COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY POWER COMPANY FROM NOVEMBER 1, 2013 THROUGH APRIL 30, 2014	: : :	**Case No. 2014-00225**

ATTACHMENT TO

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'s

FIRST SET OF DATA REQUESTS

TO

KENTUCKY POWER COMPANY

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Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price (SMP) or energy component, the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1]

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[2] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion costs and marginal loss costs.[3]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,136.1 million or 372.1 percent, from $306.0 million in the first six months of 2013 to $1,442.2 million in the first six months of 2014. Total congestion costs increased because of the cold weather in January 2014, but congestion was also much higher in March 2014 than in March 2013 and congestion was higher in each of the first six months of 2014 than in the first six months of 2013.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,164.7 million or 221.0 percent, from $527.1 million in the first six months of 2013 to $1,691.8 million in the first six months of 2014.
- **Balancing Congestion.** Balancing congestion costs decreased by $28.6 million or 12.9 percent, from -$221.1 million in the first six months of 2013 to -$249.7 million in the first six months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first six months of 2014 ranged from $54.3 million in April to $825.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South Interface, the West Interface, the Breed - Wheatland flowgate, the Cloverdale transformer, and the Bedington - Black Oak Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total congestion and marginal losses were calculated as of July 18, 2014, and are subject to change, based on continued PJM billing updates.

Market in the first six months of 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 14 times higher than the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion frequency increased by 31.0 percent from 174,119 congestion event hours in the first six months of 2013 to 228,167 congestion event hours in the first six months of 2014.

Real-time congestion frequency increased by 66.5 percent from 10,032 congestion event hours in the first six months of 2013 to 16,699 congestion event hours in the first six months of 2014.

- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of congestion facilities. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first six months of 2014. With $455.4 million in total congestion costs, it accounted for 31.6 percent of the total PJM congestion costs in the first six months of 2014.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2014. AEP had $367.6 million in total congestion costs, comprised of -$717.0 million in total load congestion payments, -$1,138.9 million in total generation congestion credits and -$54.3 million in explicit congestion costs. The AP South Interface, the West Interface, the Breed - Wheatland, Monticello - East Winamac and the Cook - Palisades flowgates contributed $268.7 million, or 73.1 percent of the total AEP Control Zone congestion costs.

- **Ownership.** In the first six months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first six months of 2014, financial companies received $202.1 million in congestion credits, an increase of $146.8 million or 265.6 percent compared to the first six months of 2013. In the first six months of 2014, physical companies paid $1,644.2 million in congestion charges, an increase of $1,282.9 million or 355.1 percent compared to the first six months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $511.7 million or 103.5 percent, from $494.5 million in the first six months of 2013 to $1,006.2 million in the first six months of 2014. Total marginal loss costs increased because of the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013 and marginal loss costs were higher in each of the first six months of 2014 than in the first six months of 2013. The loss component of LMP remained constant, $0.02 in the first six months of 2013 and $0.02 in the first six months of 2014. The loss MW in PJM increased 5.1 percent, from 8,622 GWh in the first six months of 2013 to 9,066 GWh in the first six months of 2014.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $549.0 million or 100.5 percent, from $546.0 million in the first six months of 2013 to $1,095.0 million in the first six months of 2014.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $37.2 million or 72.2 percent, from -$51.6 million in the first six months of 2013 to -$88.8 million in the first six months of 2014.

- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first six months of 2014 increased compared to the first six months of 2013, by 310.3 percent in January, 114.4 percent in February, 95.3 percent in March, 7.9 percent in April, 0.9 percent in May and 9.1 percent in June. Monthly total marginal loss costs in the first six months of 2014 ranged from $68.7 million in May to $414.6 million in January.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs plus total marginal loss costs plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[4] The marginal loss credits increased in the first six months of 2014 by $163.8 million or 101.6 percent, from $161.3 million in the first six months of 2013, to $325.0 million in the first six months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $344.6 million or 103.6 percent, from -$332.6 million in the first six months of 2013 to -$677.2 million in the first six months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $596.1 million or 169.2 percent, from -$352.2 million in the first six months of 2013 to -$948.3 million in the first six months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $255.5 million or 1,207.7 percent, from $21.2 million in the first six months of 2013 to $276.6 million in the first six months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2014 ranged from -$272.7 million in January to -$48.1 million in May.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 98.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65 (April 24, 2014), pp 64-66. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first six months of 2009 to 2014. The load-weighted average real-time LMP increased $31.96 or 84.2 percent from $37.96 in the first six months of 2013 to $69.92 in the first six months of 2014. The load-weighted average congestion component decreased $0.08 or 342.2 percent from $0.02 in the first six months of 2013 to -$0.06 in the first six months of 2014. The load-weighted average loss component ($0.02) did not change in the first six months of 2013 relative to the first six months of 2014. The load-weighted average energy component increased $32.03 or 84.5 percent from $37.92 in the first six months of 2013 to $69.95 in the first six months of 2014. Given that these results are based on system average LMP including offsetting congestion and loss components, congestion and loss components near zero are expected.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2009 through 2014[5]

(Jan-Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02
2014	$69.92	$69.95	($0.06)	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first six months of 2009 through 2014. The load-weighted average day-ahead LMP increased $32.43 or 84.8 percent from $38.23 in the first six months of 2013 to $70.66 in the first six months of 2014. The load-weighted average congestion component increased $0.21 or 238.5 percent from $0.09 in the first six months of 2013 to $0.30 in the first six months of 2014. The load-weighted average loss component decreased $0.01 from $0.00 in the first six months of 2013 to -$0.01 in the first six months of 2014. The load-

5 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.