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## Constraint Costs

Table 11-24 and Table 11-25 present the top constraints affecting congestion costs by facility for the periods 2015 and 2014.

### Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 2015

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day-Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2015 |
| 1 | Conastone - Northwest | Line | BGE | $100.9 | ($2.4) | $1.6 | $105.0 | ($1.6) | ($8.1) | ($2.7) | $3.8 | $108.8 | 7.9% |
| 2 | Bagley - Graceton | Line | BGE | $99.5 | $5.6 | $5.0 | $98.9 | ($0.2) | ($12.4) | ($3.2) | $9.0 | $107.9 | 7.8% |
| 3 | 5004/5005 Interface | Interface | 500 | ($23.0) | ($134.8) | ($9.2) | $102.6 | $7.0 | $22.5 | $1.9 | ($13.6) | $89.0 | 6.4% |
| 4 | Bedington - Black Oak | Interface | 500 | $46.1 | ($45.2) | ($7.2) | $84.1 | $2.4 | $2.2 | $3.2 | $3.5 | $87.6 | 6.3% |
| 5 | Cherry Valley | Flowgate | MISO | ($9.1) | ($82.1) | $6.7 | $79.6 | $0.0 | $0.0 | $0.0 | $0.0 | $79.6 | 5.7% |
| 6 | AP South | Interface | 500 | $38.1 | ($22.8) | ($5.5) | $55.4 | $0.3 | $0.2 | $0.6 | $0.7 | $56.2 | 4.1% |
| 7 | AEP - DOM | Interface | 500 | $28.1 | ($28.0) | ($1.1) | $55.0 | $0.9 | $1.6 | ($1.9) | ($2.6) | $52.4 | 3.8% |
| 8 | Joshua Falls | Transformer | AEP | $9.7 | ($35.9) | ($4.7) | $40.9 | $0.7 | ($0.1) | $2.3 | $3.1 | $44.0 | 3.2% |
| 9 | Bergen - New Milford | Line | PSEG | $25.2 | $18.4 | $17.9 | $24.7 | ($7.6) | $9.3 | ($51.2) | ($68.1) | ($43.5) | (3.1%) |
| 10 | Person - Halifax | Flowgate | MISO | $79.7 | $29.2 | ($10.4) | $40.1 | $0.0 | ($0.0) | ($0.1) | ($0.1) | $40.0 | 2.9% |
| 11 | Maywood - Saddlebrook | Line | PSEG | $8.9 | $3.9 | $7.5 | $12.5 | ($4.7) | $9.0 | ($22.2) | ($36.0) | ($23.4) | (1.7%) |
| 12 | East | Interface | 500 | ($13.0) | ($37.6) | ($2.1) | $22.4 | ($0.1) | $0.3 | $0.5 | $0.1 | $22.6 | 1.6% |
| 13 | Easton | Transformer | DPL | $29.0 | $6.6 | ($0.5) | $21.9 | $0.0 | $0.0 | $0.0 | $0.0 | $21.9 | 1.6% |
| 14 | Glenarm - Windy Edge | Line | BGE | $3.3 | ($13.0) | $1.0 | $17.3 | $1.9 | ($1.9) | ($0.7) | $3.2 | $20.5 | 1.5% |
| 15 | Oak Grove - Galesburg | Flowgate | MISO | ($16.1) | ($44.8) | ($6.3) | $22.4 | $0.2 | $1.1 | ($1.9) | ($2.8) | $19.7 | 1.4% |
| 16 | Mahans Lane - Tidd | Line | AEP | $7.7 | ($13.3) | ($1.6) | $19.4 | $0.4 | $1.1 | $0.9 | $0.2 | $19.6 | 1.4% |
| 17 | East Danville - Banister | Line | AEP | $8.1 | ($7.6) | $2.0 | $17.7 | $0.5 | ($1.5) | ($0.6) | $1.4 | $19.1 | 1.4% |
| 18 | 49th Street - Hoboken | Line | PSEG | $0.0 | $0.0 | $0.0 | $0.0 | ($3.0) | $2.1 | ($13.7) | ($18.8) | ($18.8) | (1.4%) |
| 19 | BCPEP | Interface | Pepco | $15.3 | ($3.0) | $0.1 | $18.4 | $0.0 | $0.0 | $0.0 | $0.0 | $18.4 | 1.3% |
| 20 | Braidwood - East Frankfort | Line | ComEd | ($2.3) | ($21.0) | $0.6 | $19.4 | $0.3 | $0.4 | ($1.2) | ($1.3) | $18.1 | 1.3% |
| 21 | Valley | Transformer | Dominion | $17.4 | ($0.2) | $0.0 | $17.7 | $0.0 | $0.0 | $0.0 | $0.0 | $17.7 | 1.3% |
| 22 | Cloverdale | Transformer | AEP | $6.6 | ($9.8) | ($1.4) | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $15.0 | 1.1% |
| 23 | Breed - Wheatland | Flowgate | MISO | ($1.7) | ($15.5) | $0.6 | $14.4 | $0.1 | ($0.6) | ($0.7) | ($0.0) | $14.4 | 1.0% |
| 24 | Miami Fort - Willey | Line | DEOK | ($0.8) | ($12.4) | $1.2 | $12.8 | $1.2 | $0.7 | ($0.3) | $0.2 | $13.0 | 0.9% |
| 25 | Central | Interface | 500 | ($15.5) | ($32.7) | ($3.9) | $13.3 | $0.1 | $1.0 | $0.3 | ($0.7) | $12.6 | 0.9% |

 

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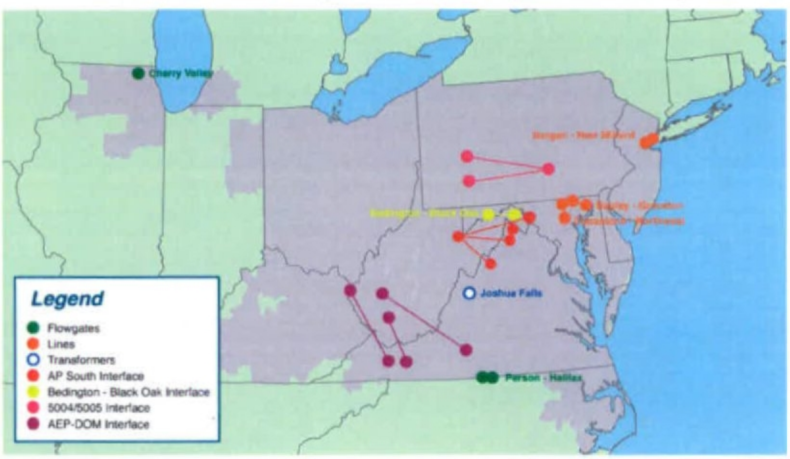
## Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2014

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day-Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2014 |
| 1 | AP South | Interface | 500 | $329.7 | ($201.4) | ($11.2) | $520.0 | $31.5 | $73.5 | $8.9 | ($33.1) | $486.8 | 25.2% |
| 2 | West | Interface | 500 | ($21.3) | ($297.0) | ($79.1) | $196.5 | $17.7 | $49.7 | $17.0 | ($15.0) | $181.6 | 9.4% |
| 3 | Bagley - Graceton | Line | BGE | $98.5 | ($9.5) | ($1.7) | $106.3 | $5.7 | ($4.0) | $4.5 | $14.2 | $120.5 | 6.2% |
| 4 | Bedington - Black Oak | Interface | 500 | $42.8 | ($43.9) | ($0.2) | $86.5 | $3.9 | $3.4 | ($2.3) | ($1.9) | $84.6 | 4.4% |
| 5 | Breed - Wheatland | Flowgate | MISO | ($17.7) | ($100.2) | ($9.3) | $73.2 | $2.4 | $1.1 | $5.6 | $6.9 | $80.1 | 4.1% |
| 6 | Benton Harbor - Palisades | Flowgate | MISO | ($12.5) | ($79.3) | ($8.0) | $58.8 | ($0.2) | $0.7 | ($1.0) | ($1.8) | $57.0 | 2.9% |
| 7 | Cloverdale | Transformer | AEP | $23.3 | ($27.3) | $0.2 | $50.7 | $0.0 | $0.0 | $0.0 | $0.0 | $50.7 | 2.6% |
| 8 | BCPEP | Interface | Pepco | $15.6 | ($15.2) | ($1.6) | $29.3 | ($1.6) | ($14.2) | $1.5 | $14.1 | $43.4 | 2.2% |
| 9 | Unclassified | Unclassified | Unclassified | $2.0 | ($11.8) | $13.4 | $27.3 | $7.6 | $1.6 | $9.0 | $15.1 | $42.4 | 2.2% |
| 10 | Monticello - East Winamac | Flowgate | MISO | ($3.8) | ($46.7) | $1.6 | $44.6 | $2.6 | $4.3 | ($10.8) | ($12.5) | $32.1 | 1.7% |
| 11 | Oak Grove - Galesburg | Flowgate | MISO | ($28.4) | ($62.2) | ($2.3) | $31.5 | ($0.4) | $0.5 | ($0.3) | ($1.3) | $30.3 | 1.6% |
| 12 | Cherry Valley | Transformer | ComEd | $21.9 | ($20.4) | $5.2 | $47.5 | ($5.1) | $1.1 | ($11.3) | ($17.5) | $30.0 | 1.6% |
| 13 | Cook - Palisades | Flowgate | MISO | ($12.6) | ($55.3) | ($5.3) | $37.4 | ($1.5) | $1.6 | ($6.2) | ($9.3) | $28.1 | 1.5% |
| 14 | Readington - Roseland | Line | PSEG | ($8.9) | ($46.1) | ($12.2) | $25.1 | $0.9 | $5.4 | $5.8 | $1.3 | $26.4 | 1.4% |
| 15 | Cloverdale | Transformer | AEP | $23.1 | ($4.8) | ($2.3) | $25.7 | $0.0 | $0.0 | $0.0 | $0.0 | $25.7 | 1.3% |
| 16 | Wolf Creek | Transformer | AEP | $4.6 | $1.3 | $4.7 | $8.0 | $3.6 | $5.6 | ($29.3) | ($31.3) | ($23.3) | (1.2%) |
| 17 | Brambleton - Loudoun | Line | Dominion | ($11.2) | ($35.1) | ($1.3) | $22.6 | $0.6 | $0.0 | $0.1 | $0.6 | $23.2 | 1.2% |
| 18 | SENECA | Interface | PENELEC | $5.6 | $9.9 | ($6.5) | ($10.9) | ($3.0) | $1.2 | ($6.1) | ($10.4) | ($21.3) | (1.1%) |
| 19 | Wescosville | Transformer | PPL | $17.6 | ($0.8) | $2.7 | $21.1 | ($0.0) | $0.0 | $0.0 | ($0.0) | $21.1 | 1.1% |
| 20 | East | Interface | 500 | ($9.8) | ($34.2) | ($3.4) | $21.0 | $0.3 | $0.7 | $0.5 | $0.1 | $21.1 | 1.1% |
| 21 | Nelson - Cordova | Line | ComEd | ($24.7) | ($47.1) | $4.2 | $26.6 | ($0.7) | $1.1 | ($4.3) | ($6.0) | $20.5 | 1.1% |
| 22 | Bridgewater - Middlesex | Line | PSEG | $0.2 | ($22.2) | ($3.0) | $19.4 | ($1.5) | $0.1 | $1.4 | ($0.2) | $19.2 | 1.0% |
| 23 | 5004/5005 Interface | Interface | 500 | ($0.7) | ($23.6) | ($3.3) | $19.5 | $8.1 | $17.5 | $7.3 | ($2.1) | $17.4 | 0.9% |
| 24 | Atlantic - Larrabee | Line | JCPL | $2.0 | ($14.8) | ($0.7) | $16.1 | $0.0 | $1.3 | $1.2 | ($0.1) | $16.0 | 0.8% |
| 25 | Amos | Transformer | AEP | $1.6 | ($12.8) | ($0.2) | $14.2 | $1.2 | ($1.6) | ($1.2) | $1.6 | $15.8 | 0.8% |

Figure 11-2 shows the locations of the top 10 constraints by PJM total congestion costs in2015. Figure 11-3 shows the locations of the top 10 constraints by PJM day-ahead congestion costs in 2015. Figure 11-4 shows the locations of the top 10 constraints by PJM balancing congestion costs in 2015.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2015



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## Constraint Costs

Table 11-25 and Table 11-26 show the top constraints affecting congestion costs by facility for 2017 and 2016. The Braidwood – East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.

### Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2017

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day-Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2017 |
| 1 | Braidwood - East Frankfort | Line | ComEd | ($4.7) | ($49.7) | $0.3 | $45.3 | $0.7 | $1.9 | ($0.7) | ($1.9) | $43.4 | 6.2% |
| 2 | Conastone - Peach Bottom | Line | 500 | $38.7 | $1.6 | $0.1 | $37.2 | $2.0 | $1.3 | $1.5 | $2.2 | $39.5 | 5.7% |
| 3 | Emilie - Falls | Line | PECO | $12.0 | ($13.6) | ($0.1) | $25.6 | ($0.1) | $1.2 | $0.8 | ($0.4) | $25.1 | 3.6% |
| 4 | Graceton - Safe Harbor | Line | BGE | $30.2 | $7.1 | ($0.0) | $23.1 | $1.7 | $2.3 | $1.4 | $0.8 | $23.9 | 3.4% |
| 5 | 5004/5005 Interface | Interface | 500 | ($9.9) | ($38.7) | ($3.8) | $25.0 | $4.3 | $11.4 | $4.6 | ($2.5) | $22.5 | 3.2% |
| 6 | AP South | Interface | 500 | $15.3 | ($9.2) | ($2.4) | $22.1 | ($0.0) | $1.3 | $0.9 | ($0.5) | $21.6 | 3.1% |
| 7 | Westwood | Flowgate | MISO | ($22.1) | ($41.3) | $0.5 | $19.7 | $1.2 | $0.8 | ($0.5) | ($0.1) | $19.6 | 2.8% |
| 8 | Cherry Valley | Transformer | ComEd | $8.9 | ($10.1) | $2.1 | $21.0 | ($0.6) | $0.9 | ($0.9) | ($2.3) | $18.7 | 2.7% |
| 9 | Carson - Rawlings | Line | Dominion | $14.5 | ($4.3) | $0.8 | $19.6 | $1.0 | $1.6 | ($0.8) | ($1.4) | $18.2 | 2.6% |
| 10 | Conastone - Otter Creek | Line | PPL | $23.0 | $8.5 | ($0.5) | $13.9 | $1.5 | $1.8 | $1.5 | $1.2 | $15.1 | 2.2% |
| 11 | Conastone - Northwest | Line | BGE | $12.7 | ($1.1) | ($0.4) | $13.4 | $0.4 | $0.7 | $1.0 | $0.7 | $14.1 | 2.0% |
| 12 | Three Mile Island | Transformer | 500 | $7.4 | ($4.9) | ($0.3) | $11.9 | ($0.1) | ($0.6) | $0.9 | $1.4 | $13.3 | 1.9% |
| 13 | Butler - Shanorma | Line | APS | ($10.5) | ($20.9) | $1.0 | $11.4 | $0.0 | $0.0 | $0.0 | $0.0 | $11.4 | 1.6% |
| 14 | Lakeview - Greenfield | Line | ATSI | ($3.5) | ($14.5) | $0.2 | $11.2 | $0.1 | $0.7 | $0.3 | ($0.4) | $10.8 | 1.5% |
| 15 | Alpine - Belvidere | Flowgate | MISO | ($2.3) | ($14.0) | ($0.9) | $10.8 | $0.0 | $0.0 | $0.0 | $0.0 | $10.8 | 1.5% |
| 16 | Bedington - Black Oak | Interface | 500 | $5.5 | ($4.1) | ($0.2) | $9.3 | $0.1 | $0.3 | $0.4 | $0.2 | $9.5 | 1.4% |
| 17 | Person - Sedge Hill | Line | Dominion | $16.2 | $3.5 | $2.0 | $14.7 | $0.6 | $2.7 | ($3.2) | ($5.3) | $9.3 | 1.3% |
| 18 | Lake George - Aetna | Flowgate | MISO | ($1.1) | ($9.0) | ($1.5) | $6.4 | ($2.2) | $0.9 | $5.8 | $2.7 | $9.2 | 1.3% |
| 19 | Batesville - Hubble | Flowgate | MISO | ($5.5) | ($19.4) | ($4.5) | $9.4 | ($0.2) | ($1.2) | ($1.6) | ($0.6) | $8.9 | 1.3% |
| 20 | Byron - Cherry Valley | Flowgate | MISO | ($0.9) | ($9.3) | ($0.4) | $8.0 | $0.0 | $0.0 | $0.0 | $0.0 | $8.0 | 1.1% |
| 21 | AEP - DOM | Interface | 500 | $3.3 | ($4.3) | ($0.1) | $7.5 | $0.5 | $0.5 | $0.2 | $0.3 | $7.8 | 1.1% |
| 22 | Brunner Island - Yorkanna | Line | Met-Ed | $6.0 | ($1.6) | ($0.3) | $7.3 | ($0.0) | ($0.1) | $0.1 | $0.2 | $7.5 | 1.1% |
| 23 | Brokaw - Leroy | Flowgate | MISO | $0.8 | ($7.6) | ($3.7) | $4.8 | $0.2 | $0.3 | $2.6 | $2.5 | $7.3 | 1.0% |
| 24 | Loretto - Vienna | Line | DPL | $8.8 | $2.3 | $0.7 | $7.2 | ($0.4) | $0.1 | $0.2 | ($0.3) | $6.9 | 1.0% |
| 25 | Pleasant View - Ashburn | Line | Dominion | $5.8 | ($3.7) | ($0.3) | $9.1 | ($1.1) | $1.0 | ($0.1) | ($2.3) | $6.8 | 1.0% |

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Table 11-26 Top 25 constraints affecting PJM congestion costs (By facility): 2016

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day-Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2016 |
| 1 | Conastone - Northwest | Line | BGE | $114.8 | $7.4 | ($4.6) | $102.8 | $3.9 | ($2.4) | $6.5 | $12.7 | $115.5 | 11.3% |
| 2 | Graceton | Transformer | BGE | $53.1 | ($21.0) | ($0.9) | $73.3 | ($0.9) | ($4.7) | $1.8 | $5.6 | $78.9 | 7.7% |
| 3 | Bagley - Graceton | Line | BGE | $72.5 | $5.8 | ($1.9) | $64.8 | $2.7 | ($2.7) | $2.2 | $7.7 | $72.5 | 7.1% |
| 4 | Cherry Valley | Transformer | ComEd | $20.4 | ($27.9) | $3.9 | $52.3 | ($3.0) | $2.6 | ($5.7) | ($11.3) | $40.9 | 4.0% |
| 5 | Cherry Valley | Flowgate | MISO | ($5.7) | ($44.0) | ($0.5) | $37.8 | $0.0 | $0.0 | $0.0 | $0.0 | $37.8 | 3.7% |
| 6 | Conastone - Peach Bottom | Line | 500 | $27.9 | ($0.2) | $0.8 | $28.9 | $1.3 | $0.9 | $0.0 | $0.4 | $29.3 | 2.9% |
| 7 | Braidwood - East Frankfort | Line | ComEd | ($3.8) | ($38.2) | $0.8 | $35.2 | $0.5 | $3.3 | ($3.5) | ($6.3) | $28.9 | 2.8% |
| 8 | Mercer IP - Galesburg | Flowgate | MISO | ($17.1) | ($49.9) | ($8.9) | $23.9 | ($0.2) | $3.6 | $2.2 | ($1.6) | $22.3 | 2.2% |
| 9 | Byron - Cherry Valley | Flowgate | MISO | ($5.5) | ($22.6) | $0.9 | $18.0 | $0.0 | $0.0 | $0.0 | $0.0 | $18.0 | 1.8% |
| 10 | Milford - Steele | Line | DPL | ($8.6) | ($26.7) | $0.1 | $18.1 | $2.2 | $1.4 | ($1.7) | ($0.9) | $17.2 | 1.7% |
| 11 | AP South | Interface | 500 | $13.8 | ($4.9) | ($1.9) | $16.8 | $0.1 | $0.1 | $0.0 | $0.0 | $16.8 | 1.6% |
| 12 | Dixon - McGirr Rd | Flowgate | MISO | ($5.0) | ($22.9) | ($1.2) | $16.7 | $0.0 | $0.0 | $0.0 | $0.0 | $16.7 | 1.6% |
| 13 | Reynolds - Magnetation | Flowgate | MISO | ($5.1) | ($23.9) | $0.9 | $19.8 | $0.5 | $1.5 | ($2.6) | ($3.5) | $16.2 | 1.6% |
| 14 | Bedington - Black Oak | Interface | 500 | $9.5 | ($6.2) | ($0.6) | $15.2 | $0.2 | $0.2 | $0.1 | $0.1 | $15.3 | 1.5% |
| 15 | Coolspring - Milford | Line | DPL | $1.3 | ($11.8) | ($0.0) | $13.1 | ($1.0) | ($1.8) | $0.3 | $1.1 | $14.1 | 1.4% |
| 16 | Loudoun | Transformer | Dominion | $1.1 | ($9.8) | ($0.2) | $10.6 | $1.5 | $2.2 | $3.4 | $2.7 | $13.3 | 1.3% |
| 17 | Person - Halifax | Flowgate | MISO | $29.9 | $16.1 | ($0.2) | $13.5 | $0.0 | $0.0 | ($0.2) | ($0.2) | $13.3 | 1.3% |
| 18 | Kanawha River - Matt Funk | Line | AEP | $2.7 | ($17.1) | ($1.1) | $18.8 | ($0.7) | $2.5 | ($3.3) | ($6.6) | $12.2 | 1.2% |
| 19 | Plymouth Meeting - Whitpain | Line | PECO | ($0.6) | ($10.9) | ($0.1) | $10.2 | ($0.1) | $0.1 | $0.2 | ($0.0) | $10.1 | 1.0% |
| 20 | AEP - DOM | Interface | 500 | $3.5 | ($4.5) | $0.2 | $8.2 | $0.3 | ($0.0) | $0.1 | $0.3 | $8.5 | 0.8% |
| 21 | Braidwood - East Frankfurt | Flowgate | MISO | ($0.1) | ($7.7) | $0.7 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 0.8% |
| 22 | Cherry Valley - Silver Lake | Flowgate | MISO | ($1.8) | ($9.4) | $0.8 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 0.8% |
| 23 | Brambleton - Loudoun | Line | Dominion | ($2.9) | ($10.2) | $0.2 | $7.5 | $0.2 | ($0.1) | $0.4 | $0.6 | $8.1 | 0.8% |
| 24 | Kanawha | Transformer | AEP | $0.1 | ($7.1) | $0.7 | $7.9 | $0.0 | $0.0 | $0.0 | $0.0 | $7.9 | 0.8% |
| 25 | Stockton - Kenney | Line | DPL | ($2.5) | $3.4 | ($1.9) | ($7.8) | $0.0 | $0.0 | $0.0 | $0.0 | ($7.8) | (0.8%) |

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in 2017. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted average CLMP in 2017. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in 2017.

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## Constraint Costs

Table 11-25 and Table 11-26 show the top constraints affecting congestion costs by facility for the first six months of 2018 and 2017. The AEP - DOM Interface was the largest contributor to congestion costs in the first six months of 2018, with $118.3 million in total congestion costs and 13.2 percent of the total PJM congestion costs in the first six months of 2018.

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2018

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day-Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2018 (Jan - Jun) |
| 1 | AEP - DOM | Interface | 500 | $54.5 | ($66.2) | ($5.1) | $115.6 | $13.0 | $19.1 | $8.8 | $2.7 | $118.3 | 13.2% |
| 2 | Cloverdale | Transformer | AEP | $46.0 | ($40.9) | ($0.8) | $86.1 | ($1.7) | $0.5 | $3.7 | $1.5 | $87.6 | 9.8% |
| 3 | Graceton - Safe Harbor | Line | BGE | $86.9 | $29.1 | $2.3 | $60.1 | $0.3 | $4.5 | ($1.5) | ($5.7) | $54.4 | 6.1% |
| 4 | Tanners Creek - Miami Fort | Flowgate | MISO | ($13.7) | ($64.7) | ($3.5) | $47.5 | $0.0 | $0.0 | $0.0 | $0.0 | $47.5 | 5.3% |
| 5 | 5004/5005 Interface | Interface | 500 | ($15.4) | ($54.3) | ($4.4) | $34.6 | $0.8 | $1.7 | $2.1 | $1.1 | $35.7 | 4.0% |
| 6 | Batesville - Hubble | Flowgate | MISO | ($10.4) | ($43.6) | ($9.4) | $23.8 | ($0.5) | ($2.1) | $0.4 | $2.0 | $25.8 | 2.9% |
| 7 | Lakeview - Greenfield | Line | ATSI | ($19.5) | ($55.4) | ($1.6) | $34.3 | ($1.5) | $8.8 | $0.5 | ($9.8) | $24.5 | 2.7% |
| 8 | Bedington - Black Oak | Interface | 500 | $9.3 | ($13.5) | ($1.4) | $21.4 | $0.6 | $0.7 | $0.5 | $0.5 | $21.8 | 2.4% |
| 9 | Capitol Hill - Chemical | Line | AEP | $11.9 | ($5.0) | $0.5 | $17.4 | $0.8 | ($0.8) | ($0.1) | $1.5 | $18.9 | 2.1% |
| 10 | AP South | Interface | 500 | $11.2 | ($7.9) | ($1.4) | $17.7 | $0.0 | $0.1 | ($0.0) | ($0.1) | $17.6 | 2.0% |
| 11 | Person - Sedge Hill | Line | Dominion | $16.9 | $2.3 | $1.7 | $16.3 | ($0.3) | ($1.0) | ($1.0) | ($0.4) | $15.9 | 1.8% |
| 12 | Gardners - Texas East | Line | Met-Ed | ($5.7) | ($20.1) | ($0.1) | $14.3 | $0.3 | ($0.1) | $0.4 | $0.8 | $15.1 | 1.7% |
| 13 | Northport - Albion | Flowgate | MISO | ($2.3) | ($18.4) | ($3.8) | $12.3 | ($0.2) | ($1.1) | $1.3 | $2.2 | $14.5 | 1.6% |
| 14 | Brokaw - Leroy | Flowgate | MISO | $0.8 | ($12.3) | ($4.4) | $8.6 | $0.5 | ($1.3) | $3.0 | $4.8 | $13.4 | 1.5% |
| 15 | Nottingham | Other | PECO | $12.3 | $0.3 | $0.3 | $12.3 | $0.0 | $0.0 | $0.0 | $0.0 | $12.3 | 1.4% |
| 16 | Tanners Creek - Miami Fort | Line | AEP | ($2.2) | ($10.0) | ($0.4) | $7.4 | ($0.8) | ($1.8) | $2.8 | $3.9 | $11.3 | 1.3% |
| 17 | Monroe - Lallendorf | Flowgate | MISO | ($1.4) | ($11.7) | ($0.4) | $9.9 | $0.0 | $0.0 | $0.0 | $0.0 | $9.9 | 1.1% |
| 18 | Maple - Jackson | Line | ATSI | ($8.0) | ($17.6) | $1.2 | $10.8 | $0.2 | $0.5 | ($0.9) | ($1.2) | $9.5 | 1.1% |
| 19 | Conastone - Northwest | Line | BGE | $8.0 | ($1.0) | ($0.7) | $8.3 | ($0.9) | ($0.3) | $1.4 | $0.8 | $9.1 | 1.0% |
| 20 | Flint Lake - Luchtman Road | Flowgate | MISO | $0.2 | ($10.4) | ($4.9) | $5.7 | ($0.2) | ($1.4) | $1.8 | $3.0 | $8.7 | 1.0% |
| 21 | Conastone - Peach Bottom | Line | 500 | $7.9 | $0.3 | $0.1 | $7.8 | $0.2 | $0.1 | ($0.3) | ($0.2) | $7.6 | 0.9% |
| 22 | Olive | Flowgate | MISO | $0.2 | ($6.6) | $0.3 | $7.0 | $0.0 | $0.0 | $0.0 | $0.0 | $7.0 | 0.8% |
| 23 | Cedar Grove Sub - Roseland | Line | PSEG | ($1.2) | ($7.3) | $0.7 | $6.8 | ($0.1) | $0.3 | $0.4 | ($0.0) | $6.8 | 0.8% |
| 24 | Emilie - Falls | Line | PECO | $1.5 | ($4.4) | $0.1 | $6.0 | $0.3 | $0.4 | $0.4 | $0.4 | $6.4 | 0.7% |
| 25 | Pleasant View - Ashburn | Line | Dominion | $5.3 | ($1.4) | ($0.4) | $6.3 | $0.0 | $0.0 | $0.0 | $0.0 | $6.3 | 0.7% |

OCA Cross Exh. 10
2/26/19 Hg JK

**Application of Transource Pennsylvania LLC**
**Independence Energy Connection-West Project**
**Docket No A-2017-2640200**

**Interrogatories of the Office of Consumer Advocate**
**Set V**
**(Responses dated 3/7/2018)**

**Data Request OCA-V-04:**

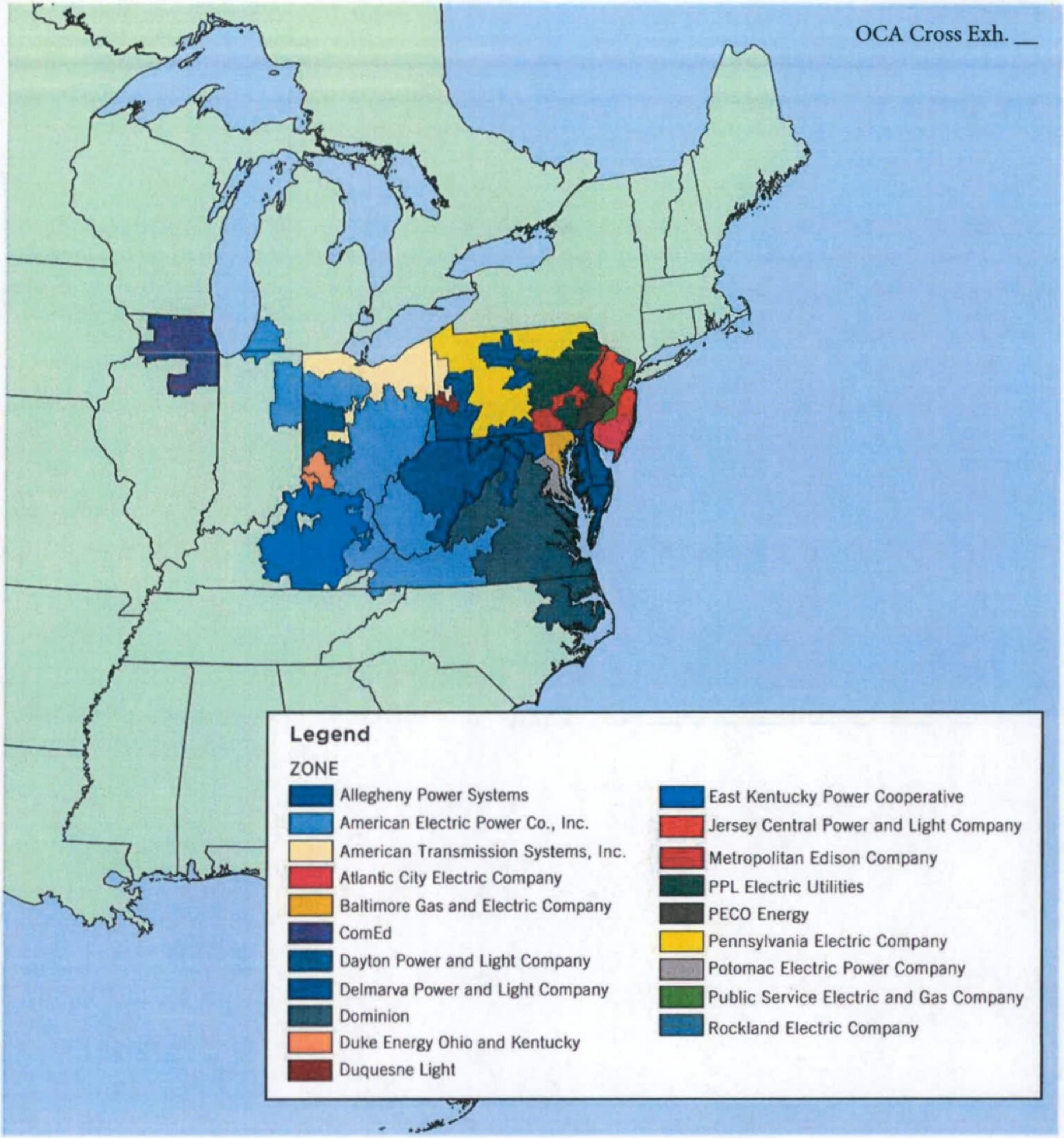
Reference: Reply to OCA I-14 Attachment 1, page 390. In response to a public comment, a Transource representative wrote: "Parts of Pennsylvania, Maryland, Virginia, West Virginia and D.C. will directly benefit from the $600 million in cost savings that PJM announced." Concerning this, please state specifically which parts of Pennsylvania will directly benefit from the cost savings associated with the project.

**Response:**

The Allegheny Power Systems Zone, which includes portions of Southern, Southwestern and Central Pennsylvania, was identified as a benefitting zone in the analyses. Please see the attached map, OCA-V-04 Attachment 1.

**Witness:** Paul McGlynn and Kamran Ali

OCA Cross Exh. __

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OCA Cross Exh. 11
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**Application of Transource Pennsylvania LLC**
**Independence Energy Connection-East Project**
**Docket Nos. A-2017-2640195 and A-2017-2640200**

**Interrogatories of the Office of Consumer Advocate**
**Set X**
**(Responses dated 05/2/2018)**

**Data Request 07:**
Reference: Reply to OCA-II-14, Attachment 1. Please state the full name for each PJM zone listed. Please do not refer the requester to PJM Manuals, including PJM Manual 35: Definitions and Acronyms, as there are several PJM zones listed on Attachment 1 that do not accurately correspond to the PJM Manual.

**Response:**

The full names of the PJM zones are as follows:

| | |
|---|---|
| AECO | Atlantic Electric Zone |
| AEP | American Electric Power Zone |
| APS | Allegheny Power Zone |
| BGE | Baltimore Gas & Electric Zone |
| COMED | Commonwealth Edison Zone |
| CONABCJK | Consolidated Edison (NYISO) - in relation to the now defunct Wheeling Arrangement. |
| DAY | Dayton Power and Light Zone |
| DEOK | Duke Energy Ohio and Kentucky Zone |
| DOM | Dominion Virginia Power Zone |
| DPL | Delmarva Power and Light Zone |
| DUQ | Duquense Light Company Zone |
| EKPC | East Kentucky Power Cooperative Zone |
| FE-ATSI | American Transmission Systems, Inc. Zone |
| JCPL | Jersey Central Power and Light Zone |
| LINDVFT | Linden VFT Merchant Transmission Facility |
| METED | Metropolitan Edison Zone |
| NEPTHVDC | Neptune Merchant Transmission Facility |
| O66HVDC | Hudson Merchant Transmission Facility |
| PECO | PECO Zone |

OCA Cross Exh. __

**Application of Transource Pennsylvania LLC**
**Independence Energy Connection-East Project**
**Docket Nos. A-2017-2640195 and A-2017-2640200**

**Interrogatories of the Office of Consumer Advocate**
**Set X**
**(Responses dated 05/2/2018)**

| | |
|---|---|
| PENELEC | Pennsylvania Electric Zone |
| PEPCO | Potomac Electric Power Zone |
| PLGRP | Pennsylvania Power & Light Zone |
| PSEG | Public Service Electric & Gas Zone |
| RECO | Rockland Electric (East) Zone |

**Witness:** Paul F. McGlynn

OCA Cross Exh. 12
2/26/19 Hbg TX

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| PJM Interconnection, L.L.C. | ) ) ) | Docket No. ER19-80-000 |

**COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM**

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments responding to the filing submitted by PJM Interconnection, L.L.C. ("PJM") on December 26, 2018 ("December 26th Filing"), in response to the deficiency letter issued in this proceeding November 27, 2018.

# I. COMMENTS

## A. PJM's Proposal does not Level the Playing Field for Comparing Transmission Projects

PJM claims (at 1) that its proposal to cap the benefit/cost ratio calculation at 15 years beyond the year in which the project is included in the regional transmission expansion plan ("RTEP"), will "level the playing field on which to evaluate project proposals with different in-service dates." PJM states (at 4) that its proposed changes "simply align the evaluation of project proposals (both benefits and costs) so all projects being compared are

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1 18 CFR § 385.211 (2018).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

evaluated from the time the project is expected to be in-service to the end of PJM's 15-year planning period (RTEP year + 14)." PJM argues (at 3) that under its proposed approach "projects will be more comparable as developers will no longer be able to rely on the more speculative benefits, beyond the RTEP period, to justify their project as more beneficial to a comparable project with an earlier proposed in-service date."

The Commission questions these claims. The Commission asks (at 4) whether the proposed changes would favor "smaller, ad hoc transmission projects rather than larger scale transmission solutions that...may be more efficient or cost effective." The Commission also asks (*id*) if PJM's proposed changes would "favor incumbent transmission providers that are capable of developing smaller incremental projects in the competitive proposal window process."

PJM responded (at 11) that, based on the data it provided in its initial filing, it "found no evidence to indicate that under this proposal projects with an in-service date later than the RTEP year will be disadvantaged when compared to smaller projects built by the RTEP year." PJM states (*id.*) that "under the new rules proposed, 85 percent of the projects submitted through the competitive proposal window for the 2016/2017 market efficiency planning cycle would have a higher Benefit/Cost Ratio." PJM states that, based on this data, "it appears that larger projects with in-service dates beyond the RTEP year would not be disadvantaged under these revisions to Schedule 6, section 1.5.7(d)"

PJM's data do not support PJM's determinations that its proposal will create a level playing field or a more equitable basis for comparing projects than PJM's current approach. PJM's data do not support the determination that there is no evidence that "projects with an in-service date later than the RTEP year will be disadvantaged when compared to smaller projects built by the RTEP year." PJM's response indicates that 15 percent of the projects submitted through the competitive proposal window for the 2016/2017 market efficiency planning cycle would be disadvantaged by the PJM proposal. There is no basis for an assertion that this result creates a more level playing field. PJM's data, and arguments about the effect of its proposal, do not support a conclusion that its proposal will not disadvantage projects with later start dates. PJM's data and arguments do not support a conclusion that their proposal will not disadvantage larger or non-incumbent proposals which may tend to be later in service dates.

PJM's response only highlights that the effect of its proposal to arbitrarily truncate the evaluation period for projects with later start dates on the projects' benefit/cost ratio can be positive or it can be negative. That is because, as PJM indicates elsewhere (at 9), the effect of the proposal on a project's benefit/cost ratio depends on whether the projected annual benefits calculated by PJM are increasing or decreasing for that project. If the projected benefits of a project are increasing due to expectations about future congestion costs, excluding years beyond RTEP+14 will disadvantage the project because every year past RTEP+14 would be adding years with increasing benefit to cost ratios. The evaluations all use a levelized cost approach so that changes in the benefit/cost ratio over time are entirely a function of changes in benefits over time. Fifteen percent of the projects submitted through the competitive proposal window for the 2016/2017 market efficiency planning cycle would be disadvantaged by the PJM proposal because they have increasing annual benefits beyond RTEP+14. Conversely, if the expected benefits of a project with a later start date are decreasing due to expectations about future congestion costs, excluding years beyond RTEP+14 will advantage the project as every year past RTEP+14 would be adding years with decreasing benefit/cost ratios. Eighty five percent of the projects submitted through the competitive proposal window for the 2016/2017 market efficiency planning cycle would be advantaged by the PJM proposal because they have decreasing annual benefits beyond RTEP+14.

PJM's proposal does not, therefore, generate a level playing field for comparing "project proposals with different in-service dates." Relative to projects with RTEP (year zero) in service dates, PJM's proposal disadvantages projects with later in service dates that show benefits that would increase over time. Relative to projects with RTEP (year zero) in service dates, PJM's proposal advantages projects with later in service dates that show benefits that would decrease over time.

Further, assuming PJM's modeling and analysis provide reasonable results, PJM's proposal is counterproductive to any effort to improve the benefit/cost ratio analysis used to evaluate and compare competing projects on a benefit/cost ratio basis. All projections and forecasts, positive or negative, are speculative. Projects with increasing benefits should not be disadvantaged relative to projects with decreasing benefits, based on the same speculative analysis.

If the objective is to provide a more level playing field, a better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project was 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over their actual term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.

**B. PJM's Proposal Would Not Eliminate Bad Incentives for Developers**

PJM argues that "[t]he ability of a later in-service date project using benefits calculated with data beyond the 15-year planning horizon to be selected over a project with an earlier in-service date creates incentives for developers with closely comparable projects to move out the in-service date in order to improve their benefit/cost ratio when compared with other projects." PJM argues (at 3) that its proposal will make projects "more comparable as developers will no longer be able to rely on the more speculative benefits, beyond the RTEP period, to justify their project as more beneficial to a comparable project with an earlier proposed in-service date." FERC questions (*id.*) this assertion.

Based on PJM's own arguments, PJM's proposal would not eliminate incentives for developers with closely comparable projects to move out the in service date in order to improve their benefit/cost ratio when compared with other projects. PJM's proposal would only change the projects that would benefit from moving out the in service dates in order to improve their benefit/cost ratio when compared with other competing projects. PJM's proposal would create a relative advantage for projects with in service dates later than RTEP with benefits that decrease over time. This is because PJM's proposal would eliminate years of declining benefits from the analysis of that project. This means that, under PJM's proposal, projects with decreasing benefits would, based on PJM's arguments, have an incentive to push back in service dates in order to have an advantage over similar projects with earlier in service dates. Any arbitrary truncation of the actual project life will create inappropriate metrics and inconsistent incentives.

An approach that eliminates the incentives to push back in service dates would establish a common end date for all projects so that the minimum included years for any evaluated project was 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost analysis would include the relevant benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over their actual term to the same present value date rather than an artificially truncated term. Under this approach all projects would equally benefit, or be hurt by, the analysis over the same planning horizon.

### C. PJM's Benefit Calculation Needs to Be Revaluated

For an RTEP project to be recommended to the PJM Board of Managers for approval as a Market Efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the present value of calculated Energy Market Benefits and calculated Reliability Pricing Model (RPM) Benefits for the 15 year period. The net present value of the benefits of the project at year zero are calculated for 15 years, starting with the projected in service date. Benefits are calculated in terms of changes in congestion and production costs. Projected reductions in congestion and production costs due to the project are calculated as a positive benefit. The method for calculating Energy Market Benefits and Reliability Pricing Model Benefits used to measure the benefit of an RTEP project for purposes of the 1.25:1 benefit/cost ratio threshold depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kV.

The Energy Market Benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, complete with total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in Energy Production Costs and Load Energy Payments. Changes in Energy Production Costs are calculated on a system wide basis. Using the modeled changes in LMPs, changes in Load Energy Payments are calculated on a zonal basis and are netted against corresponding changes in the value of any Auction Revenue Rights (ARR) that sink in that zone. The value of the ARR rights with and without the RTEP project is evaluated based on changes in CLMPs on the latest, historic allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade. To generate the estimate of the Energy Market Benefits, PJM simulates four year (RTEP -4, RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Energy Market Benefit for each modeled year is equal to 50 percent of the change in system wide Total Energy Production Costs with and without the project plus 50 percent of the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments. For subregional projects, the Energy Market Benefits for each modeled year is equal to the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments.

The Reliability Pricing Model Benefit analysis is conducted using the Reliability Pricing Model solution software, with and without the proposed RTEP project, using a set of estimated capacity offers. To generate the estimate of the Energy Market Benefits, PJM simulates three years (RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Reliability Pricing Model Benefit for each modeled year is equal to 50 percent of the change in system wide Total System Capacity Cost with and without the project plus 50 percent of the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments. For subregional projects, the Reliability Pricing Model Benefits for each modeled year is equal to the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments.

The Market Monitor recommends that the rules governing benefit/cost analysis be revaluated. The current benefit/cost analysis for a regional project, for example, explicitly ignores the negative effects that an RTEP project may have on a subset of zones when calculating the Energy Market Benefits. All costs should be included in all zones and LDAs. All are relevant to an evaluation of the actual costs and benefits. There is no reason to ignore any of the costs of the projects. The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin, making the cost benefit analysis effectively meaningless and inappropriately favoring transmission projects over market generation projects. The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets. But PJM fails to explicitly address this fact either in this filing or in the design of the market efficiency process. While the market efficiency process and metrics require improvement, for example in the way congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation is already providing a significant competitive advantage to transmission over generation which is built entirely based on market prices and with the concomitant risks. The risks of cost increases for transmission projects should be incorporated in the cost benefit analysis.

## II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it resolves the issues raised in this proceeding.

Respectfully submitted,

Jeffrey Mayes

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Dated: January 11, 2019

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 11th day of January, 2019.

Jeffrey Mayes

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