KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY™

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January 14, 2026

Linda C. Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, Kentucky 40602-0615

RE: THE STANDARD FUEL ADJUSTMENT CLAUSE BACKUP FILING

Dear Ms. Bridwell:

In compliance with the Commission's Order dated November 25, 1981 in Case No. 8058-A, Kentucky Power is forwarding herewith for the month of November, 2025 the required backup information for the fuel adjustment clause applied to customers' bills in the month of January, 2026:

1. Fuel Inventory Schedule – Coal
2. Fuel Inventory Schedule – Gas
3. Fuel Inventory Schedule – Oil
4. Fuel Purchase Schedule – Coal
5. Fuel Purchase Schedule – Gas
6. Fuel Purchase Schedule – Oil
7. Power Transaction Schedule
8. Unit Performance Data
9. Fuel-Related PJM Billing Line Items

Pursuant to the Commission's Order dated October 3, 2002 in Case No. 2000-495-B, and as modified by the Commission's January 18, 2018 Order in Case No. 2017-00179, the Company began using the peaking unit equivalent approach to calculate the level of non-economy purchased power costs to flow through the fuel adjustment clause in the actual fuel costs. These fuel costs are documented on the attached Power Transaction Schedule.

In accordance with the Commission's letter dated June 13, 2014, fuel contracts will be filed electronically.

Should you have any questions, please contact me at (606) 327-2603.

Sincerely,

Tanner S. Wolffram
Director, Regulatory Services

Attachment

KENTUCKY POWER COMPANY
ANALYSIS OF COAL PURCHASES
November 2025

Station and Supplier (a)	PBDU (b)	POCN (c)	PT (c1)	MT (d)	ST (e)	Tons Purchased (f)	BTU Per LB. (g)	No. MMBTU Per Ton (h)	FOB Mine Price Per Ton (i)	FOB Mine Cents Per MMBTU (j)	Trans Cost Per Ton (k)	Trans Cost Cents Per MMBTU (l)	Delivered Cost Per Ton (m)	Delivered Cost Cents Per MMBTU (n)	% Sulfur (o)	% Ash (p)	% H2O (q)
TOTAL KENTUCKY POWER																	
ACNR Coal Sales, Inc.	P	03-00-22-003	A	C	WV	11,080.00	12,835	25.67	75.14	292.72	0.00	0.00	75.14	292.72	2.59	8.22	6.62
Alpha Thermal CS Company	P	03-00-25-9M1	A	B	WV	3,067.45	12,643	25.29	94.00	371.70	-21.28	-84.15	72.72	287.55	0.86	8.74	8.23
BAMM, Inc.	P	03-00-26-001	A	B	WV	2,190.15	12,209	24.42	75.90	310.83	-16.61	-68.03	59.29	242.80	0.68	7.40	9.65
Pocahontas Sales and Logistics	P	03-00-23-002	A	B	WV	4,943.95	12,601	25.20	114.99	456.33	-17.40	-69.06	97.59	387.27	0.87	7.52	8.30
TOTAL SYSTEM WEIGHTED AVERAGE						21,281.55	12,689	25.38	87.20	343.98	(8.82)	(35.17)	78.38	308.80	1.74	8.05	7.55

(b) PDBU = Producer, Broker, Distributor or Utility

(c) POCN = Purchase Order or Contract Number

(c1) PT = Product Type
By contract, Product Types designate different commodity sources (mines)

(d) MT = Mode of Transportation
Designated by Symbol
R = Rail
B = Barge
T = Truck
C = Conveyor Belt
P = Pipeline

(e) ST = State of origin

KENTUCKY POWER COMPANY
ANALYSIS OF COAL PURCHASES
November 2025

Station and Supplier (a)	PBDU (b)	POCN (c)	PT (c1)	MT (d)	ST (e)	Tons Purchased (f)	BTU Per LB. (g)	No. MMBTU Per Ton (h)	FOB Mine Price Per Ton (i)	FOB Mine Cents Per MMBTU (j)	Trans Cost (A) (B) Per Ton (k)	Trans Cost (A) (B) Cents Per MMBTU (l)	Delivered Cost Per Ton (m)	Delivered Cost Cents Per MMBTU (n)	% Sulfur (o)	% Ash (p)	% H2O (q)
MITCHELL PLANT																	
Long Term Contracts:											(A) (B)						
ACNR Coal Sales, Inc.	P	03-00-22-003	A	C	WV	22,160.00	12,835	25.67	75.14	292.72	0.00	0.00	75.14	292.72	2.59	8.22	6.62
BAMM, Inc.	P	03-00-26-001	A	B	WV	4,380.30	12,209	24.42	75.90	310.83	-16.61	-68.03	59.29	242.80	0.68	7.40	9.65
Pocahontas Sales and Logistics	P	03-00-23-002	A	B	WV	9,887.90	12,601	25.20	114.99	456.33	-17.40	-69.06	97.59	387.27	0.87	7.52	8.30
Station Weighted Average						36,428.20	12,696	25.39	86.05	339.31	-6.72	-26.93	79.33	312.38	1.89	7.93	7.44
Spot Market:											(A) (B)						
Alpha Thermal CS Company	P	03-00-25-9M1	A	B	WV	6,134.90	12,643	25.29	94.00	371.70	-21.28	-84.15	72.72	287.55	0.86	8.74	8.23
Station Weighted Average						6,134.90	12,643	25.29	94.00	371.70	(21.28)	(84.15)	72.72	287.55	0.86	8.74	8.23
TOTAL STATION WEIGHTED AVERAGE						42,563.10	12,689	25.38	87.20	343.98	(8.82)	(35.17)	78.38	308.80	1.74	8.05	7.55

Notes

(A) There were Campbell Q4 true-up cost of $(550,710.01) ($275,355.01 kKPCO Share) and no other demmurage costs for the month. Due to the credit true-up transportation cost reproted for November 2025 are lower compared to historical and contractual amounts.

(B) Total Station Weighted Average Transportation Costs includes the ACNR Coal Sales, Inc. ("ACNR", formerly Consolidation Coal Company) contract which has no associated transportation costs. ACNR assumed the former Consolidation Coal Company's contract as part of the sale of Murray Energy's assets.

(C) Contura Energy, Inc. changed its name to Alpha Metallurgical Resources, Inc. In connection with this initiative all Contura Coal Sales, LLC thermal coal sales contracts are now using the Alpha Thermal Coal Sales Company name.

ANALYSIS OF OIL PURCHASES

Supplier	PBDU	POCN	MT	Station Name	Gal or Cu. Ft. Purchased	BTU per Unit	Delivered Cost Per Gal	Cents Per MMBTU
Marathon Petroleum LP	P	03-FO-24-001	T	Mitchell	82,519.00	138,100.00	2.93	2,119.48

MITCHELL PLANT - KENTUCKY POWER SHARE OF PURCHASES

Kentucky Power Share of Oil Receipts				41,259.50
Mitchell Total Oil Receipts				82,519.00
Mitchell - Kentucky Power Oil Receipts Ratio				50.00%
Marathon Petroleum LP	P	03-FO-24-001	T	41,259.50
Heritage Cooperative, Inc.	P	03-FO-25-001	T	-

(b) PDBU = Producer, Broker, Distributor or Utility
(c) POCN = Purchase Order or Contract Number
(c1) PT = Product Type
By contract, Product Types designate different commodity sources (mines)
(d) MT = Mode of Transportation
Designated by Symbol
R = Rail
B = Barge
T = Truck
C = Conveyor Belt
P = Pipeline
(e) ST = State of origin

KENTUCKY POWER COMPANY
ANALYSIS OF GAS PURCHASES
November-2025

Supplier (a)	POCN (b)	MT (c)	Station Name (d)	Gross MMBTU Purchased (e)	Net MMBTU Purchased (f)	Delivered Cost $ (g)	Gross $ Per MMBTU (h)	Net $ Per MMBTU (i)	% SO2 (j)
DTE	-	P	Big Sandy	437,000	421,252	1,115,100.00	2.55	2.65	-
ECOENERGY	-	P	Big Sandy	24,900	24,003	76,206.75	3.06	3.17	-
J ARON	-	P	Big Sandy	300,000	289,189	847,500.00	2.83	2.93	-
KOCH ES	-	P	Big Sandy	10,000	9,640	30,300.00	3.03	3.14	-
MACQUARIE	-	P	Big Sandy	402,000	387,514	1,340,092.50	3.33	3.46	-
SNYDER	-	P	Big Sandy	8,100	7,808	29,767.50	3.68	3.81	-
UNITED	-	P	Big Sandy	4,000	3,856	13,370.00	3.34	3.47	-
VITOL	-	P	Big Sandy	37,500	36,149	128,343.75	3.42	3.55	-
Columbia Gas*	173522 & 177527	P	Big Sandy			-75,991.57	0.00		-
Columbia Gas - Reservation Fee	173522	P	Big Sandy			488,804.40	0.00		-
				1,223,500	1,179,410	3,993,493			

(b) POCN = Purchase Order or Contract Number

(c) MT = Mode of Transportation
Designated by Symbol
R =Rail
B =Barge
T =Truck
C =Conveyor Belt
P =Pipeline

(j) % of sulfur in natural gas is not applicable

KENTUCKY POWER COMPANY
MITCHELL PLANT - KPCO SHARE
November-2025

COAL INVENTORY SCHEDULE

		Tons	Amount	Per Unit
Beginning Inventory		562,054.39	$51,286,134.87	$91.2476
Purchases		21,281.55	$1,667,985.37	$78.3771
Adjustments	1	3,958.50	$229,505.30	$57.9778
Sub-Total		587,294.44	$53,183,625.54	$90.5570
Less Coal Burned		99,804.50	$8,735,699.02	$87.5281
Ending Inventory		487,489.94	$44,447,926.52	$91.1771

1 Survey Adjustment this reporting period INCREASED the ending coal pile inventory.

KENTUCKY POWER COMPANY
BIG SANDY PLANT
November-2025

GAS INVENTORY SCHEDULE

	MMBTU		Amount	$/MMBTU
Beginning Inventory	34,015.00	$	80,817.50	$2.3759
Purchases	1,179,410.00	$	3,993,493.33	$3.3860
Gas Sales	-69,000.00	$	(204,062.50)	$2.9574
Adjustments(Imblance point usage)	0.00	$	-	$0.0000
Sub-Total	1,144,425.00	$	3,870,248.33	$3.3818
Less Disposed				
Generation	1,098,054.00	$	3,778,212.01	$3.4408
Loss or (Gain) on Sale	0.00	$	(35,903.75)	$0.0000
Other(Tax expense)	0.00	$	-	$0.0000
Ending Inventory	46,371.00	$	127,940.07	$2.7591

(1) Due to purchases of natural gas being day ahead, consumption may differ from purchased natural gas leading to an imbalance at the beginning or end of every month.

KENTUCKY POWER COMPANY
MITCHELL PLANT - KPCO SHARE
November-2025

OIL INVENTORY SCHEDULE

	Gallons	Amount	Per Unit
Beginning Inventory	374,582.21	$971,605.12	$2.5938
Purchases	41,259.50	$120,766.49	$2.9270
Adjustments	0.00	$0.00	$0.0000
Sub-Total	415,841.71	$1,092,371.61	$2.6269
Less Disposed			
Generation	112,322.50	$295,059.16	$2.6269
Chemical Cleaning/Other	4,055.00	$10,652.08	$2.6269
Ending Inventory	299,464.21	$786,660.37	$2.6269

KENTUCKY POWER COMPANY
POWER TRANSACTION SCHEDULE
November 2025

TRANSACTION TYPES *

SPOT MARKET ENERGY - DA	PJM MARKET SPOT ENERGY - DAY AHEAD
SPOT MARKET ENERGY - BAL	PJM MARKET SPOT ENERGY - BALANCING

* Due to voluminous transactions, they are aggregated by type
rather than by interconnected utility.

KENTUCKY POWER COMPANY
POWER TRANSACTION SCHEDULE
MONTH ENDED: NOVEMBER 2025

PURCHASES

TRANSACTION TYPE	MWH	BILLING COMPONENTS FUEL CHARGE ($)	DEMAND ($)	OTHER CHARGES ($)	TOTAL CHARGES ($)
SPOT MARKET ENERGY - BAL	146,580	7,300,455.30	0.00	0.00	7,300,455.30
SPOT MARKET ENERGY - DA	79,411	2,905,640.50	0.00	0.00	2,905,640.50
Subtotal:	225,991 (1)	10,206,095.80	0.00	0.00	10,206,095.80
ROCKPORT UNIT #1 - LEASE	0	0.00	0.00	0.00	0.00
ROCKPORT UNIT #2 - LEASE	0	0.00	0.00	0.00	0.00
Subtotal:	0	0.00	0.00	0.00	0.00
INTERRUPTIBLE BUY/THROUGH	0	0.00	0.00	0.00	0.00
TOTALS:	225,991	10,206,095.80	0.00	0.00	10,206,095.80

	MWH	Total Energy Charges
(1) SME PURCHASES - ALLOCATED TO SYSTEM SALES:	82,963	4,641,263.74
SME PURCHASES - ALLOCATED TO INTERNAL CUSTOMERS:	143,028	5,564,832.06
ROCKPORT PURCHASES - ALLOCATED TO SYSTEM SALES:	0	0.00
ROCKPORT PURCHASES - ALLOCATED TO INTERNAL CUSTOMERS:	0	0.00
	225,991	10,206,095.80
LESS: PJM IMPLICIT CONGESTION INCLUDED IN THE INTERNAL CUSTOMER'S FIGURE:	0	0.00
NET INCLUDABLE ENERGY CHARGES:	225,991	10,206,095.80

KENTUCKY POWER COMPANY
POWER TRANSACTION SCHEDULE
MONTH ENDED: NOVEMBER 2025

SALES		BILLING COMPONENTS				
	KPCO	SUPPLIED BY KPCO SOURCES				
TRANSACTION TYPE	DELIVERED MWH	MWH	FUEL CHARGE ($)	DEMAND ($)	OTHER CHARGES ($)	TOTAL CHARGES ($)
SPOT MARKET ENERGY - BAL	14,334	14,334	509,924	0	21,245	531,169
SPOT MARKET ENERGY - DA	112,141	112,141	5,546,836	0	995,814	6,542,650
	126,475	126,475	6,056,760 (1)	0.00	1,017,059	7,073,819
PRIOR PERIOD ADJUSTMENT	0	0	0.00	0.00	0.00	
INTERRUPTIBLE BUY/THROUGH	0	0	0.00	0.00	0.00	0.00
TOTALS:	126,475	126,475	6,056,760	0	1,017,059	7,073,819

KPCo's other costs incurred, (other than fuel from Account 151):	211,277.30
AEP energy cost less the actual energy costs incurred by KPCo:	0.00
Difference (Total AEP energy charges - Total AEP energy costs):	805,782
Total (Other Charges):	1,017,059

SUPPLIED BY KPCo SOURCES - FUEL CHARGE (Page 3)		**6,056,760**
Add: ALLOCATED TO SYSTEM SALES (PAGE 2)	4,641,264	
Less: FUEL ALLOCATED TO SYSTEM SALES	4,641,264	-
INTER-SYSTEM SALES - FUEL COSTS (PAGE 4)		**6,056,760**

FINAL SCHEDULE NOVEMBER 2025 COSTS - ACTUAL

KENTUCKY POWER COMPANY
FUEL COST SCHEDULE
MONTH ENDED: NOVEMBER 2025

		BIG SANDY 1	MITCHELL 1 KP	MITCHELL 2 KP	FUEL AMOUNTS ($)
	(A) COMPANY GENERATION				
	COAL BURNED		5,008,591.05	3,497,602.67	8,506,193.72
	OIL BURNED		82,089.81	212,969.35	295,059.16
(3)	GAS BURNED	3,778,212.10			3,778,212.10
	FUEL (JOINTLY OWNED PLANT)				-----------------
(1)	FUEL (ASSIGNED COST DURING F.O.)				120,789.86
	FUEL (SUBSTITUTE FOR F.O.)				-----------------
	SUB-TOTAL				12,700,254.84
	(B) PURCHASES				
	IDENTIFIABLE FUEL COST - OTHER PURCHASES				10,206,095.80
	IDENTIFIABLE FUEL COST - ROCKPORT PURCHASES				0.00
(1)	IDENTIFIABLE FUEL COST (SUBSTITUTE FOR F.O.)				161,095.55
(2)	IDENTIFIABLE FUEL COST (PEAKING UNIT EQUIVALENT)				309,553.51
	SUB-TOTAL				9,735,446.74
	(C) INTER-SYSTEM SALES				
	FUEL COSTS				6,056,760.08
	TOTAL FUEL COSTS (A + B - C)				16,378,941.50

F.O. = FORCED OUTAGE

DETAILS:

(1) FUEL (ASSIGNED COST DURING FORCED OUTAGE)

TOTAL REPLACEMENT (IDENTIFIABLE FUEL COST) FUEL COST DUE TO F.O.:	3,167,479	kWh	50.859	MILLS/kWh	161,095.55
TOTAL ALLOWABLE (IDENTIFIABLE FUEL COST) REPLACEMENT FUEL COST FOR F.O.:	3,167,479	kWh	38.134	MILLS/kWh	120,789.86

(1) 0 BIG SANDY FORCED OUTAGE THIS MONTH
0 MITCHELL UNIT 1 FORCED OUTAGES THIS MONTH
0 MITCHELL UNIT 2 FORCED OUTAGES THIS MONTH

(2) Amount in excess of peaking unit equivalent as callculated in accordance with KPSC Order OF October 3, 2002 in Case No. 2000-00495-B.

(3) The amount shown above as the gas burned for Big Sandy 1 includes the reservation fee.

AMERICAN ELECTRIC POWER SERVICE CORPORATION
FUEL AND ENERGY SYSTEM PRACTICES
AMERICAN ELECTRIC POWER
MONTHLY PURCHASE SUMMARY REPORT FOR KPCO
(Year:2025 Month:11 Cycle:Actual) East Purchase Power Report for Book Name: Nov 2025 Act East

		TOTAL			ALLOCATED			FIRM		
NERC Id	Transaction Class	MWH	ENERGY COST	FUEL COST	MWH	ENERGY COST	FUEL COST	MWH	ENERGY COST	FUEL COST
OVPS	OVPS	0	0	0	0	0	0	0	0	0
PJM	SPOT MARKET ENERGY - BAL	146579.581	7300455.3	7300455.3	73808.471	4303125.5	4303125.5	72771.11	2997329.8	2997329.8
PJM	SPOT MARKET ENERGY - DA	79411	2905640.5	2905640.5	9154.255	338138.24	338138.24	70256.745	2567502.26	2567502.26
Total		225990.581	10206095.8	10206095.8	82962.726	4641263.74	4641263.74	143027.86	5564832.06	5564832.06

APPENDIX A

KENTUCKY POWER COMPANY
BIG SANDY - TOTAL PLANT
November-2025

Line No.	Item Description	
1.	**Unit Performance:**	
	a. Capacity (name plate rating) (MW)	295.4
	b. Capacity (average load) (MW)	163.7
	c. Net Demonstrated Capability (MW)	295.4
	d. Net Capability Factor (%)	49.5
2.	**Heat Rate:**	
	a. Btu's Consumed (MMBTU ('000s))	1,098.1
	b. Gross Generation (MWH)	112,246
	c. Net Generation (MWH)	105,330
	d. Heat Rate (L2a divided by L2c) (BTU/KWH)	10,425
3.	**Operating Availability:**	
	a. Hours Unit Operated	643.4
	b. Hours Available	643.4
	c. Hours During the Period	721.0
	d. Availability Factor (%)	89.2
4.	**Cost per KWH:**	
	a. Gross Generation - FAC Basis (Cents/KWH)	3.3
	b. Net Generation - FAC Basis (Cents/KWH)	3.6
5.	**Inventory Analysis:**	
	a. Number of Days Supply based on actual burn at the station	NA

APPENDIX A

KENTUCKY POWER COMPANY
MITCHELL - TOTAL PLANT
November 2025

Line No.	Item Description	Total Mitchell	KPCo Share
1.	**Unit Performance:**		
	a. Capacity (name plate rating) (MW)	1,560.3	780.2
	b. Capacity (average load) (MW)	671.8	335.9
	c. Net Demonstrated Capability (MW)	1,560.3	780.2
	d. Net Capability Factor (%)	41.5	41.4
2.	**Heat Rate:**		
	a. Btu's Consumed (MMBTU)	4,776.6	2,388.3
	b. Gross Generation (MWH)	515,557	257,778
	c. Net Generation (MWH)	465,536	232,768
	d. Heat Rate (L2a divided by L2c) (BTU/KWH)	10,681	10,681
3.	**Operating Availability:**		
	a. Hours Unit Operated	Reported on Unit Basis Only	
	b. Hours Available	Reported on Unit Basis Only	
	c. Hours During the Period	Reported on Unit Basis Only	
	d. Availability Factor (%)	Reported on Unit Basis Only	
4.	**Cost per KWH:**		
	a. Gross Generation - FAC Basis (Cents/KWH)	3.3	3.3
	b. Net Generation - FAC Basis (Cents/KWH)	3.7	3.7
5.	**Inventory Analysis:**		
	a. Number of Days Supply based on actual burn at the station	197.8	197.8

APPENDIX A

KENTUCKY POWER COMPANY
MITCHELL - UNIT 1
November 2025

Line No.	Item Description	
1.	Unit Performance:	
	a. Capacity (name plate rating) (MW)	770.1
	b. Capacity (average load) (MW)	374.5
	c. Net Demonstrated Capability (MW)	770.1
	d. Net Capability Factor (%)	48.0
2.	Heat Rate:	
	a. Btu's Consumed (MMBTU)	2,811
	b. Gross Generation (MWH)	296,897
	c. Net Generation (MWH)	266,224
	d. Heat Rate (L2a divided by L2c) (BTU/KWH)	10,870
3.	Operating Availability:	
	a. Hours Unit Operated	669.1
	b. Hours Available	710.9
	c. Hours During the Period	721.0
	d. Availability Factor (L3b divided by L3c) (%)	98.6
4.	Cost per KWH:	
	a. Gross Generation - FAC Basis (Cents/KWH)	Reported on total plant basis only
	b. Net Generation - FAC Basis (Cents/KWH)	Reported on total plant basis only
5.	Inventory Analysis:	
	a. Number of Days Supply based on actual burn at the station	Reported on total plant basis only

APPENDIX A

KENTUCKY POWER COMPANY
MITCHELL - UNIT 2
November 2025

Line No.	Item Description	
1.	Unit Performance:	
	a. Capacity (name plate rating) (MW)	790.2
	b. Capacity (average load) (MW)	297.3
	c. Net Demonstrated Capability (MW)	790.2
	d. Net Capability Factor (%)	35.1
2.	Heat Rate:	
	a. Btu's Consumed (MMBTU)	1,965.7
	b. Gross Generation (MWH)	218,660
	c. Net Generation (MWH)	199,312
	d. Heat Rate (L2a divided by L2c) (BTU/KWH)	10,429
3.	Operating Availability:	
	a. Hours Unit Operated	555.5
	b. Hours Available	670.4
	c. Hours During the Period	721.0
	d. Availability Factor (L3b divided by L3c) (%)	93.0
4.	Cost per KWH:	
	a. Gross Generation - FAC Basis (Cents/KWH)	Reported on total plant basis only
	b. Net Generation - FAC Basis (Cents/KWH)	Reported on total plant basis only
5.	Inventory Analysis:	
	a. Number of Days Supply based on actual burn at the station	Reported on total plant basis only

November 2025

Allowable BLI	Description	Amount
1200	Day-ahead Spot Market Energy	-
1200a		-
1205	Balancing Spot Market Energy	-
1205a		-
1210	Day-ahead Transmission Congestion	663,639.49
1210a		
1215	Balancing Transmission Congestion	(419,043.08)
1215a		
1218	Planning Period Congestion Uplift	
1218a		
1220	Day-ahead Transmission Losses	558,141.34
1220a		
1225	Balancing Transmission Losses	(205,554.19)
1225a		
1230	Inadvertent Interchange	(5,256.81)
1230a		
1250	Meter Error Correction	26,251.79
1250a		(28,491.06)
1260	Emergency Energy	
1260a		
1340	Regulation and Frequency Response Service Charge	(100,468.70)
1340a		(64.35)
1350	Energy Imbalance Service Charge	
1350a		
1360	Synchronized Reserve Charge	24,742.75
1360a		27.08
1370	Day-ahead Operating Reserve Charge	4,308.78
1370a		
1375	Balancing Operating Reserve	92,407.34
1375a		(18.61)
1377	Synchronous Condensing Charge	
1377a		
1378	Reactive Services Charge	
1378a		
1400	Load Reconciliation for Spot Market Energy	225.57
1400a		
1410	Load Reconciliation for Transmission Congestion	22.40
1410a		(1.73)
1420	Load Reconciliation Transmission Losses	2.45
1420a		0.11
1430	Load Reconciliation for Inadvertent Interchange	0.05
1430a		
1460	Load Reconciliation for Regulation and Frequency Response Service	0.83
1460a		
1470	Load Reconciliation for Synchronized Reserve	0.91
1470a		
1478	Load Reconciliation for Balancing Operating Reserve	0.29
1478a		
1480	Load Reconciliation for Synchronous Condensing	
1480a		
1490	Load Reconciliation for Reactive Services	

1490a		
1500	Financial Transmission Rights Auction	779,599.41
1500a		
1930	Generation Deactivation Charge	
1930a		36,817.35
2210	Transmission Congestion Credit	
2210a		
2211	Day-ahead Transmission Congestion	(792,204.75)
2211a		(0.01)
2215	Balancing Transmission	232,759.97
2215a		43.15
2217	Planning Period Excess Congestion Credit	
2217a		
2218	Planning Period Congestion Uplift Credit	
2218a		
2220	Transmission Losses Credit	(245,823.63)
2220a		
2260	Emergency Energy Credit	
2260a		
2340	Regulation and Frequency Response Service Credit	842,584.51
2340a		380.33
2350	Energy Imbalance Service Credit	
2350a		
2360	Synchronized Reserve Credit	3,315.56
2360a		(16.03)
2370	Day-ahead Operating Reserve Credit	
2370a		
2375	Balancing Operating Reserve Credit	1,335.00
2375a		
2377	Synchronous Condensing Credit	
2377a		
2378	Reactive Services Credit	
2378a		
2415	Balancing Transmission Congestion Load Reconciliation	(2.07)
2415a		
2420	Load Reconciliation for Transmission Losses	(2.82)
2420a		
2500	Financial Transmission Rights Auction	
2500a		
2510	Auction Revenue Rights	(779,602.46)
2510a		
2930	Generation Deactivation Credit	
2930a		
Sum of Allowable BLIs (In accounts outside those already being captured)		690,056.16