel Costs	(-)	$	332,288.61
D. Total Fuel Costs (A + B - C)		$	10,714,049.76
E. Total Fuel Costs Previously Reported	(-)		$10,766,255.68
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(52,205.92)

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **July 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 10,130,811.06		
2	Sales S_m (Schedule 3, Line C)	÷	334,089,359		0.030324
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.004923

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: July 2022			2021	2021	2021	2021	2021	2022	2022	2022	2022	2022	2022	2022
			August	September	October	November	December	January	February	March	April	May	June	July
			Schedule 6	Schedule 6	Schedule 6	Schedule 6	Schedule 6	Schedule 6	Schedule 6	Schedule 4	Schedule 4	Schedule 4	Schedule 2	Schedule 2
		Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,557,528.75	6,113,635.94	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.69	6,414,479.82	6,885,984.78	4,444,351.24	6,032,691.48	8,522,735.43	7,226,973.11
Oil Burned	(+)	256,829.03	125,805.03	176,644.74	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51	128,605.31
Gas Burned	(+)	536,451.65	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50	893,000.00	2,102,900.00
Net Fuel Related RTO Billing Line Items	(-)	(72,256.19)	(53,051.79)	(76,866.82)	34,899.08	433,172.73	(206,177.84)	(591,448.66)	(488,166.83)	52,652.15	(330,817.67)	(585,432.98)	709,395.33	234,769.08
Fuel (assigned cost during Forced Outage[a])	(+)	423,832.78	1,814,872.94	1,060,259.05	0.00	0.00	123,617.55	11,241.72	271,590.96	0.00	0.00	959,488.20	375,626.32	469,296.58
Fuel (substitute cost during Forced Outage[a])	(-)	33,780.79	0.00	3,681.48	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00	0.00	0.00	396,717.32
Sub-Total		$ 5,813,117.60	8,895,875.70	2,301,657.13	(69,421.75)	186,180.03	1,827,625.96	9,715,877.03	7,566,662.46	7,300,315.25	5,249,888.58	8,162,099.30	9,324,362.93	9,296,288.60
B. Purchases														
Economy Purchases	(+)	$ 9,415,566.29	5,036,984.92	13,871,945.59	15,200,280.60	18,385,750.28	16,480,073.26	2,806,649.29	4,128,979.51	3,089,413.56	9,522,658.64	7,587,761.09	4,706,418.95	12,169,879.82
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	995,591.98	3,555,798.70	1,782,944.50	0.00	0.00	190,400.08	27,556.86	649,303.60	0.00	0.00	3,044,032.32	1,212,552.28	1,484,515.40
Less purchases above highest cost units	(-)	528.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,336.76	0.00
Sub-Total		$ 8,419,446.25	1,481,186.22	12,089,001.09	15,200,280.60	18,385,750.28	16,289,673.18	2,779,092.43	3,479,675.91	3,089,413.56	9,522,658.64	4,543,728.77	3,487,529.91	10,685,364.42
C. Non-Native Sales Fuel Costs	(-)	$ 458,843.86	566,442.20	94,083.47	(30,407.30)	0.00	35,172.90	1,285,864.43	332,288.61	537,910.74	515,503.69	789,751.59	821,504.20	558,011.84
D. Total Fuel Costs (A + B - C)	(+)	$ 13,773,719.99	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$9,851,818.07	$14,257,043.53	$11,916,076.48	$11,990,388.64	$19,423,641.18
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 3,994,829.24												
F. Adjustment indicating the difference in actual fuel cost for the month of June 2022 and the estimated cost orginally reported $11,891,400.73 (actual) - $11,990,388.64 (estimate)	(+)	($98,987.91)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ 450,908.22												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 10,130,811.06	$9,810,619.72	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$9,851,818.07	$14,257,043.53	$11,916,076.48	$11,990,388.64	$19,423,641.18

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: July 2022

		kWh	2021 August kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh	2022 June kWh	2022 July kWh
A. Generation (Net)	(+)	206,122,058	324,125,000	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000	369,741,500	306,513,000
Purchases Including Interchange-In	(+)	160,901,740	116,515,780	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770	42,561,250	131,990,110
Sub-Total		367,023,798	440,640,780	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770	412,302,750	438,503,110
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	13,237,133	19,232,610	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370	24,849,720	7,529,830
System Losses [(a)]	(+)	19,697,307	21,070,409	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707	26,346,806	39,649,542
Sub-Total		32,934,439	40,303,019	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077	51,196,526	47,179,372
C. Total Sales (A - B)		334,089,359	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693	361,106,224	391,323,738

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: June 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	8,522,736.84
Oil Burned	(+)	242,396.51
Gas Burned	(+)	893,000.00
Net Fuel Related RTO Billing Line Items	(-)	830,446.78
Fuel (assigned cost during Forced Outage[(a)])	(+)	358,737.70
Fuel (substitute cost during Forced Outage[(a)])	(-)	62,290.34
Sub-Total		9,124,133.93
B. Purchases		
Economy Purchases	(+)	4,801,436.83
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	1,212,553.95
Less purchases above highest cost units	(-)	6,336.76
Sub-Total		3,582,546.12
C. Non-Native Sales Fuel Costs	(-)	815,279.32
D. Total Fuel Costs (A + B - C)		$11,891,400.73

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: May 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.014139
2	Retail kWh Billed at Above Rate	(x)		616,301,670
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	8,713,889.31
4	kWh Used to Determine Last FAC Rate Billed	(+)		333,761,940
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			333,761,940
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	4,719,060.07
8	Over or (Under) (Line 3 - Line 7)		$	3,994,829.24
9	Total Sales (Schedule 3, Line C)	(-)		334,089,359
10	Kentucky Jurisdictional Sales	(÷)		334,089,359
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	3,994,829.24
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	3,994,829.24

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: March 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,885,984.78
Oil Burned	(+)		154,732.62
Gas Burned	(+)		312,250.00
Net Fuel Related RTO Billing Line Items	(-)		63,094.80
Fuel (assigned cost during Forced Outage[a])	(+)		-
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	7,289,872.60
B. Purchases			
Economy Purchases	(+)	$	3,484,268.43
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	3,484,268.43
C. Non-Native Sales Fuel Costs	(-)	$	471,414.74
D. Total Fuel Costs (A + B - C)		$	10,302,726.29
E. Total Fuel Costs Previously Reported	(-)		$9,851,818.07
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	450,908.22

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	Updated in Exp Month: Month Year	Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[(a)])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **August 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 13,284,687.97		
2	Sales S_m (Schedule 3, Line C)	÷	332,721,066		0.039927
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.014526

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: August 2022

		Dollars ($)	2021 September Schedule 6 Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 6 Dollars ($)	2022 January Schedule 6 Dollars ($)	2022 February Schedule 6 Dollars ($)	2022 March Schedule 6 Dollars ($)	2022 April Schedule 4 Dollars ($)	2022 May Schedule 4 Dollars ($)	2022 June Schedule 4 Dollars ($)	2022 July Schedule 2 Dollars ($)	2022 August Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,315,315.11	842,768.00	(326,122.67)	0.00	1,055,995.12	7,476,852.69	6,414,479.82	6,885,984.78	4,444,351.24	6,032,691.48	8,522,736.84	7,226,973.11	3,207,070.88
Oil Burned	(+)	276,669.82	176,644.74	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51	128,605.31	363,894.41
Gas Burned	(+)	571,299.48	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50	893,000.00	2,102,900.00	1,206,684.00
Net Fuel Related RTO Billing Line Items	(-)	(61,146.59)	(76,866.82)	34,899.08	433,172.73	(206,177.84)	(591,448.66)	(488,166.83)	63,094.80	(330,817.67)	(585,432.98)	830,446.78	234,769.08	(51,230.70)
Fuel (assigned cost during Forced Outage[a])	(+)	298,260.49	1,060,259.05	0.00	0.00	123,617.55	11,241.72	271,590.96	0.00	0.00	959,488.20	358,737.70	469,296.58	324,894.14
Fuel (substitute cost during Forced Outage[a])	(-)	43,642.28	3,681.48	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00	0.00	62,290.34	396,717.32	56,047.55
Sub-Total		$ 5,479,049.20	2,301,657.13	(69,421.75)	186,180.03	1,827,625.96	9,715,877.03	7,566,662.46	7,289,872.60	5,249,888.58	8,162,099.30	9,124,133.93	9,296,288.60	5,097,726.58
B. Purchases														
Economy Purchases	(+)	$ 11,415,923.41	13,871,945.59	15,200,280.60	18,385,750.28	16,480,073.26	2,806,649.29	4,128,979.51	3,484,268.43	9,522,658.64	7,587,761.09	4,801,436.83	12,169,879.82	28,551,397.54
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	798,494.24	1,782,944.50	0.00	0.00	190,400.08	27,556.86	649,303.60	0.00	0.00	3,044,032.32	1,212,553.95	1,484,515.40	1,190,624.11
Less purchases above highest cost units	(-)	528.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,336.76	0.00	0.00
Sub-Total		$ 10,616,901.11	12,089,001.09	15,200,280.60	18,385,750.28	16,289,673.18	2,779,092.43	3,479,675.91	3,484,268.43	9,522,658.64	4,543,728.77	3,582,546.12	10,685,364.42	27,360,773.43
C. Non-Native Sales Fuel Costs	(-)	$ 430,980.99	94,083.47	(30,407.30)	0.00	35,172.90	1,285,864.43	332,288.61	471,414.74	515,503.69	789,751.59	815,279.32	558,011.84	304,808.60
D. Total Fuel Costs (A + B - C)	(+)	$ 15,664,969.32	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,257,043.53	$11,916,076.48	$11,891,400.73	$19,423,641.18	$32,153,691.41
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 1,749,736.40												
F. Adjustment indicating the difference in actual fuel cost for the month of July 2022 and the estimated cost orginally reported $18,880,363.52 (actual) - $19,423,641.18 (estimate)	(+)	($543,277.66)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (87,267.29)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 13,284,687.97	$14,296,574.75	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,257,043.53	$11,916,076.48	$11,891,400.73	$19,423,641.18	$32,153,691.41

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: August 2022

		kWh	2021 September kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh	2022 June kWh	2022 July kWh	2022 August kWh
A. Generation (Net)	(+)	189,607,558	62,622,000	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000	369,741,500	306,513,000	125,951,000
Purchases Including Interchange-In	(+)	175,543,367	289,604,930	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770	42,561,250	131,990,110	292,215,300
Sub-Total		365,150,925	352,226,930	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770	412,302,750	438,503,110	418,166,300
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	11,969,000	5,569,430	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370	24,849,720	7,529,830	4,015,020
System Losses [(a)]	(+)	20,460,860	16,639,560	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707	26,346,806	39,649,542	30,233,043
Sub-Total		32,429,860	22,208,990	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077	51,196,526	47,179,372	34,248,063
C. Total Sales (A - B)		332,721,066	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693	361,106,224	391,323,738	383,918,237

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: July 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	7,226,972.27
Oil Burned	(+)	128,605.31
Gas Burned	(+)	2,102,900.00
Net Fuel Related RTO Billing Line Items	(-)	371,897.07
Fuel (assigned cost during Forced Outage[a])	(+)	471,852.06
Fuel (substitute cost during Forced Outage[a])	(-)	346,958.19
Sub-Total		9,211,474.38
B. Purchases		
Economy Purchases	(+)	11,706,005.62
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	1,488,752.80
Less purchases above highest cost units	(-)	0.00
Sub-Total		10,217,252.82
C. Non-Native Sales Fuel Costs	(-)	548,363.68
D. Total Fuel Costs (A + B - C)		$18,880,363.52

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: June 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.019510
2	Retail kWh Billed at Above Rate	(x)		423,604,980
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	8,264,533.16
4	kWh Used to Determine Last FAC Rate Billed	(+)		333,920,900
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			333,920,900
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	6,514,796.76
8	Over or (Under) (Line 3 - Line 7)		$	1,749,736.40
9	Total Sales (Schedule 3, Line C)	(-)		332,721,066
10	Kentucky Jurisdictional Sales	(÷)		332,721,066
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	1,749,736.40
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	1,749,736.40

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: April 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	4,444,351.24
Oil Burned	(+)		184,625.12
Gas Burned	(+)		290,094.55
Net Fuel Related RTO Billing Line Items	(-)		(328,746.53)
Fuel (assigned cost during Forced Outage[a])	(+)		-
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	5,247,817.44
B. Purchases			
Economy Purchases	(+)	$	9,444,577.17
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	9,444,577.17
C. Non-Native Sales Fuel Costs	(-)	$	522,618.37
D. Total Fuel Costs (A + B - C)		$	14,169,776.24
E. Total Fuel Costs Previously Reported	(-)		$14,257,043.53
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(87,267.29)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **September 2022**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 15,369,378.44		
2	Sales S_m (Schedule 3, Line C)	÷	331,984,336		0.046295
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.020894

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: September 2022

		Dollars ($)	2021 October Schedule 6 Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 6 Dollars ($)	2022 January Schedule 6 Dollars ($)	2022 February Schedule 6 Dollars ($)	2022 March Schedule 6 Dollars ($)	2022 April Schedule 6 Dollars ($)	2022 May Schedule 4 Dollars ($)	2022 June Schedule 4 Dollars ($)	2022 July Schedule 4 Dollars ($)	2022 August Schedule 2 Dollars ($)	2022 September Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,683,561.72	(326,122.67)	0.00	1,055,995.12	7,476,852.69	6,414,479.82	6,885,984.78	4,444,351.24	6,032,691.48	8,522,736.84	7,226,972.27	3,207,070.88	5,261,728.21
Oil Burned	(+)	300,899.93	0.00	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51	128,605.31	363,894.41	467,406.17
Gas Burned	(+)	576,786.98	291,600.00	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50	893,000.00	2,102,900.00	1,206,684.00	214,650.00
Net Fuel Related RTO Billing Line Items	(-)	(64,741.39)	34,899.08	433,172.73	(206,177.84)	(591,448.66)	(488,166.83)	63,094.80	(328,746.53)	(585,432.98)	830,446.78	371,897.07	(51,230.70)	(259,203.65)
Fuel (assigned cost during Forced Outage[a])	(+)	213,564.27	0.00	0.00	123,617.55	11,241.72	271,590.96	0.00	0.00	959,488.20	358,737.70	471,852.06	324,894.14	41,348.89
Fuel (substitute cost during Forced Outage[a])	(-)	39,188.89	0.00	0.00	0.00	0.00	4,970.62	0.00	0.00	0.00	62,290.34	346,958.19	56,047.55	0.00
Sub-Total		$ 5,800,365.41	(69,421.75)	186,180.03	1,827,625.96	9,715,877.03	7,566,662.46	7,289,872.60	5,247,817.44	8,162,099.30	9,124,133.93	9,211,474.38	5,097,726.58	6,244,336.92
B. Purchases														
Economy Purchases	(+)	$ 11,401,444.33	15,200,280.60	18,385,750.28	16,480,073.26	2,806,649.29	4,128,979.51	3,484,268.43	9,444,577.17	7,587,761.09	4,801,436.83	11,706,005.62	28,551,397.54	14,240,152.39
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	660,892.76	0.00	0.00	190,400.08	27,556.86	649,303.60	0.00	0.00	3,044,032.32	1,212,553.95	1,488,752.80	1,190,624.11	127,489.35
Less purchases above highest cost units	(-)	528.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,336.76	0.00	0.00	0.00
Sub-Total		$ 10,740,023.52	15,200,280.60	18,385,750.28	16,289,673.18	2,779,092.43	3,479,675.91	3,484,268.43	9,444,577.17	4,543,728.77	3,582,546.12	10,217,252.82	27,360,773.43	14,112,663.04
C. Non-Native Sales Fuel Costs	(-)	$ 442,711.99	(30,407.30)	0.00	35,172.90	1,285,864.43	332,288.61	471,414.74	522,618.37	789,751.59	815,279.32	548,363.68	304,808.60	237,388.90
D. Total Fuel Costs (A + B - C)	(+)	$ 16,097,676.94	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,169,776.24	$11,916,076.48	$11,891,400.73	$18,880,363.52	$32,153,691.41	$20,119,611.06
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 252,596.37												
F. Adjustment indicating the difference in actual fuel cost for the month of August 2022 and the estimated cost orginally reported $31,770,826.66 (actual) - $32,153,691.41 (estimate)	(+)	($382,864.75)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (92,837.37)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 15,369,378.44	$15,161,266.15	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,169,776.24	$11,916,076.48	$11,891,400.73	$18,880,363.52	$32,153,691.41	$20,119,611.06

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: September 2022

		kWh	2021 October kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh	2022 June kWh	2022 July kWh	2022 August kWh	2022 September kWh
A. Generation (Net)	(+)	198,643,058	1,198,000	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000	369,741,500	306,513,000	125,951,000	171,048,000
Purchases Including Interchange-In	(+)	166,323,583	310,543,560	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770	42,561,250	131,990,110	292,215,300	178,967,520
Sub-Total		364,966,641	311,741,560	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770	412,302,750	438,503,110	418,166,300	350,015,520
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	12,047,423	-	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370	24,849,720	7,529,830	4,015,020	6,510,510
System Losses [(a)]	(+)	20,934,882	14,340,112	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707	26,346,806	39,649,542	30,233,043	22,327,826
Sub-Total		32,982,305	14,340,112	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077	51,196,526	47,179,372	34,248,063	28,838,336
C. Total Sales (A - B)		331,984,336	297,401,448	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693	361,106,224	391,323,738	383,918,237	321,177,184

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: August 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	3,207,071.35
Oil Burned	(+)	363,894.41
Gas Burned	(+)	1,206,684.00
Net Fuel Related RTO Billing Line Items	(-)	366,083.23
Fuel (assigned cost during Forced Outage[(a)])	(+)	324,894.14
Fuel (substitute cost during Forced Outage[(a)])	(-)	42,787.80
Sub-Total		4,693,672.87
B. Purchases		
Economy Purchases	(+)	28,564,509.77
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	1,190,624.11
Less purchases above highest cost units	(-)	0.00
Sub-Total		27,373,885.66
C. Non-Native Sales Fuel Costs	(-)	296,731.87
D. Total Fuel Costs (A + B - C)		$31,770,826.66

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: July 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.004923
2	Retail kWh Billed at Above Rate	(x)		385,398,799
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	1,897,318.29
4	kWh Used to Determine Last FAC Rate Billed	(+)		334,089,359
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			334,089,359
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	1,644,721.92
8	Over or (Under) (Line 3 - Line 7)		$	252,596.37
9	Total Sales (Schedule 3, Line C)	(-)		331,984,336
10	Kentucky Jurisdictional Sales	(÷)		331,984,336
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	252,596.37
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	252,596.37

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: May 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	6,032,691.47
Oil Burned	(+)		584,268.14
Gas Burned	(+)		218.50
Net Fuel Related RTO Billing Line Items	(-)		(589,284.53)
Fuel (assigned cost during Forced Outage[(a)])	(+)		953,898.36
Fuel (substitute cost during Forced Outage[(a)])	(-)		56.42
Sub-Total		$	8,160,304.58
B. Purchases			
Economy Purchases	(+)	$	7,504,981.11
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[(a)])	(-)		3,029,095.63
Less purchases above highest cost units	(-)		-
Sub-Total		$	4,475,885.48
C. Non-Native Sales Fuel Costs	(-)	$	812,950.95
D. Total Fuel Costs (A + B - C)		$	11,823,239.11
E. Total Fuel Costs Previously Reported	(-)		$11,916,076.48
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(92,837.37)

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average Expense Month: **October 2022**

Line No.	Description		Amount	Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ 16,673,049.58	
2	Sales S_m (Schedule 3, Line C)	÷	329,352,393	0.050624
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057		(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)			0.025223

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average Expense Month: October 2022

		Dollars ($)	2021 November Schedule 6 Dollars ($)	2021 December Schedule 6 Dollars ($)	2022 January Schedule 6 Dollars ($)	2022 February Schedule 6 Dollars ($)	2022 March Schedule 6 Dollars ($)	2022 April Schedule 6 Dollars ($)	2022 May Schedule 6 Dollars ($)	2022 June Schedule 4 Dollars ($)	2022 July Schedule 4 Dollars ($)	2022 August Schedule 4 Dollars ($)	2022 September Schedule 2 Dollars ($)	2022 October Schedule 2 Dollars ($)
A. Company Generation														
Coal Burned	(+)	$ 4,710,738.65	0.00	1,055,995.12	7,476,852.69	6,414,479.82	6,885,984.78	4,444,351.24	6,032,691.47	8,522,736.84	7,226,972.27	3,207,071.35	5,261,728.21	0.00
Oil Burned	(+)	309,693.02	89,049.96	454,576.85	569,348.65	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51	128,605.31	363,894.41	467,406.17	105,516.98
Gas Burned	(+)	588,141.15	530,302.80	(12,741.40)	1,066,985.31	25,500.00	312,250.00	290,094.55	218.50	893,000.00	2,102,900.00	1,206,684.00	214,650.00	427,850.00
Net Fuel Related RTO Billing Line Items	(-)	32,191.88	433,172.73	(206,177.84)	(591,448.66)	(488,166.83)	63,094.80	(328,746.53)	(589,284.53)	830,446.78	371,897.07	366,083.23	(259,203.65)	784,636.04
Fuel (assigned cost during Forced Outage[(a)])	(+)	213,098.45	0.00	123,617.55	11,241.72	271,590.96	0.00	0.00	953,898.36	358,737.70	471,852.06	324,894.14	41,348.89	0.00
Fuel (substitute cost during Forced Outage[(a)])	(-)	38,088.61	0.00	0.00	0.00	4,970.62	0.00	0.00	56.42	62,290.34	346,958.19	42,787.80	0.00	0.00
Sub-Total		$ 5,751,390.76	186,180.03	1,827,625.96	9,715,877.03	7,566,662.46	7,289,872.60	5,247,817.44	8,160,304.58	9,124,133.93	9,211,474.38	4,693,672.87	6,244,336.92	(251,269.06)
B. Purchases														
Economy Purchases	(+)	$ 11,569,322.71	18,385,750.28	16,480,073.26	2,806,649.29	4,128,979.51	3,484,268.43	9,444,577.17	7,504,981.11	4,801,436.83	11,706,005.62	28,564,509.77	14,240,152.39	17,284,488.91
Other Purchases	(+)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	659,648.03	0.00	190,400.08	27,556.86	649,303.60	0.00	0.00	3,029,095.63	1,212,553.95	1,488,752.80	1,190,624.11	127,489.35	0.00
Less purchases above highest cost units	(-)	528.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,336.76	0.00	0.00	0.00	0.00
Sub-Total		$ 10,909,146.62	18,385,750.28	16,289,673.18	2,779,092.43	3,479,675.91	3,484,268.43	9,444,577.17	4,475,885.48	3,582,546.12	10,217,252.82	27,373,885.66	14,112,663.04	17,284,488.91
C. Non-Native Sales Fuel Costs	(-)	$ 453,512.92	0.00	35,172.90	1,285,864.43	332,288.61	471,414.74	522,618.37	812,950.95	815,279.32	548,363.68	296,731.87	237,388.90	84,081.27
D. Total Fuel Costs (A + B - C)	(+)	$ 16,207,024.46	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,169,776.24	$11,823,239.11	$11,891,400.73	$18,880,363.52	$31,770,826.66	$20,119,611.06	$16,949,138.58
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (1,059,244.60)												
F. Adjustment indicating the difference in actual fuel cost for the month of September 2022 and the estimated cost orginally reported $20,106,481.68 - $20,119,611.06 (actual) (estimate)	(+)	($13,129.37)												
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (580,090.11)												
H. Prior Period Correction	(+)	$ -												
I. Deferral of Current Purchased Power Costs	(-)	$ -												
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -												
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 16,673,049.58	$18,571,930.31	$18,082,126.24	$11,209,105.03	$10,714,049.76	$10,302,726.29	$14,169,776.24	$11,823,239.11	$11,891,400.73	$18,880,363.52	$31,770,826.66	$20,119,611.06	$16,949,138.58

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average Expense Month: October 2022

		kWh	2021 November kWh	2021 December kWh	2022 January kWh	2022 February kWh	2022 March kWh	2022 April kWh	2022 May kWh	2022 June kWh	2022 July kWh	2022 August kWh	2022 September kWh	2022 October kWh
A. Generation (Net)	(+)	199,138,808	7,944,000	31,128,900	355,827,000	272,467,500	282,677,800	177,365,000	281,855,000	369,741,500	306,513,000	125,951,000	171,048,000	7,147,000
Purchases Including Interchange-In	(+)	163,416,087	305,752,619	304,669,964	59,046,028	77,618,700	62,007,070	136,902,100	93,608,770	42,561,250	131,990,110	292,215,300	178,967,520	275,653,610
Sub-Total		362,554,895	313,696,619	335,798,864	414,873,028	350,086,200	344,684,870	314,267,100	375,463,770	412,302,750	438,503,110	418,166,300	350,015,520	282,800,610
B. Pumped Storage Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Native Sales Including Interchange Out	(+)	12,123,673	-	1,048,300	19,619,560	15,867,250	16,088,530	12,588,990	36,451,370	24,849,720	7,529,830	4,015,020	6,510,510	915,000
System Losses [(a)]	(+)	21,078,829	13,802,651	15,733,277	19,367,420	17,045,166	16,758,413	16,290,618	19,323,707	26,346,806	39,649,542	30,233,043	22,327,826	16,067,480
Sub-Total		33,202,502	13,802,651	16,781,577	38,986,980	32,912,416	32,846,943	28,879,608	55,775,077	51,196,526	47,179,372	34,248,063	28,838,336	16,982,480
C. Total Sales (A - B)		329,352,393	299,893,968	319,017,287	375,886,048	317,173,784	311,837,927	285,387,492	319,688,693	361,106,224	391,323,738	383,918,237	321,177,184	265,818,130

Note: [(a)] Average of prior 12 months.

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Expense Month: September 2022

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	5,261,728.92
Oil Burned	(+)	467,406.17
Gas Burned	(+)	214,650.00
Net Fuel Related RTO Billing Line Items	(-)	(163,765.93)
Fuel (assigned cost during Forced Outage[a])	(+)	10,000.25
Fuel (substitute cost during Forced Outage[a])	(-)	0.00
Sub-Total		6,117,551.27
B. Purchases		
Economy Purchases	(+)	14,264,370.09
Other Purchases	(+)	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	36,136.70
Less purchases above highest cost units	(-)	0.00
Sub-Total		14,228,233.39
C. Non-Native Sales Fuel Costs	(-)	239,302.98
D. Total Fuel Costs (A + B - C)		$20,106,481.68

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month: August 2022

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.014526
2	Retail kWh Billed at Above Rate	(x)		259,800,468
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	3,773,861.60
4	kWh Used to Determine Last FAC Rate Billed	(+)		332,721,066
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			332,721,066
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	4,833,106.20
8	Over or (Under) (Line 3 - Line 7)		$	(1,059,244.60)
9	Total Sales (Schedule 3, Line C)	(-)		329,352,393
10	Kentucky Jurisdictional Sales	(÷)		329,352,393
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			1.00000
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	(1,059,244.60)
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	(1,059,244.60)

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Expense Month: June 2022

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	8,522,736.85
Oil Burned	(+)		242,396.51
Gas Burned	(+)		893,000.00
Net Fuel Related RTO Billing Line Items	(-)		729,656.84
Fuel (assigned cost during Forced Outage[a])	(+)		362,992.49
Fuel (substitute cost during Forced Outage[a])	(-)		62,290.34
Sub-Total		$	9,229,178.67
B. Purchases			
Economy Purchases	(+)	$	4,229,451.10
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		1,209,768.10
Less purchases above highest cost units	(-)		5,918.65
Sub-Total		$	3,013,764.35
C. Non-Native Sales Fuel Costs	(-)	$	931,632.40
D. Total Fuel Costs (A + B - C)		$	11,311,310.62
E. Total Fuel Costs Previously Reported	(-)		$11,891,400.73
F. Prior Period Adjustment	(+)	$	-
G. Adjustment due to PJM Resettlements		$	(580,090.11)

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE

Expense Month: Month Year

		Original	Revised	Adjustment
		Exp Month: Month Year	**Updated in Exp Month: Month Year**	**Dollars ($)**
A. Company Generation				
Coal Burned	(+)	$ -	$ -	$ -
Oil Burned	(+)	-	-	-
Gas Burned	(+)	-	-	-
Net Fuel Related RTO Billing Line Items	(-)	-	-	-
Fuel (assigned cost during Forced Outage(a))	(+)	-	-	-
Fuel (substitute cost during Forced Outage(a))	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
B. Purchases				
Economy Purchases	(+)	$ -	$ -	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ -	$ -	$ -
C. Non-Native Sales Fuel Costs		$ -	$ -	$ -
D. Total Fuel Costs (A + B - C)		$ -	$ -	$ -
E. Total Fuel Costs Previously Reported		$ -	$ -	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ -	$ -	$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-005

REQUEST:

Refer to the Direct Testimony of Sarah E. Lawler, page 14, lines 19–23.

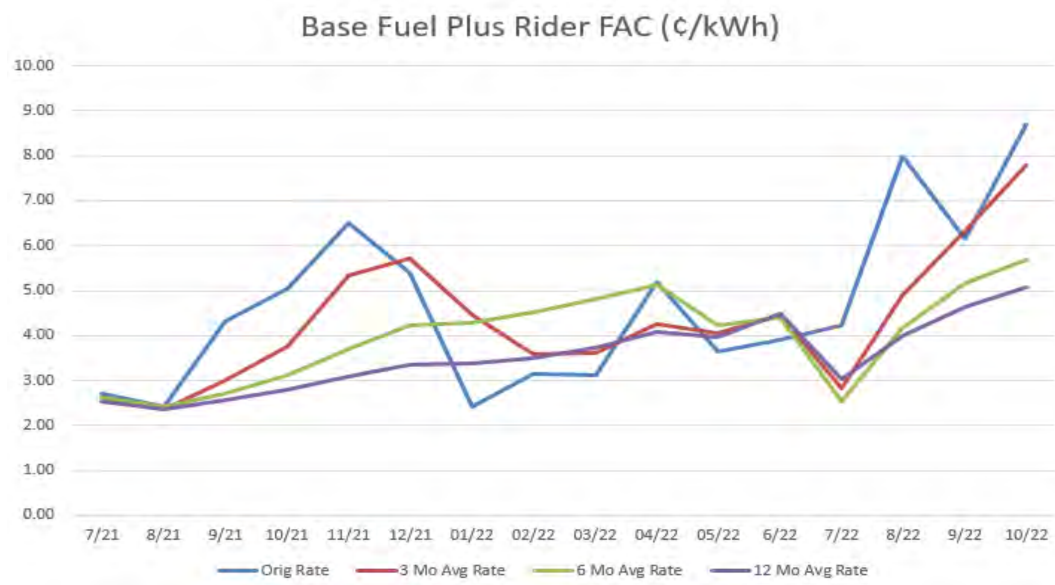
a. Explain why Duke Kentucky chose to propose a 12-month average for the FAC instead of a three or six-month average.

b. Also, refer to the Direct Testimony of Sarah E. Lawler, page 15, illustration. Provide an updated illustration of how Duke Kentucky's FAC rate would look like compared to the monthly FAC rate if Duke Kentucky were to use a three-month average and a six-month average.

RESPONSE:

a. Duke Energy Kentucky proposed a 12-month rolling average for the FAC instead of a three- or six-month rolling average to try to mitigate volatility. The longer the time frame the less impact a one month swing will have on the overall FAC rate. As the chart below shows the 3-month rolling average has more spikes in price than the 6-month rollings average and the 12-month rolling average has less spikes than the 6-month rolling average.

b. Please see the chart below comparing the original FAC rate to a 3-month, 6-month, and 12-month rolling average:



PERSON RESPONSIBLE: Sarah E. Lawler

STAFF-DR-04-006

REQUEST:

Refer to the Direct Testimony of Sarah E. Lawler, page 15, lines 3–8.

a. Explain what deferral accounting authority from the Commission Duke Kentucky currently has in regards to its FAC.

b. Explain in detail how changing the FAC rate from a monthly calculation to a 12-month average calculation would not change Duke Kentucky's current deferral accounting in regards to its FAC.

RESPONSE:

a. Under normal generally accepted accounting principles (GAAP), Accounting Standards Codification 980 (ASC 980), amounts incurred as an expense but to be recovered soon thereafter are deferred. 807 KAR 5:056, Kentucky's FAC regulations, authorizes the recovery of the fuel costs incurred to be recovered in future periods. The regulation states that "fuel costs (F) shall be the most recent actual monthly cost." A historical cost is not known until the future so must be recovered in future periods. As such ASC 980 applies. This has been the practice for accounting of the Rider FAC since its inception.

b. This normal accrual accounting would still be followed regardless of how the balance is calculated.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-007

REQUEST:

Refer to the Direct Testimony of Sarah E. Lawler, page 17, lines 1–4. Explain how Duke Kentucky would track recovery of its fuel related expenses through the proposed twelve-month average FAC rate calculation to ensure that Duke Kentucky is not under or over recovering from its customers.

RESPONSE:

The actual costs are deferred on the books no differently than they are today. The revenue recovery that gets applied monthly to that deferral balance is just being calculated differently to smooth recovery in customer bills. This could lead to a larger or smaller deferral balance at any given month as to compared to what the deferral balance would be in today's recovery methodology.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-008

REQUEST:

Refer to the Direct Testimony of Bruce L. Sailers, page 26, lines 17–19. Explain why Duke Kentucky is proposing to fold the Brownfield Redevelopment Program into Rider DIR, Development Incentive Rider.

RESPONSE:

The Company proposes to consolidate to a single tariff sheet given the similarities of the programs and reduced tariff sheet administration.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-04-009

REQUEST:

Refer to Duke Kentucky's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 59. For each account, provide a comparison of depreciation expense using the existing and proposed depreciation rates.

RESPONSE:

The attached schedule, STAFF-DR-04-009 Attachment, sets forth the expense calculated using the currently approved depreciation rates and the proposed depreciation rates from the 2021 Depreciation Study.

PERSON RESPONSIBLE: John J. Spanos
Huyen C. Dang

DUKE ENERGY KENTUCKY

COMPARISON OF ANNUAL DEPRECIATION ACCRUALS USING CURRENT AND PROPOSED RATES AS OF DECEMBER 31, 2021

		ORIGINAL COST AS OF	CURRENT ANNUAL ACCRUAL		PROPOSED ANNUAL ACCRUAL		
	ACCOUNT	DECEMBER 31, 2021	AMOUNT	RATE	AMOUNT	RATE	DIFFERENCE
	(1)	(2)	(3)=(2)*(4)	(4)	(5)	(6)=(5)/(2)	(7)=(5)-(3)
	COMMON PLANT						
1900	STRUCTURES AND IMPROVEMENTS						
	ERLANGER OPERATIONS CENTER	4,528,568.63	43,927	0.97	128,268	2.83	84,341
	KENTUCKY SERVICE BUILDING - 19TH AND AUGUSTINE	9,151,984.16	37,523	0.41	492,900	5.39	455,377
	MINOR STRUCTURES	123,818.00	2,650	2.14	3,184	2.57	534
	TOTAL STRUCTURES AND IMPROVEMENTS	13,804,370.79	84,100		624,352		540,252
1910	OFFICE FURNITURE AND EQUIPMENT	788,868.79	39,443	5.00	39,443	5.00	(0)
1911	ELECTRONIC DATA PROCESSING	5,177.15	1,035	20.00	518	10.01	(517)
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	113,849.90	4,554	4.00	4,555	4.00	1
1970	COMMUNICATION EQUIPMENT	6,414,002.97	427,814	6.67	427,921	6.67	107
1980	MISCELLANEOUS EQUIPMENT	95,300.80	6,357	6.67	6,353	6.67	(4)
	TOTAL COMMON PLANT	**21,221,570.40**	**563,303**		**1,103,142**		**539,839**
	STEAM PRODUCTION PLANT						
3110	STRUCTURES AND IMPROVEMENTS	183,717,638.42	4,537,826	2.47	11,576,821	6.30	7,038,995
3120	BOILER PLANT EQUIPMENT	545,368,156.24	12,216,247	2.24	23,609,292	4.33	11,393,045
3123	BOILER PLANT EQUIPMENT - SCR CATALYST	7,984,157.58	364,078	4.56	472,160	5.91	108,082
3140	TURBOGENERATOR UNITS	109,285,792.05	2,579,145	2.36	4,954,311	4.53	2,375,166
3150	ACCESSORY ELECTRIC EQUIPMENT	48,173,349.90	1,079,083	2.24	1,442,046	2.99	362,963
3160	MISCELLANEOUS POWER PLANT EQUIPMENT	23,997,105.75	760,708	3.17	1,171,041	4.88	410,333
	TOTAL STEAM PRODUCTION PLANT	**918,526,199.94**	**21,537,086**		**43,225,671**		**21,688,585**
	OTHER PRODUCTION PLANT						
3410	STRUCTURES AND IMPROVEMENTS	36,379,260.23	916,757	2.52	645,377	1.77	(271,380)
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	61,310,889.91	1,305,922	2.13	3,347,024	5.46	2,041,102
3430	PRIME MOVERS	10,340,709.70	0	N/A	635,081	6.14	635,081
3440	GENERATORS	211,248,425.04	7,097,947	3.36	5,985,695	2.83	(1,112,252)
3446	GENERATORS - SOLAR						
	CRITTENDEN	4,143,038.53	195,551	4.72	214,222	5.17	18,671
	WALTON	5,670,767.07	267,660	4.72	293,216	5.17	25,556
	TOTAL GENERATORS - SOLAR	9,813,805.60	463,212		507,438		44,226
3450	ACCESSORY ELECTRIC EQUIPMENT	19,858,901.69	758,610	3.82	642,291	3.23	(116,319)
3456	ACCESSORY ELECTRIC EQUIPMENT - SOLAR						
	CRITTENDEN	637,652.33	28,312	4.44	34,811	5.46	6,499
	WALTON	979,306.42	43,481	4.44	53,462	5.46	9,981
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR	1,616,958.75	71,793		88,273		16,480
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	5,152,109.78	191,143	3.71	135,197	2.62	(55,946)
	TOTAL OTHER PRODUCTION PLANT	**355,721,060.70**	**10,805,384**		**11,986,376**		**1,180,992**
	TRANSMISSION PLANT						
3501	RIGHTS OF WAY	1,333,532.32	16,936	1.27	12,417	0.93	(4,519)
3520	STRUCTURES AND IMPROVEMENTS	5,985,540.28	117,317	1.96	101,410	1.69	(15,907)
3530	STATION EQUIPMENT	29,941,037.25	646,726	2.16	692,521	2.31	45,795
3531	STATION EQUIPMENT - STEP UP	9,373,633.98	192,160	2.05	236,594	2.52	44,435
3532	STATION EQUIPMENT - MAJOR	11,448,790.49	198,064	1.73	204,290	1.78	6,226
3534	STATION EQUIPMENT - STEP UP EQUIPMENT	7,672,013.50	316,854	4.13	219,899	2.87	(96,955)
3550	POLES AND FIXTURES	15,265,498.48	268,673	1.76	392,346	2.57	123,673
3560	OVERHEAD CONDUCTORS AND DEVICES	11,048,347.48	211,023	1.91	231,320	2.09	20,297
3561	OVERHEAD CONDUCTORS AND DEVICES - CLEARING AND RIGHT OF WAY	1,841,852.59	32,048	1.74	28,365	1.54	(3,683)
	TOTAL TRANSMISSION PLANT	**93,910,246.37**	**1,999,801**		**2,119,162**		**119,361**
	DISTRIBUTION PLANT						
3601	RIGHTS OF WAY	4,497,571.31	46,325	1.03	31,113	0.69	(15,212)
3610	STRUCTURES AND IMPROVEMENTS	1,420,206.00	32,097	2.26	26,676	1.88	(5,421)
3620	STATION EQUIPMENT	74,309,691.33	1,746,278	2.35	2,908,569	3.91	1,162,291
3622	STATION EQUIPMENT - MAJOR	42,685,560.46	678,700	1.59	739,611	1.73	60,911
3640	POLES, TOWERS AND FIXTURES	74,482,036.53	1,556,675	2.09	1,770,540	2.38	213,865
3650	OVERHEAD CONDUCTORS AND DEVICES	144,890,225.86	3,100,651	2.14	3,640,144	2.51	539,493
3651	OVERHEAD CONDUCTORS AND DEVICES - CLEARING AND RIGHT OF WAY	7,177,611.92	118,431	1.65	107,441	1.50	(10,990)
3660	UNDERGROUND CONDUIT	43,372,544.85	780,706	1.80	694,427	1.60	(86,279)
3670	UNDERGROUND CONDUCTORS AND DEVICES	81,870,581.37	1,694,721	2.07	2,074,660	2.53	379,939
3680	LINE TRANSFORMERS	73,741,779.67	1,238,862	1.68	1,498,764	2.03	259,902
3682	LINE TRANSFORMERS - CUSTOMER	273,660.52	848	0.31	1,453	0.53	605
3691	SERVICES - UNDERGROUND	2,765,626.10	51,717	1.87	54,614	1.97	2,897
3692	SERVICES - OVERHEAD	19,464,620.52	235,522	1.21	330,957	1.70	95,435
3700	METERS AND METERING EQUIPMENT	2,620,523.38	165,617	6.32	120,438	4.60	(45,179)
3702	UoF METERS	25,906,841.19	1,774,619	6.85	1,586,353	6.12	(188,266)
3711	INSTALLATIONS ON CUSTOMERS' PREMISES - AREA LIGHTING	1,051.24	0	N/A	48	4.57	48
3712	COMPANY-OWNED OUTDOOR LIGHTING	861,284.30	45,304	5.26	92,852	10.78	47,548
3720	LEASED PROPERTY ON CUSTOMERS' PREMISES	9,647.36	0	-	0	-	0
3731	STREET LIGHTING - OVERHEAD	2,507,459.22	18,304	0.73	31,453	1.25	13,149
3732	STREET LIGHTING - BOULEVARD	3,368,422.54	39,747	1.18	37,692	1.12	(2,055)
3733	STREET LIGHTING - CUSTOMER POLES	3,858,522.09	103,023	2.67	162,629	4.21	59,606
	TOTAL DISTRIBUTION PLANT	**610,085,467.76**	**13,428,146**		**15,910,434**		**2,482,288**

DUKE ENERGY KENTUCKY

COMPARISON OF ANNUAL DEPRECIATION ACCRUALS USING CURRENT AND PROPOSED RATES AS OF DECEMBER 31, 2021

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2021	CURRENT ANNUAL ACCRUAL AMOUNT	CURRENT ANNUAL ACCRUAL RATE	PROPOSED ANNUAL ACCRUAL AMOUNT	PROPOSED ANNUAL ACCRUAL RATE	DIFFERENCE
	(1)	(2)	(3)=(2)*(4)	(4)	(5)	(6)=(5)/(2)	(7)=(5)-(3)
	GENERAL PLANT						
3900	STRUCTURES AND IMPROVEMENTS	165,341.66	5,622	3.40	5,505	3.33	(117)
3910	OFFICE FURNITURE AND EQUIPMENT	374,028.27	18,701	5.00	18,699	5.00	(2)
3911	ELECTRONIC DATA PROCESSING	2,793,949.44	558,790	20.00	558,763	20.00	(27)
3920	TRANSPORTATION EQUIPMENT	1,059,153.65	90,664	8.56	65,691	6.20	(24,973)
3921	TRANSPORTATION EQUIPMENT - TRAILERS	272,066.39	10,447	3.84	5,253	1.93	(5,194)
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	3,161,672.92	126,467	4.00	126,327	4.00	(140)
3960	POWER OPERATED EQUIPMENT	11,770.00	793	6.74	492	4.18	(301)
3970	COMMUNICATION EQUIPMENT	9,004,323.97	600,588	6.67	600,577	6.67	(11)
	TOTAL GENERAL PLANT	**16,842,306.30**	**1,412,072**		**1,381,307**		**(30,765)**
	TOTAL COMMON AND ELECTRIC PLANT	**2,016,306,851.47**	**49,745,793**		**75,726,092**		**25,980,299**

STAFF-DR-04-010

REQUEST:

Refer to Duke Kentucky's response to Staff's Third Request, Item 16.

a. Provide the balance for land for East Bend and Woodsdale.

b. Explain whether Duke Kentucky proposes to include the value of land in the proposed Generating Asset True-Up Mechanism.

c. For the 2022 capital additions to East Bend, explain each specific project and provide the total plant in service additions.

RESPONSE:

a. The November 2022 land balance for East Bend is $7,036,025. The November 2022 land balance for Woodsdale is $2,258,588. These amounts are shown on STAFF DR-02-020 Attachment on the Calculation tab of the excel worksheet.

b. The Company does not plan to include the value of land in the proposed Rider GTM.

c. Please see STAFF-DR-04-010(c) Attachment.

PERSON RESPONSIBLE: Huyen C. Dang – a.
Sarah E. Lawler – b.
William C. Luke – c.

Duke Energy Kentucky
East Bend Plant Additions (excluding unitization*)
January 2022-December 2022

Asset Loc Long Desc PRD	Funding Project	Project CB	Project CB - Description	Amount
East Bend Unit 2	EB020350	EB020350X	EB020350X - UNDERGROUND FUEL OIL DAY TANK (EF)	37,467.08
East Bend Unit 2	EB020641	EB020641X	EB020641X - REPLACE STACK LADDER	217,849.21
East Bend Unit 2	EB020680	EB020680X	EB020680X - EVERGREEN UPGRADE	5,200,310.55
East Bend Unit 2	EB020701	EB020701X	EB020701X - LBU DUST MITIGATION	29,507.84
East Bend Unit 2	EB020818	EB020818X	EB020818X - FGD BIOCIDE SYSTEM H2S MITIGATION	303,128.92
East Bend Unit 2	EB020826	EB020826X	EB020826X - REPLACE FLAME SCANNERS & IGNITERS	7,705.36
East Bend Unit 2	EB020879	EB020879X	EB020879X - REPL 2-4 CT FAN BRKR ARC FLASH MITG	13,589.96
East Bend Unit 2	EB020890	EB020890X	EB020890X - GENERATOR STATOR REWIND	13,095,283.91
East Bend Unit 2	EB021162	EB021162X	EB021162X - ECONOMIZER EXPANSION JOINT	(18,214.85)
East Bend Unit 2	EB021199	EB021199X	EB021199X - WSP 2ST2 6.9KV TRANSFORMER REPL	205,686.50
East Bend Unit 2	EB021307	EB021307X	EB021307X - 2-6 PULV ROLL WHEEL REPL	85,909.41
East Bend Unit 2	EB021379	EB021379X	EB021379X - REPLACE GEN/GSU/UAT PROT RELAYS	(5,873.99)
East Bend Unit 2	EB021449	EB021449X	EB021449X - REPLACE A MODULE INLET EXP JOIN	51,286.12
East Bend Unit 2	EB021589	8SFYTOOLS	8SFYTOOLS - ENTP HIGH RISK TOOL - FHO DEK COAL	3,897.29
East Bend Unit 2	EB021598	EB021598X	EB021598X - LPA AND LPB L-2 BLADE REPLACEMENT	4,153,632.93
East Bend Unit 2	EB021688	EB021688X	EB021688X - SCR NOX ANALYZERS	854,544.73
East Bend Unit 2	EB021751	EB021751X	EB021751X - PHYSICAL LOCK PILOT	193,256.30
East Bend Unit 2	EB021752	EB021752X	EB021752X - TURBINE VENTILATING VALVE SV-2	93,794.45
East Bend Unit 2	EB021763	EB021763X	EB021763X - REPL SCR SONIC HORN AIR COMPRESSOR	18,043.63
East Bend Unit 2	EB021772	EB021772X	EB021772X - 2-2 PA OUTLET DAMPER CABLE REPLACE	12,956.11
East Bend Unit 2	EB021785	EB021785X	EB021785X - REPLACE IK SOOTBLOWER	74,059.14
East Bend Unit 2	EB021787	EB021787X	EB021787X - WSP CAKE TRANSFER CONVEYOR BELT REP	830.31
East Bend Unit 2	EB021789	EB021789X	EB021789X - 2021 CBU INSHORE LADDER HEAD SHAFT	(124.99)
East Bend Unit 2	EB021793	EB021793X	EB021793X - ORIENTATION TRAINING TRAILER HVAC	24,008.25
East Bend Unit 2	EB021794	EB021794X	EB021794X - 2-1 & 2-2 PA FAN SHAFTS	204,386.10
East Bend Unit 2	EB021799	EB021799X	EB021799X - 2A & 2C MODULE OUTLET EXP JNT	253,526.30
East Bend Unit 2	EB021813	EB021813X	EB021813X - MAIN OIL TANK EARTHEN BERM LINER	128,627.28
East Bend Unit 2	EB021815	EB021815X	EB021815X - MAIN & NEUTRAL FLEX LINK REPL	62,821.68
East Bend Unit 2	EB021823	EB021823X	EB021823X - GOVERNOR VALVE REPL 2021	267,394.51
East Bend Unit 2	EB021894	EB021894X	EB021894X - 2-2 PULVERIZER MOTOR REWIND	73,209.87
East Bend Unit 2	EB021895	EB021895X	EB021895X - 2-10 CT MOTOR AND GEARBOX REPLACEME	183,020.04
East Bend Unit 2	EB021910	EB021910X	EB021910X - PAH OUTLET EXPANSION JOINT	64,380.18
East Bend Unit 2	EB021928	EB021928X	EB021928X - TURBINE VENTILATING VALVE SV-1	104,704.01
East Bend Unit 2	EB021947	EB021947X	EB021947X - REPL WSP MIXER DISCHARGE BELT	34,907.05
East Bend Unit 2	EB021956	EB021956X	EB021956X - 2-1 WSP VACUUM PUMP REPLACEMENT	72,513.27
East Bend Unit 2	EB021960	EB021960X	EB021960X - SAH 2-1 BASKET REPLACEMENT	1,618,017.06
East Bend Unit 2	EB021966	EB021966X	EB021966X - WSP MIXER FEED CONVEYOR BELT	15,503.97
East Bend Unit 2	EB021968	EB021968X	EB021968X - 2-4 CT GEARBOX REPLACEMENT	229,454.77
East Bend Unit 2	EB021980	EB021980X	EB021980X - REPLACE 4 FIRE HYDRANTS	56,055.23
East Bend Unit 2	EB022000	EB022000X	EB022000X - 2-4 PULVERIZER MOTOR REWIND	69,100.69
East Bend Unit 2	EB022025	EB022025X	EB022025X - 2-2 FGD SERVICE WATER PUMP REWIND	22,108.58
East Bend Unit 2	EB022027	EB022027X	EB022027X - LBU HOPPER BELT & SKIRTING	57,864.02
East Bend Unit 2	EB022030	EB022030X	EB022030X - REPL 2-1 CONDENSATE TRANSFER PUMP	13,156.32
East Bend Unit 2	EB022031	EB022031X	EB022031X - 3R & 8R COAL NOZZLE REPLACEMENT	65,200.34
East Bend Unit 2	EB1912	CEBVLV21	CEBVLV21 - 2021 MISC VALVE BLANKET	26,608.34
East Bend Unit 2	EB1912	CEBVLV22	CEBVLV22 - 2022 MISC VALVE BLANKET	541,133.62
East Bend Unit 2	EB1922	CEB1922	CEB1922 - EBS-2 GENERAL EQUIPMENT	72,531.28
East Bend Unit 2	EBS01262	EBS01262X	EBS01262X - SAH 2-2 BASKET REPLACEMENT	2,366,051.48
East Bend Unit 2 - SCR	EB020863	EB020863X	EB020863X - SCR REPLACE 3RD LAYER CATALYST	1,721,465.99
East Bend Unit 2 - SCR	EB021161	EB021161X	EB021161X - SCR EXPANSION JOINTS	7,947.49
Grand Total				**32,984,223.64**

** Unitization is the process to finalize assets from Plant Inservice Unclassified (106)to Plant in Service-Classified (101)*

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-011

REQUEST:

Refer to Duke Kentucky's response to Staff's Third Request, Item 23, in which Duke Kentucky explains how it determines the cost a customer must pay for a change in installation when the primary distribution main line system is impacted. Provide the provision in Duke Kentucky's current tariff that allows it to charge a customer for the costs of changes to the primary distribution main line system when the customer is seeking only a change in their installation.

RESPONSE:

Changes in Installations are addressed in Sheet No. 22, Section III – Customer's Installations, item 4. The details of the Customer's payment responsibility are not in the tariff sheet but are addressed generally with the following, "Company as promptly as possible after receipt of such notice will give it's written approval to the proposed change or increase or will advise Customer upon what conditions service can be supplied for such change or increase." For many years, the Company has consistently applied the process previously described. The Company is agreeable to further revising Sheet No. 22 with additional detail as requested by the Commission.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-012

REQUEST:

Refer to Duke Kentucky's response to Staff's Third Request, Item 10(c), in which Duke Kentucky states that for changes or extensions greater than $1 million or greater than three times the estimated gross annual revenue, customers have the option of a minimum bill agreement or paying a contribution in aid of construction (CIAC) amount equal to the cost less the three-year estimated gross revenues. Explain why the option of paying a CIAC amount equal to the cost less the three-year estimated gross revenues is not included in the tariff.

RESPONSE:

The Company acknowledges that this option is only implied in the line extension tariff sheet by use of the phrase "…the customer *may* [emphasis added] be required to guarantee…". If requested by the Commission, the Company is agreeable to further revision of the line extension tariff sheet to document this option.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-013

REQUEST:

Beginning from May 2020 to the most recent available month, provide Duke Kentucky's monthly net income, equity balance, and earned ROE. Exclude from the monthly net income any expenses that were subsequently deferred to a regulatory asset.

RESPONSE:

Please see STAFF-DR-04-013 Attachment. The ROE is calculated on a trailing twelve-month net income amount. This amount has been adjusted for intercompany rents. Equity is based on a 13-month average. For this calculation monthly balances of the total company equity was reduced by the goodwill amount. As Duke Energy does not systematically bifurcate equity to a gas and an electric component a proxy was needed. A ratio to determine the electric and gas portion of equity was developed relying on the proportion of fixed assets. The Property, Plant and Equipment balance in the ledger was adjusted for Cost of Removal in FERC 108 accounts that is currently mapped to regulatory liabilities. The proportion that belongs to electric is applied accordingly.

PERSON RESPONSIBLE: Danielle L. Weatherston

Period	Duke Energy Kentucky Electric Income from Continuing Operations	IC Rent Adjustment	Adjusted Duke Energy Kentucky Electric Income from Continuing Operations	Electric Monthly Equity	Trailing 12 Month Net Income	13 Month Equity Average	ROE
May-19	3,620,985.42	26,559.00	3,647,544.42	444,996,009			
Jun-19	3,473,220.12	26,409.00	3,499,629.12	445,389,279			
Jul-19	6,345,362.19	25,742.00	6,371,104.19	448,052,247			
Aug-19	3,086,409.53	26,149.00	3,112,558.53	449,174,048			
Sep-19	3,726,831.86	27,098.00	3,753,929.86	450,900,965			
Oct-19	735,158.08	25,184.00	760,342.08	449,524,173			
Nov-19	4,202,551.07	24,930.00	4,227,481.07	451,930,794			
Dec-19	805,601.10	25,522.00	831,123.10	454,381,162			
Jan-20	2,282,561.24	25,281.00	2,307,842.24	460,164,936			
Feb-20	3,249,156.14	25,020.00	3,274,176.14	463,925,591			
Mar-20	141,397.92	25,247.00	166,644.92	465,645,988			
Apr-20	1,791,458.72	25,276.00	1,816,734.72	468,014,392			
May-20	3,351,968.38	25,681.00	3,377,649.38	469,221,928	33,191,676	455,486,270	7.287%
Jun-20	4,979,388.07	25,570.00	5,004,958.07	486,764,217	34,697,844	458,699,209	7.564%
Jul-20	6,903,006.71	26,442.00	6,929,448.71	489,858,559	35,255,489	462,119,923	7.629%
Aug-20	5,881,405.32	26,354.00	5,907,759.32	492,741,533	38,050,485	465,557,560	8.173%
Sep-20	2,363,091.31	26,269.00	2,389,360.31	493,130,936	36,686,744	468,938,860	7.823%
Oct-20	471,167.91	26,137.00	497,304.91	492,628,627	36,422,754	472,148,680	7.714%
Nov-20	1,825,474.29	26,245.00	1,851,719.29	494,839,637	34,045,677	475,634,485	7.158%
Dec-20	(1,305,983.86)	26,672.00	(1,279,311.86)	499,727,840	31,934,092	479,311,180	6.662%
Jan-21	4,378,476.70	28,938.00	4,407,414.70	497,889,843	34,030,008	482,658,002	7.051%
Feb-21	3,683,159.91	29,074.00	3,712,233.91	502,160,959	34,464,011	485,888,465	7.093%
Mar-21	1,890,053.72	29,230.00	1,919,283.72	505,356,247	36,212,667	489,075,439	7.404%
Apr-21	2,216,073.16	29,031.00	2,245,104.16	505,522,489	36,637,282	492,142,862	7.444%
May-21	3,413,536.66	29,095.00	3,442,631.66	506,934,037	36,698,850	495,136,681	7.412%
Jun-21	3,955,069.98	24,934.00	3,980,003.98	541,101,386	35,674,532	500,665,870	7.125%
Jul-21	6,182,776.77	25,145.00	6,207,921.77	544,075,824	34,954,302	505,074,455	6.921%
Aug-21	6,265,365.62	25,266.00	6,290,631.62	547,233,915	35,338,262	509,487,944	6.936%
Sep-21	3,574,530.08	24,756.00	3,599,286.08	548,361,795	36,549,701	513,766,426	7.114%
Oct-21	1,848,884.34	24,656.00	1,873,540.34	549,435,648	37,927,417	518,097,557	7.321%
Nov-21	3,044,065.14	25,569.00	3,069,634.14	554,847,462	39,146,008	522,883,622	7.487%
Dec-21	338,324.38	25,879.00	364,203.38	556,720,737	40,790,316	527,643,706	7.731%
Jan-22	6,583,072.89	27,578.00	6,610,650.89	574,589,889	42,994,913	533,402,325	8.061%
Feb-22	1,429,678.30	27,192.00	1,456,870.30	577,806,846	40,741,431	539,549,787	7.551%
Mar-22	770,189.46	25,872.00	796,061.46	580,061,362	39,621,567	545,542,126	7.263%
Apr-22	2,483,995.11	25,894.00	2,509,889.11	581,709,004	39,889,489	551,415,415	7.234%
May-22	2,813,784.58	26,558.00	2,840,342.58	582,796,909	39,289,737	557,359,601	7.049%
Jun-22	(1,897,823.60)	26,412.00	(1,871,411.60)	580,146,437	33,436,843	562,991,324	5.939%
Jul-22	8,573,828.46	26,586.00	8,600,414.46	583,548,668	35,827,895	566,256,500	6.327%
Aug-22	8,244,621.21	26,655.00	8,271,276.21	587,842,963	37,807,150	569,623,203	6.637%
Sep-22	7,585,626.48	27,412.00	7,613,038.48	597,931,208	41,818,247	573,522,994	7.291%
Oct-22	(104,515.35)	26,681.00	(77,834.35)	597,073,839	39,864,847	577,270,075	6.906%
Nov-22	1,686,082.56	26,185.00	1,712,267.56	599,604,473	38,506,864	581,129,215	6.626%
Dec-22	4,089,121.03	25,764.00	4,114,885.03	603,607,375	42,257,661	584,879,978	7.225%
Jan-23	5,784,560.94	25,363.00	5,809,923.94	609,066,674	41,459,149	588,906,588	7.040%
Feb-23	(160,763.31)	25,137.00	(135,626.31)	608,648,134	39,868,708	591,526,453	6.740%

PUBLIC STAFF-DR-04-014

REQUEST:

Provide Duke Kentucky's current distribution system engineering and planning manual(s) and any relevant guides, requirements, and standards. If Duke Kentucky's current distribution planning manual criteria and processes were updated in the last 5 years, provide the analysis that was used to update the criteria and processes.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment 3 only)

The following five documents are being provided:

1) STAFF-DR-04-014 Attachment 1 - Planning Guidelines
   - This document is used as a general reference in developing studies and recommendations for meeting present and future capacity obligations. Factors that are evaluated include equipment load capabilities, power factor correction, system efficiency (losses), average voltage level, voltage and load balance, power quality, reliability factors, system protection factors.
2) STAFF-DR-04-014 Attachment 2 - Self Optimizing Grid Application Guide Rev 3
   - This document provides guidance on how to implement the Self Optimizing Grid (SOG). It includes guidance on the capacity, connectivity, and automation components of SOG. Sufficient capacity is needed at substations and on distribution lines to carry the load of other parts of the

distribution grid during an outage. Historical reliability is one of the items used for prioritization of when to implement SOG on a circuit.

3) STAFF-DR-04-014 Confidential Attachment 3 - Substation Design Guide

- This document outlines the design of Transmission to Distribution (T/D) substations. This document was developed to meet the basic objective of achieving a reasonable cost for a new T/D substation, while providing a focus on safety, future load growth, functionality, and reliability considerations.

4) STAFF-DR-04-014 Attachment 4 - D-Conductor And Equipment Ratings Guide

- This document is an Engineering Guide for conductor and equipment ratings. It incorporates applicable National Electrical Safety Code (NESC) clearance requirements for conductor sag. It also details the operational ratings for conductor and equipment.

5) STAFF-DR-04-014 Attachment 5 - D-Conductor Ratings Spreadsheets

- This is the Conductor Ratings Chart referenced on page 10 of the D-ConductorAndEquipmentRatings Guide. It includes capacity planning detail for each conductor type.

Also, for capital planning purposes, the following tiers are used to rank the highest priority (Tier 1, then Tier 2, then Tier 3) capacity projects higher in the capital plan.

Tier 1	Actual (or very firm projected) Load at the requested in-service date: Summer Load > 110% of 65C rise Nameplate rating or Winter Load > 120% of 65C Nameplate rating, or >110% Conductor overload
Tier 2	Actual (or very firm projected) Load at the requested in-service date: 100% < Summer Load < 110% of 65C Nameplate rating or 110% < Winter Load < 120% of 65C Nameplate rating or 100-110% Conductor Overload

Tier 3	Actual (or very firm projected) Load at the requested in-service date: 90% < Summer Load < 100% of 65C Nameplate rating or 100% < Winter Load < 110% of 65C Nameplate rating, or 90-100% Conductor load

Some of these have been updated in the last 5 years, but the analysis used to update them was not saved. Any relevant information was incorporated into the documents.

PERSON RESPONSIBLE: Dominic "Nick" J. Melillo

PLANNING GUIDELINES FOR THE DISTRIBUTION AND SUBTRANSMISSION SYSTEM

INTRODUCTION

T&D planning is a process of study and analysis through which Duke assures itself that it will economically and reliably meet its present and future delivery obligations. To this end the T&D Planning Department has adopted the following mission statement:

> *Planning will be a valuable technical resource for Duke that aggressively manages existing electric delivery system assets as well as future capital investment decisions within the precepts of safety, reliability, and financial objectives.*

In order to be consistent within the planning organization, the following set of guidelines should be used as a general reference in developing studies and recommendations. These guides are not intended to be all inclusive. It is impossible for every situation to be taken into account. The objective of this document is to establish uniform methods by which the planners will deliver high quality and reliable service to our customers at a reasonable cost.

There are many performance factors to look at when determining where there may be needs on the system. Equipment load capabilities, power factor correction, system efficiency (losses), average voltage level, voltage and load balance, power quality (flicker, surges, sags, transients, harmonic distortion, neutral to earth voltage), reliability factors (SAIDI, SAIFI, average cost of outages to customers, maximum restoration time), system protection factors (fault duty, available fault current, protection device load carrying capabilities). As a planning department, we may not be solely or directly responsible for seeing that all these areas are addressed in each study. We may touch on each at specific times, and communicate to those other responsible departments where we see a potential system deficiency. We can provide input and guidance in evaluating potential solutions.

The guidelines are divided into two sections. Section one covers the distribution planning guidelines. Section two covers the subtransmission guidelines.

SECTION ONE
DISTRIBUTION PLANNING GUIDELINES

RELIABILITY

Distribution planning has a direct impact on service reliability for our customers, and we also interface with other departments having responsibility for review and improvement of distribution circuit reliability.

EQUIPMENT LOAD CAPABILTIES

Keeping equipment at proper loading levels is one way we ensure that the load will be served with a reasonable continuity. Duke's normal service facilities will be adequate to supply the half hour integrated electric energy and reactive volt-ampere demands. Non-traditional approaches such as targeted DSM, distributed generation, or interruptible loads will also be considered as alternatives to traditional capacity enhancements.

- Substation Transformers

  Substation transformers are one of the most expensive single pieces of equipment on the distribution system. Their loading capabilities will normally be determined according to the "Duke Transformer Loading Guidelines" which is based on the thermal capability of the transformer under a normal daily load cycle and a normal ambient temperature variation over a 24 hour period. If the transformer is subjected to an unusual load cycle (i.e… high load factor) or has some other limiting concern, then that will need to be taken into account.

- Conductor and Cable

  Conductor capacity will normally be defined by ampacity as determined by thermal capability and line sag design. Historically we have used an $80^{O}C$ design limit with a $35^{O}C$ ambient temperature and a 2 mph wind for determining minimum sag clearances. From a planning perspective, the conductor temperature could rise to $100^{O}C$ without any detrimental loss of life to the conductor. However, the conductor must still meet clearance requirements.

  Underground cable ampacity is determined on a thermal capability at $90^{O}C$ cable temperature with a $25^{O}C$ ambient earth temperature and a 75% load factor.

- Ancillary Equipment

  Ancillary equipment (i.e… switches, protection devices, LTC's, regulators, etc…) capacity will normally be determined by manufacturer ratings or industry standards. These devices are usually limited by their load breaking capability instead of thermal capability as is the case for transformers and conductors. Limiting the travel of LTC's or regulators can sometimes increase their capability based on manufacture published tables. The risk that each device adds to the system must be considered separately as its manufacturer's rating is approached or exceeded.

<u>SERVICE RESTORATION</u>

Duke's normal service facilities include one source of supply. These facilities are sometimes referred to as a radial system. Therefore, immediate back-up capability will not be provided as a normal practice. We should be able to restore service after an outage or failure of any single system component in 24 hours or less. Longer interruptions may occur when numerous outages occur simultaneously or when damage is catastrophic (major thunderstorms , tornadoes, ice storms, etc…). Distribution substation transformer failures can normally be restored with mobile transformers and/or remotely stored replacement units that will require transport and connection. For transformers larger than available mobile substations and/or spare units, remotely installed capacity or other options will be considered for that portion of capacity that is greater than the available mobile substation and/or spare units. Partial substation transformer backup capacity is often available from adjacent transformers in multi-bank substations or via circuit ties with remote capacity, although the distribution system is not specifically designed for this purpose.

<u>RELIABILITY STUDIES</u>

Distribution Planning will use probabilistic planning techniques as a tool to evaluate the reliability impact of different options available to serve customers' load. This will help ensure that the customer's total cost of electric power is considered in the decision making process.

Historically poor performing distribution circuits will be evaluated on an annual basis to determine problem areas and prudent improvements will be recommended.

POWER FACTOR CORRECTION

Planning takes responsibility for power factor correction because of the impact on our ability to serve Duke's electric delivery obligations in a reliable and economic manner. Power factor correction frees up equipment capacity, provides voltage support to the electric system, and allows a method of system loss reduction.

<u>CAPACITOR PLACEMENT</u>

The general guideline is to install capacitors close to the producer of lagging vars to improve their effects in reducing system losses and freeing up capacity on more pieces of equipment. Most capacitors are strategically placed, along the distribution circuits, to allow for effective voltage control which historically has given a corrected power factor close to unity at the high side of the distribution substation transformer.

Where it is not practical to install more capacitors on the distribution system, there may be a need to install capacitors directly to the subtransmission system.

CAPACITOR SWITCHING

New capacitor installations will be designed for a 3% maximum voltage change during switching. From a practical standpoint, the voltage change is usually 2.5% or less in order to make the control settings coordinate properly.

VOLTAGE REQUIREMENTS

This is another area for which distribution planners are responsible. The distribution system will provide delivered customer utilization voltages as specified by ANSI C84.1-1996. We interface with the design group in this function because they are responsible for sizing service equipment to meet rms average voltage requirements. We also interface with the power quality group to assist them as they deal with harmonic distortion, voltage sags, voltage swells, flicker, transient over voltages and neutral to earth voltage. Much of the following information is found in the "Electric Service from Duke." document, and changes to that document will supersede these planning guidelines.

RMS AVERAGE VOLTAGE

Steady state voltages should comply with ANSI C84.1-1996. This standard describes a preferred range A and occasional occurrence range B of voltages for each of three voltage classes. Those ranges are shown in the table below. It is recommended practice to limit total voltage drop in customer utilization voltage systems to no more than 5%.

Table 1: Standard nominal service voltages and voltage ranges (ANSI C84.1-1996).

Nominal Service Voltage at Meter	Minimum Range B	Minimum Range A	Maximum Range A	Maximum Range B
Low Voltage				
208Y/120	191Y/110	197Y/114	218Y/126	220Y/127
240/120	220/110	228/114	252/126	254/127
480Y/277	424Y/245	456Y/263	504Y/291	508Y/293
Distribution Voltage				
4,160/2,400	3,950/2,280	4,050/2,340	4,370Y/2,520	4,400Y/2,540
12,470/7,200	11,850Y/6,840	12,160Y/7020	13,090Y/7,560	13,200Y/7,620
34,500/19,920	32,780Y/18,930	33,640Y/19,420	36,230Y/20,920	36,510Y/21,080
Transmission - 69,000 Volts and Higher				
These are considered to be bulk energy delivery systems. Voltage may vary between -12% and +8%. Customers should provide their own regulation.				

A statistical method measures the rms voltage. This method calculates the average rms voltage in 10 minute intervals over each week for a total of 1,008 intervals per week. At least 95% of all 10 minute rms averages for each week will be within Range A. At least 98% of the 10 minute average intervals each week will meet Range B. Normally engineering should allow no more than 3% voltage drop in the secondary service facilities. In order to meet the requirements of Range A from the table above, Distribution Planning will normally plan the primary distribution system to range from 105% to 98% of nominal voltage. An example of the resulting voltage profile is shown in the IEEE Red Book, Chapter 3.

VOLTAGE UNBALANCE

During each period of one week, 95% of the 10 minute average rms unbalance values of the supply voltage shall be within the range between 0 to 2%. In some areas with partly single phase or two-phase connected customers, unbalances up to about 3% at three-phase supply terminals occur. In cases where customer loads are the main source of unbalance, the customer may need to balance load currents. The equation for calculating percent voltage unbalance is:

$$Percent\,Unbalance = \frac{Maximum\,Deviation\,From\,Average}{Average\,of\;3\,Phase\,to\,Phase\,Voltages} \bullet 100$$

HARMONIC DISTORTION

Duke will deliver voltage quality that meets or exceeds IEEE Standard 519-1992 ***provided the customer harmonic current demands also comply with the same standard***. Duke may relax the current requirements provided the customer releases Duke from voltage distortion requirements and provided IEEE 519 is met at the point of common coupling with other Duke customers. Voltage and current quality standards will be met for 95% of all ten minute average samples in each week.

FLICKER

Voltage flicker at the delivery point will be better than IEEE Standard 141-1993 border line of irritation. Flicker above this level may occur up to 5% of the time in any single weekly period. Customers with flicker causing loads may wish to accept higher flicker levels at their own loads that cause the flicker to avoid financial penalties for excess supply facilities. Customers with flicker causing loads will be required to prevent their loads from causing flicker worse than these limits for other customers.

NEUTRAL TO EARTH VOLTAGE

Duke operates a multi-grounded wye distribution system. One characteristic of this system is that the neutral conductor will have some voltage on it with respect to the earth voltage (Neutral to Earth Voltage - NEV). This gives rise to a small voltage difference between grounded objects and nearby earth. Neutral to earth voltage may cause slight shock sensations to people and animals. Indicative values for NEV range from zero to four volts for normal operation. NEV may be higher during short circuits or other unusual circumstances.

SECTION TWO
SUBTRANSMISSION PLANNING GUIDELINES

For the purposes of these guidelines the subtransmission system is defined as the regional electric transmission system serving distribution substations, usually 69kV and in specific locations 138kV.

CAPACITY

Installed capacity will be available to serve the peak MW and MVAr demands of the system under anticipated normal operating conditions.

Capacity to serve peak MW and MVAr demands during single contingency component outages will be planned using a combination of traditional deterministic planning and newly developed probabilistic planning techniques. The deterministic approach will be used to screen for system operational deviations from planning guidelines and to determine traditional system need date for correctional actions. The probabilistic techniques will be used to help match projects with optimal timing taking into account the probability of a system failure, the estimated outage cost, length of repair, and severity of system impact.

Non-traditional approaches such as targeted DSM, distributed generation, or interruptible loads will also be considered as alternatives to traditional capacity enhancements.

EQUIPMENT LOAD CAPABILITIES

- Substation Transformers

  Substation transformers are one of the most expensive single pieces of equipment on the subtransmission system. Their loading capabilities will normally be determined according to the "*Duke* Transformer Loading Guidelines" which is based on the thermal capability of the transformer under a normal daily load cycle and a normal ambient temperature variation over a 24 hour period. If the transformer is subjected to an unusual load cycle (i.e… high load factor) or has some other limiting concern, then that will need to be taken into account.

- Conductor

  Conductor capacity will normally be defined by ampacity as determined by thermal capability and line sag design. Historically we have used an 80^{O}C design limit with a 35^{O}C ambient temperature and a 2 mph wind for determining minimum sag clearances. From a planning perspective, the conductor temperature could rise to 100^{O}C without any detrimental loss of life to the conductor. However, the conductor must still meet clearance requirements.

- Ancillary Equipment

  Ancillary equipment (i.e… switches, protection devices, LTC's, regulators, etc…) capacity will normally be determined by manufacturer ratings or industry standards. These devices are usually limited by their load breaking capability instead of thermal capability as is the case for transformers and conductors. Limiting the travel of LTC's or regulators can sometimes increase their capability based on manufacture published tables. The risk that each device adds to the system must be considered separately as its manufacturer's rating is approached or exceeded.

VOLTAGE REQUIREMENTS

The subtransmission system itself is not considered to be regulated within any prescribed limits. It is intended as a source of supply to lower voltage systems which are equipped with voltage regulating equipment or other means to insure adequate voltage. The subtransmission system voltages will be maintained to enable delivered customer utilization voltages to be as specified by ANSI standard C84.1-1996. Large customers taking service at 69kV or higher voltage are responsible for the maintenance of adequate utilization voltages. In general, fulfilling the above requirements will require the subtransmission voltages to be in the range of -12% to +5% of nominal.

VOLTAGE FLICKER

Voltage flicker at the delivery point will be better than IEEE Standard 141-1993 border line of irritation. Flicker above this level may occur up to 5% of the time in any single weekly period. Customers with flicker causing loads may wish to accept higher flicker levels at their own loads that cause the flicker to avoid financial penalties for excess supply facilities. Customers with flicker causing loads will be required to prevent their loads from causing flicker worse than these limits for other customers

New 69kV capacitor installations will generally be designed for a 3% maximum voltage change during switching with normal system operations. The voltage change may be considerably higher for switching during contingencies and emergency situations.

RELIABILITY

Reliability impact of the recommended plan and the alternate plans will be evaluated as part of all area subtransmission planning studies. This will be done by considering estimated outage cost, outage indices such as SAIDI and SAIFI, and other factors.

Historically poor performing subtransmission circuits will be evaluated on an annual basis to determine and recommend feasible improvements.

Self Optimizing Grid Application Guide

(This document is **not** intended to supersede existing Distribution Standards)

Document Number: GDLP-ADM-GRS-00166

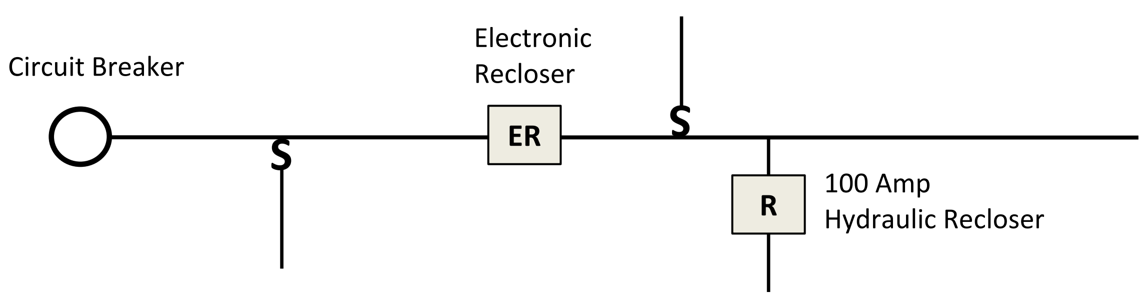
Table of Contents

Self Optimizing Grid Purpose and Description

Current State:
The existing distribution grid consists mostly of individual circuits that fall into three categories with respect to sustained outages; radial circuits with no alternate source tie capabilities, circuits with alternate source tie capabilities via manual switches, and circuits on self-healing teams. Although the number of self-healing teams on our system is increasing, the percentage of circuits on a self-healing team is relatively low. Capacity rules concerning substation bank and circuit loading are not the same across the company. Utilizing alternate feeders to restore power to part or all of the load on a circuit that is experiencing a major outage is typically limited by equipment and conductor ratings and can be dependent on the time of day or year.

Sectionalization on each circuit typically consists of the breaker, a mainline midpoint recloser (hydraulic or electronic), along with laterals/taps off of the mainline that are protected by either a recloser or fuse. The term mainline is a generic term that differs based on the jurisdiction and is sometimes called the feeder backbone, circuit backbone and recloser subfeeder. These protective devices are coordinated in an effort to affect the fewest customers possible in the event of a sustained fault and outage. Sustained faults along the mainline typically result in all or a large portion of the customers on a circuit experiencing an outage. Although circuits with self-healing technology do isolate around sustained faults and restore power to un-faulted line segments, the number of customers that experience an outage tends to be high due to the number of customers on the faulted line segment.

Typical Existing Distribution Circuit

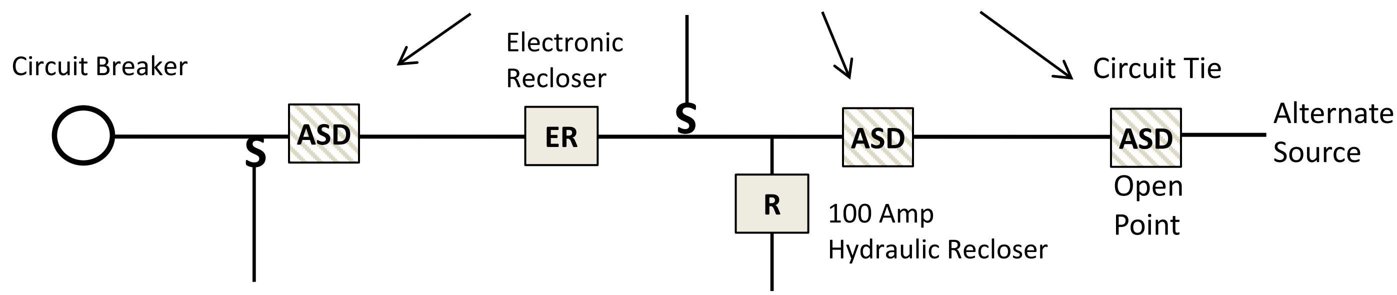


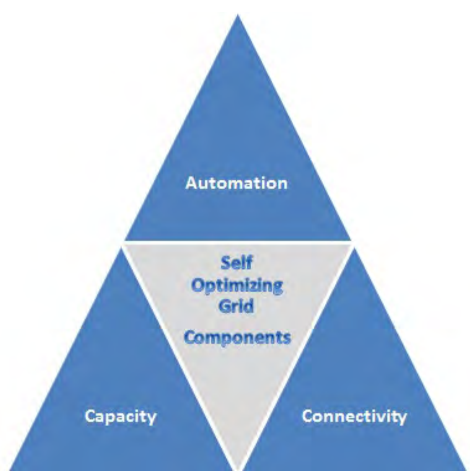
Self Optimizing Grid Purpose and Description

Future State:
Self Optimizing Grid (S.O.G.) is the concept of transforming the distribution system from a population of circuits with minimal automated alternate source capability, to a network of circuits with spare load capacity, automated inter-circuit connectivity and smaller automatically switchable line segments along the feeder backbone. With the integration of self-healing/Closed Loop FISR technology, a sustained fault will be automatically isolated to a smaller line segment, while all other un-faulted line segments are restored from alternate sources most of the time. The objective is to drastically change the customer experience through improved reliability.

Self Optimizing Grid will consist of three components: **Capacity, Connectivity** and **Automation** (see Section II). To become part of S.O.G, a circuit must meet all three component rules. Due to topology, not all circuits have potential alternate sources nearby. Also, some circuits have a lower customer count. As a result, the target is to apply all S.O.G. components to 80% of our distribution customers. The remaining 20% of our customers will have the Automation component applied only and will not be considered part of S.O.G. (see Section IV). However, they will still benefit from smaller line segments and SCADA enabled devices. The implementation of S.O.G. will result in the addition of SCADA enabled switchable devices between each line segment and at utilized circuit ties to alternate sources. Depending on the current state of capacity and connectivity to alternate sources, the work required to meet S.O.G. rules may include reconductoring, the installation of new circuit ties, line regulator upgrades and new installs, along with substation bank upgrades and additions.

Circuit Part of S.O.G.





Section I – Definitions

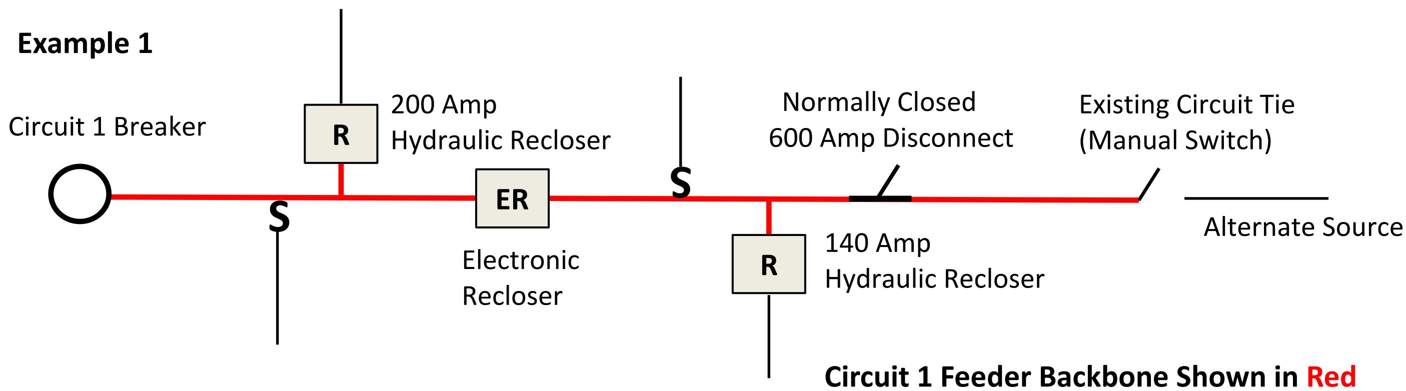
Feeder Backbone - definition to be used in applying the S.O.G. rules in this document

The Self Optimizing Grid <u>Feeder Backbone</u> of a circuit is defined as the following:

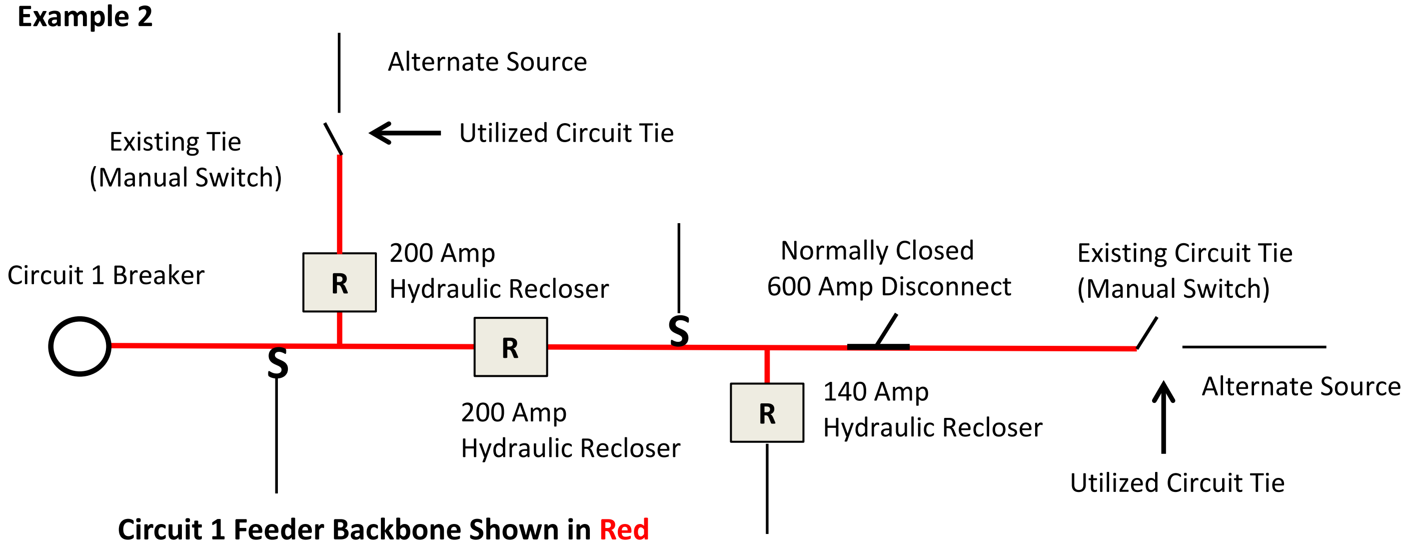
- All 3 phase, unfused line sections protected by a reclosing device larger than 200 amps, including the breaker.
- Any three phase line section protected by a reclosing device 200 amps or smaller with a circuit tie that will be utilized for self optimizing grid is considered feeder backbone.
- Any three phase line section protected by a reclosing device 200 amps or smaller without a utilized circuit tie is <u>not</u> considered the backbone.

Background: The goal of the Self Optimizing Grid (S.O.G.) is to further segment our lines and add inter-circuit connectivity to automatically restore power to as many customers as possible in the event of a sustained fault. In most cases, load and customer count is high beyond electronic reclosers and as a result the line section beyond electronic reclosers is considered feeder backbone. In most cases, hydraulic reclosers have fewer customers and therefore the line section beyond hydraulic reclosers are not considered part of the feeder backbone except when there is a utilized circuit tie.

Example 1



Example 2



Definitions (Continued)

Alternate Source – An alternate electrical source used to restore power to un-faulted line segments during a major outage. This will typically be an adjacent distribution circuit. However, this could be a DER in a future state.

Utilized Circuit Tie – If a circuit has multiple existing circuit ties, not all circuit ties must be used and converted to automated devices under these standards. “Utilized” circuit tie refers to a circuit tie that will be converted to an automated device for restoration purposes under these standards.

Automated Switching Device (ASD) – As part of the Self Optimizing Grid standards, a key part to automation is having SCADA controllable field equipment that allows remote switching. The term “automated switching device” refers to a switchable SCADA controllable device. These devices will most likely be electronic reclosers setup as a switches, but in some cases may be setup as reclosers or sectionalizers.

Line Segment – A section of line on a distribution circuit bound by switching devices on all sides with the exception of circuit end points without a circuit tie.

Segmentation – The act of dividing a distribution circuit into switchable line segments for the purpose of fault isolation and restoration. All devices placed to define line segments in these standards will be SCADA enabled and controllable switching devices.

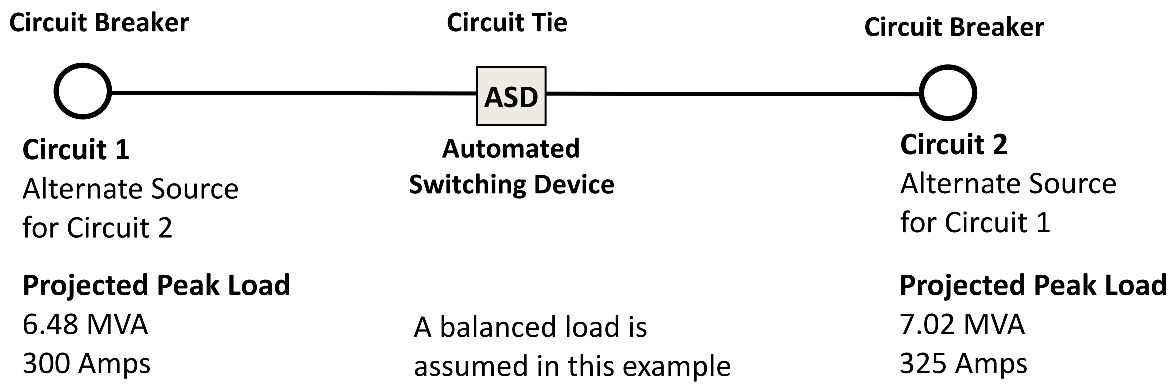
Section II – Self Optimizing Grid Components (Applies to Overhead and Underground)

1.0 Capacity and Connectivity (Circuit Ties)

- Minimum Requirement: Any circuit part of Self Optimizing Grid (S.O.G.) shall be designed such that all of the circuit load can be restored from an alternate source(s) 90% of the hours in a year (90% Restoration Availability minimum requirement). This correlates to being able to restore all of the load on a circuit at approximately 75% of the projected peak load. **See Example 1 for application. See below for further explanation of how this percentage was derived.**
  Exception: Restoration at 75% of projected peak load in order for the average circuit to be restored 90% of the hours in a year is based on retail system load data. If substantial capacity work is required in order to meet this requirement and individual hourly circuit load data is available, circuit level data can be used to determine a more accurate % of projected peak load to meet the 90% Restoration Availability minimum requirement. Follow the steps on page 7 (next page) to determine an individual circuit % of projected peak load.
- Restoration of load to meet the 90% Restoration Availability minimum requirement shall not exceed the emergency thermal ratings of any distribution equipment including the substation bank, circuit breaker, the wire, reclosers, automated switching devices, regulators and inline disconnects.
- When performing a circuit study, the alternate source(s) substation bank loading should also be considered at 75% of projected peak.
- Multiple alternate sources per circuit can be utilized to meet the 90% Restoration Availability minimum requirement, if available.
- Alternate source(s) used to meet the 90% Restoration Availability minimum requirement should preferably include circuits from a different substation or from a different bank in the same substation if possible. **Note: While it is preferred to have an alternate source(s) from a different substation or bank, this is not a requirement. The minimum requirement is to be able to restore a single circuit, i.e. single circuit loss contingency.**
- If the only possible alternate source is from a circuit on the same substation bank, the circuit tie point should be in a location on the circuit in which at least half of the circuit customer count is upstream. A circuit tie close to the substation adds limited value for restoration. Use engineering judgment in accessing the reliability benefits in this scenario.

Percent of Projected Peak Load Derivation:
Hourly system load data was obtained for multiple years in each jurisdiction. For each year, the peak load hour was identified. The remaining hours of the year were then compared to this peak to determine an hourly percentage of that peak. 90% of the hours in a year equates to 8760 X .9 or 7884 hours. This also represents a possible unavailability of 10% or 876 hours per year. By sorting the hourly data from highest to lowest, the percentage of peak load for which at or below represented approximately 90% of the hours for each year was established. For example, in DEF for 2014, there were 790 hours in which the system hourly load was higher than 75% of the annual peak hour of that year. There were also 7970 hours in 2014 in which the load was below 75% of the annual peak hour, which equates to a 91% availability. All jurisdictions were very close to 75% and as a result, 75% of projected peak load should be used unless you have data to calculate the percent for an individual circuit.

Example 1: (Both Circuits are 12.47KV)



Circuit 1 and Circuit 2 are the only alternate sources for each other in this example, similar to a typical two circuit self-healing team. Applying the 90% restoration availability minimum requirement results in the following load assumptions in considering capacity compliance:

Circuit 1 load at *75% of peak = 0.75 X 6.48 MVA = 4.860 MVA(total), 225 amps/phase
Circuit 2 load at *75% of peak = 0.75 X 7.02 MVA = 5.265 MVA(total), 244 amps/phase

If Circuit 1 restores all of the load of Circuit 2, the capacity of the bank, wires (including both sides of the circuit tie), voltage regulators, switching devices, etc., must be able to carry an extra 5.265 MVA, plus the existing load of 4.860 MVA without exceeding emergency thermal ratings. Note: When considering if the substation bank for circuit 1 has capacity to pick-up the additional load of circuit 2, assume the bank is also loaded at 75% of projected peak.

If Circuit 2 restores all of the load of Circuit 1, the capacity of the bank, wires (including both sides of the circuit tie), voltage regulators, switching devices, etc., must be able to carry an extra 4.860 MVA, plus the existing load of 5.265 MVA without exceeding emergency thermal ratings. Note: When considering if the substation bank for circuit 2 has capacity to pick-up the additional load of circuit 1, assume the bank is also loaded at 75% of projected peak.

Individual Circuit % of Peak Load Determination (in Excel)

Step 1: Obtain circuit level hourly load data for at least one year. You can use more frequent data if available.
Step 2: Filter out outages, blanks, etc.
Step 3: Sort all load data from largest to smallest with all data in one column.
Step 4: Click on the top of the load data column and view the bottom to see the total data "count". This is needed in figuring out the 90% availability.
Step 5: In a column next to the load data, divide each row of load data by the peak load. This will give you a percentage of peak load for each row.
Step 6: Multiply the total data count by 0.1. This is the number of load data points that are at or above 90% availability.
Step 7: Scroll down until the row number equals the count calculated in step 6. This represents the percentage of peak load that equates to 90% availability.

2.0 Automation (Includes segmentation and self healing/FISR integration)

The feeder backbone will be transitioned to automated switchable segments. See Section I for feeder backbone definition. Segment target characteristics are:

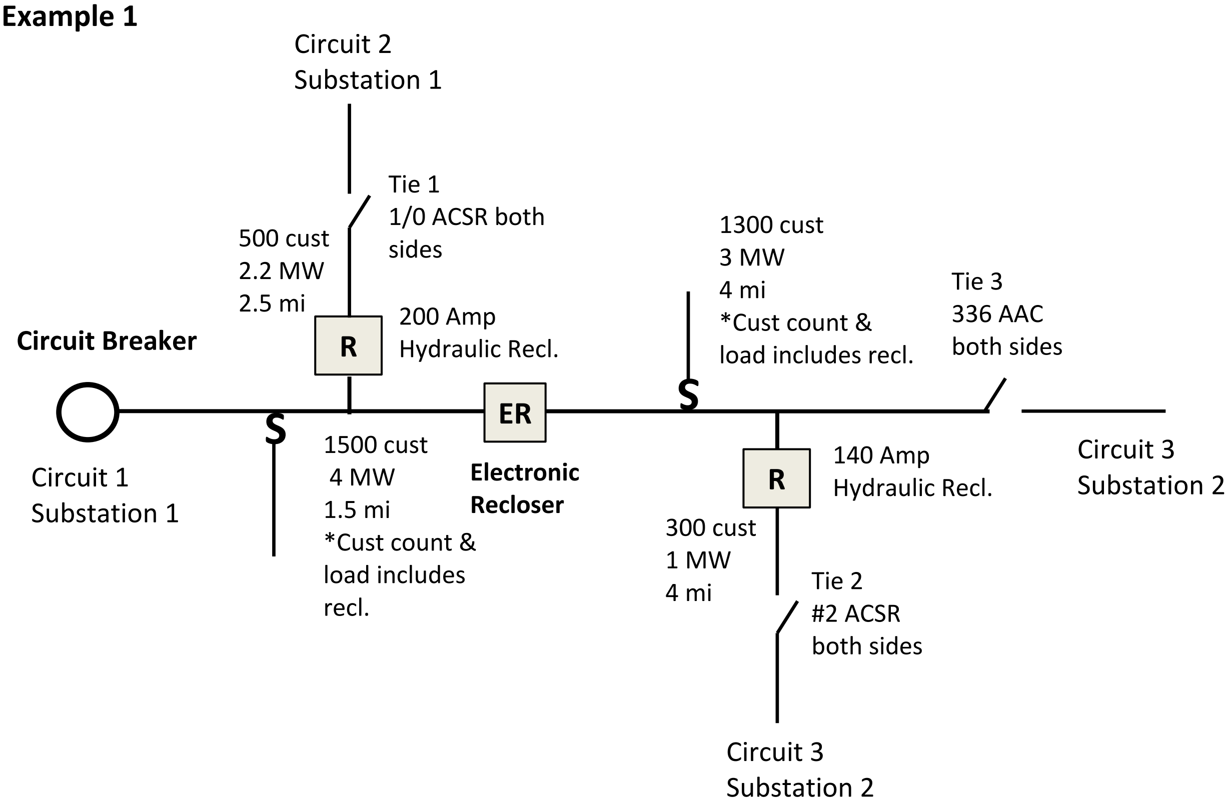
- No more than 400 customers in the segment. *
- No more than 3 miles of exposure in the segment. *
- No more than 2 MW load in the segment. *

  *These are general guidelines that will vary depending on field conditions. Note that the segment load target is based on meeting 90% availability rule (75% of projected peak).

  - New switches installed to define segments will be automated, including utilized circuit ties. Existing manual switches and hydraulic reclosers that define segments will be converted in accordance with these Automation rules.
  - Planning engineers and Grid Management will use current standards and engineering judgment for additional segmentation switches (critical customer feeds, T points, OH to UG, etc.).
  - Segments will have adequate fault protection and coordination between devices to facilitate the ability for load transfers between circuits.
  - Voltage levels should be maintained within ANSI C84.1 Range A (minimum 114V at the meter), whenever there is a segment transfer. When performing a circuit analysis to ensure voltage levels are maintained during a reconfiguration, limit that analysis to adjacent interconnected circuits only.
  - All substation circuit breakers must have electronic relays and are SCADA enabled and controllable.
  - Self-healing/Closed Loop FISR will be enabled on each circuit after work is complete for the appropriate Self Optimizing Grid components.
  - **Feeder backbone segmentation exception:** If a line segment has no feasible circuit tie, is protected by a reclosing device regardless of size and has 700 or more customers, further segmentation should be performed. Any segmentation should utilize automated switching devices.

3.0 Automation and Connectivity (Circuit Ties) Examples

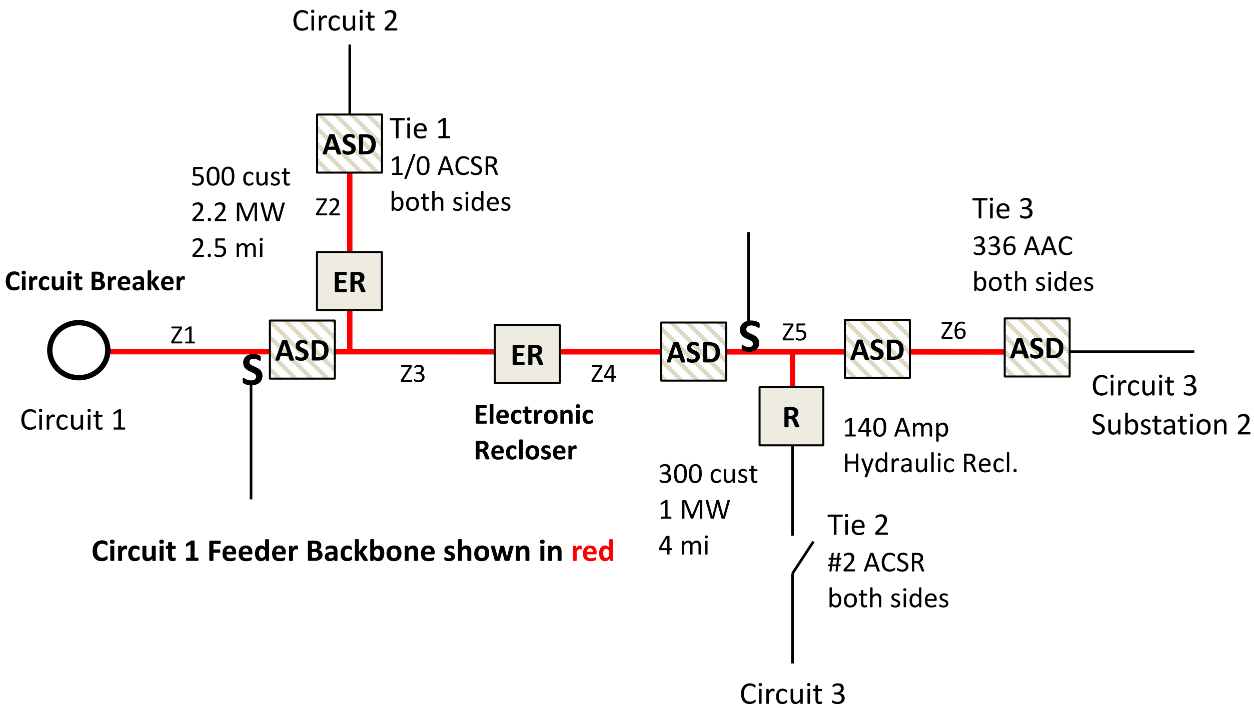
3.1 Example 1



Background:

- All segment loads shown are at 75% of peak.
- All load of Circuit 1 can be picked up from **Circuit 3** per the capacity rules through **Tie 3**.
- Tie 1 and Tie 2 can only pick up partial load but add some redundancy.
- The line segments downstream of both the 200 and 140 amp hydraulic reclosers exceed SOG line segment rules.
- Circuits 1 & 2 are fed out of the same substation and bank.
- Circuit 3 is out of a different substation.

3.1.1 Example 1 Solution



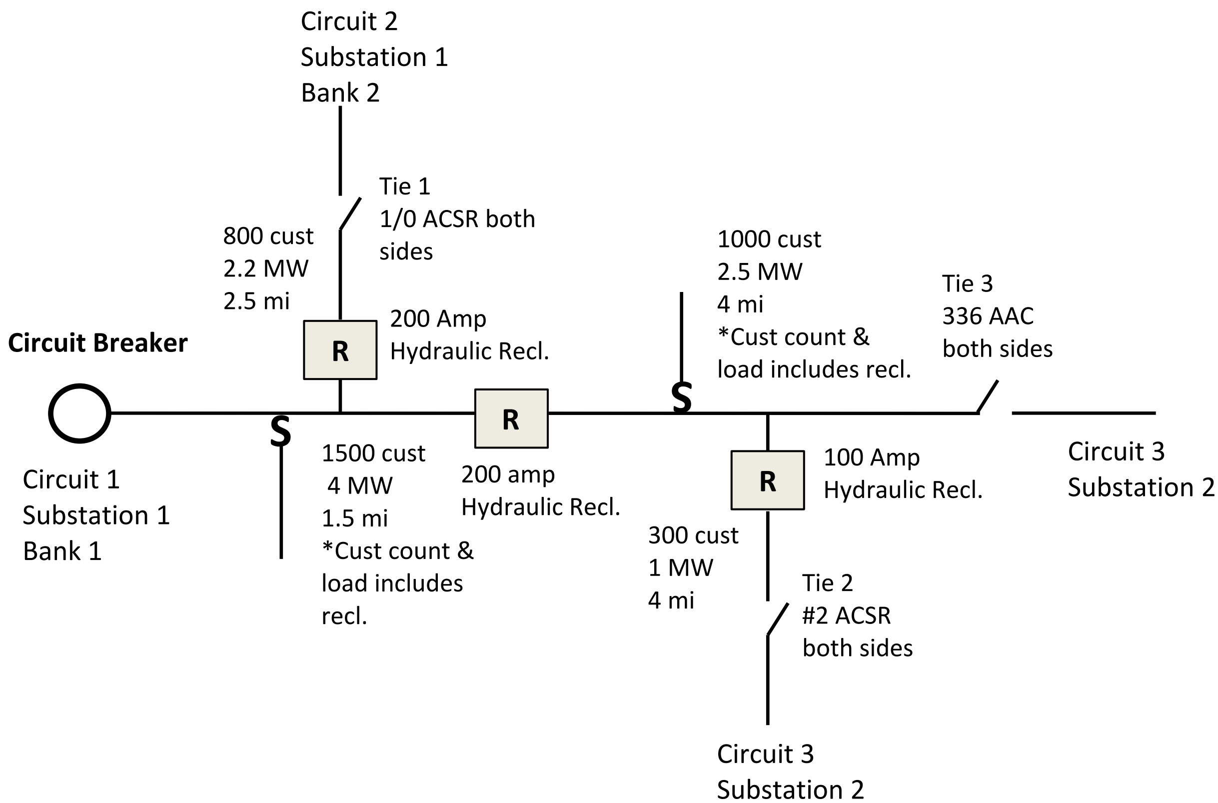
Circuit 3 is capable of picking up all of the load of Circuit 1 and is out of another substation making it the highest priority tie at the lowest cost to utilize. Tie 1 is considered a weak tie and is out of the same substation and bank. However, not utilizing this tie would result in a zone with 950 customers. Utilizing this tie will result in a lower zonal customer count, plus replace an existing hydraulic recloser. It should be noted that this was an engineering judgment decision based on the relative low risk of a bank failure versus the expected benefits. In the event of a bank failure, Circuit 3 can still pick up all of the load. By definition, since Tie 1 is being utilized, the line segment beyond the old 200 amp hydraulic recloser becomes part of the feeder backbone shown in red. Tie 2 is also considered a weak tie, with very little spare capacity. Increasing the capacity and adding automated devices for Tie 2 is not justified and therefore, by feeder backbone definition, the line section beyond the 140 amp hydraulic recloser is not feeder backbone.

Zone Information:

Z1 – 550 customers, 0.8 MW, 1.1 miles Z4 – 450 customers, 1.1 MW, 1.4 miles
Z2 – 500 customers, 2.4 MW, 0.5 miles Z5 – 500 customers, 1.2 MW, 1.0 miles
Z3 – 450 customers, 0.8 MW, 0.8 miles Z6 – 350 customers, 0.7 MW, 0.9 miles

Average Customers per Line Segment = 467
Average Load per Line Segment = 1.17 MW
Average Distance per Line Segment =0.95 miles

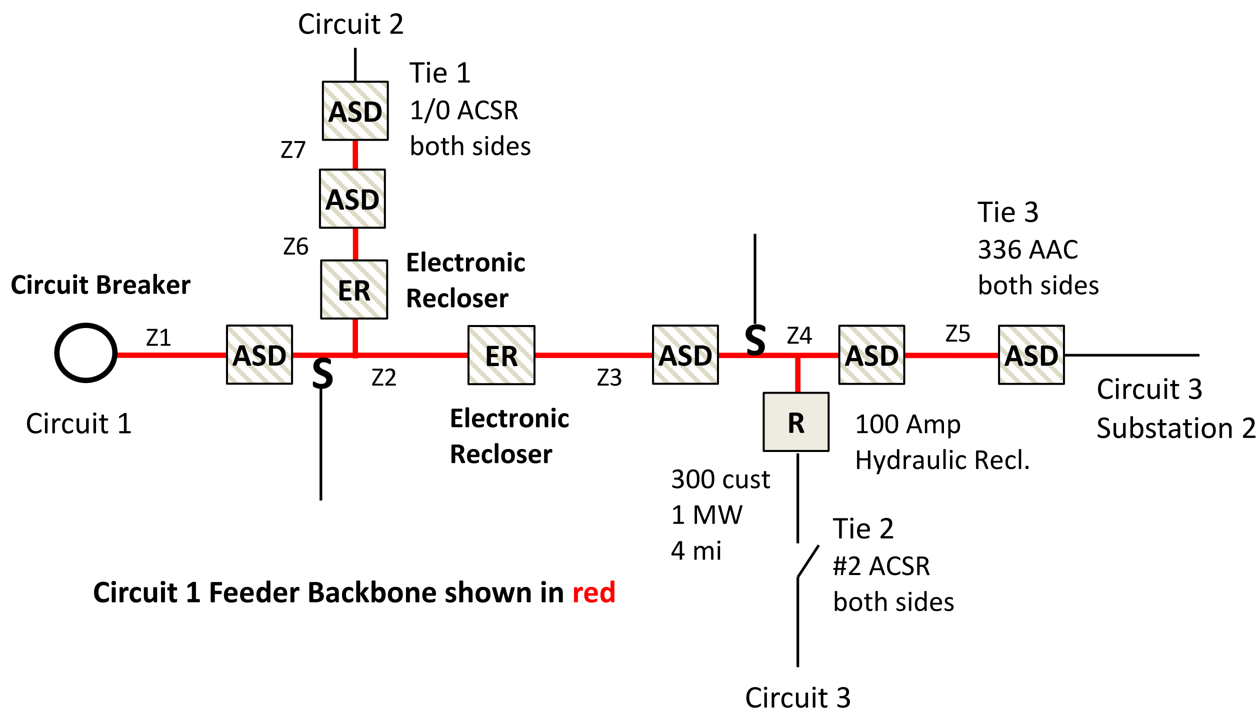
3.2 Example 2



Background:

- All segment loads shown are at 75% of peak.
- All load of circuit 1 can be picked up from **Circuit 3** per the capacity rules through **Tie 3**.
- Tie 1 and Tie 2 can only pick up partial load but add some redundancy.
- Circuits 1 & 2 are fed out of the same substation but on different banks.
- Circuit 3 is out of a different substation.

3.2.1 Example 2 Solution



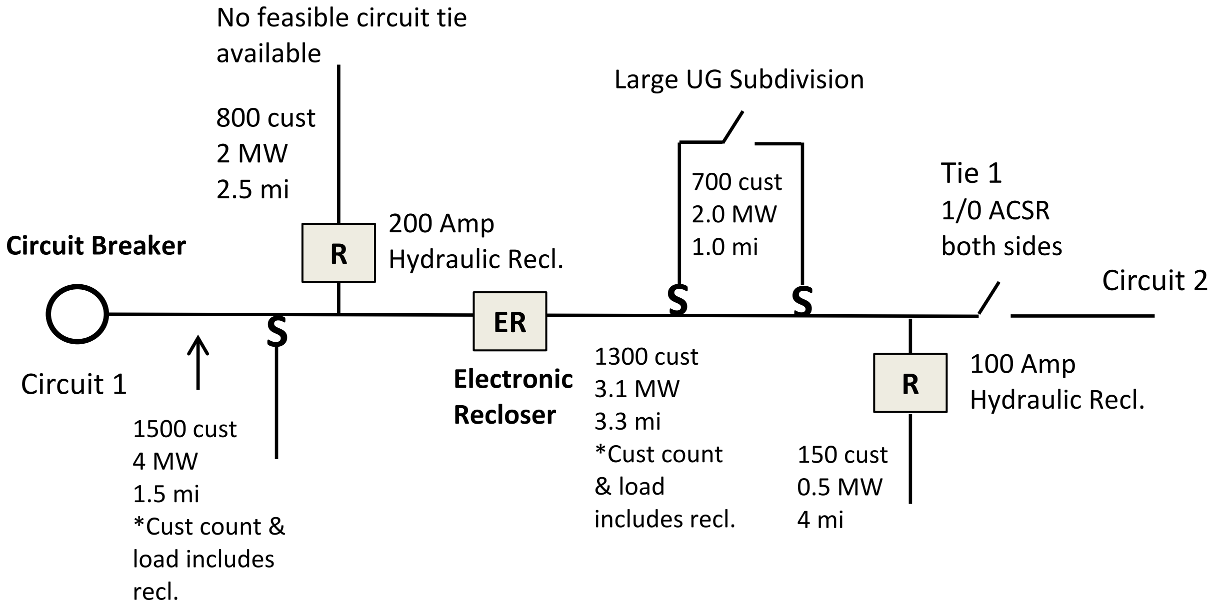
Circuit 3 is capable of picking up all of the load of Circuit 1 and is out of another substation making it the highest priority tie at the lowest cost to utilize. As a result of Tie 3 being utilized, the line section beyond this recloser is considered the feeder backbone and therefore is segmented and automated accordingly. Although Tie 1 is not a full capacity tie and this lateral is protected by a 200 amp hydraulic recloser, the line section has a high customer count and the alternate source is a circuit on a different bank. Therefore, this line section is also considered feeder backbone and as a result is subject to be further segmented and automated. Tie 2 is considered a weak tie, with very little spare capacity. Increasing the capacity and adding an automated device for Tie 2 is not justified.

Zone Information:

Z1 – 300 customers, 0.8 MW, 1.1 miles
Z2 –400 customers, 1.0 MW, 0.5 miles
Z3 – 350 customers, 0.6 MW, 0.8 miles
Z4 – 400 customers, 1.3 MW, 1.4 miles
Z5 – 250 customers, 0.6 MW, 1.0 miles
Z6 – 450 customers, 1.2MW, 0.9 miles
Z7 – 350 customers, 1.0 MW, 0.8 miles

Average Customers per Line Segment = 357
Average Load per Line Segment = 0.93 MW
Average Distance per Line Segment =0.93 miles

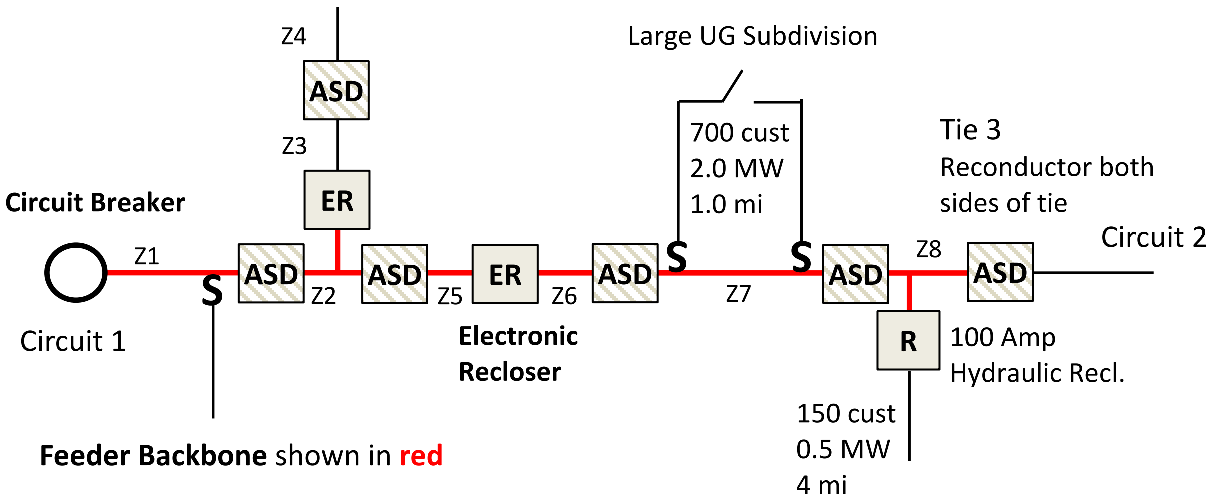
3.3 Example 3



Background:

- All segment loads shown are at 75% of peak.
- The only available existing circuit tie is Tie 1, which does not meet the capacity rules due to the small conductor.
- Circuit 2 is out of another substation.
- The line segment downstream of the 200 amp hydraulic recloser has 800 customers, above the segmentation rule for reclosing devices with no feasible tie.
- A very large looped subdivision exists downstream of the electronic recloser.

3.3.1 Example 3 Solution



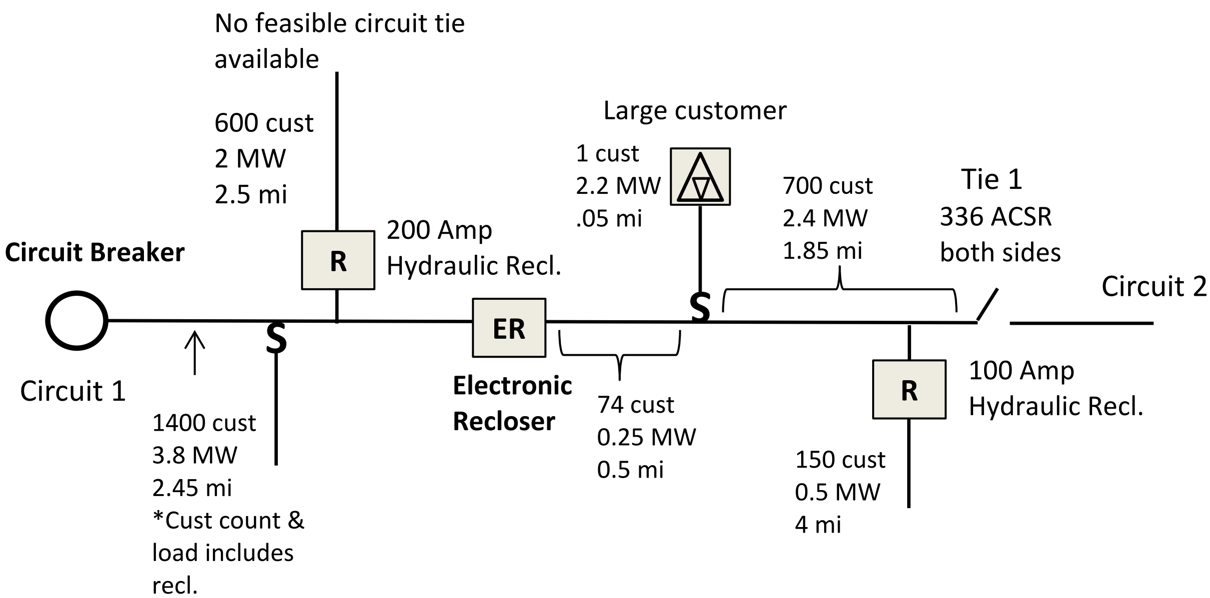
Circuit 2 is capable of picking up all of the load of Circuit 1 from an equipment and bank capacity perspective, but the 1/0 ACSR around the tie point is not adequate. Reconductoring must take place on both sides of the tie to meet capacity rules. The 200 amp recloser has 800 customers, meaning it is drastically higher than the 400 customer count segment target. Even though there is not a feasible tie point for back-feeding, the section of line beyond the 200 amp hydraulic recloser is subject for further segmentation and automation based on the feeder backbone segmentation exception on page 8. Because there is no tie point, this line section is **not** considered feeder backbone. Cases with this many customers beyond a hydraulic recloser should be rare but does exist. Beyond the existing electronic recloser, the tendency would be to place a device between the two dips of the large underground subdivision in an effort to lower the customer count per segment. However, doing so creates operational concerns due to potentially having two different circuits feeding this subdivision if the tie point moves in the future. Therefore, automated switching devices were installed on both sides of these dips. Reference: Legacy Progress Engineering manual – Section 9.0, part D, Legacy DEC Engineering Resources manual – Section 9.4, Enterprise Wide Construction manual - Section 20. There may be cases in which segmenting outside of the dips will result in very large segments due to the distance between dips. Consider utilizing ASD's to prevent a loop split or splitting the loop into two loops.

Zone Information:

Z1 – 400 customers, 0.9 MW, 1.1 miles   Z5 – 250 customers, 0.6 MW, 0.8 miles
Z2 – 850 customers, 2.5 MW, 0.5 miles   Z6 – 325 customers, 1.1 MW, 1.4 miles
Z3 – *400 customers, 1.0 MW, 1.3 miles Z7 – 700 customers, 1.2MW, 1.0 miles
Z4 – *400 customers, 1.0 MW, 1.2 miles   Z8 – 275 customers, 0.8MW, 0.9 miles
*Z2 includes the customer count and load of Z3 and Z4.

Average Customers per Line Segment = 467
Average Load per Line Segment = 1.18 MW
Average Distance per Line Segment =0.95 miles

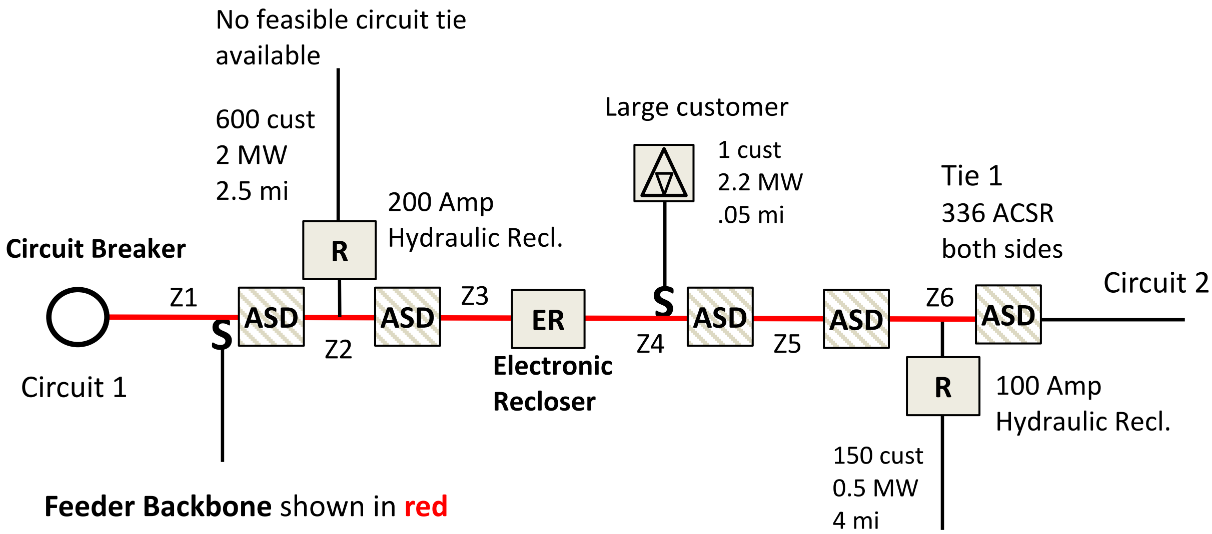
3.4 Example 4



Background:

- All segment loads shown are at 75% of peak.
- The only available existing circuit tie is Tie 1.
- Circuit 2 is out of another substation.
- The line segment downstream of the 200 amp hydraulic recloser has 600 customers, below the 700 or more exception for further segmentation.
- There is a large single customer off the backbone.

3.4.1 Example 4 Solution



Circuit 2 is capable of picking up all of the load of Circuit 1 from an equipment and bank capacity perspective. The 200 amp recloser has 600 customers with no feasible circuit tie. The customer count is below the segmentation threshold of 700 customers for radials. As a result, no further segmentation is justified. The 200 amp recloser can be changed out to an ASD through the oil filled recloser replacement budget in the H&R program. Because there is no tie point, this line section is **not** considered feeder backbone. There is a large customer below the existing electronic recloser that is greater than the segment target. By the segment target for load, ASD's should be placed on both sides of the customer along the feeder backbone. While this was no issue on the downstream side, placing an ASD on the upstream side would create a segment with only 74 customers and very little load. Although not placing the additional upstream ASD increased the segment load even more, the additional load was minimal and avoided an extra device.

Zone Information:

Z1 – 400 customers, 1.0 MW, 1.0 miles
Z2 – 625 customers, 2.1 MW, 0.35 miles
Z3 – 375 customers, 0.7 MW, 1.1 miles
Z4 – 75 customers, 2.45 MW, 0.5 miles
Z5 – 450 customers, 1.5 MW, 1.1 miles
Z6 – 400 customers, 1.4 MW, 0.75 miles

Average Customers per Line Segment = 488
Average Load per Line Segment = 1.53 MW
Average Distance per Line Segment = 0.8 miles

Section III – Work Flow Process

1.0 Self Optimizing Grid Circuit Identification and Prioritization Rules

1.1 Background and Initial Circuit Identification:

The Grid Improvement Plan target is to have 80% of our customers on the Self Optimizing Grid. 80% of our customers are on approximately 60% of our circuits. Therefore, the top 60% of our highest customer count circuits will be targeted per jurisdiction as a starting point in determining which circuits will become part of the S.O.G. Circuits equal to or above the customer count listed below are to be considered first for becoming part of S.O.G.

Jurisdiction	Circuit Customer Count
DEI	725
DEO	1060
DEK	1025
DEC	880
DEP	1155
DEF	1400

Note: The above criteria is a general guideline in determining what circuits should be in scope for S.O.G. Even though a circuit may meet the customer count criteria above, it may be excluded due to other factors such as no feasible ties or alternate sources. Also, there will be circuits that are below the listed customer count that will become part of the S.O.G. due to the proximity to circuits that do meet the customer count.

1.2 Annual circuit prioritization should be based on the following in order:

From the population of circuits selected by using the chart above, use the following items in sequential order to further target/identify circuits annually. Go through all 7 items before making circuit selections. Selecting S.O.G. circuits in this manner is expected to result in a higher reliability impact earlier in the program.

1. **Customer count** - Choose circuits with the highest customer count.
2. **Load growth** – Circuits requiring capacity upgrades as a result of load growth should be coordinated with S.O.G. work. The intent is to prevent capacity rework as a result of S.O.G.
3. **Historically poor reliability** – Choose circuits with the worst reliability.
4. **Available circuit tie to alternate source** – To increase early cost benefit, choose circuits with existing circuit ties to alternate sources early in the program if possible.
5. **No substation upgrade work required** – To increase early cost benefit, choose circuits that do not need substation upgrade work (New or larger bank, a new circuit breaker, or relay) early in the program if possible.
6. **Lowest cost*** – Choose circuits where the least amount of work is needed.
7. **Societal impact** – Choose circuits that have societal impacts such as hospitals and airports.

***Note:** Determining a highly accurate estimate of the lowest cost circuits can be more difficult, requiring circuit modeling for final determination. However, for circuit selection in item 6 above, consider if work will be needed concerning Connectivity and Capacity components only (wire, regulators and substation bank). Automation will be performed on every circuit regardless of S.O.G.

1.2.1 Alternate Sources

- Any circuit that will serve as the only alternate source for another circuit that is part of S.O.G. should also be brought up to S.O.G. standards even if the circuit is below the circuit customer count guidance.
- If a circuit does not meet the circuit customer count and is one of multiple alternate sources to another circuit part of S.O.G., this circuit is not required to be part of S.O.G., but should eventually be segmented and automated along the feeder backbone. Use engineering judgment in these cases.

1.3 Next Steps

- Each potential circuit should be studied to understand the full scope of work in applying and meeting all three components (capacity, connectivity, automation) of S.O.G. Once the scope of work required has been determined, the remaining items below (2.0 – 5.0) should be referenced for work generation.

1.4 Visualization Tool

The Visualization Tool can be utilized to assist in year to year planning to quickly identify potential issues around lack of ties, weak ties and small conductor. This tool provides a SOG growth area view by year that can potentially be used for planning beyond the next year. A full study will still need to be performed on each circuit. See the Visualization Tool Manual below:

SOG Visualization Tool - Manual V6 201

SOG Visualization Tool - CheatSheet V2

2.0 S.O.G. Work Process Steps and Owners (Per Circuit)

Work Process Steps	DEO/DEK/DEI	DEC/DEP	DEF
1. Create Kickoff (Shell) W.O.	Grid Solutions (G.S.)	Grid Solutions (G.S.)	Grid Solutions (G.S.) Planning Engineer
2. Attach Scope Documents to Kickoff W.O.	* Capacity Planning	Capacity Planning	Grid Solutions (G.S.) Planning Engineer
3. Forward Kickoff (Shell) W.O. to	Cust Delivery PM	E&TCR	Contractor – Automation Cust Delivery PM - C&C
4. Create all Needed W.O.'s Per Circuit	Project Controls	E&TCR/Contractor	Contractor – Automation Cust Delivery PM - C&C
5. Design Job for Construction	E&TCR/Contractor	E&TCR/Contractor	Contractor

*For segmentation devices, info is entered in a workbook/template

3.0 S.O.G. Circuit Work Order Structure and Creation

The chart below refers to the work order (W.O.) structure per circuit for SOG work. **1)** Grid Solutions will create the initial Kickoff (Shell) W.O. per SOG circuit. This W.O. is intended to hold all capacity planning generated analysis and scope documents. **2)** Attach all scope documents to the Kickoff W.O. **3)** Forward Kickoff W.O. **4)** Utilizing the Kickoff W.O. and attachments, the remaining W.O.'s are created for the circuit. **5)** Design jobs for construction. All W.O.'s should utilize the common naming convention and include the circuit number, along with using "Related Record" Ref Type "SOG" and Ref Value "Circuit #" to link all SOG W.O.'s per circuit for tracking purposes. See next page for common W.O. description naming conventions. See W.O. creation job aid below. Exception: Capacity (inside fence) work is initiated via a communication from Capacity Planning to the Transmission organization.

Analysis	**Automation** **(Segmentation device Installs. Includes tie devices)**	**Connectivity** **(Excludes tie devices)**	**Capacity** **Outside Fence** **(SOG Driven Circuit Capacity Work)**	**Capacity** **Inside Fence** **(SOG Driven Sub Capacity Work)**
Kickoff (Shell) W.O. for scope/analysis attachments. **Job Plan =** SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt# **Grid Solutions: Creates Kickoff W.O.'s for each circuit targeted for SOG**	**Work Order - N** **Job Plan =** SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Specific Project ID** When creating WO's, a specific project may be generated requiring approval.	**Specific Project ID** When creating WO's, a specific project may be generated requiring approval.	**Capacity Planning:** Communication to Transmission organization to initiate work. All W.O. creation, design and construction performed by Transmission. **Grid Solutions:** Monitoring of job status via SOG program management reporting.
	Work Order – N+1 **Job Plan =** SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order - N** **Job Plan =** SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order - N** **Job Plan =** SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	
	Work Order – N+2 **Job Plan =** SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+1** **Job Plan =** SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+1** **Job Plan =** SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	
	Work Order – N+3 **Job Plan =** SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+2** **Job Plan =** SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+2** **Job Plan =** SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	

Work Order Creation Job Aid SOG WO Creation Job Aid Rev 0.docx **Mass Work Order Creation Tool Job Aid** Mass Work Order Creation Job Aid.doc

4.0 S.O.G. Work Order Description Naming Convention

4.1 S.O.G. Circuit Kickoff (Shell) WO Naming Convention - this Naming Convention is for the Kickoff (Shell) work order that will define SOG circuit scope of work.

➢ **Circuit Kickoff (Shell) Naming Convention**

GIP_SOG_Feeder Number_BACKBONE

- Example: GIP_SOG_T4600B04_BACKBONE
  - SOG work for circuit T4600B04

➢ **I&C Tech/ Equipment Operator Site Evaluation Naming Convention**

GIP_ASD_Feeder Number_BACKBONE _ SITE EVAL_DIS#/Field Tag ID or Lat.,Long.

- Example: GIP_ASD_T4600B04_BACKBONE_ SITE EVAL_ 1DDQ93 or 35.1234,73.456

4.2 Individual Work Orders Under Annually Funded Work Stream (AFWS)

➢ **Automated Switching Device (ASD) Naming Convention (Typically Electronic Reclosers)**

GIP_ASD_(Feeder Number)_BACKBONE_(Field Tag ID or Lat.,Long.)

- Example: GIP_ASD_T4600B04_BACKBONE_1DDQ93 or 35.1234,73.456

➢ **Open Point Recloser/ASD Naming Convention**

GIP_ASD_(Feeder Number)_BACKBONE_(Field Tag ID or Lat.,Long.)_Open Point

- Example: GIP_ASD_T4600B04_BACKBONE_1DDQ93 or 35.1234,73.456_ Open Point

➢ **Circuit Capacity Naming Convention**

GIP _CAP_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CAP_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

➢ **Substation Capacity Naming Convention**

Transmission Generated

➢ **Connectivity Naming Convention**

GIP _CON_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CON_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

➢ **Conductor Ampacity Upgrades (driven by new conductor ratings and not SOG)**

GIP _CUPG_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CUPG_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

5.0 Enterprise Self Optimizing Grid Strategic Program Charging Guide:

Annually Funded Work Stream (AFWS)	Job Plan	Description
Automation & Self Healing	SGSELFHEAL DEF-SGSELFHEALF DEC-SGSELFHEALC DEP-SGSELFHEALC DEO-SGSELFHEALOK DEK-SGSELFHEALOK	This work stream involves installing DSCADA-enabled electronic reclosers on the backbone for segmentation purposes. Recall the design criteria of segmenting the backbone is an average of 400 customers, 3 miles of circuit or 2MW of load. Normally-open reclosers for circuit ties will also be charged to this Job Plan. The Job Plan starts with **SGSELFHEAL** and ends with a unique code for each jurisdiction. Note the change from Specific to a Blanket charging mechanism since the average work request cost for a recloser is generally less than $50,000. Also, all work associated with Self-Healing modeling and testing will be charged to the jurisdiction blankets.
Capacity	SGFEEDERCAP	Circuit Capacity - Projects to increase Circuit Capacity as a result of meeting SOG restoration targets.
	SGAMPACITYUPG (Not SOG Driven)	Conductor Ampacity Upgrades - This effort involves upgrading conductors utilizing the common rating standards now used enterprise-wide.
	SGSYSCAPACT	Substation Capacity - Projects to increase substation capacity as a result of meeting SOG restoration targets. This “inside-the-fence” effort could involve transformer bank increases, new circuit breakers or new substations.
Connectivity (excludes tie device)	SGUPGDISTLINE	Projects to build circuit ties to alternate sources which will allow for reconfiguration options when sustained faults occur. Note the normally-open recloser will be designed under the Automation and Self-Healing AFWS .

Section IV - Circuits not Qualifying for Self Optimizing Grid

Background: Based on estimates, 20% of our customers are on the remaining 40% of our distribution circuits not targeted for full implementation for Self Optimizing Grid. These circuits either do not have enough customers on the circuit or do not have a feasible means for inter-circuit connectivity with an alternate source. These remaining circuits will still be segmented with automated switching devices and utilized by Closed Loop FISR. Work on these circuits will take place in the latter years of the Grid Improvement Plan unless abnormal performance issues drive an accelerated deployment. This section is intended serve as a guide for what should be done on these circuits.

Segmentation – Apply the segmentation rules of Section II

Connectivity (Circuit Ties) –

- The installation of new circuit ties are not required under the Self Optimizing Grid program for non-qualifying circuits. Based on engineering judgment, if a new circuit tie is deemed necessary, the cost should be covered under the Reliability and Integrity Programs in the Grid Improvement Plan. New construction circuit tie work should <u>not</u> be charged to Self Optimizing Grid for non-qualifying circuits.
- Utilize an existing circuit tie only if the conductor on both sides of the tie is 1/0 ACSR or greater.
- Do not upgrade conductors as part of utilizing a circuit tie. Closed Loop FISR (CL FISR) bases restoration decisions on real time load flow circuit models and therefore should not utilize a tie if doing so results in an overload and voltage violation situation.
- Any utilized circuit tie must have a SCADA enabled and controllable device.

Capacity – Does not apply. Existing radial circuits should have adequate capacity. In the event that an automated switch is placed at a circuit tie, Closed Loop FISR will determine the feasibility of automatic restoration and will operate only if doing so does not create an overload or a voltage violation situation.

Automation – Apply the automation rules in Section II

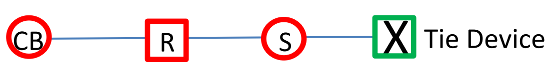
Section V: Self Optimizing Grid Segmentation Device Mode of Operation Guide

General Recommendations: Applies to the feeder backbone of each circuit part of Self Optimizing Grid

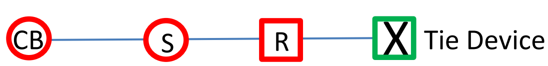
- There will be only one segmentation device setup as a recloser on the feeder backbone. This recloser should be somewhere close to midpoint based on customer count. Use judgment as to which device is setup as the recloser based on circuit characteristics such as large customers or outage probability. There will be reasons in some jurisdictions for which the recloser needs to be closer to the substation due to fault current levels and breaker reach. Exception: If needed to address a reach issue, two reclosers in series is acceptable. Setting up two segmentation devices as reclosers is expected if the circuit has a major load split close to the substation (device setup as a recloser on both sides of the split).
- Any first device downstream of the circuit breaker or the recloser should be setup as a sectionalizer.
- Any second, third, nth device downstream of a breaker or recloser should be setup as a switch. No series sectionalizer between the breaker and the recloser or between the recloser and the tie point. Some jurisdictions have three operations to lockout on breakers and reclosers. As a result, from an enterprise perspective, two sectionalizers cannot be placed in series directly behind the same reclosing device (open point excluded). The number of counts for sectionalizers is a jurisdictional decision. Note: Use judgment as to which device is setup as a sectionalizer based on circuit characteristics such as large customers or outage probability.
- Tie point device can be setup as desired based on jurisdictional preferences.

Theoretical Circuits CB Circuit Breaker S Sectionalizer R Recloser Sw Switch

2 Segmentation Devices



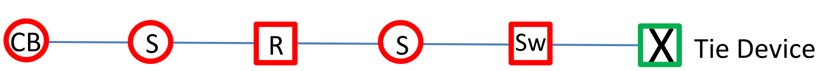
Preferred – Lower MAIFI with single phase trip. Better breaker reach for some jurisdictions.



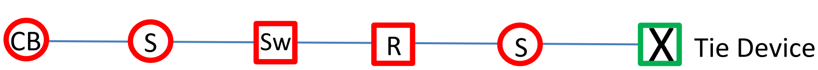
Alternate – May allow larger customers to be upstream of the recloser for fewer blinks.

3 Segmentation Devices

4 Segmentation Devices



Preferred – Lower MAIFI with single phase trip. Better breaker reach for some jurisdictions.

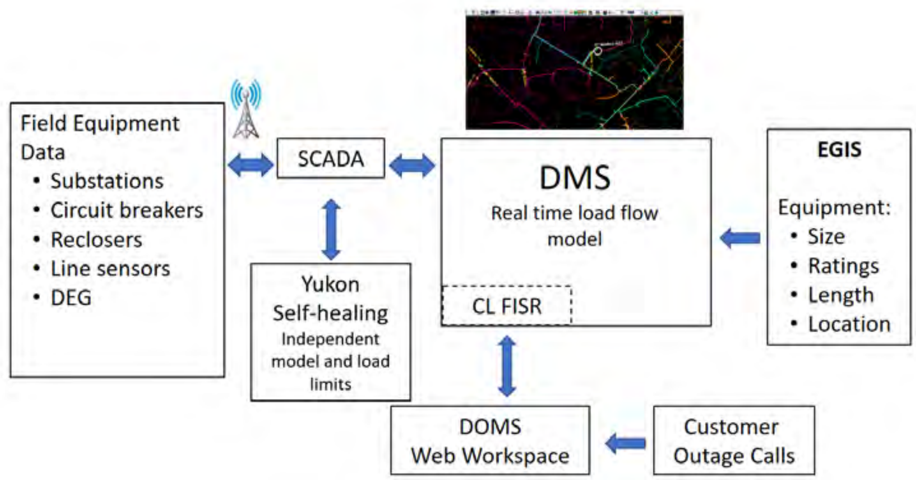


Alternate – May allow larger customers to be upstream of the recloser for fewer blinks.

5 Segmentation Devices

Section VI: FISR and Protection Validation Feature (in development)

Background: Across the enterprise, the Cooper Yukon Feeder Automation (YFA) has been the control system for self healing and S.O.G since 2010. This system has provided excellent operational reliability improvements over the years, but does require independent modeling in parallel to DMS, determination of load limits, data point setup per device, along with significant license and maintenance fees. The GE ADMS system that is being rolled out across the enterprise has an integrated automation system called Fault Isolation and Service Restoration (FISR). This system provides enhanced functionality to gain additional reliability benefits without the added licensing costs or modeling labor. FISR can be ran in two modes. The Open Loop mode means that FISR will provide reconfiguration plans for an operator to execute manually while the Closed Loop mode means the best plan will be selected and reconfiguration is executed automatically. Currently approximately half of the circuits in the Burlington, NC footprint are being controlled by FISR in the Closed Loop mode, commonly referred to as CL FISR. The diagram below shows how FISR resides in DMS and ties into EGIS and DOMS. At some future point, Duke Energy will migrate existing self healing teams from YFA to FISR. There is no set transition date at this time.



FISR Benefits:

- No separate self-healing system – FISR is part of DMS. Reduced O&M costs.
- FISR runs off of a real-time power flow model that estimates currents and voltages even if a device loses communications.
- FISR can estimate what the voltage will be after restoration and stop a restoration if voltage will be in violation.
- FISR determines load limits automatically (how much it can back-feed) because all circuit equipment attributes are in the DMS model such as conductor sizes, equipment ratings, bank capacity, etc.
- FISR can retry operating a device if the trip or close does not go through initially.
- Minimal additional device setup is required to enable automation once setup in DMS/SCADA.
- FISR considers substation bank loading.
- No team concept. The whole system is a team meaning many restoration options.
- FISR automatically disables automation to a circuit when HLT is applied.

Protection Validation Feature - Currently in most jurisdictions, recloser group settings are being changed depending on circuit configuration within self healing/SOG. This is done to accommodate load, maintain coordination and ensure adequate protective reach in all possible scenarios. This is manageable for smaller teams. However, as you begin to build out a network that involves many circuits and devices with many reconfiguration options, this becomes very difficult to maintain. An extreme example is a device in the Burlington FISR footprint that has seven different possible sources calling for four different group settings depending on reconfiguration.

During a reconfiguration, it is highly important that our equipment is not overloaded and protective reach is maintained such that if there is an additional fault, our reclosers can detect it. Maintaining coordination is good to have, but not critical in this temporary configuration. Both YFA and FISR currently have a miscoordination feature such that if two devices see the same fault and lockout at the same time, the upstream device will be closed if automation remains enabled.

Duke Energy is currently working with GE to develop a feature called Protection Validation (PRV) that will check for adequate reach before a restoration occurs. FISR already checks the load against the device trip settings in the lookup table before reconfiguring. The concept is to have a default group setting for all devices in their normal configuration like a typical radial feeder. Discontinue the practice of determining the group setting for all possible scenarios and rely on the Protection Validation (PRV) feature to check for adequate reach. If reach is determined to be inadequate, PRV changes the group settings for all devices in the violating protection zone to a group that maintains reach without tripping for overload. This will result in a potential loss of coordination, but as mentioned, FISR has a miscoordination feature and this would be considered a temporary configuration. This will require a new template that indicates the default group, for "Return to Normal" and the template number DNP data point for FISR to understand the settings in the other groups of the template.

More information will be included in future revisions as this feature is in development and could change slightly upon completion. This feature will be tested on two self healing teams in Ohio before determining future implementation. The PRV feature development completion is expected in the 4th quarter of 2020 with implementation in the two Ohio teams to occur shortly after that.

Appendix I - Questions and Answers: This section is intended to provide further clarification on this application guide based on submitted questions.

SOG Analysis and Capacity Related

Question: How does SOG affect existing extra facilities such as a customer paying for an alternate feed with reserve capacity?
Answer: There two angles to this question. If a customer is paying extra facilities for an alternate feeder, this means they are paying for the automatic throw-over and reserve capacity. SOG is not intended to serve as a replacement since there is no guarantee that restoration will take place to all unfaulted line segments as intended. Pre-existing ATO's and the input feeders should not be altered by SOG unless the contract has expired and the customer chooses not to renew. Also, the reserve capacity must be factored in when considering capacity requirements for SOG.

Question: When considering the 75% of projected peak rule for unloading to relief circuits, does that apply to the bank as well? For example, look at the peak load at the relief bank and assume you will be picking up the extra load when the bank is at 75% of its peak.
Answer: Assume the relief bank is at 75% of peak demand as well. Designing capacity to handle additional circuit load at 75% of peak, while considering the bank load at 100% of peak could lead to unintended bank upgrades.

Question: When considering the 2MW segment load target, should that load also be considered at 75% of peak load.
Answer: Yes. All load considerations under SOG should be taken at 75% of projected peak to meet the 90% of the hours in a given year availability rule.

Question: Do we consider load growth while performing SOG circuit analysis.
Answer: In general, do not include load growth. If there is a circuit with or expecting a much higher than normal load growth, this can be considered as part of the circuit analysis. When executing load growth projects, the project should be built to SOG rules. Segmentation device installations as part of this project can be charged to SOG.

Question: Post SOG circuit work, how far is the capacity allowed to be eroded due to load growth before action is taken to regain the original availability target of 90% of hours per year? Do we allow large customers adds without work to redesign the segment or add capacity to meet the original SOG design?
Answer: The original intent was that the business will maintain SOG to original design, post deployment. However, there have been no set rules around when and how this happens. More work is needed to address this question.

Question: If a SOG feeder has multiple ties, should we stop our review when we can unload the SOG feeder at 75 % peak even if that means several ties were not reviewed. If there is a feeder tie that is not selected to be part of the SOG network, should we install an automatic switching device at the unused tie point?
Answer: If there is another feeder tie that is above what is necessary to unload a SOG circuit, engineering judge should be utilized to weigh the benefit of the additional tie. If this additional tie helps to unload a SOG circuit, adds additional switching options, and the conductor is greater than #2 ACSR, the installation of this additional tie is acceptable. Do not install non-essential ties until SOG work is planned on the alternate (relief) circuit. If the tie is between 2 non-SOG circuits, installing an ASD must be funded from a different bucket of money.

Question: How far do we go into the alternate (relief) circuit with SOG principles? SOG the entire circuit?
Answer: If the circuit is in the 10 year SOG plan, analyze the alternate (relief) circuit for connectivity, capacity and automation. If the circuit is not in the 10 year plan, only apply the automation (segmentation) rules. Exception: If the relief circuit is not on the SOG list, but is the only alternate source for circuit part of SOG, the relief circuit should be included in SOG also. In the either case, stop work on the alternate (relief) circuit at circuit ties to a third circuit, i.e. don't add ASD's at tie points on circuits beyond the relief circuit until the scheduled SOG analysis on those circuits.

Question: How should we model capacitor banks for voltage support when performing a SOG circuit analysis?
Answer: Assume that all switched bank capacitors are on.

Question: What conductor ratings should be used in the model?
Answer: Refer to the new conductor ratings published in the enterprise Distribution Standards manual. Per the listed notes below the ampacity chart, legacy ratings can continue to be used on lines constructed before the 2016 publication as long as the legacy ampacity rating was based on a conductor temperature of 185F or less. Legacy ampacity ratings that were based on a conductor temperature greater than 185F are now required to utilize the published enterprise ratings, which includes DEC. There are no longer emergency ratings.

Question: Do we design SOG such that we have bank failure contingency, i.e. be able to pick up the entire load of the bank if there is a failure.
Answer: Although it is desired to have the ability to pick up as much load as possible in most circumstances, requiring a bank failure contingency would lead to the need to upgrade a lot of banks for a very low risk event. Therefore, SOG should be designed for a single circuit contingency.

Question: What are the rules concerning "utilized" circuit ties for a tie in a loop on the same circuit?
Answer: While there may be some benefit, a circuit tie ASD in a loop on the same circuit does not provide benefit if losing most or all a circuit during an event. As a result, it is not a recommended practice. However, if the additional tie allows adherence to the rule of isolating a fault to one segment, while restoring all other customers, this would be allowed. Use engineering judgment.

Question: What are the rules around DER with respect to SOG?

Answer: A general recommendation is to exclude circuits with DER for the first couple of years of the program if possible. The current self healing system software, YFA, can model DER. However, this system does not control regulators, which presents an issue when an upstream line regulator controller is locked on CoGen mode and the regulator is back-fed from a new stiff source. Essentially, the regulator can go into runaway either stepping to max buck or boost. Below are further recommendations per jurisdiction.

DEMW – Include DER as desired. The Midwest uses the M-6200 regulator control that has an auto determination feature eliminating the runaway concern.

DEC – If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. If there is a strong desire to include immediately, a control change-out will be necessary. Contact Rod Hallman.

DEP - If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. A control change-out to prevent the concern is not possible until the full DMS conversion to Alstom.

DEF - If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. If there is a strong desire to include immediately, a control change-out will be necessary. Contact Rod Hallman.

Load Limits and Protection Settings

Question: Is there a plan to coordinate determining protection settings and recloser mode?

Answer: Enterprise-wide, who determines the settings that are put in the reclosers and even how they are setup (recloser, sectionalizer or switch) are not the same. In DEF, DEI, DEO and DEK this is determined by the capacity planners. In the Midwest, these recommendations are installed through DPAC. In the Carolinas, although the capacity planners may look at reach and recommend how they think the device should be setup, determining the protection settings and the device mode is ultimately a DPAC decision. The implementation of SOG was not meant to and should not change this current process of determining reach or protection settings. Recently, an enterprise guide for determining the recloser mode/setup (also called mode of operation) was established and should be used. See Section V. In all jurisdictions, the planner has some level of involvement and should keep in mind the downstream customer type in making recommendations on the setup. For example, if there are multiple ASD's and a larger customer exists close the midpoint, it may be better to setup the first ASD downstream from this customer as a recloser to reduce momentary operations seen by this customer.

Question: Existing SH rule in DEC concerning setting load limits is set with respect to equipment ratings or no higher than 75% of the trip settings of the protective devices in an effort not to cause another lockout. How does SOG affect this?

Answer: Load limits on individual devices are Cooper YFA specific. How they are determined and who makes the determination is a little different across the company. For example, load limits in DEF may be set based on expected conductor sag rather than on equipment ratings and trip protective settings due to tight clearances and larger conductors. SOG should not change the current process for determining load limit or protection settings. Once FISR is in place, load limits settings per device will no longer be needed.

Appendix II: Gang Operated Air Break (GOAB) Switch Replacement Guidance

Objective: Gang operated air break switches exist on the Duke Energy distribution system for the purpose of switching with the advantage of being able to operate, including breaking load if needed, from the ground. However, these switches do need routine maintenance to ensure proper operation and have increasingly failed to operate as expected as they age. This includes both hook-stick operated and down-the-pole operated GOAB switches. In an effort to eliminate maintenance requirements and reduce operational difficulties, a replacement program has been developed to replace these switches with either a standard electronic recloser, a new SCADA capable electronic switch, manual disconnect switches or switch removal. Below is the guidance for determining the replacement option per switch location.

Preface: Beginning in 2022, any new SOG circuit studies will include addressing all GOAB switches present on these circuits. This also includes GOAB switches at tie points between SOG and non-SOG circuits. There is an existing population of circuits currently on SOG, work scope completed to be on SOG and circuits not targeted for SOG (non-SOG). These circuits need to be addressed independently from new SOG circuit scoping work starting in 2022.

GOAB Switch Target Locations

GOAB Target List

Perform the following steps to determine the GOAB switch replacement option for each targeted location: Replace with electronic recloser, electronic switch, manual disconnect or remove

1. Determine if the GOAB switch is currently on a SOG circuit or a circuit targeted for SOG in the future. If so, go to step 2. Otherwise go to step 3. Go to "Important Links" below to make this determination.

2. GOAB Switches on Circuits Part of SOG (currently on SOG or future SOG)

   Normally Open GOAB Switches (Tie Points) – Any GOAB switch at a circuit tie point between two SOG circuits should be replaced with a SOG segmentation device/electronic recloser if utilized for SOG. If the GOAB switch will not be utilized as a tie point for SOG, replace with a manual disconnect. If the GOAB switch is between a SOG and non-SOG circuit and the primary conductor size on both sides is larger than 1/0, replace with a SOG segmentation device/electronic recloser. If the primary conductor size on both sides is 1/0 or smaller, replace with an electronic switch. Background: Most circuits will be part of SOG and even non-SOG circuits that have a viable circuit tie can become a partial SOG/automated circuit at some point in the future and therefore a remotely controlled device is justified.

Normally Closed GOAB Switches – Any GOAB switch on a SOG circuit should either be replaced with SOG segmentation device/electronic recloser, a manual disconnect or removed. Do not replace with an electronic switch. If the switch will not be replaced with an electronic recloser as part of SOG segmentation, determine if switch should be replaced with a manual disconnect or removed. Ideally within a SOG segment, the switch should be located at approximately 50% of the limiting SOG segmentation criteria. However, because the switches are already in place use the following rule of thumb. Ensure that no more than 75% of the line exposure or customer count exists on either side of the GOAB switch between the SOG segmentation devices. Exceptions to this rule include: 1) A very high percentage of the customers or load in a segment exist on one side, while a very high percentage of the line exposure is on the other side. 2) The switch location could assist in the restoration of critical customers. The installation of manual disconnects requires truck accessibility. If there are accessibility issues, it is acceptable to remove the GOAB switch and install a manual disconnect in another truck accessible location. This may require a site visit for confirmation as accessibility is not always clear in MyWorld.

3. GOAB Switches on Circuits **not** Part of SOG (non-SOG circuits)

Normally Open GOAB Switches (Tie Points) - If the GOAB switch is between two circuits not on the SOG Circuit Master List and the primary conductor size on both sides is larger than 1/0, replace with an electronic recloser. If the primary conductor size on both sides is 1/0 or smaller, replace with an electronic switch.

Normally Closed GOAB Switches - Answer the following criteria questions. If any two or more of these questions are yes, replace with an electronic switch. Otherwise replace with a manual disconnect. If replacing with a manual disconnect and there are accessibility issues, it is acceptable to remove the GOAB switch and install a manual disconnect in another truck accessible location. This may require a site visit for confirmation as accessibility is not always clear in MyWorld.

A. Are there critical customers such as a nursing home, hospital, airport or other utilities (water/sewer behind/downstream from the switch)? This assumes there is a viable tie to an alternate source to back-feed this customer(s). If there is not an alternate source, the answer is no.
B. Are there accessibility issues? (Truck setup would result in blocking traffic in a high traffic area or there is poor truck accessibility)
C. Has the device been operated more than 3 times in 1 year? – future link
D. From the substation to the circuit tie point used to back-feed, is there a remotely controlled electronic switch, recloser or breaker on either side of the GOAB more than 3 miles away. If remotely controlled devices on either side are more than 3 miles away, the intent is to reduce drive time for emergency switching during an outage?

Important Links: Circuits already part of SOG and SOG scoping work completed prior to 2022 do not include addressing GOAB switch replacements. Starting in 2022, SOG circuit studies will include GOAB switch replacements. Therefore, it is important to understand which SOG circuits will need to be revisited for GOAB switch replacements, which will need to be addressed independently from future SOG work. Below are links to tracking spreadsheets to help make that determination. GOAB switch replacement decisions on scoped SOG circuits prior to 2022 should involve consulting with the appropriate planner to understand planned circuit work.
DEP DEC DEF DEO/DEK

GOAB Replacement Options:

- **Electronic Switch** - ABB OVR or G&W Diamondback

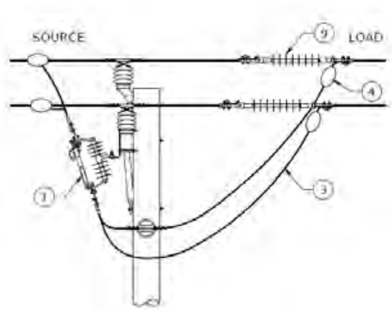
Refer to the Distribution Construction Standards manual, Section 8

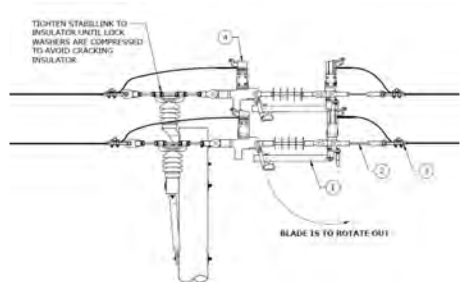
- **Electronic Recloser** – G&W Viper ST (For utilizing at Circuit Tie Points Only as part of GOAB replacements)

Refer to the Distribution Construction Standards manual, Section 8

- **900/600 Amp Manual Disconnect Switch** – Single Insulator Style or Inline Tension Disconnects

Both switch types are acceptable





Refer to the Distribution Construction Standards manual, Section 8

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STAFF-DR-04-014
CONFIDENTIAL ATTACHMENT 3

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Duke Energy Midwest Engineering Guide

Conductor and Equipment Ratings

June 2011

Developed by: T&D Standards

Preface:

Planning, Engineering and Operational Guidelines for Loading Transmission Lines and Terminal Equipment.

Conductors are rated based on thermal conditions. Ratings may be set by the maximum temperature that the conductor, using its designed installation, can operate at and still maintain required NESC clearances. Ratings may also be set to avoid thermal damage to conductor or line accessories. All new transmission line construction shall be capable of operating at 100 deg. C or greater. Existing lines may have varying allowable temperatures of operation due to original design conditions. Equipment ratings are based on American National Standards Institute (ANSI) requirements or by limits set by the equipment manufacturer.

Duke Energy Midwest will maintain a PLS-CADD, 3 dimensional model for its 230kV and 345kV transmission system. This model is based upon utilizing LiDAR, or equivalent, survey data that provides a profile of the entire right of way utilized by the transmission line. This model was initially developed for the bulk electric transmission system (230kV and higher) ground clearance study. All new transmission lines (100kV and higher) are to be engineered and modeled in the same manner. Additionally, any existing facilities reviewed for rating changes are to utilize this approach and be modeled as well.

The ratings for conductors and equipment are to be adjusted for as-built conditions that are discovered in the field. These can result from items such as enchroachment on the right of way by others or through errors created during the initial design and construction of the facility. When an as-built condition is discovered that delivers clearances less than those required by the NESC the following actions should be taken:

1. *Identify all the spans that do not meet the NESC clearance requirements.*
2. *Analyze each span identified to determine the new temperature rating.*
3. *Notify System Operations of the new temperature rating.*
4. *System Operations, together with Field Operations, Planning and Engineering as appropriate, will perform an operational risk assessment associated with implementing the new rating.*
    a. *If the risk assessment determines that the operational risk is acceptable, then de-rate the line to the new rating and develop a work plan to return the line to the desired rating in a timely fashion.*
    b. *If the risk assessment determines that the operational risk is not acceptable, then put an emergency operational plan in place that allows the facility to be operated at a rating that mitigates the operational risk. Additionally, a work plan will be developed to return the line to the desired rating in a timely fashion.*
5. *The PLS-CADD model is to be updated to reflect as-built conditions.*

The rating for conductors and equipment may also be adjusted for changes in ambient conditions. During normal operating conditions all conductor loads shall be maintained below published ampacities. During operating emergencies, it may be necessary to operate lines at currents above the published ratings. This is allowable if ambient conditions permit additional current flow without exceeding line clearance requirements or equipment limitations outlined in the Duke Energy Midwest Engineering Guide. The procedure listed below is to be followed to determine if a transmission line can be operated at ampacities greater than those published.

1. *The line shall be evaluated using PLS-CADD. If the PLS-CADD model indicates the line has clearances greater than what is required by the NESC, the following steps should be taken to determine the adjusted rating:*
    a. *Determine which span(s) are closest to the allowable NESC clearance limits.*
    b. *Calculate the sag allowable in this span(s).*
    c. *The temperature which produces this additional sag will become the operating temperature during the emergency.*
2. *If the PLS-CADD model indicates the line does not have clearances greater than what is required by the NESC, the line cannot be operated at greater than published ratings.*

All new transmission substations, switching stations and line switch installations are to be designed so that the line conductor is the limiting factor for loadability. At no time should any terminal equipment be the limiting factor.

The rating of a Duke Energy Midwest facility which may include transmission lines, transformers, and other devices shall not exceed the rating of the component with the lowest rating in series with the facility. This means that breakers, switches, current transformers, terminal connections, metering equipment, and other equipment associated with the facility may define the rating. In cases where protection systems or control settings may impose a loading limit on a facility, then the rating for the entire facility will be held to that limit.

The rating of jointly-owned and jointly-operated facilities will be coordinated among the joint owners and operators so that there is a single set of ratings for these facilities.

Planning activities shall use the published rating of transmission line conductors and equipment as the maximum allowable ampacity for normal load flow calculations and n-1 contingency evaluations. When studies indicate normal ampacities will be exceeded, a CER shall be generated to initiate a project to alleviate the excessive loading condition.

All equipment shall be inspected and maintained at appropriate intervals allowing optimal performance at thermal limits.

Conductor and Equipment Loading:
Among the most important factors in the design and operation of the electric transmission and distribution system are the current ratings that are used for the conductors. The current carrying capacity or ampacity, for a given conductor is calculated for a very specific set of conditions. Changes to these conditions can drastically affect the current rating. The rating conditions are different for overhead and underground conductors but all are based on the temperature of the conductors and the surroundings.

When a current passes through a conductor, it generates heat due to the resistance of the conductor. Larger conductors have lower electrical resistance, so they can carry larger currents without generating as much heat. The easiest solution would be to select a conductor size that was sufficiently large that it would never get heated up to the level where it was a problem. There is a practical limit to the size of the conductor that can be used however. Studies are done to determine the most economic conductor size based on the amount of load that must be carried. The choice of a maximum conductor size is very important because it dictates so many other parts of the system design. Larger conductors may carry more current but they are also heavier and require stronger supporting structures and handling equipment. In addition to the material cost for the larger conductor by itself, there are costs for the additional labor and materials that must be evaluated. The best selection is the one that meets the current carrying requirements and minimizes the other costs.

The maximum allowable temperature that a conductor can carry depends on the materials used in its manufacture and in how it is designed. Most overhead conductors can be operated at temperatures of up to 150ºC without damage to the conductor or to the connecting hardware. It is very unusual to do this because there is little margin for error. For example, if the dead ends and other conductor clamps are not properly installed, they may cause increased heating and damage the conductor. Underground cables and overhead conductors with coverings (weatherproof) are even more restricted to be sure that the highest operating temperatures will not cause damage to the insulating materials or cable accessories. The maximum operating temperature for most cable designs used by Duke Energy Midwest is 90°C under normal loading circumstances. Higher temperatures (up to 130°C) are allowed under emergency conditions. The time that a covered or insulated cable is allowed to operate at elevated temperatures (above the normal maximum) should be limited, otherwise damage to the cable can occur and premature failure may be expected.

The amount of heat that conductors may carry is also influenced by other conditions. The temperature of the surroundings (ambient temperature) is very important. If the temperature is high, less current is needed to cause the conductor to reach its maximum rated temperature. Conductor ratings are usually established for both summer and winter conditions to recognize the impact that ambient temperature can have on a conductor. For overhead conductors, the winter and summer ratings are based on typical daily air temperatures during the winter and summer. Soil temperatures at a depth of 30" are used for underground cables.

Ventilation also plays an important role in rating conductors. If a conductor is installed where the air is free to move around like an overhead conductor, it will be able to carry larger currents than a conductor that is installed where ventilation is poor (an underground cable). This is because the air is very effective in helping to cool the cable. The direction that the wind travels across the conductor has a major effect on the rating. If the wind travels across the conductors at a right angle it provides significantly more cooling than a wind that is blowing parallel with the conductors. For underground cables where ventilation is not a factor in most cases, the ability of backfill materials to carry away heat (thermal resistivity or rho (ρ)) is an important part of determining the allowable current rating. If the heat is unable to move into the surrounding soil at a fast enough rate, the cables will fail due to thermal runaway (the insulations will soften or melt!). For Duke Energy Midwest ratings, the rho is assumed to be 90. This is an industry standard value.

Conductor and Hardware Operations:
Conductor ratings at Duke Energy Midwest are based on maintaining designed minimum clearances as mandated by the National Electrical Safety Code (NESC). An integral part of establishing clearances is the assumption of a maximum operating temperature for the conductor upon which sag calculations are made. Establishing a maximum temperature limit based on clearances, eliminates the need to establish "normal" ratings and "emergency" or "contingency" ratings since the conductor may be operated at any temperature on a continuous basis up to the maximum temperature limit without compromising required clearances. Consequently "normal" ratings and "emergency" ratings are the same. All framing clearances and minimum pole height requirements for T&D installations using wood poles are based on these assumptions.

Use of the framing dimensions in the Duke Energy Midwest standards with those conductors defined for new construction at Duke Energy Midwest will result in designs that meet applicable NESC clearance requirements if proper design and construction practices are followed. No specific buffers are included as hedges against variations in applications. Designers are expected to include any additional clearance that they might expect to be needed in their finished designs. Construction crews are expected to follow framing dimensions and use commonly applied work practices to insure that conductors are sagged properly. Designs outside of those included in the T&D Standards (i.e. lattice-steel or tubular steel pole transmission structures, H-frames, or other special constructions) must be evaluated for proper clearances on an individual basis by the designer.

Designers and planners, particularly those involved with projects around DUKE ENERGY OHIO and DUKE ENERGY KENTUCKY, have been cautioned that existing lines must be evaluated carefully to insure that appropriate clearances are maintained if the line is to be upgraded to operate under the new Duke Energy Midwest conductor ratings. These line must be evaluated individually because of the possibility that they may have been designed to operate at lower thermal ratings. Lower operating limits would result in lesser clearances because of reduced sag in the conductor at the rated operating temperatures.

Determination of Conductor Rating Criteria:
The conductor rating criteria selected for use to rate Duke Energy Midwest conductors and the establishment of a maximum allowable conductor temperature based on NESC designed clearances forms a valid and acceptable practice for line design and operation.

It has to be understood that using a fixed set of design criteria does expose Duke Energy Midwest to some risk, since some of the assumed conditions may be exceeded under rare circumstances. It is felt that this risk is low and that the cost to accommodate all of the variables that could influence the ratings so that the probability of exceeding the design criteria would be essentially zero would be excessive.

As Duke Energy Midwest and the rest of the utility industry have responded to pressures to provide lower cost energy with minimal interruptions to service, more and more emphasis is placed on operating at or near the design capabilities of the equipment. A natural tendency is to extend operating limits beyond those used in the past. There is significant risk that must be accepted by those that select such an option.

The ratings that were developed for application on Duke Energy Midwest circuits are based on conservative parameters. Only in very rare circumstances when atmospheric conditions exceed assumed values should conductor temperature go above the rated values. The rating conditions for new conductors do not automatically apply to installations made before the merger, especially overhead lines built in the DUKE ENERGY OHIO & DUKE ENERGY KENTUCKY service areas. Because of that lack of information about past operational history for existing lines, the variability in materials used for the construction of existing lines and the effects of many years of exposure to the elements, T&D Standards feels it is unwise to arbitrarily extend the operational ratings established in the ratings guide beyond the values published in the guide.

At Duke Energy Midwest, aluminum conductors have a maximum operating temperature of 100ºC and copper conductors have a maximum operating temperature of 80ºC Duke Energy Midwest distribution standards are based on conductor sags at 80ºC. There are some circuits, particularly in the DUKE ENERGY OHIO/DUKE ENERGY KENTUCKY service territories, with clearances based on a maximum of 50ºC. Circuits installed prior to revised NESC requirements issued in 1991 could be affected by the 50ºC limitation. Conductor temperatures in excess of design limits may cause conductor clearances to be reduced below current NESC requirements. Contact with other facilities at lower levels on the pole is possible. For overhead systems in the Duke Energy Midwest East area, it is very important to determine the age of the overhead mainline conductor (336kcmil ACSR, 477kcmil ACSR or 795kcmil AA) to insure that the proper limiting temperature is selected to define the rating. The 336 and 477kcmil ACSR conductors are of most concern because the sag increase due to conductor heating (from 50º to 80ºC or higher) will be proportionally higher for them. 795kcmil AAC is unlikely to sag significantly beyond design limits by additional load currents up to 700A.

Adoption of Duke Energy Midwest loading criteria has placed an additional burden on designers and planners in the DUKE ENERGY OHIO/DUKE ENERGY KENTUCKY service area because rating criteria used in the past there were based on less stringent conditions allowed by the NESC. Lower operating temperatures might have to be considered for many circuits in the East because the lines are not able to meet required clearances if they are operated at the temperatures used for current ratings.

Operating limits are calculated using a software package provided by Southwire. This software is based on IEEE standard 738- 1993. This software utilizes a number of inputs to determine what currents will create what temperatures in the conductors... The most significant variables are: Wind Speed, Ambient

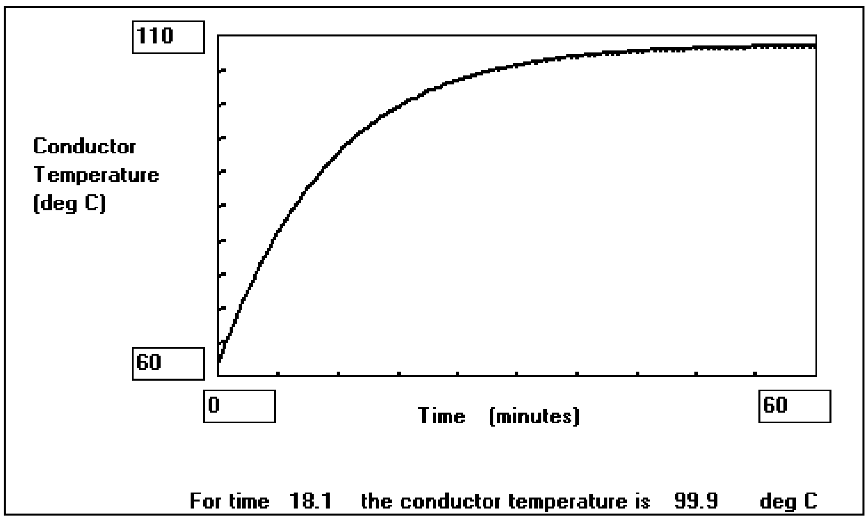
Temperature, and Wind Direction (relative to the conductor). The sensitivity to changes in these criteria is discussed elsewhere in the Duke Energy Midwest Conductors & Equipment Ratings Guide.

Transient Loading for Overhead Conductors:
Overhead conductors react quickly to changes in the current flowing in them. Operating personnel do not have a lot of time to make decisions and to react when loads increase suddenly.

For example, when the load on a 954kcmil 45x7 ACSR (RAIL) conductor is raised from 50% of its summer maximum rating (639A) to the rated current (1279A), the conductor will reach the maximum allowable temperature of 100ºC in about 40 minutes.

Applying currents in excess of the rated current can shorten the time necessary to reach the allowable operating temperature. For example if the same 954kcmil conductor was carrying about 90% of the rated current (1151A) and the current was increased to a level 10% above the rated current (to 1400A), the maximum allowable conductor temperature (100ºC) will be attained in about 6 minutes.

The SWRate Software is used to determine the approximate time necessary for a conductor to reach a specific temperature. This is done by dong a transient calculation and reviewing the plot results (Shown below). The time and temperature information are displayed when the cursor is placed anywhere on the plotted curve.



<u>Operations Above Design Criteria</u>
If it is necessary to operate a line above the design limitations, several important points must be considered. There may be occasions when it is necessary to operate a line beyond the conductor rating established on the conductor ratings guide. Should such a situation occur, it is important that the individuals involved with the decision to operate at elevated temperatures understand the possible problems associated with overload conditions. They must also be prepared to accept the consequences for a failure during a period of high temperature operation. If time allows, a thorough assessment of clearances at elevated temperatures should be made and the physical condition of the conductor and accessories should be evaluated before the extended operation begins

<u>Physical Clearances:</u> - If a line is to be considered for operation at elevated temperature, the design of the line must be reviewed. If it is found that the design criteria are based on lower conductor operating temperatures, a review of possible clearance problems must be made. Duke Energy Midwest is required to meet minimum NESC clearances under all operating conditions. Emergency operating conditions allow only a small reduction in the allowable clearances (NESC Rule 230A2b). Prior to operating at higher conductor temperatures, the PLS CAD model is to be utilized to determine if the conductor can be operated at this level.
<u>Material Limitations:</u> - Another key component to allow operation of a line at elevated temperature is to review the condition of the line itself. The age of the line and the materials used to construct it have a huge bearing on the ability of a line to operate at higher temperatures.

- *Conductors:* The age and type of conductor has to be evaluated carefully. Copper and aluminum conductors are common on the Duke Energy Midwest T&D system. They are very different in their ability to accommodate high temperature operations.

  The biggest concern is that high temperature operation may cause annealing of the conductor. Annealing of a conductor is the gradual loss of tensile strength when it is exposed to temperatures above a specific limit. The loss of strength is based on the amount of time that a conductor is exposed to a high temperature. Annealing is a cumulative process, and results in permanent loss of strength. The original characteristics are not restored when the conductor returns to a normal temperature. Any loss of strength in a conductor can affect the sag/tension relationship and result in the loss of required NESC clearances.

  Conductor construction and materials have a large impact of the annealing of the conductor. Conductors with homogeneous construction (all of the same materials) are usually more susceptible to damage from annealing. Composite constructions where two materials are combined for strength and conductivity such as ACSR & ACSS, may not be affected by annealing problems at normal operating temperatures because of the high tensile strength of the steel cores in them.

  Operational records for transmission lines are not available at Duke Energy Midwest so prior loading history cannot be determined. Operation above the 100°C limit established by the standards is not recommended because of the lack of information on what the past loadings might have been.

- *Conductor Accessories:* The splices, dead-ends and suspension hardware used on the conductors must also be evaluated for high temperature operations. Those accessories that are part of the current carrying path are the most likely to experience overheating. In addition to the limits established by the accessory designs, concern must also be directed toward the installation of them too

  Copper conductors often use malleable iron clamps and dead-ends. If these are made entirely of iron, a rudimentary current transformer is created by the iron clamp encircling the conductor. The induced currents in the clamp or dead end will cause localized heating in both the clamp and the conductor. This heating can be as much as 10° above the conductor temperature.

  Properly installed aluminum accessories are expected to operate at or below the conductor temperature. Because aluminum is not normally a magnetic metal, the induced current problems created by malleable iron fittings do not exist. Of more concern is the preparation of the conductor prior to splicing or dead-ending. Aluminum oxidizes easily. The oxide that is formed has a high electrical resistance compared to the aluminum. It is not easily removed. Work practices used for aluminum conductors involve thorough cleaning of he conductor and connector as well as application of corrosion inhibiting compounds that minimize the oxidation of the aluminum. Failure to use good work practices can lead to thermal heating and damage to surrounding conductors.

  Most connectors used for aluminum are installed by compressing the connector onto the conductor. In addition to proper cleaning, the quality of the compression connection is tied to the use of proper tools and techniques. Failure to use the correct presses, dies, or press techniques (overlaps and rotation) will compromise the quality of the connection. Bolted connections (jumper taps, bolted dead ends etc.) require proper cleaning, inhibiters and the application of the proper torque to the bolts to insure a proper connection.

Overhead Conductor Rating Assumptions:

Covered Wires; Secondary or Service Conductor (Overhead):

- Maximum Conductor Temperature - 90°C for XLPE and EPR based coverings; 75°C for PE based coverings
- Ambient Temperature - 40°C
- Emissivity – 0.9
- 2 Ft/Sec. Wind Speed
- No Sun Exposure

Bare Wires Used for Primary Conductors (Transmission or Distribution):

- Maximum Conductor Temperature – Overhead Conductors
  - 50ºC for all distribution conductors installed prior to 1991 in the DUKE ENERGY OHIO or DUKE ENERGY KENTUCKY service territories UNLESS

clearances have been verified and found suitable for operation at higher temperatures.

- 80ºC for all new aluminum distribution conductors (Duke Energy Midwest), all distribution conductors installed at DUKE ENERGY INDIANA and all distribution conductors installed at DUKE ENERGY OHIO or DUKE ENERGY KENTUCKY after 1991; All bare copper conductors (Transmission or Distribution), if clearances are adequate (See previous bullet).
- 100ºC for all aluminum transmission conductors Duke Energy Midwest wide. (Note operation above 100ºC is restricted to special applications – please consult with T&D Planning for specific criteria)

- Ambient Temperature - 0°C Winter; 35°C Summer
- Emissivity Factor 0.8; Solar Absorption Factor 0.8
- 2.93 Ft/Sec. (2 mph) Wind Speed
- Sun Exposure at 39° Latitude, 2:00PM in the afternoon, Clear Atmosphere
- East to West Line Orientation
- Wind is blowing at right angles to the line direction
- Line elevation is 500ft.

Since the current rating is directly related to the sag of overhead conductors, extreme caution should be used to be sure that the designer or planning engineer fully understands the basis of the ampacity calculations and the effect of changes to the design assumptions. It is strongly suggested that these ratings should not be used for operational limits if actual field conditions differ from the design assumptions.

Overhead and underground conductor ratings are very sensitive to changes in the assumptions used when making calculations. The most influential factors affecting the ratings of overhead conductors are ambient temperature, wind speed, and wind direction in relation to the conductors. Some examples include:

- If all other design assumptions remain unchanged, ampacity will change about 1% for each degree change in ambient temperature (up or down). For 566kcmil AAC, the ampacity drops from 766A to 709A if the ambient temperature rises from 30ºC (90ºF) to 38ºC (100ºF).
- A change in wind speed from 2.93 ft/sec to 2.0 ft/sec decreases the rating of 556kcmil AAC by about 8% (766A to 701A).
- If the angle of incidence of the wind against the conductors changes from perpendicular to the conductors to parallel to the conductors, the current rating will be reduced by about 34% (from 766 to 505A).

During periods where it may be necessary to load a circuit to high levels, an ampacity calculation based on the existing conditions is suggested. This calculation will establish operating limits based on the specific conditions that are in place at the time of the emergency.

Underground Conductor Rating Assumptions:

Secondary or Service Conductor):

- Maximum Conductor Temperature - 90°C for XLPE and EPR based coverings
- Ambient Earth Temperature - 5°C Winter; 25°C Summer
- Soil Thermal Resistivity (rho) 90
- 75% Load Factor

Primary Conductors (Transmission or Distribution):

- Maximum Conductor Temperature – Underground Cables
  - 90°C for Normal Operations;
  - 130°C for Emergency Operation for XLPE, TRXLPE or EPR Insulations EXCEPT for 1000kcmil AL power cables installed in a single duct. (See Detailed Explanation Below)

- Ambient Earth Temperature - 5°C Winter; 25°C Summer
- Soil Thermal Resistivity (rho) 90 (includes backfill material also) and 50 for concrete encasement
- 75% Load Factor

The maximum operating temperature for 3-1000kcmil AL power cables has been adjusted to meet the planning assumptions for substation and feeder loading. It was necessary to rate these cables at a normal operating temperature of 100C to meet desired loading targets. The effect of allowing these cables to operate *above the industry standard temperature rating (90°C) is expected to be negligible since it is unlikely that any Duke Energy Midwest circuit will operate at current levels sufficient to cause the conductor to exceed 90°C for long periods of time. Industry research and manufacturer's data indicate that modern cable insulations are capable of operating at temperatures in excess of current standards. There is concern however about the long-term capability of the cable accessories during extended periods of high temperature operation.*

As with overhead conductors, some rating criteria have more impact than others. The earth ambient temperature and the thermal resistivity of the surrounding soil will have a major impact on the capacity to load the conductor. For 1000kcmil Al feeder cables installed in a duct:

- A five degree increase in the ambient temperature (from 5ºC to 10ºC) around the cable will decrease the current carrying capacity by about 20A (655A to 636A). This relationship is fairly constant up through 25ºC.
- Each ten point increase in soil thermal resistivity (rho) (i.e. from 70 to 80) will decrease the current carrying capacity by 10A (593A to 583A).

The consequences of overloading an underground cable are usually not recognized immediately. Only in rare cases will UG cables go into thermal runaway and fail while the excessive loading is still applied. Usually, the failures occur at a later date and often in a splice or termination that was unable to withstand the elevated temperatures. As with overhead conductors, the designer must understand the limitations that are built into the ampacity ratings. For situations outside of the design assumptions (i.e. multiple circuits in a duct bank; poor soil resistivity), the designer must evaluate the specific conditions carefully to insure that the system is properly designed.

Underground Backfill Materials

To maintain the thermal ratings of the backfill several things can be done. Cables (or ducts) should to be installed in a bed of thermally conditioned backfill that has well defined thermal dissipation qualities. For Duke Energy Midwest, *Flash fill with Sand®.* , which is a licensed product from AEP should be used. This material is in a family of materials called "Controlled Density Backfills" (CDFs) that are required by the governmental agencies in the Cincinnati area for trench restoration. It has been selected because it is the only one with stable thermal characteristics. It is available locally (Cincinnati) from Roth Ready Mix. The cost is approximately the same as that of concrete. Other materials may have very different characteristics that can cause damage to the cable because they do not dissipate heat well. "Pipe" sand, washed sand, pea gravel, and other common granular backfill materials that have been cleaned or washed are actually very good insulators (have high resistivity values - rho>150) and should not be used for backfill around electric cables or ducts. On the other hand, materials that have mixtures of fine and course particles that retain water well make very good backfill materials. "Thermal" sand, bank run sand, etc. fit this category.

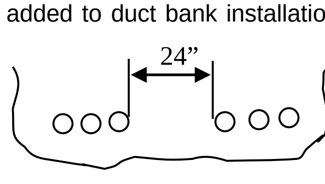
The cables (or ducts) should be covered on the sides and top by at least 3 inches of this material.

If conduit is used, it must be appropriate for the installation. In the case of designs that require the use of alternate backfill materials to achieve lower thermal resistivities, it is assumed that the ducts are completely surrounded by the thermally conductive material. All conduit must be suitable for use with electric cables. It should be capable of operating at 90°C., additionally; it must meet appropriate specification requirements depending on the application (NEMA for utility installations and UL for non-reg installations). If concrete encasement is specified, the ampacity values associated with a thermal resistivity of 90 (rho-90) must be used. All conduit installations that are made within the public rights of way in the City of Cincinnati *must* be concrete encased as a permit requirement. The thermal resistivity (rho) of the concrete encasement is approximately 90 (rho=90).

The entire length of the underground circuit must be of similar construction to apply a uniform rating to all of it. If a portion of the circuit is in duct and a portion is direct buried, the ampacity of the entire circuit will be determined by the portion of the circuit that has the greatest thermal constraints. Usually this is the portion installed in ducts.

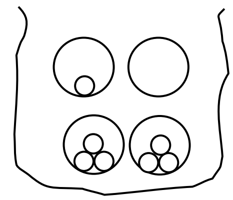
For insulated cables, the load factor must be evaluated. The load factor is a measure of the amount of time that the full rated load for the circuit will be applied to the cables during a 24-hour day. Because cables heat up slowly when load is applied and will cool slowly when it is removed the current rating is affected by the length of time that the load is applied. If the load factor is low, more current can be carried.

The number of cables operating close to each other can affect the current carrying ability of all of them. This is particularly true for cables installed in duct banks. The affect of adjacent circuits can be dramatic and has to be evaluated carefully. Ratings drop off very quickly as circuits are added to duct bank installations. To



incur no thermal conductor de-rating from adjacent direct buried circuits, they should be spaced at least 24 inches apart. The individual cables of each circuit should be installed in a flat configuration but closely spaced (as they would come from a reel where they were paralleled together.). If single conductor reels are used, the individual cables should to be grouped together as close as possible.

The recommended installation technique for power cable installations at Duke Energy Midwest is to install the cables (and neutral) either directly buried or into a single duct. Cable sizes and loading criteria have been evaluated and meet the planning requirements if a single duct is used. Designers will have to select which application is the most appropriate at the time they do the layout work.



When multiple cable circuits are installed in duct banks, each cable adds heat into the entire duct bank. The temperatures will not be the same throughout the duct bank. To maximize the current carrying capacity for cables in duct banks, the phases are usually located in the bottom ducts. A neutral cable is in one of the top ducts; the other is empty (a spare). Ducts may vary in diameter from 2" to 6" depending on the application without affecting the ampacity to any great extent. Cables are arranged in a cradled configuration within the duct. For applications where additional circuits are present or required, special calculations for that specific installation should be done.

A final concern with high temperature operation is what happens to the conductor accessories. These are the parts that are used to connect or terminate the conductors. As stated before, most overhead conductors can operate to 150C while underground conductors can operate to 90C continuously. At these temperatures, though, the connection points become critical to successful operation. If these connections are not well made, they will run hotter than the conductor due to the increased resistance of the poor connection. The excessive temperatures affect the mechanical strength of the conductor material and the accessories used to connect the conductors together resulting in mechanical failure.

Duke Energy Midwest Conductor Rating Charts
The summary of conductor data for a number of conductors used at Duke Energy Midwest is contained in the charts linked here. Conductors used for overhead and underground primary and secondary/service applications and substation bus are included. Not all conductors have been included on the list. Designers are reminded that for new construction, only a very small number of conductors are available. These should be used in all but the most special of circumstances and then only with the permission of the electric planning staff and construction supervision. Appendix 1 contains information on the approximate equivalent sizes for common copper and aluminum conductors.

The data included in the charts comes from a variety of resources. The physical data (diameters, weights, ultimate strengths, etc.) comes from industry standards and manufacturer's data. Current carrying capacity (ampacity) is either calculated for all bare overhead conductors and for all primary underground cables. Ampacity values for covered overhead wires and both overhead and underground secondary/service conductors are taken from published manufacturer's information. The descriptive data comes directly from the Material Management Department catalogue description.

Engineers from planning and operations have reviewed the design conditions used to rate all of the conductors. They have concluded that these conditions will be used for the basis of overhead conductor ratings at Duke Energy Midwest.

> Ratings in the tables are given for several allowable conductor temperatures. The user MUST determine which condition applies to the conductor he wishes to rate. Failure to properly select the maximum operating temperature can adversely affect clearances and the mechanical strength of the conductor and conductor accessories (splices, dead-ends, etc).

Alternate Rating Information - Duke Energy Midwest uses several software packages for calculating the ampacity ratings for underground primary cables. These ratings were calculated with USAMP+ and confirmed with CYMECAP. Southwire Conductor Rating software (SWRATE) is used to calculate the ampacities for the bare overhead conductors. Each of these programs may be used to calculate ratings for specific field conditions if needed. If this is needed, please contact T&D Standards.

Equipment Rating Information:
There are many different types of equipment used on a typical electric T&D system. Each may have limitations that will determine the maximum capacity of an electrical system. The following information will help to determine where the limiting equipment for a circuit or substation is so that a maximum current rating can be documented. Some pieces of equipment have "*do not exceed*" limits; other equipment has ampacities that are dependent on ambient temperature or other environmental conditions.

During the operation of a utility distribution system, there are times when extraordinary circumstances dictate that operations beyond normal capacities may be required. When these situations arise, decisions must be made whether to operate beyond the ratings or not. There is risk involved in operating at currents above nameplate that must be weighed against the consequences of an equipment failure that may be caused. The operational characteristics of different types of electrical equipment that would normally be found on a utility distribution system are outlined below. This information is intended for operational and engineering personnel so that they may determine maximum loading of a piece of equipment and perform risk assessment during situations where loading may exceed the nameplate rating of the equipment for brief periods of time.

All operational ratings are based on the assumption that the equipment is installed, maintained and subsequently operated using proper methods, materials, and work practices. Failure to allow for proper clearances in the design, or to properly sag or tension lines during installation, or to properly install line connection devices may severely limit the ability of the line to carry full load currents. In circumstances where application or construction practices are deficient, operation at levels above the full load capability carries a higher risk.

Substation Transformers
Substation transformer maximum loadings (normal and emergency) will be established by the existing practice of performing a heat run calculation for each transformer. This will determine the summer and winter peak loading of each transformer and will be published. Once a transformer nears or reaches nameplate the maximum temperature readings should be taken to evaluate performance. (If the temperature readings do not match the calculations then the loading guide should be adjusted to match actual readings.) Internal and external limiting factors of existing transformers should be brought to the attention of the planning department to be published in the transformer loading guide. The transformer loading criteria assumes a 35ºC (95ºF) ambient temperature and allows the top oil to reach 105ºC and the calculated hot spot temperature to reach 140ºC based on 65ºC rise insulation. During emergency operation 110ºC top oil and 150ºC hot spot are allowable. Transformers with 55ºC rise insulation shall use 95ºC and 130 ºC normal and 110ºC and 140ºC for emergency. Bulk transmission transformers shall use 105ºC and 120 ºC for normal operation and 110ºC and 140ºC for emergency operation.

Load Tap Changers
Transformers purchased new after 2001 should be specified so that the LTC will adequately supply load equal to or greater than the maximum thermal loadability of the transformer they are installed on. Transformers with LTC's installed prior to 2001 should be evaluated on an individual basis to determine if the LTC is a limiting factor. Some LTC's are capable of excursions above the continuous current rating while some are not. If an LTC is found to be rated less than the thermal limit of a transformer it should be evaluated to see if the maximum load should be limited. If loadings are limited, the LTC should be noted as the limiting factor in the transformer loading guide.

Substation Breakers or Reclosers
The maximum operating rating of a substation breaker or recloser is defined on the nameplate as continuous current. Due to its characteristics, the operating rating of a breaker or recloser shall not exceed its continuous current rating. Therefore, during emergency situations or peak loading conditions breakers or reclosers cannot be loaded above their nameplate rating. All new breakers installed are 1200A or 2000A units. There are some older 600A breakers and 560A reclosers still in service.

Overcurrent Protection Relays
The maximum load current of a feeder circuit can be limited by the overcurrent protection relay settings. Allowing feeder circuits to carry current that is in excess of the relay settings will cause the relay to operate.

If an emergency condition exists, a circuit may be loaded up to the relay pickup setting minus tolerance of 5%. Careful consideration of circuit phase unbalance, cold load-pickup, anticipated daily load cycle, and loop flow should be taken prior to loading the circuit near the pickup rating of the relay. Normal loadability of a relay is to be determined by System Protection. The cost of exceeding the relay pickup is a lengthy circuit restoration. Many substations now employ a secondary relay setting. This secondary setting is greater than the primary setting and is used for switching or contingency loading and is very easy to place in service.

Voltage Regulators
The maximum operating rating of a voltage regulator is defined on the regulator nameplate and should reflect the following. On units rated 668A or less, loading is based on percent regulation and allows higher loading if percent regulation is limited up to a maximum of 668A. The following table is a list of regulator loadability per IEEE Std. C57.15-1999: Loads in excess of the following recommendations will likely lead to accelerated loss of life.

All single-phase voltage regulators rated 668A or less up to 19.9kV have the following continuous current rating up to a maximum not to exceed of 668A.

Range of Voltage Regulation (%)	Number of Steps	Continuous –Current Rating (%)
10	+ 16, -16	100
8.75	+14, -14	110
7.5	+12. -12	120
6.25	+10, -10	135
5.0	+8, -8	160

1. Single-phase Voltage Regulators in a 10.5 MVA Substation (Single phase regulators 668A or less)
   333/373KVA (55ºC/65ºC) regulators – Continuous current rating at 65ºC 10% raise = 519 A.
   416/466KVA (55ºC/65ºC) regulators – Continuous current rating at 65ºC 10% raise = 647A.

2. Single-phase Voltage Regulators in a 22.4 MVA Substation:
   - For all tap settings of the VR the overload factor is 1.0
   - Nameplate rating of the device is 889/996KVA (55ºC/65ºC) – Continuous current rating at 65ºC = 1308A with no overload rating.

3. Three-phase Voltage Regulators 668A or less up to 13.8kV has the following continuous – current rating up to a maximum not to exceed of 668A.

Range of Voltage Regulation (%)	Number of Steps	Continuous – Current Rating (%)
10	+ 16, -16	100
8.75	+14, -14	108
7.5	+12. -12	115
6.25	+10, -10	120
5.0	+8, -8	130

4. Regulators rated in excess of 668A should be evaluated individually. IEEE C57 provides for no operation above the nameplate amp rating of these devices.

5. Distribution line voltage regulators are typically rated less than 668A. All of these devices should conform to the rating chart for single-phase regulators, 688A or less.

Substation Bus and Conductor Ampacity
Operating ratings of substation bus and jumpers are defined in the Duke Energy Midwest Conductor and Equipment Rating Guide. Normal loading should be based on this publication. Due to the short length of conductors being used as either a substation bus or a substation jumper and the overload capability of the rigid bus, overloading of substation conductor and rigid bus is permissible during contingency situations. Substation conductor and rigid bus should not be considered the limiting factor in the case where emergency conditions require additional capacity.

Reactors
Operating ratings of reactors are defined by the manufacturer's nameplate. The continuous operating rating of a reactor should not exceed it's the nameplate rating. Due to aging, it is unknown as to how much an older reactor can be overloaded even though some older reactors were over designed.

If, an emergency condition exists, the following overload rating factors may be used with the understanding that such practice will shorten the life of the reactor.

Season	Overload Factor (< 15 Hr)
Winter	1.25
Summer	1.03

Assumption: Average Winter temperature is 0ºC (32°F) and average Summer temperature is 35ºC (95°F).

Please note that the overloading period of the reactor shall not exceed a period of more than 15 hours.

Switches
The continuous current rating of substation and line switches is defined on the manufacturer's nameplate. The materials that the switch is made from and the ambient temperature have a large impact on the capacity of the switch. Switch ratings can be adjusted for changes in ambient temperature similar to other equipment. It is recommended that the load current for switches does not exceed the temperature adjusted nameplate rating.

Switch nameplate ratings are based IEEE Std C37.37. Nameplate ratings are set using an ambient temperature of 104deg. F with no wind applied. Duke Energy Midwest uses an ambient temperature of 95deg. F. to calculate ratings for equipment and conductor. To normalize the IEEE switch rating to the same ambient used for rating other equipment at Duke Energy Midwest, the following table must be used.

Season	Thermal Adjusting Factor
Winter	1.4
Summer	1.1

Assumptions: Average Winter temperature is 0ºC (32°F) and average Summer temperature is 35ºC (95°F).

If a switch is equipped with a loadbreak device, the factors defined above may also be applied. However, loadbreak switches must not be operated (opened), if the current exceeds the nameplate rating of the switch. The nameplate rating applies to switches that are in "good condition" and have been properly maintained. If the condition and maintenance of the switch are unknown, there is a possibility that the switch will not carry the nameplate current rating

Current Transformers
The maximum current that a Current Transformer (CT) can carry depends on its connected ratio and the thermal rating factor – "k". A CT can be loaded up to its connected ratio rating times its k rating factor. For example, a 600/5 multi ratio CT with a 'k' rating factor of 1.5 and connected to the load at 400/5 tap can carry up to 600A. If the K factor is unknown a value of 1 should be assumed.

Allowing a CT to carry current that exceeds its connected ratio rating times its 'k' rating factor is not recommended.

Conductors
Operating ratings for overhead and underground conductors are defined in a previous section of this guide. Ratings are based on a specific set of conditions that govern the current carrying capacity of the wire or cable.

Line Cutouts (100A, 200A or 300A)
Duke Energy Midwest uses line cutouts, and occasionally underground fused cabinets for switching and fusing taps and equipment installations fed from distribution lines. The current ratings for cutouts are based on the continuous current carrying capacity of the fuse tube installed in the cutout. Continuous operation above the limits of the fuse tube risks failure of the fuse tube assembly. When the 100A or 200A fuse tube is replaced by a solid blade, the cutout is capable of carrying up to 300A continuously without damage

The current carrying capacity of the fuse links installed in the tube is based on the time/current characteristics of the fuse link. It is possible to carry currents higher than the fuse ratings for some period of time before the fuse link melts. This is a particular concern because cutouts are often used to fuse conductors large enough to carry currents in excess of the rating of the tube or blade. In these circumstances, the cutout and fuse are vulnerable to damage that may prevent proper operation. Fuses that have been exposed to high operational currents may not perform as expected during fault conditions causing mis-coordination of equipment.

Cutouts should be limited to operation at continuous currents below the rating for the fuse tube or blade (100A, 200A, or 300A). Non-loadbreak cutouts should not make or break currents without use of proper tools. Loadbreak cutouts should not be operated if the currents are greater than the loadbreak rating of the cutout.

Underground fuse or switching cabinets are limited by the capabilities of the loadbreak elbows since they are used as the line side switch mechanism (See Loadbreak and Non-loadbreak Elbows).

Line Reclosers and Sectionalizers)

Hydraulic reclosers should not be operated beyond the continuous current rating for the device. Operations beyond the continuous current rating (nameplate rating) will damage the operating coil in the recloser. The continuous current rating is usually about 50% of the "pick-up" current at which the recloser will trip. Newer reclosers with electronic controls allow the "pick-up" current to be set within a broad range. The continuous rating is still the upper limit for normal operations. A hydraulic recloser will normally not begin to operate until approximately 2 times the rating of the device. This minimizes unwanted operations. Care should be taken when evaluating electronic reclosers. They will begin to trip at the setting of the device with a margin of error of 5%. For example the pickup current of a 200A hydraulic recloser is equivalent to a 400A electronic recloser.

Sectionalizers are rated the same as reclosers except the "pick-up" rating or "count current" is usually 160% of the continuous current rating.

Other Equipment:

Line Splices (Overhead and Underground): Splices used on overhead and underground conductors are designed to match the current carrying capacity of the conductor on which they are installed. Full circuit capacity requires that the correct connector be used for the conductor material and size and that the splice be properly installed. When aluminum connectors are used for copper and aluminum or copper-to-copper connections, they must be rated for use with both copper and aluminum cables. Proper conductor preparation is essential. Correct tools must be used to compress the connector. Properly designed conductor accessories (splices, terminations etc.) are generally expected to run as cool as or cooler than the conductor because of the increased mass of the connection.

Line Terminations (Underground): Terminations for underground cable have been selected which match the conductor size and material of the cable that they are installed on.

Line Dead-Ends (Overhead): Dead end connections for overhead lines are usually selected to meet the mechanical characteristics of the conductor on which they are applied because most dead ends are not part of the current carrying path. The conductor extends through them to a jumper or other conductor where the current carrying connection is made. If compression dead ends are used, then the dead end becomes part of the current carrying path and installation practices are more significant.

Loadbreak and Non-Loadbreak Elbows (Underground): -

- Loadbreak elbows used on URD cable systems are rated for currents of 200A. Non-loadbreak URD elbows are also rated for 200A continuous currents. Non-loadbreak elbows must not be moved while energized.
- Dead front connectors (600A T-Bodies, 600A Elbows, etc.) used on dead front padmount switches etc. are designed to carry up to 600A continuously. The designs used at Duke Energy Midwest are limited by the aluminum materials used in the connectors and the apparatus bushings. 600A elbows MUST not be moved while energized.

Operating limits for loadbreak elbows are based on the design tests done to meet IEEE standards (IEEE 386 – Latest Edition). Elbow designs must pass a specific number of loadbreak-loadmake operations and fault close operations to be deemed acceptable. There are no specific operating limits published for the elbows but some manufacturers recommend that the probe of a loadbreak elbow be replaced after each 10 operations of the elbow. If an elbow is closed into a fault, manufactures recommend replacement of both the elbow and the loadbreak bushing. Closing elbows into faulted cables as part of the fault locating process is not recommended.

The current carrying capacity of #4/0ALTRXLPECNJ15 URD cable used for commercial underground installations exceeds the 200A switching limitation for loadbreak elbows. While the splices and terminations are designed to match the conductor rating, the elbow retains the 200A switching rating. Additional current may be applied beyond the 200A level as long as the elbow is not switched and the temperature of the elbow in the connector region remains below 90ºC. If it is necessary to operate elbows connected with #4/0 AL URD cable, it is always wise to verify that current levels are within design limits (<200A).

References:

1. National Electrical Safety Code (2002 Edition)
2. Southwire Overhead Conductor Manual – First Edition (Includes SWRate Software)
3. Southwire Power Cable Manual – Second Edition
4. IEEE Std C57.15-1999 (Loadability Table for Voltage Regulators)
5. IEEE Std 605-1988 (Buss Ratings)
6. ANSI Std C37.37-1996 (Switch Overload Rating Information)
7. IEEE Std 386 (Loadbreak Elbow Ratings)
8. DUKE ENERGY OHIO and DUKE ENERGY INDIANA Historical Rating Information

Substation Bus
Current Carrying Capacity
Copper Conductors & Bars

Conductor Size Wire:	Stranding	SIN Number	Weight (Lb/100ft)	Outside Diameter (in)	Ampacity (80ºC)	Ampacity (100ºC)
2/0	7	104902	41.1	0.414	376	454
4/0	7	104940	65.3	0.521	504	610
300kcmil	19	104991	92.7	0.629	630	765
500kcmil	37	105016	154.3	0.813	867	1060
750kcmil	37		231.7	0.997	1112	1366
1000kcmil	61	105055	308.6	1.152	1320	1629
Tubing						
½” Type SPS			95.6	0.840	615	
¾” Type SPS			130.0	1.050	765	
1” Type SPS			183.0	1.315	975	
1 ¼” Type SPS			268.0	1.660	1275	
1 ½” Type SPS			319.0	1.90	1445	
2” Type SPS			421.0	2.375	1780	
2 ½” Type SPS			612.0	2.875	2275	
3” Type B			345.0	3.5	*1435	

Notes:

1) Wire Ratings are based on criteria given in the Duke Energy Midwest and Equipment Rating Guide
2) Tubing Ratings are based on the Anderson Electric Technical Data, Table 13 (Ratings at 40ºC Ambient Temperature and 40ºC Rise with a Wind Velocity of 2MPH at a 90º angle to the bus).
3) Duke Energy Midwest Substation Standard Rating for copper conductor is 100ºC and for existing copper tubing is 80ºC.
4) * Estimated Rating.

From Drg# STD-ENG-3-00
CAD Filename: STDENG3.dwg
Date: Aug 30, 2001

Substation Bus
Current Carrying Capacity
Aluminum Conductors

Conductor Size	Stranding	SIN Number	Weight (Lb/100ft)	Outside Diameter (in)	Ampacity (80ºC)	Ampacity (100ºC)
Wire – ACSR:						
#2/0	6 x 1	103445	18.3	0.447	287	340
#4/0	6 x 1	103463	29.2	0.563	371	438
336.4kcmil	26 x 7	103490	46.2	0.720	554	674
477kcmil	26 x 7	103517	65.6	0.858	692	844
954kcmil	45 x 7	103529	107.4	1.165	1045	1284
Wire – AAC						
#4/0	7		19.8	0.522	400	484
336.4kcmil	19	103787	31.6	0.666	538	653
477kcmil	19	103784	44.7	0.793	670	817
[556kcmil]	19	103369	52.1	0.856	738	901
[954kcmil]	37	107840	89.5	1.124	1034	1271
1590kcmil	61	100380	148.9	1.454	1408	1745
[2500kcmil]	91	103793	236.5	1.823	1823	2274
Wire - AAAC						
#2/0	7	103747	14.5	0.447	309	339
#4/0	7	103752	23.0	0.563	414	466
336.4kcmil	19	103759	36.8	0.721	559	682
477kcmil	19	103786	52.2	0.858	696	853

Notes: 1) Wire Ratings are based on criteria given in the Duke Energy Midwest and Equipment Rating Guide
2) Duke Energy Midwest Substation Standard Rating for aluminum conductor is 100ºC

[ ] – Common Duke Energy Midwest Substation Standard Materials

From Drg# STD-ENG-4 -00
CAD Filename: STDENG4.dwg
Date: Aug 30, 2001

Substation Bus

Current Carrying Capacity
Aluminum Bus Bars

Conductor size Tubing – Schedule 40 6063-T6	SIN Number	Weight (Lb/100ft)	Outside Diameter (in)	Ampacity (100ºC)
~ 0.75		39.1	1.05	588
1.00	881111	58.1	1.315	840
~ 1.25	881114	78.6	1.660	966
1.50	881113	94.0	1.900	1199
[2.00]	881118	126.4	2.375	1490
[2.50]	881122	200.4	2.875	1992
[3.00]		262.1	3.50	2422
{3.50}	881124	315.1	4.00	2770
~ [4.00]*	881134	373.3	4.50	2614
~ [5.00]*	881145	505.7	5.563	3268
~ 6.00*		655.4	6.625	3951
U.A.B.C 6101-T6				
3 ¼ x 3 ¼ x ¼"	880585	185		2279
4 x 4 x 3/8"	880605	336		3153
I.W.B.C 6061-T6				
4 x 4 x .312	880920	525		4134
6 x 6 x .550 **		1319		6950

Notes: 1) Ratings are based on 0.2 Emissivity with sun; 40ºC Ambient; 60ºC Rise (IEEE Std 605-1988)
* 6061 – T6
** 6061 – T61
[ ] – Common Duke Energy Midwest Substation Standard Materials

From Drg# STD-ENG-5 -00
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Appendix 1

Conductor Equivalence

Duke Energy Midwest has used many different conductors over the years. The information contained in the engineering guide cannot cover all of them. Copper conductors have been replaced by aluminum for new construction. When it is necessary to replace a copper conductor, an equivalent to aluminum conductor should be used. The chart below depicts approximate equivalence between copper and aluminum conductors based on electrical resistance.

Approximate Equivalent Conductor Sizes

Copper	Aluminum	Resistance (Ω/1000ft)
#10	#8 **	1.05
#8	#6	0.664
#6	#4	0.415
#4	#2	0.263
#2	#1/0	0.165
#1/0 **	#2/0	0.103
#2/0	#4/0	0.0823
#4/0	350kcmil **	0.051
250kcmil **	400kcmil **	0.0436
300kcmil **	500kcmil	0.0357
350kcmil **	600kcmil **	0.0301
500kcmil	750kcmil **	0.0226
600kcmil **	1000kcmil	0.0178
750kcmil **	1250kcmil **	0.0143
1000kcmil	1500kcmil **	0.0113

**** NOT available for new construction - Use next larger standard size.**

For most common conductor sizes, a copper conductor has about the same resistance as an aluminum conductor two sizes larger

Resistance Values are DC resistances at 25°C for Class B Stranded Conductors

Source: Okonite Engineering Data (Pub EHB-88). Res Values are the average of the CU & AL values

Example: A designer is working on a rehabilitation of an old underground secondary system. The old conductors are #4/0 copper (4/0CURRSUG). What conductor would be used to replace the old copper ones?

Before selecting a replacement conductor based solely on an aluminum equivalent size, the designer must verify the loads that are now fed by the cables. The cable size would be determined by the load to be served. If the existing 4/0CURRSUG is the correct size, the table can be used to determine a replacement size. From the table, the aluminum equivalent to a 4/0 copper conductor is 350kcmil. Duke Energy Midwest does not purchase this conductor for new construction so the next larger size that is purchased should be selected. This would be 500kcmil (500ALTXUG).

Revisions:

- Revised 1/13/05 Delete "If an emergency condition exists" from the first sentence of the 3rd paragraph under "Switches" (Page 14).
- Revised the first paragraph of the section titled " Duke Energy Midwest Conductor Rating charts" (Page 10) to read:
    - The summary of conductor data for a number of conductors used at Duke Energy Midwest is contained in charts at the end of this guide. Conductors used for overhead and underground primary and secondary/service applications and substation bus are included. Not all conductors have been included on the list. Designers are reminded that for new construction, only a very small number of conductors are available. These should be used in all but the most special of circumstances and then only with the permission of the electric planning staff and construction supervision. Appendix 1 contains information on the approximate equivalent sizes for common copper an aluminum conductors.

- Add Appendix 1: Equivalent Conductor Size Chart
- Revised switch rating information to address thermal adjustments. Revised aluminum bare wire data to update to new software package at the request of Transmission Planning.

- March 2006
    - Added words to the preface to define limits for facilities loading
    - Added a section for Transient Conductor Loading
    - Added T2 and OVAL ratings to the tables (Special Conductors)

- January 2007
    - Changed spreadsheet chart to reflect new Duke Energy conductors.
    - Changed to Duke Energy and company area applicable for use.

- June 2009
    - Changed references of "Cinergy" to "Duke Energy Midwest" throughout the document. Corrected minor grammatical errors.
- December 2010
    - Added information on pages 1 & 2 to detail the use of LiDAR to determine if a line could be rerated during an emergency.

- June 2011
    - Added document to Filenet for future revisions and added a link on page 9 to a Conductor Ratings Spreadsheet that could not be an actual part of this document and is also located in Filenet.

Duke Energy Midwest Conductor Summary

Description	Conductor Size (Stranding)	Wire Code	Industry Code Name	SIN	Ampacity DB or Air: Summer - 50C SEE NOTE	Summer - 80C	Summer 100C (200C)	Winter - 50C SEE NOTE	Winter - 80C	Winter - 100C (200C)	Resistance Ohms /Mi. 50C	Cond. Dia.	Weight lbs / ft	Ultimate Strength	Duke Energy Catalogue Description (Materials Management)	Misc
Bare Wire - Overhead																
All Aluminum Alloy Conductor (AAAC)																
	1/0 (7)	1/0AAACB7	Azusa	103745	130	266	--------	288	362	--------	0.953	0.3981	0.1149	4460	WIRE, ELECTRICAL, "AZUSA", 1/0 AWG, (7) STRAND, AAA 6201, BARE INS, 0.1157 LB/FT 8.643 FT/LB	No Longer Used for New Construction
	2/0 (7)	2/0AAACB7	Anaheim	103747	--------	308	--------	--------	420	--------	0.7563	0.4470	0.1450	5390	WIRE, ELECTRICAL, "ANAHEIM", 2/0 AWG, (7) STRAND, AAA 6201, BARE INS	No Longer Used for New Construction
	4/0 (7)	4/0AAACB7	Alliance	103752	192	412	501	446	563	624	0.4764	0.5634	0.2302	8560	WIRE, ELECTRICAL, "ALLIANCE", 4/0 AWG, (7) STRAND, AAA 6201, NO INS, SHIP ON 1200# REEL, 0.2318 LB/FT, 4.310 FT/LB	No Longer Used for New Construction
	336kcmil (19)	394AAACB19	Canton	103759	--------	556	--------	--------	761	--------	0.2988	0.7210	0.3680	13300	WIRE, ELECTRICAL, "CANTON", 336.4 KCM, (19) STRAND, AAA 6201, BARE INS, SHIP ON REELS NOT LARGER THAN 48", 0.3703 LB/FT 2.701 FT/LB.	Actual Conductor Size - 394.5kcmil - Equivalent Diameter to 336kcmil 26/7 ACSR
	477kcmil(19)	559AAACB19	Darien	103786	--------	693	--------	--------	951	--------	0.2114	0.8580	0.5220	18800	WIRE, ELECTRICAL, "DARIEN", 477 KCM, (19) STRAND, AAA 6201, NO INS	Actual Conductor Size - 559.5kcmil - Equivalent Diameter to 477kcmil 26/7 ACSR
All-Aluminum Conductor (AAC)																
	336.4kcmil (19)	**336AACB19**	**Tulip**	**50124390**	**--------**	**538**	**--------**	**--------**	**736**	**--------**	**0.3052**	**0.6660**	**0.3155**	**6150**	**WIRE/CABLE, BARE ELECTRICAL, TULIP, 19 STRAND, 336.4 KCMIL, ALL ALUMINUM, 0.666 IN DIA.; 0.316LBS/FT; 2.77FT/LB**	*Current Duke Energy Standard for Overhead Distribution*
	556.5kcmil (19)	**556AACB19**	**Dahlia**	**103369**	**318**	**734**		**794**	**1008**	**1117**	**0.1855**	**0.8560**	**0.5214**	**9750**	**WIRE, ELECTRICAL, BARE, 556.5 KCMIL, 9 STRAND, ALL ALUMINUM, CODE NAME "DAHLIA", 0.521 LB/FT, 1.9193 FT/LB**	*Current Duke Energy Standard for Overhead Distribution*
	795kcmil (37)	795AACB37	Arbutus	103368	380	915	1121	988	1260	1399	0.1311	1.0260	0.7450	13900	WIRE, ELECTRICAL, BARE, 795 KCM, 37 STRAND, ALL ALUMINUM AAC, CODE NAME "ARBUTUS", 0.745 LB/FT, 1.342 FT/LB	No Longer Used for New Construction
	954kcmil (37)	954AACB37	Magnolia	107840	--------	1023	1255	--------	1410	1567	0.1101	1.1240	0.8950	16400	WIRE, ELECTRICAL, BARE, 954KCM, 1.124" DIA, ALL ALUM	Transmission Conductor - - (Maintenance Only)
	1033kcmil (37)	1033AACB37	Bluebell		--------	1076	1321	--------	1484	1650	0.102	1.1700	0.9680	17700		Transmission Conductor - - (Maintenance Only)
	1590 kcmil (61)	1590AACB61	Coreopsis		--------	1386	1711	--------	1920	2138	0.0689	1.454	1.4890	27000	WIRE:ELECTRICAL,MAINTENANCE,1024.5 KCMIL,30/7 STRAND,ACAR CONDUCTOR	Transmission Conductor - - (Maintenance Only)
Aluminum Conductor, Aluminum Reinforced (ACAR)																
	247.9KCMIL (6x1)	247ACAR6X1)	--------	--------	221	472	571	512	644	712	Calculated ***	0.563	0.2320	6040	CABLE:ELECTRICAL,246.9 KCMIL,ACAR,BARE INSULATION,NO COVER	No Longer Used for New Construction
	852.6kcmil(30X7)	852ACAR30X7	--------		--------	947	1160	--------	1303	1448	0.1253	1.063	0.7990	17700		Transmission Conductor - - (Maintenance Only)
	1024.5kcmil(30X7)	1024ACAR30X7	--------	--------	--------	1057	1298	--------	1451	1621	0.1054	1.165	0.9600	21300	WIRE:ELECTRICAL,MAINTENANCE,1024.5 KCMIL,30/7 STRAND,ACAR CONDUCTOR	Transmission Conductor - - (Maintenance Only)
Aluminum Conductor, Steel Reinforced (ACSR)																
	159kcmil ACSR (Static) (12 x 7)	159ACSR12X7	Guiinea	103481	--------	--------	--------	--------	--------	--------	0.7263	0.5760	0.3970	15200	WIRE, ELECTRICAL, "GUINEA", 159 KCMIL, 12/7 STRANDED, ACSR	No Longer Used for New Construction
	4 (6x1)	4ACSR6X1	Swan	103409	--------	144	--------	--------	195	--------	2.459	0.2500	0.0570	1860	WIRE, ELECTRICAL, "SWAN", 4 AWG, 6/1 STRAND, ACSR, NO INS	No Longer Used for New Construction
	2 (6x1)	**2ACSR6X1**	**Sparrow**	**50124388**	**--------**	**190**	**--------**	**--------**	**258**	**--------**	**1.583**	**0.3160**	**0.0913**	**2850**	**WIRE, ELECTRICAL, "SPARROW", 2 AWG, 6/1 STRAND, ACSR, NO INS**	*Current DukeStandard for Overhead Distribution*
	1/0 (6x1)	**1/0ACSR6X1**	**Raven**	**103436**	**127**	**252**	**--------**	**281**	**342**	**--------**	**1.034**	**0.3980**	**0.0145**	**4380**	**CABLE, ELECTRICAL, "RAVEN", 1/0 AWG, ACSR, BARE INS, 0.398" DIA**	*Current DukeStandard for Overhead Distribution*
	2/0 (6x1)	2/0ACSR6X1	Quail	103445	--------	287	--------	--------	391	--------	0.843	0.4470	0.1830	5310	CABLE, ELECTRICAL, "QUAIL", (1) 2/0 AWG, ACSR, BARE INS, 0.447"	No Longer Used for New Construction
	3/0 (6x1)	3/0ACSR6X1	Pidgeon	103454	--------	327	--------	--------	446	--------	0.692	0.5020	0.2300	6620	CABLE, ELECTRICAL, "PIGEON", (1) 3/0 AWG, ACSR, BARE INS, 0.502" DIA 0.836" DIA OVER ARMOR ROD, RIGHT HAND LAY	No Longer Used for New Construction
	4/0 (6x1)	**4/0ACSR6X1**	**Penguin**	**103463**	**184**	**376**	**445**	**426**	**514**	**555**	**0.573**	**0.5630**	**0.2921**	**8420**	**WIRE, ELCTRICAL, "PENGUIN", 4/0 AWG, 6/1 STRAND, ACSR, NO INS**	*Current DukeStandard for Overhead Distribution*
	336.4kcmil (18x1)	336ACSR18X1)	Merlin	107842	245	541	657	587	740	--------	0.3027	0.6840	0.3650	8680	WIRE, ELECTRICAL, T&D, 336.4 KCM, 18/1 STRAND, ACSR	No Longer Used for New Construction
	336.4kcmil (26x7)	336ACSR26X7)	Linnet	103490	---------	551	670	--------	755	**836**	0.2996	0.7200	0.4620	14100	WIRE, ELECTRICAL, "LINNET", 336.4 KCM, 26/7 STRAND, ACSR, BARE INS	No Longer Used for New Construction
	477kcmil (18x1)	477ACSR18X1	Pelican	50078886	296	674	822	730	925	**1025**	0.2141	0.8140	0.5180	11800	ALUMINUM 477000CM 18/1	No Longer Used for New Construction
	477kcmil (26x7)	**477ACSR26X7**	**Hawk**	**103517**	**298**	**688**	**839**	**744**	**944**	**1047**	**0.2117**	**0.8580**	**0.6557**	**19430**	**WIRE, ELCTRICAL, "HAWK", 477KCM, 26/7 STRAND, ACSR, NO INS**	*Current Duke Energy Standard for Overhead Transmission*

Duke Energy Midwest Conductor Summary

Description	Conductor Size (Stranding)	Wire Code	Industry Code Name	SIN	Ampacity DB or Air: Summer - 50C SEE NOTE	Summer - 80C	Summer 100C (200C)	Winter - 50C SEE NOTE	Winter - 80C	Winter - 100C (200C)	Resistance Ohms /Mi. 50C	Cond. Dia.	Weight lbs / ft	Ultimate Strength	Duke Energy Catalogue Description (Materials Management)	Misc
	636kcmil (26x7)	636ACSR26X7	Grosbeak	103520	--------	825	1009	--------	1134	1260	0.1592	0.9900	0.8740	25200	WIRE, ELECTRICAL, "GROSBEAK", 636 KCM, 26/7 STRAND, ASCR, NO INS	Transmission Conductor - - (Maintenance Only)
	795kcmil (26x7)	795ACSR26X7	Drake	103535	--------	947	1161	--------	1304	1450	0.1278	1.1080	1.0940	31500	WIRE, ELECTRICAL, "DRAKE", 795 KCMIL, 26/7 STRAND, ACSR, NO INS	Transmission Conductor - - (Maintenance Only)
	795kcmil (45x7)	795ACSR45X7	Tern	107841	--------	928	1137	--------	1278	1420	0.1305	1.0630	0.8960	22100	WIRE, ELECTRICAL, T&D, 795 KCMIL, 4-5/7 STRAND, ACSR	Transmission Conductor - - (Maintenance Only)
	900kcmil (54X7)	900ACSR54X7	Canary	103526	--------	1017	1249	--------	1402	1560	0.1165	1.1620	1.1570	31900	WIRE, ELECTRICAL, "CANARY", 900 KCM, 54/7 STRAND, ACSR, NO INS	Transmission Conductor - - (Maintenance Only)
	954kcmil (45x7)	**954ACSR45X7**	**Rail**	**103529**	**--------**	**1041**	**1279**	**-------**	**1436**	**1597**	**0.1094**	**1.1650**	**1.0740**	**25900**	**WIRE, ELECTRICAL, "RAIL", 954 KCM, 45/7 STRAND, ACSR, NO INS**	*Current Duke Energy Standard for Overhead Transmission*
	954kcmil (54X7)	954ACSR54X7	Cardinal	103531	--------	1055	1296	--------	1455	1618	0.11	1.1960	1.2290	33800	WIRE, ELECTRICAL, "CARDINAL", 954 KCM, 54/7 STRAND, ACSR, NO INS	Transmission Conductor - - (Maintenance Only)
	1113kcmil (45X7)	1113ACSR45X7	Bluejay	50078894	--------	1144	1407	--------	1579	1758	0.0943	1.2590	1.2532	29800	WIRE, ELECTRICAL, "BLUEJAY", 1113 KCMIL, 45/7 STRAND, ACSR/GALV STEEL, BARE INS	Transmission Conductor - - (Maintenance Only)
	1351kcmil (45/7)	1351ACSR45X7	Dipper	--------	--------	1286	1586	--------	1778	1981	0.0786	1.3860	1.5210	36200		Transmission Conductor - - (Maintenance Only)
	2167kcmil (72X7)	2167ACSR72X7	Kiwi	103540	--------	1675	2071	--------	2330	2598	0.0523	1.7350	2.3000	49800	WIRE, ELECTRICAL, "KIWI", 2167 KCMIL, 72/7 STRAND, ACSR, BARE INS	Transmission Conductor - - (Maintenance Only)
Aluminum Conductor - Steel Supported (ACSS)																
	954kcmil (45X7)	954ACSS45X7	Rail/ACSS		--------	--------	1307 (2053)	--------	--------	1632 (2222)	0.105	1.1650	1.0740	26000		
Spaced Conductors (Hendrix Cable)																
	1/0 AL	1/0AACHC7	-------	50078954	--------	234++	--------	--------	--------	--------	See Manufacturer's Catalogue	0.6680	0.2150	1990	WIRE, ELECTRICAL, SPACED CONDUCTOR, 1/0 AWG, (1) 7 STRAND, AAC, GRAY TRACK RESISTANT HDPE INS, 15KV	Limited Use - Special Applications Only
	2/0AL	2/0AACHC7	-------	104003	--------	269++	--------	--------	--------	--------	See Manufacturer's Catalogue	0.7110	0.2510	2510	WIRE, ELECTRICAL, AERIAL SPACER, 2/0 AWG, (7) STRAND, AA, HDPE/THERMOPLASTIC INS, 15KV	Limited Use - Special Applications Only
	4/0AL	4/0AACHC7	-------	104023	--------	356++	--------	--------	--------	--------	See Manufacturer's Catalogue	0.8080	0.3510	3830	WIRE, ELECTRICAL, AERIAL SPACER, 4/0 AWG, (7) STRAND, AA, BLACK SEMI-CONDUCTING POLYETHYLENE INS, 15KV	Limited Use - Special Applications Only
	336kcmil AL	336AACHC19	-------	104024	--------	475++	--------	--------	--------	--------	See Manufacturer's Catalogue	0.9370	0.4970	6150	WIRE, ELECTRICAL, AERIAL SPACER, 336.4 KCMIL, (19) STRAND, AA, BLACK SEMI-CONDUCTING POLYETHYLENE INS, 15KV	Limited Use - Special Applications Only
	477kcmil AL	477AACHC19	-------	100562	--------	588++	--------	--------	--------	--------	See Manufacturer's Catalogue	1.0620	0.6620	8360	WIRE, ELECTRICAL, AERIAL SPACER, 477 KCM, 37 STRAND, ALL ALUMINUM, ALLOY 1350-H19, COMPRESSED, 0.150" GRAY TRACK RESISTANT HIGH DENSITY INS	Limited Use - Special Applications Only
	795kcmil AL	795AACHC37	-------	50078967	--------	805++	--------	--------	--------	--------	See Manufacturer's Catalogue	1.2920	1.0490	13480	CABLE, ELECTRICAL, STRANDED, 15KV, 795 KCMIL, AAC, HDPE INS, POLYETHYLENE	Limited Use - Special Applications Only
Bare Copper Conductor (BC)																
	6 BC (Sol)	6CUBS	-------	104538							2.417	0.1620	0.0790	1280	WIRE, ELECTRICAL, 6 AWG, SOLID, HARD DRAWN COPPER, NO INS	
	4 BC(Sol)	4CUBS	-------	104556	--------	177	--------	--------	239	--------	1.5196	0.2043	0.1264	1970	WIRE, ELECTRICAL, MAINTENANCE, 4 AWG, SOLID, HARD DRAWN COPPER, BARE INS, SHIP ON 200# COILS, 0.1264 LB/FT 7.9114 FT/LB	
	2 BC(Sol)	2CUBS	-------	104572	--------	237	--------	--------	321	--------	0.956	0.2576	0.2009	3003	WIRE, ELECTRICAL, MAINTENANCE, 2 AWG, SOLID, HARD DRAWN COPPER, NO INS, SHIP ON 50 LB COILS 0.2009 LB/FT, 4.9776 FT/LB	
	1/0BC (7)	1/0CUB7	-------	104486	--------	325	--------	--------	441	--------	0.6137	0.3684	0.3260	4750	CABLE, ELECTRICAL, MAINTENANCE, (1) 1/0 AWG, HARD DRAWN COPPER, BARE INS, 0.368" DIA SHIP ON 50 LB COILS, 0.3258 LB/FT, 3.0694 FT/LB	No Longer Used for New Construction
	2/0BC(7)	2/0CUB7	-------	104904	213	376	--------	409	512	--------	0.4866	0.4137	0.4110	5930	WIRE, ELECTRICAL, GROUND, 2/0 AWG, (7) STRAND, HARD DRAWN COPPER, BARE INS, SHIP ON 100 LB COIL, 0.4109 LB/FT, 2.4337 FT/LB	No Longer Used for New Construction
	4/0BC(7)	4/0CUB7	-------	104949	279	504	--------	546	687	--------	0.3067	0.512	0.6530	9160	WIRE, ELECTRICAL, MAINTENANCE, 4/0 AWG, (7) STRAND, HARD DRAWN COPPER, NO INS, SHIP 100# COIL, 0.6533 LB/FT 1.5307 FT/LB	No Longer Used for New Construction
	300kcmil HDBC	300CUBS19	-------	50078928	--------	630	765	--------	861	954	0.217	0.6285	0.9269	13500	WIRE, ELECTRICAL, GROUND BUS, 300 KCMIL, (19) STRAND, HARD DRAWN COPPER, BARE INS	No Longer Used for New Construction
	400kcmil HDBC	400CUBS19	-------	50078929	--------	754	919	--------	1033	1146	0.1636	0.7255	1.2350	17800	WIRE, ELECTRICAL, 400 KCMIL, (1) 19 STRAND, HARD DRAWN COPPER, BARE INS	No Longer Used for New Construction
Copper weld/Copper Conductor (CWC)																
	8A	8ACWC	-------	106981	58	110	--------	121	149	--------	3.82	0.1990	0.0740	2233	WIRE:ELECTRICAL,MAINTENANCE,8 AWG,(1) STRAND,(2) STRAND,COPPERWELD,COPPER CONDUCTOR	No Longer Used for New Construction
	6A	6ACWC	-------	106990	--------	142	--------	--------	194	--------	2.4	0.2300	0.1016	2585	WIRE, ELECTRICAL, MAINTENANCE, 6 AWG, (1) STRAND, (2) STRAND, COPPERWELD, COPPER, NO INS, SHIP ON 150# COIL, 0.1016 LB/FT 9.8425 FT/LB	No Longer Used for New Construction

Duke Energy Midwest Conductor Summary

	Description	Conductor Size (Stranding)	Wire Code	Industry Code Name	SIN	Ampacity DB or Air						Resistance Ohms /Mi. 50C	Cond. Dia.	Weight lbs / ft	Ultimate Strength	Duke Energy Catalogue Description (Materials Management)	Misc
						Summer - 50C SEE NOTE	Summer - 80C	Summer 100C (200C)	Winter - 50C SEE NOTE	Winter - 80C	Winter - 100C (200C)						
		4A	4ACWC	-------	107008	--------	189	--------	--------	259	--------	1.511	0.2900	0.1610	3938	WIRE, ELECTRICAL, MAINTENANCE, 0.29", (1) COPPERWELD, (2) COPPER, NO INS, 4A, 30% CONDUCTIVITY SHIP ON 200 LB COILS	No Longer Used for New Construction
		2A	2ACW	-------	107017	--------	253	--------	--------	--------	--------	0.95	0.3660	0.2560	5876	WIRE, ELECTRICAL, MAINTENANCE, 0.366", (1)COPPERWELD, (2) COPPER, NO INS	No Longer Used for New Construction
Steel																	
		5/16 Guy Strand	5/16ST7	-------	108226	--------	--------	--------	--------	--------	--------	--------	0.3125	0.2050	11200	WIRE, GUY, 5/16", GALV STEEL, 7, 11200 LB, GRADE A COATING STD PKG, SHIP ON 500 FT COIL	
		3/8" Steel (Static)	3/8ST7	-------	108192	--------	--------	--------	--------	--------	--------	--------	0.3600	0.2730	15400	WIRE, GUY, 3/8", COATED GALV STEEL GR C, 7, 15400 LB	
		7/16 Guy Strand	7/16ST7	-------	108232	--------	--------	--------	--------	--------	--------	--------	0.4375	0.3990	20800	WIRE, GUY, 7/16", GALV STEEL, 7, 20800 LB, GRADE A COATING, DIA OF .343" (7 X .114"), RATED BREAKING STRENGTH OF 12,500 LBS. IN	
Aluminum	OH Service/Secondary																
	4AL Duplex	4 (7)	4ALDX	Whippet	103002	--------	90	--------	--------	--------	--------		0.5650	0.1050	1760	CABLE, ELECTRICAL, "WHIPPET", 600V, (2) 4 AWG, AA/AAA, (1) POLYETHYLENE, (1) BARE INS, (1) 7 STRAND BARE, (1) 7 STRAND W/3/64"	
	2 AL Triplex - 500' Coil	2 (7)	2ALTX	Clam	103031	--------	120	--------	--------	--------	--------		0.7600	0.2380	1350	CABLE, ELECTRICAL, "CLAM", 600V, (3) 2 AWG, AA, (1) BARE INS, POLYETHYLENE, ALL ALUM (1) 7 STRAND BARE, (2) 7 STRAND, W/ 3/64" POLYETHYLENE	
	2Al Triplex - 1800' Reel	2 (7)	2ALTX	Clam	104480	--------	120	--------	--------	--------	--------					CABLE, ELECTRICAL, "CLAM", 600V, (3) 2 AWG, AA, (1) BARE, POLYETHYLENE	
	4 Al Triplex - HS Messenger	4 (7)	4ALTX	Barnacle	107844	--------	90	--------	--------	--------	--------		0.6400	0.1650	1760	CABLE, ELECTRICAL, SERVICE DROP, 4 AWG, ALUMINUM, POLYETHYLENE INS, NO, 3 CONDUCTOR, 2) EC-H-19 7Y STRANDINSULATED WITH 3/64" CONVENTIONAL P	
	4AL Triplex Std. Messenger	4 (7)	4ALTX	Oyster	106721	--------	90	--------	--------	--------	--------		0.6400	0.1580	881	WIRE, ELECTRICAL, T&D, #4, 7 STRAND, ALUMINUM, POLYETHYLENE (2 CONDUCTORS INS	
	1/0AL Triplex	1/0 (7)	1/0ALTX	Murex	103360	--------	155	--------	--------	--------	--------		0.9700	0.3830	1990	CABLE, ELECTRICAL, SERVICE DROP, TRIPLEX, 600V, 1/0 AWG, ALUM, (1) 7 STRAND BARE, (2) 7 STRAND, W/60 MILS, POLYETHYLENE COVER, CODE "MUREX",	
	4/0 Al Triplex	4/0 (7)	4/0ALTX	Portunus	103041	--------	245	--------	--------	--------	--------		1.3100	0.7120	4020	CABLE, ELECTRICAL, "PORTUNUS", 600V, (3) 4/0 AWG, AA, (1) BARE INS, XLPE, ALL ALUM (1) 19 STRAND BARE, (2) 19 STRAND W/, 60 MIL XLPE COVER 0	
	1/0 Al. Quadruplex (4/C) Secondary	1/0 (7)	1/0ALQX	Criollo	103065	--------	140	--------	--------	--------	--------		1.0900	0.5100	1990	CABLE, ELECTRICAL, "CRIOLLO", 600V, (4) 1/0 AWG, AA, (1) BARE INS, POLYETHYLENE, 0.510 LB/FT, 1.961 FT/LB	
	4/0 Al. Quadruplex 4/C) Secondary	4/0 (7)	4/0ALQX	Oldenberg	103072	--------	210	--------	--------	--------	--------		1.4700	0.9710	4020	CABLE, ELECTRICAL, "OLDENBURG", 600V, (4) 4/0 AWG, AA, (1) BARE INS, POLYETHYLENE, ALL ALUM (1) 19 STRAND BARE, (3) 19 STRAND W/, 4/64" POLY	
	1/0 Aluminum Parallel Lay (3/C)	1/0 (7)	1/0AL3PL	Hot Springs	100034	--------	160	--------	--------	--------	--------		0.67 x 1.59	0.4410	4460	CABLE, ELECTRICAL, PARALLEL LAY, 600V, (3) 1/0 AWG, AA/AAAC 6201, (2) XLPE, (1) BARE INS, ALUM & ALUM ALLOY 6201 (1) 7 STR, BARE & (2) 19 ST	
	4/0 Aluminum Parallel Lay (3/C)	4/0 (7)	4/0AL3PL	Tumacacori	103023	--------	300	--------	--------	--------	--------		0.73 x 1.92	0.7510	8560	CABLE, ELECTRICAL, PARALLEL LAY, 600V, (3) 4/0 AWG, ALUM/AAAC 6201, (2) XLPE, (1) BARE INS, ALUM & ALL ALUM ALLOY 6201 (1) 7 STR BARE &	
	4/0 Aluminum Quad Lay (4/C)	4/0 (7)	4/0AL4PL	Virgin	103020	--------	270	--------	--------	--------	--------			0.9820		CABLE, ELECTRICAL, "VIRGIN", 600V, (4) 4/0 AWG, ALUM/AAAC 6201, (3) XLPE, (1) BARE INS, ALUM & ALL ALUM ALLOY 6201 (1) 7 STRAND BARE	

Duke Energy Ratings:

Primary Overhead	0C Winter; 35C Summer 80C or 100C Conductor Temp. 2.93 f/s Wind. Sun .8 Emissivity. E-W Line Direction, Wind at 90Deg. (using SouthWire Rating Software)
Secondary Overhead	From Southwire Products Catalogue. Temp Rise of 40C over 40C Amb. 2f/s Wind .5Emissivity, no Sun
Spaced Conductors	From Hendrix Catalogue - Based on 75C Conductor Temp; 25C Ambient 2 ft/sec Wind with Sun

NOTE: Installations in the CG&E (including ULH&P and WHG&E) service territory and using conductors installled before 1990 should be reviewed to determine clearances prior to operating at conductor temperatures above 50C.

Calculated *** Value of resistance used for 247kcmil ACAR calculation determined by extrapolation from 355 & 466kcmil sizes because 247 is no longer an standard industry size (Southwire)

Duke Energy Midwest Conductor Summary

	Description	Conductor Size (Stranding)	Wire Code	SIN	Single Cable or Circuit Ampacity				Cond. Dia.	Weight lbs / ft	Ultimate Strength	Reel Length	Cinergy Catalogue Description (Materials Management)	Misc
					Summer - Direct Buried	Summer - In Duct	Winter - Direct Buried	Winter - In Duct						
Underground Cables														
Aluminum UG Primary														
	2Al. 15kV. Jacketed Concentric Neutral (1/C)	2	2ALTRXLPECNJ15	103364	207	160	237	183	1.12	0.55	398	1 x 5000'	CABLE, ELECTRICAL, POWER, 15KV, 2 AWG, ALUMINUM WITH COPPER NEUTRAL, CLASS B COMPRESSED STRANDED ALUM ALLOY 1350	No Longer Used for New Construction
	2Al. 15kV Jacketed Concentric Neutral (3 - 1/C)	2	2ALTRXLPECNJ15	103365	160	124	183	142	1.12 (ea) 2.41 (3)	1.65	398 (ea) 796 (3)	3 x 2000'	CABLE, ELECTRICAL, POWER, 15KV, 2 AWG, 3, EACH CABLE - CLASS B COMPRESSED STRANDED ALUM	No Longer Used for New Construction
	1/0 Al solid, 15kV, Jacketed, LC Shield Neutral (1/C)	1/0	1/0ALTRXLPELCJ15	50124763	267	206	305	235	1.10	0.61	633	1 x 5000'	CABLE, ELECTRICAL, POWER, 15KV, 1/0 SOLID, ALUMINUM, WITH 8MIL LC SHIELD, 175 MIL TRXLPE INS, INSULATING JACKET, PER	Current DukeStandard for Underground Distribution
	1/0 Al solid, 15kV, Jacketed, LC Shield Neutral (3/C)	1/0	1/0ALTRXLPELCJ15	50124764	204	158	233	180	2.36	1.83	1266(3)	3 x 1500	CABLE, ELECTRICAL, POWER, 15KV, 1/0 SOLID, ALUMINUM, WITH 8MIL LC SHIELD, 175 MIL TRXLPE INS, INSULATING JACKET, PER CURRENT DUKE SPEC CS-22	Current DukeStandard for Underground Distribution
	1/0AL 15kV Jacketed Concentric Neutral	1/0	1/0ALTRXLPECNJ15	102875	267	206	305	235	1.10	0.61	633	----------	CABLE, ELECTRICAL, POWER, 15KV, (2) 1/0 AWG, (1) 16-14 AWG, (2) ALUM, (1) COPPER, (2) XLPE, (1) BARE INS, LLDPE	No Longer Used for New Construction
	1/0AL 15kV Jacketed Concentric Neutral (3 - 1/C)	1/0	1/0ALTRXLPECNJ15	102875	204	158	233	180	2.36	1.83	1266 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, (2) 1/0 AWG, (1) 16-14 AWG, (2) ALUM, (1) COPPER, (2) XLPE, (1) BARE INS, LLDPE	No Longer Used for New Construction
	2/0AL 15kV Jacketed Concentric Neutral	2/0	2/0ALTRXLPECNJ15	----------	314	240	359	274	1.14	0.71	798	----------	CABLE, ELECTRICAL, POWER, 15KV, 2/0 AWG Alum Cond., 16-14 AWG COPPER Conc Neut.	No Longer Used for New Construction
	2/0AL 15kV Jacketed Concentric Neutral (3 - 1/C)	2/0	2/0ALTRXLPECNJ15	----------	236	182	270	208	2.46	2.13	1596 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, 2/0 AWG Alum Cond., 16-14 AWG COPPER Conc Neut.	No Longer Used for New Construction
	4/0Al. 15kV Jacketed Concentric Neutral (3 1/C)	4/0	4/0ALTRXLPECNJ15	103363	303	242	346	276	1.41 (ea) 3.03 (3)	3.15	1567	3 x 700'	CABLE, ELECTRICAL, POWER, 15KV, 4/0 AWG WITH 1/2 NEUTRAL, ALUMNIUM WITH COPPER NEUTRAL, CLASS B COMPRESSED STRANDED ALUM ALLOY 1350,	Do not use for new construction, unless approved Supervisor
	1/0Al. 35kv Jacketed Concentric Neutral (1/C)	1/0	1/0ALTRXLPECNJ35	103361	259	207	296	236	1.60	0.95	1650	1 x 2000'	CABLE, ELECTRICAL, POWER, 35KV, 1/0 AWG, ALUMINUM - WITH COPPER NEUTRAL, CLASS B COMPRESSED STRANDED ALUM ALLOY 1350	Current DukeStandard for Underground Distribution
	1/0Al. 35kv Jacketed Concentric Neutral (3- 1/C)	1/0	1/0ALTRXLPECNJ35	103362	204	161	234	183	1.60 (ea) 3.44 (3)	2.85	633 (ea) 1233 (3)	3 x 700'	CABLE, ELECTRICAL, POWER, 35KV, 1/0 AWG, ALUMINUM - WITH COPPER NEUTRAL	Current DukeStandard for Underground Distribution
	500kcmil AL 15kV TRXLPE Power Cable (3 - 1/C)	500kcmil	500ALTRXLPEJ15	102759	497	404	569	461	3.35	3.96	6000 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, (1) 500 KCMIL, (1) 15-22 AWG, ALUM, (1) XLPE, (1) BARE INS, LLDPE, MATERIAL: ALUM 37 STRAND, 90 DEGREE C	No Longer Used for New Construction
	750kcmil AL 15kV TRXLPE Power Cable (3 - 1/C)	750kcmil	750ALTRXLPEJ15	102761	621	505	710	577				----------	CABLE, ELECTRICAL, POWER, 15KV, 750 KCM, 1	No Longer Used for New Construction
	1000kcmil 15kV TRXLPE WS Power Cable (1/C)	1000kcmil	1000ALTRXLPEJ15	102762	713	584	815	668	1.95 (ea) 4.19 (3)	4.36	6000 (ea) 12000 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, (1) 1000 KCMIL, (1) 20-22 AWG, ALUM, (1) XLPE, (1) BARE INS, LLDPE, 61 STRAND, 90 DEGREE C, 25 MIL CROSS-LIN	No Longer Used for New Construction
	1000kcmil 15kV TRXLPE LC Power Cable (1/C)	1000kcmil	1000ALTRXLPEJ15	050099562	696	620"	796	697"	1.95	2.17	6000	1 x 1000'	CABLE, ELECTRICAL, 15KV, 1000KCMIL, ALUM, 175 MIL TRXLPE INSUL INS, LLDPE JACKET, W/LONGITUDINALLY CORRUGATED	Current DukeStandard for Underground Distribution
	1000kcmil 15kV TRXLPE LC Power Cable (3 - 1/C)	1000kcmil	1000ALTRXLPEJ15	050099565	696	620"	796	697"	1.95 (ea) 4.19 (3)	4.36	6000 (ea) 12000 (3)	3 x 1200'	CABLE, ELECTRICAL, 15KV, 3-1/C 1000KCMIL, ALUM, 175MIL TRXLPE INS. INS, LLDPE JKT	Current DukeStandard for Underground Distribution
	1000kcmil 15kV TRXLPE LC Power Cable (3 - 1/C) with #4/0 CU Ground Wire	1000kcmil	1000ALTRXLPEJ15	050099565	682	620"	780	697"	1.95 (ea) 4.19 (3)	4.36	6000 (ea) 12000 (3)	3 x 1200'	CABLE, ELECTRICAL, 15KV, 3-1/C 1000KCMIL, ALUM, 175MIL TRXLPE INS. INS, LLDPE JKT	Current DukeStandard for Underground Distribution
	"Ratings for 1000kcmil aluminum power cable in duct have been calculated based on an allowable maximum conductor temperature of 100°C. This was necessary to achieve a minimum ampacity of 600A for all new Cinergy feeders. While this is above industry standards for cables of this design, there are no detrimental effects that are expected from operating this cable at temperatures up to 103°C. Also see Page 5 of the guide.													
Copper Underground Primary														
	250kcmil CU 15kV XLPE Power Cable (3 - 1/C)	250kcmil	250CUXLPEJ15	--------	430	350	492	399	2.97	5.94	4000 Ea 8000 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, 250 KCMIL, COPPER, XLPE Insulated, Tape Shjield, jacketed	No Longer Used for New Construction
	500kcmil CU 15kV TRXLPE WS Power Cable (3 - 1/C)	500kcmil	500CUTRXLPEJ15	102766	617	506	705	578	3.25	7.86	4000 Ea 8000 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, (1) 500 KCMIL, (1) 24 AWG, COPPER, (1) XLPE, (1) BARE INS, MYLAR TAPE/PVC	No Longer Used for New Construction
	500kcmil CU 15kV EPR TS Power Cable (3 - 1/C)	500kcmil	500CUEPRJ15	100029	----------	528	----------	581	3.52	8.10	4000 Ea 8000 (3)		CABLE, ELECTRICAL, FEEDER, 15KV, 500 KCMIL, CLASS "B" STRANDED COATED COPPER, 90 DEG. C, TYPE "HT" INS, PVC	No Longer Used for New Construction
	750kcmil CU 15kV TRXLPEWS Power Cable (3 - 1/C)	750kcmil	750CUTRXLPEJ15	102759	776	650	887	743	4.14	11.67	6000 (ea) 12000 (3)	----------	CABLE, ELECTRICAL, POWER, 15KV, (1) 500 KCMIL, (1) 15-22 AWG, ALUM, (1) XLPE, (1) BARE INS, LLDPE, MATERIAL: ALUM 37 STRAND, 90 DEGREE C	No Longer Used for New Construction
	750kcmil 15kV CU EPR FS Power Cable	750kcmil	750CUEPRJD15	100040	737	610	842	698	1.60 (ea) 3.50 (3)	3.89 Ea. 11.67 (3)	6000 (ea) 12000 (3)	3 x 1200'	CABLE, ELECTRICAL, POWER, 15KV, 750KCMIL, COPPER, EPR INS, LLDPE, 1/C, 175MIL ETHYLENE PROPYLENE, RUBBERINSULATION, FLAT STRAP NEUTRAL, RED	Current DukeStandard for Underground Distribution

Duke Energy Midwest Conductor Summary

Description	Conductor Size (Stranding)	Wire Code	SIN	Single Cable or Circuit Ampacity				Cond. Dia.	Weight lbs / ft	Ultimate Strength	Reel Length	Cinergy Catalogue Description (Materials Management)	Misc
				Summer - Direct Buried	Summer - In Duct	Winter - Direct Buried	Winter - In Duct						
750kcmil 15kV CU EPR FS Power Cable with #4/0 CU Ground Wire	750kcmil	750CUEPRJD15	100040	720	604	822	691	1.60 (ea) 3.50 (3)	3.89 Ea. 11.67 (3)	6000 (ea) 12000 (3)	3 x 1200'	CABLE, ELECTRICAL, POWER, 15KV, 750KCMIL, COPPER, EPR INS, LLDPE, 1/C, 175MIL ETHYLENE PROPYLENE, RUBBERINSULATION, FLAT STRAP NEUTRAL, RED	
750kcmil 35kV CU TRXLPE LC Power Cable	750kcmil	750CUTRXLPEJD35	050079058	804	628	919	717	2.05 (ea) 4.60 (3)	5.1 Ea.. 15.3 (3)	6000 (ea) 12000 (3)	3 x 600'	CABLE, ELECTRICAL, POWER, 35KV, 3-750 KCMIL, COPPER, XLPE	*Current DukeStandard for Underground Distribution*
Paper Insulated Lead Covered ((PILC) Primary													
#2 CU 1/C 15kV PILC		2CUPILCJD15	50065093	-------	205	-------	235	1.01	4.26 (3)	530 1060 (3)	3 x 1000	CABLE, ELECTRICAL, PILIJ, 15KV, (1) 2 AWG, COPPER, IMPREGNATED PAPER INS, POLYETHYLENE	Maintenance Use Only - CG&E Service Area
#2 CU 3/C 15kV PILC		2CUPILCJ3D15	100001	-------	-------	-------	-------	2.05	4.3100	1060	1 x 1000	CABLE, ELECTRICAL, NETWORK SERVICE, 15KV, #2, COPPER, IMPREGNATED PAPER INS, POLYETHYLENE	Maintenance Use Only - CG&E Service Area
#2/0 CU 1/C 15kV PILC		2/0CUPILCJD15	100000	-------	180	-------	205	1.11	5.31 (3)	1065 2130 (3)	3 x 1000	CABLE, ELECTRICAL, NETWORK FEEDER, 15KV, #2/0, NON-COMPACT COPPER, CLASS "B" STRANDING, IMPREGNATED PAPER INS, POLYETHYLENE	Maintenance Use Only - CG&E Service Area
#2/0 CU 3/C 15kV PILC		2/0CUPILCJ3D15	100005	-------	-------	-------	-------	2.11	5.1500	2130	1 x 1000	CABLE, ELECTRICAL, NETWORK, 15KV, #2/0, STANDARD CONCENTRIC ROUND COPPER, IMPREGNATED PAPER INS, POLYETHYLENE	Maintenance Use Only - CG&E Service Area
400kcmil CU 1/C 15kV PILC		400CUPILCJD15	100007	-------	454	-------	496	1.47	9.91 (3)	3200 6400 (3)	3 x 750	CABLE:ELEC,NETWORK,15KV,400KCMIL,STANDARD CONCENTRIC STRANDED NON-COMPACT COPPER	Maintenance Use Only - CG&E Service Area
400kcmil CU 3/C 15kV PILC		400CUPILCJ3D15	100008	-------	-------	-------	-------	2.68	9.1300	6400	1 x 750	CABLE:ELEC,NETWORK,15KV,400KCMIL,STRANDED COPPER,NONCOMPACT SECTOR,IMPREGNATED P	Maintenance Use Only - CG&E Service Area
650kcmil CU 1/C 15kV PILC		650CUPILCJD15	100012	-------	559	-------	640	1.63	13.38 (3)	5200 10400 (3)	3 x 700'	CABLE:ELEC,NETWORK & FEEDER,15KV,650KCMIL,COMPACT ROUND COPPER,IMPREGNATED PAPER	Maintenance Use Only - CG&E Service Area
650kcmil CU 3/C 15kV PILC		650CUPILCJ3D15	100011	-------	-------	-------	-------	2.86	11.5300	10400	1 x 700'	CABLE:ELEC,NETWORK,15KV,650KCMIL,NON-COMPACT SECTOR STRANDED COPPER,IMPREGNATED	Maintenance Use Only - CG&E Service Area
750kcmil CU 1/C 15kV PILC		750CUPILCJD15	----------	-------	599	-------	687	1.6	13.95 (3)	6000 12000 (3)	3 x 600'		Maintenance Use Only - CG&E Service Area
1000kcmil CU 1/C 15kV PILC		1000CUPILCJD15	100004	-------	682	-------	781	1.85	17.28 (3)	8000 16000 (3)	3 x 600'	CABLE:ELEC,FEEDER,15KV,#1000KCMIL,COMPACT ROUND COPPER,IMPREGNATED PAPER,HMW POL	Maintenance Use Only - CG&E Service Area
2000kcmil CU 1/C 15kV PILC		2000CUPILCJD15	100006	-------	860	-------	985		14.00 (Ea)	16000	1 x 500'	CABLE:ELEC,FEEDER,15KV,2000KCMIL,NON COMPACT CONCENTRIC 127 STR COPPER,IMPREGNAT	Maintenance Use Only - CG&E Service Area
Aluminum Underground Secondary (600v)													
6 Aluminum UG Duplex	6	6ALDXUG	101534	95	70	-------	-------	-------	0.1040	175		CABLE, ELECTRICAL, POWER, 600V, (2) 6 AWG, ALUM, XLPE INS, XLPE, ALUM 7 STRAND, 90 DEGREE C, 3/4 HARD, 78 MIL, COLOR CODED CROSS-LINKED POLY	
2/0 Al UG Sec/Service - 2-2/0 & 1-1/0	2/0	2/0ALTXUG	101585	245	180	-------	-------	-------	0.5040	800	3 x 1000'	CABLE, ELECTRICAL, "CONVERSE", 600V, (1) 1 AWG, (2) 2/0 AWG, ALUM, XLPE INS, ALUM (3) 19 STRAND, 90 DEGREE C, (1) W/ 80 MIL	URD Services
4/0 Al UG Sec/Service 2-4/0 & 1-2/0	4/0	4/0ALTXUG	101606	315	240	-------	-------	-------	0.7400	1270		CABLE, ELECTRICAL, "SWEETBRIAR", 600V, (1) 2/0 AWG, (2) 4/0 AWG, ALUM, XLPE INS, ALUM (3) 19 STRAND 90	URD Services
500AL Sec /Service 2-500 & 1-350	500kcmil	500ALTXUG	101597	495	395	-------	-------	-------	1.6460	3000	3 x 500'	CABLE, ELECTRICAL, "RIDER", 600V, (1) 350, (2) 500 KCM, ALUM, XLPE INS, (3) 37 STRAND, 90 DEGREE	URD Services
4/0AL UG Quadruplex	4/0	4/0ALQXUG	101610	290	225	-------	-------	-------	1.0160	1270		CABLE, ELECTRICAL, "WAKE FOREST", 600V, (1) 2/0 AWG, (3) 4/0 AWG, ALUM, XLPE INS, ALUM (4) 19	URD Services
500AL UG Quadruplex	500kcmil	500ALQXUG	101611	460	370	-------	-------	-------		3000		CABLE, ELECTRICAL, "WOFFORD", 600V, (1) 350, (3) 500 KCM, ALUM, XLPE INS, ALUM (4) 37 STRAND, 90 DEGREE C, (1) W/95 MIL	URD Services

Duke Energy Midwest Conductor Summary

	Description	Conductor Size (Stranding)	Wire Code	SIN	Single Cable or Circuit Ampacity				Cond. Dia.	Weight lbs / ft	Ultimate Strength	Reel Length	Cinergy Catalogue Description (Materials Management)	Misc
					Summer - Direct Buried	Summer - In Duct	Winter - Direct Buried	Winter - In Duct						
Copper Underground Secondary (600v)														
	2 Cu	2	2CURRUG	100381	-------	230	-------	-------	0.4420	0.2800	530	1 x 2000'	WIRE, ELECTRICAL, #2, CLASS "B" NON-COMPACT STRANDED, COPPER	
	4/0 Cu	4/0	4/0CURRUG	100016	-------	417	-------	-------	0.7820	0.8600	1700	1 x 2000'	WIRE, ELECTRICAL, #2, CLASS "B" NON-COMPACT STRANDED, COPPER	Network Services Downtown Cincinnati
	500 Cu		500CURRUG	100015	-------	-------	-------	-------	1.1200	1.9200	4000	1 x 1500'	CABLE, ELECTRICAL, NETWORK SERVICES, 600V, 500 KCMIL, CLASS "B" NON-COMPACT STRANDED COATED, 1/O - COATED STRANDS, ADJACENT TO THEINSULATIO	Network Services Downtown Cincinnati
	500 Cu	500	500CURRUG	100014	-------	657	-------	-------	1.12 (ea) 2.40 (3)	5.7600	4000	3 x 500'	CABLE, ELECTRICAL, NETWORK SERVICES, 600V, 500 KCMIL, CLASS "B" NON-COMPACT STRANDED COATED, 1/C - HAVING COATED STRANDS, ADJACENT TOTHE IN	Network Services Downtown Cincinnati
	1000 Cu	1000	1000CURRUG	100021	-------	928	-------	-------	1.4900	3.1000	8000	1 x 750'	CABLE, ELECTRICAL, NETWORK SERVICES, 600V, 1000 KCMIL, CLASS "B" NON-COMPACT 61 OR 127 STRANDED	Network Services Downtown Cincinnati
	2000 Cu	2000	2000CURRUG	100022	-------	1250	-------	-------	2.030	7.110	16000	1 x 500'	CABLE, ELECTRICAL, NETWORK SERVICE, 600V, 2000 KCMIL, CLASS "B" NON-COMPACT STRANDED COPPER, EPR INS, HEAVY DUTY BLACK NEOPRENE OR HEAVY DUT	Network Services Downtown Cincinnati

Cinergy Ratings:

Primary Underground -
- Soil Thermal Resitivity for the earth and for the backfill materia - 90; 50 for Concrete Encasement when used
- Ambient Earth Temperature; 25C Summer; 5C Winter
- Load factor - 75%
- Maximum Conductor Temperature for Continuous Operation - 90C Except for 1000kcmil Al TRXLPE Cables which are rated at 100C
- Cable Configuration: Direct Buried Cables - FLAT; In Duct - TRIANGULAR
- Duct Material and Size: 3" PVC up to 2/0 JCN (15 & 35kV Class); 5" PVC for 4/0 JCN (2/0 PILC) through 1000kcmil 15kV Class; 6" PVCfor 750kcmil 35kVB Class
- Calculations done with USAMP+ Software

600V Underground
- Ratings based on manufaturer's catalogue data (Southwire, Alcoa, et.al)
- Maximum Conductor Temperature for Continuous Operation - 90C

Duke Energy Midwest Conductor Summary

Description	Conductor Size (Stranding)	Wire Code	Industry Code Name	SIN			Ampacity DB or Air				Resistance Ohms /Mi. 50C	Cond. Dia.	Weight lbs / ft	Ultimate Strength	Cinergy Catalogue Description (Materials Management)	Misc
					Summer - 50C SEE NOTE	Summer - 80C	Summer 100C (200C)	Winter - 50C SEE NOTE	Winter - 80C	Winter - 100C (200C)						
- Overhead																
esistant (VR) Conductors **																
	533.6 (52/14) VR (2x266.8kcmil 26/7) 477kcmil Equiv.	533.6AL52x14T2	Partridge VR	103555	--------	762	938	--------	1102	1215	0.18977	1.051 (0.684 x 1.368)	0.7340	22,600	WIRE/CABLE, BARE ELECTRICAL, PARTRIDGE, (2), 477 KCMIL, ACSR (2) 266.8 KCM CONDUCTORS LEFT HAND LAY VIBRATION RESISTANT, 0.734LB/FT, 1.362FT/LB	
	954kcmil 24/7 OVAL	945AL24x7OVAL	Rail/OVAL	50100544	--------	1032	1275	--------	1499	1654	0.1084	1.1462 (1.375 x 0.901)	0.1450	25,900	WIRE, ELECTRICAL, RAIL/OVAL, 954 KCM, OVAL, OVAL/ACSR, BARE INS MOTION-RESISTANT CONDUCTOR. OVAL SHAPE TO REDUCE IF NOT ELIMINATE GALLOP OR AEOLIAN VIBRATION.	

**** Ampacties for Special Purpose Conductors *CANNOT* be calculated using SWRate 16. Contact Southwire for Specific Ratings**

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-015

REQUEST:

Provide a list of Duke Kentucky's distribution system planning criteria and processes and explain in detail how each is evaluated when addressing system needs, including but not limited to capacity and asset health.

RESPONSE:

Please see response to STAFF-DR-04-014 and STAFF-DR-04-014 Attachments 1 through 5 for a list of distribution system planning criteria and process and the explanation in detail how each is evaluated when addressing system needs.

PERSON RESPONSIBLE: Dominic "Nick" J. Melillo

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-016

REQUEST:

Describe how Duke Kentucky sizes equipment for capacity upgrades. If there are standard sizes, provide the appropriate reference used.

RESPONSE:

Please see STAFF-DR-04-014 Attachments 1 through 5 for all of the documents utilized to size equipment for capacity upgrades.

Distribution Planning consists of a process of study and analysis through which Duke Energy Kentucky assures itself that it will provide a safe, economical, and reliable system to meet its present and future delivery obligations at the end-user level.

Many performance factors are utilized when determining where system modifications are needed. Examples of these factors include customer load growth, economic development, area construction, equipment loading capabilities, system efficiency, power quality, reliability factors (SAIDI, SAIFI), and system protection factors. Utilizing these factors, in conjunction with a system planning software tool, allows a detailed system analysis of the Duke Energy Kentucky electrical distribution system.

Based on analysis, construction projects are then developed to enhance available system supply, maintain system public safety, and improve performance deficiencies. Construction project options are reviewed with other stakeholders to ensure a balanced, efficient, and workable plan has been developed. Approval to implement the project is the responsibility of management based on the effectiveness and total cost of the project.

PERSON RESPONSIBLE: Dominic “Nick” J. Melillo

STAFF-DR-04-017

REQUEST:

Confirm that Duke Kentucky has implemented IEEE 1547-2018. If confirmed, explain the process that was used and the resulting default and optional smart inverter settings available to interconnecting facilities. If not implemented, explain why.

RESPONSE:

Duke Energy Kentucky, along with other Duke Energy jurisdictions, is in the process of a phased implementation process for IEEE 1547-2018. Duke Energy does not assume that existing generating facilities are capable of modifications to their operating characteristics (e.g. smart inverter functions such as volt-watt functions, voltage regulation functions, etc.) These modified operating characteristics are under consideration for future adoption by Duke Energy Kentucky but are still considered technologies not yet widely accepted by good utility practice.

PERSON RESPONSIBLE: Dominic "Nick" J. Melillo

STAFF-DR-04-018

REQUEST:

Explain how Duke Kentucky integrated, if at all, smart inverter functionality into its distribution system planning process and assumptions. Include how smart inverter setting have altered distribution system planning criteria.

RESPONSE:

Duke Energy Kentucky has not yet integrated smart inverter functionality into its distribution system planning process and assumptions. Smart inverter settings, as stated in STAFF-DR-04-017, are still being evaluated as to their benefits or detriments to the stability and integrity of the grid.

PERSON RESPONSIBLE: Dominic "Nick" J. Melillo

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-019

REQUEST:

Confirm that Duke Kentucky currently offers automated load management, also known as electric vehicle energy management system, options for connecting electric vehicle charging customers. If confirmed, explain the process in place and the available options to customers. If not, explain why not.

RESPONSE:

The Company does not currently offer EV load management programs. A program with an EV load management component was proposed in KyPSC Case No. 2019-00271 but was not approved. Additionally, the Company has proposed a time-of-use rate in this proceeding that is envisioned as one option ultimately available to customers to help them make informed decisions as to when to charge their EV. Finally, the Company desires to leverage the customer connectivity that would be enabled by the proposed Make Ready Credit and EVSE programs to design & deploy load management programs – both automated and manual – that address multiple customer profiles and pain points.

PERSON RESPONSIBLE: Cormack C. Gordon

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-020

REQUEST:

Provide details regarding Duke Energy Inc.'s experience with Automated Network Management (ANM) and similar flexible interconnection options. Include in your response:

a. Details regarding any pilot programs that have been conducted that use ANM. Include in the final evaluations of the pilot programs if completed.

b. Provide the different forms of flexible interconnection Duke Energy, Inc. has offered, and which technologies were leveraged for each type.

RESPONSE:

a. Except for a Smart Inverter Pilot that was developed as part of a 2020 settlement agreement in North Carolina with a group of interconnection customers, Duke Energy has not utilized flexible interconnection service. The Smart Inverter Pilot includes seven (7) distribution system interconnections that have been identified as creating unacceptable voltage levels on the distribution feeders they are proposing to connect to. The Smart Inverter Pilot allows those interconnection customers to configure their inverters to use volt-var or volt-watt settings to react to adjust output to mitigate the voltage issues. The intent is to complete the pilot, monitor the performance of the pilot participants when operational, and evaluate results for further implementation. To date, only one of the seven facilities is operational, so we have limited data to evaluate the performance.

b. Duke Energy conducts Distributed Energy Resource (DER) system impact studies using the maximum requested output capacity requested by the interconnecting customer. Studies that would be required to identify flexible interconnection options is outside the scope of the impact study. Duke Energy is developing and implementing a DER Dispatch system that will enable the utility to manage DER that is connected to the transmission or distribution system. However, we do not currently have plans to use that system to offer flexible interconnection service.

PERSON RESPONSIBLE: Dominic “Nick” J. Melillo

STAFF-DR-04-021

REQUEST:

Confirm that Duke Kentucky subtracts BTM load when evaluating capacity constraints at substations. Include in the response, how capacity constraints at substations are defined, identified, the solutions considered, and how solutions are chosen.

RESPONSE:

Behind the meter (BTM) generation/ distributed energy resource (DER) can be considered when evaluating capacity constraints if it is dispatchable. If BTM generation/DER is not dispatchable, it may not be available during the peak load day/time, and the distribution system is sized to ensure sufficient capacity is available on the peak day/time.

Distribution Planning consists of a process of study and analysis through which Duke Energy Kentucky assures itself that it will provide a safe, economical, and reliable system to meet its present and future delivery obligations at the end-user level.

Capacity constraints are identified by comparing substation and circuit peak loading to the equipment ratings. Any future identified large customer load addition is also considered, and the loading is classified into the following tiers:

Tier 1	Actual (or very firm projected) Load at the requested in-service date: Summer Load > 110% of 65C rise Nameplate rating or Winter Load > 120% of 65C Nameplate rating, or >110% Conductor overload
Tier 2	Actual (or very firm projected) Load at the requested in-service date: 100% < Summer Load < 110% of 65C Nameplate rating or 110% < Winter Load < 120% of 65C Nameplate rating or 100-110% Conductor Overload

Tier 3	Actual (or very firm projected) Load at the requested in-service date: 90% < Summer Load < 100% of 65C Nameplate rating or 100% < Winter Load < 110% of 65C Nameplate rating, or 90-100% Conductor load

In addition to capacity, other factors such as system efficiency (losses), average voltage level, voltage and load balance, power quality, and reliability are also considered as recommendations for distribution upgrades are evaluated.

Based on analysis, construction projects are then developed to enhance available system supply, maintain system public safety, and improve performance deficiencies. Construction project options are reviewed with other stakeholders to ensure a balanced, efficient, and workable plan has been developed. Approval to implement the project is the responsibility of management based on the effectiveness and total cost of the project.

PERSON RESPONSIBLE: Dominic “Nick” J. Melillo

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-022

REQUEST:

Reference Confidential Attachment "CONF Attachment PLH-3 LABELED.xlsx," "Rev Rq_Benefits" tab.

a. Reference cell Q12, which lists variable benefits as $[redacted] in 2025 (Year 1). Identify how this figure was calculated, include an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

b. Reference cell V12, which lists capacity/capital deferral benefits as [redacted] in 2025 (Year 1). Identify how this figure was calculated and include an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE:

a. As mentioned throughout the Direct Testimony of Paul L. Halstead, an example of the CEC program benefits and costs were included in the referenced attachment. Further, Mr. Halstead stated the costs and benefits of the actual program would be included in the CPCN filing. As such, the variable benefits shown in the referenced attachment are illustrative and do not necessarily represent any forecasted values but instead are used to provide a numerical example of how these benefits flow to the various credit and savings components. The CEC program's variable benefits would include approaches used in the IRP such as avoided energy purchases, fuel, O&M savings, ancillary as well as any additional solar valuations the Commission could determine in future solar filings.

b. Similar to the response provided for (a) above, the values noted in the spreadsheet are meant to be representative of values that will be identified as part of the CPCN which could include items such as capacity deferral values or avoided firm gas transmission costs. The formulas provide a framework to share the benefits between participating and non-participating customer as the subscription price is calculated.

PERSON RESPONSIBLE: Paul L. Halstead

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-023

REQUEST:

Reference Confidential Attachment "CONF Attachment PLH-3 LABELED.xlsx," "Results - C&I and Residential" tab. Reference cell S6, which lists the customer credit as [redacted] cents/kWh in Year 1. Explain how this was calculated and provide an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE:

On page 16 of his Direct Testimony, Mr. Halstead states, the energy credit is a derived value taking into account various inputs including the subscription cost, energy credit escalation rate and targeted participant payback. As a result, the value in referenced cell S6 is established to meet these parameters. The specific cell S6 would have used a Goal Seek function to calculate the example provided. The Goal Seek function creates a value within the cell that does not include a formula.

PERSON RESPONSIBLE: Paul L. Halstead

STAFF-DR-04-024

REQUEST:

Refer to the Application, Volume 13, Direct Testimony of Paul Halstead (Halstead Direct Testimony) beginning at 13, line 18.

a. Describe the methodology for calculating each individual fixed and variable benefit considered for Duke Kentucky's system and its customers.

b. Identify the specific tabs and cells in Confidential Attachment PLH-3 where Duke Kentucky has separately quantified these individual benefits.

c. If the methodologies for calculating each individual benefit are not supported in the attachment, attach all supporting workpapers for the calculations in an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible. If Duke Kentucky did not quantify these benefits in the course of developing its bill credit, explain why not.

RESPONSE:

a. The variable benefits include avoided energy purchases, fuel, and O&M savings as well as ancillary services benefits. The fixed benefits, consist of capital and capacity deferral values as well as avoided firm gas transmission costs. The Company will be providing those values once the actual project is finalized and the CPCN is filed.

b. Please refer to the responses to STAFF-DR-04-022 parts (a) and (b). Values are inputs into the model on tab "Rev Rq_Benefits" in columns Q-T (variable benefits) and column V (fixed benefits).

c. The Company did not quantify these benefits for the purposes of this filing or in the referenced attachment due to the fact no specific project has been identified and there is a high likelihood the input assumptions to derive such benefits would change from the time of this filing until that of a CPCN filing for the proposed asset. As referenced in the Direct Testimony of Mr. Halstead page 11, starting with line 17, the Company would present the proposed costs and benefits at the time of the CPCN filing for approval by the KyPSC.

PERSON RESPONSIBLE: Paul L. Halstead

STAFF-DR-04-025

REQUEST:

Refer to the Halstead Direct Testimony at 12, lines 6–10.

a. Explain the decision to use 105 percent of Clean Energy Connection (CEC) program costs in its Subscription Fee Formula.

b. Explain why Duke Kentucky subtracts 75 percent of capital deferral/capacity benefits in its Subscription Fee Formula.

c. Explain why Duke Kentucky subtracted only capital deferral/capacity benefits from CEC program costs in its Subscription Fee Formula, but not variable benefits.

d. Explain the assumption of 100 percent participation for the entire CEC program life. Explain the impact on the Subscription Fee if participation was less than 100 percent.

RESPONSE:

a. The decision to use 105% is rooted in our experience with our similar program in Florida. The Company felt it was important for participants to pay a premium before considering program benefits to ensure non-participants benefit as a result of the program design.

b. Similar to the response to (a) above, the Company thinks it is important for some portion of the system benefits to flow back to non-participants given the underlying asset recovery will be included in base rates.

c. The reason for excluding variable benefits is twofold. First, the underlying revenue requirement for the asset is predominately associated with recovery of fixed capital cost so reducing that amount by fixed or capital related benefits was appropriate. Second, including the variable benefits would have resulted in a zero or negative subscription fee and a near zero credit. At that point, all participants in the program are guaranteed a savings from day 1.

d. The intent is to develop a program of sufficient size and characteristics such that it would be fully subscribed to lower the net cost to non-participants from day 1 compared to no program overlay. In the event the program is not fully subscribed, the revenue credit assumed in setting base rates would not be collected but would have been included as a reduction to rate base requirements for non-participants. This creates an incentive for the Company to actively market the program and replace customers as they leave the program. Energy credits associated with the actual program participation will be included in the fuel clause. In the event of under-subscription, non-participants would retain the variable benefits associated with the unsubscribed CEC program capacity.

PERSON RESPONSIBLE: Paul L. Halstead

Duke Energy Kentucky
Case No. 2022-00372
STAFF Fourth Set Data Requests
Date Received: March 30, 2023

STAFF-DR-04-026

REQUEST:

Refer to the Halstead Direct Testimony at 16, lines 13–19.

a. Explain the desired payback for the NPV of the bill credit.

b. Clarify whether the subscription fee is an input into the bill credit calculation.

RESPONSE:

a. The desired payback is the result of various customer discussions in Kentucky, but also includes learnings over a number of years for other renewable programs in the Company's other regulated jurisdictions. This experience suggests there is limited interest in programs that do not provide a possibility of a net economic benefit to participants. At the same time, the Company is ensuring non-participants are not subsidizing participants over the program/asset life.

b. Yes, as detailed in the response to STAFF-DR-04-023, the energy credit associated with a customer's bill credit is a calculated value resulting from various inputs including the subscription fee to ensure the maximum benefit to non-participating participants.

PERSON RESPONSIBLE: Paul L. Halstead