Exhibit RRM -
Table 1
Summary of Near Term Benefits and Costs

	2005	2006	2007	2008	2009	2010
Costs of MISO Membership						
RTO Administrative Costs - Sch. 10, 16 & 17 Charges	$14,150,839	$14,150,839	$14,150,839	$14,150,839	$14,150,839	$14,150,839
Transmission Usage Costs - Congestion Costs	$35,204,526	$35,204,526	$35,204,526	$35,204,526	$35,204,526	$35,204,526
Uplift Charges - GFA Option B & Narrow Constrained Area	$1,370,508	$1,370,508	$1,370,508	$1,370,508	$1,370,508	$1,370,508
Internal LG&E / KU Administrative & General Costs	$2,620,000	$2,620,000	$2,620,000	$2,620,000	$2,620,000	$2,620,000
Subtotal Costs of MISO Membership	***$53,345,873***	***$53,345,873***	***$53,345,873***	***$53,345,873***	***$53,345,873***	***$53,345,873***
Costs of Withdrawal from MISO and TORC Operations						
Exit Fee	$40,239,034					
Administrative & General Costs including Third Party Reliability Coordination Services	$1,840,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000
Increase in Generation & Purchased Power Costs to Serve Control Area Load	$3,969,155	$3,969,155	$3,969,155	$3,969,155	$3,969,155	$3,969,155
Lost Margin on Off-System Sales - Net of Incremental Generation and Transmission Costs	$27,296,216	$27,296,216	$27,296,216	$27,296,216	$27,296,216	$27,296,216
Net Loss of Transm'n Revenues - MISO Revenue Distribution less TORC Transm'n Revenues	$6,092,180	$6,092,180	$6,092,180	$6,092,180	$6,092,180	$6,092,180
Financial Transmission Rights	$58,039,359	$58,039,359	$58,039,359	$58,039,359	$58,039,359	$58,039,359
Subtotal Costs of Withdrawal from MISO and TORC Operations	***$137,475,944***	***$97,236,910***	***$97,236,910***	***$97,236,910***	***$97,236,910***	***$97,236,910***
Net Cost to LG&E / KU of Withdrawal from MISO and TORC Operations	**$84,130,071**	**$43,891,037**	**$43,891,037**	**$43,891,037**	**$43,891,037**	**$43,891,037**
Cumulative Net Cost to LG&E / KU of Withdrawal from MISO and TORC Operations	**$84,130,071**	**$128,021,109**	**$171,912,146**	**$215,803,183**	**$259,694,221**	**$303,585,258**
Net Present Value Cost to LG&E / KU of Withdrawal from MISO and TORC Operations	**$84,130,071**	**$41,019,661**	**$38,336,132**	**$35,828,161**	**$33,484,262**	**$31,293,703**
Cumulative NPV Cost to LG&E / KU of Withdrawal from MISO and TORC Operations	**$84,130,071**	**$125,149,732**	**$163,485,864**	**$199,314,025**	**$232,798,287**	**$264,091,990**

Exhibit RRM -
Table 3
Annual Net Cost to Serve Control Area Load

Cost to Serve LG&E / KU Control Area Load under MISO Day 1 Operations

Month	Generation Costs	Purchased Power Costs	Schedule 10 Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Net Cost to Serve Control Area Load
January	$64,156,085	$0	$0	$9,598,101	$2,991,738	$51,566,246
February	$61,490,189	$0	$0	$13,317,819	$3,113,962	$45,058,408
March	$64,753,889	$27	$0	$17,690,736	$2,353,516	$44,709,663
April	$61,398,588	$1,614	$0	$14,556,245	$1,242,052	$45,601,905
May	$61,407,243	$559,998	$0	$7,693,283	$1,693,369	$52,580,590
June	$72,310,286	$66,149	$0	$15,024,071	$2,025,520	$55,326,843
July	$83,923,935	$0	$0	$23,657,229	$1,675,310	$58,591,397
August	$78,673,010	$456,850	$0	$17,400,357	$1,744,882	$59,984,721
September	$71,837,703	$0	$0	$21,780,706	$1,678,961	$48,378,037
October	$64,122,697	$0	$0	$24,870,870	$2,308,078	$36,943,750
November	$60,499,241	$0	$0	$14,659,141	$2,581,094	$43,259,006
December	$62,810,008	$33,712	$0	$11,421,674	$2,264,265	$49,157,781
Total	$807,382,876	$1,118,449	$7,078,924	$191,670,231	$25,672,746	$598,237,271

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Nominations - LG&E / KU in MISO

Month	Generation Costs to Serve Contrtol Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 and 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$55,464,898	$15,103,867	$264	-$264	$1,334,550	$0	$0	$0	$0	$0	$16,779,195	$1,675,592	$2,991,738	$4,336,000	$0	$47,796,382	$70,568,765	$0
February	$50,099,007	$16,995,942	$0	$0	$1,716,039	$0	$0	$0	$0	$0	$19,974,024	$2,978,082	$3,113,962	$3,164,300	$0	$42,558,701	$67,094,949	$0
March	$50,488,381	$18,548,545	$10,525	-$3,676	$440,158	$0	$0	$0	$0	$0	$23,645,378	$5,100,510	$2,353,516	$4,028,145	$0	$39,456,893	$69,036,926	$6,848
April	$50,090,419	$12,072,824	$81,746	-$61,789	$1,594,352	$0	$0	$0	$0	$0	$15,937,736	$3,926,701	$1,242,052	$9,358,170	$0	$37,239,593	$62,163,242	$19,957
May	$54,059,618	$11,900,177	$647,822	-$77,676	$1,122,741	$0	$0	$0	$0	$0	$13,195,036	$1,372,534	$1,693,369	$8,708,179	$0	$44,056,099	$65,959,795	$570,147
June	$60,385,037	$16,626,146	$141,690	-$90,748	$5,413,153	$0	$0	$0	$0	$0	$20,953,752	$4,418,354	$2,025,520	$12,507,143	$0	$46,988,862	$77,011,183	$50,941
July	$67,724,518	$20,710,053	$665	-$665	$7,277,136	$0	$0	$0	$0	$0	$29,802,680	$9,093,292	$1,675,310	$18,784,944	$0	$45,448,774	$88,434,571	$0
August	$66,299,491	$16,677,432	$558,124	-$186,785	$6,640,429	$0	$0	$0	$0	$0	$22,686,114	$6,195,467	$1,744,882	$16,420,317	$0	$49,137,379	$82,976,924	$371,339
September	$56,145,613	$20,254,484	$0	$0	$4,282,982	$0	$0	$0	$0	$0	$28,454,095	$8,199,611	$1,678,961	$4,554,383	$0	$45,995,640	$76,400,096	$0
October	$48,108,984	$20,820,667	$0	$0	$1,303,174	$0	$0	$0	$0	$0	$32,969,311	$12,148,644	$2,308,078	-$1,205,357	$0	$36,160,793	$68,929,651	$0
November	$48,380,655	$17,200,850	$0	$0	$2,607,906	$0	$0	$0	$0	$0	$21,146,295	$3,945,445	$2,581,094	$2,239,533	$0	$42,222,489	$65,581,505	$0
December	$52,533,249	$17,503,658	$36,402	-$8,774	$1,471,906	$0	$0	$0	$0	$0	$19,920,458	$2,425,574	$2,264,265	$3,951,390	$0	$45,400,329	$70,036,907	$27,628
Total	$669,779,869	$204,414,646	$1,477,237	-$430,378	$35,204,526	$14,150,839	$0	$331,392	$1,039,116	$2,620,000	265,464,074	61,479,806	$25,672,746	$86,847,147	$2,000,000	$538,603,280	$864,194,516	$1,046,860

* Shown for purposes of companson to Direct Testimony.

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Allocation and Maximum Counterflow Restoration - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 and 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$55,464,898	$15,103,867	$264	-$264	$1,334,550	$0	$0	$0	$0	$0	$16,779,195	$1,837,455	$2,991,738	$3,470,470	$0	$48,661,912	$70,568,765	$0
February	$50,099,007	$16,995,942	$0	$0	$1,716,039	$0	$0	$0	$0	$0	$19,974,024	$3,251,830	$3,113,962	$1,758,883	$0	$43,964,118	$87,094,949	$0
March	$50,488,381	$18,548,545	$10,525	-$3,676	$440,158	$0	$0	$0	$0	$0	$23,645,378	$5,381,475	$2,353,516	$1,580,418	$0	$41,904,620	$69,036,926	$6,848
April	$50,090,419	$12,072,824	$81,746	-$61,789	$1,594,352	$0	$0	$0	$0	$0	$15,937,736	$4,160,248	$1,242,052	$3,541,271	$0	$43,056,492	$62,163,242	$19,957
May	$54,059,618	$11,900,177	$647,822	-$77,676	$1,122,741	$0	$0	$0	$0	$0	$13,195,036	$1,465,282	$1,693,369	$6,925,152	$0	$45,839,126	$65,959,795	$570,147
June	$60,385,037	$16,626,146	$141,690	-$90,748	$5,413,153	$0	$0	$0	$0	$0	$20,953,752	$4,944,337	$2,025,520	$9,576,047	$0	$49,919,958	$77,011,183	$50,941
July	$67,724,518	$20,710,053	$665	-$665	$7,277,136	$0	$0	$0	$0	$0	$29,802,680	$10,722,600	$1,675,310	$13,176,804	$0	$51,056,914	$88,434,571	$0
August	$66,299,491	$16,677,432	$558,124	-$186,785	$6,640,429	$0	$0	$0	$0	$0	$22,686,114	$7,115,336	$1,744,882	$11,243,843	$0	$54,313,853	$82,976,924	$371,339
September	$56,145,613	$20,254,484	$0	$0	$4,282,982	$0	$0	$0	$0	$0	$28,454,095	$8,620,569	$1,678,961	$2,666,272	$0	$47,883,751	$76,400,098	$0
October	$48,108,984	$20,820,667	$0	$0	$1,303,174	$0	$0	$0	$0	$0	$32,969,311	$12,375,039	$2,308,078	-$2,201,189	$0	$37,156,625	$88,929,651	$0
November	$48,380,655	$17,200,850	$0	$0	$2,607,906	$0	$0	$0	$0	$0	$21,146,295	$4,287,322	$2,581,094	$828,526	$0	$43,633,496	$65,581,505	$0
December	$52,533,249	$17,503,658	$36,402	-$8,774	$1,471,906	$0	$0	$0	$0	$0	$19,920,458	$2,581,252	$2,264,265	$3,472,862	$0	$45,878,857	$70,036,907	$27,628
Total	$669,779,869	$204,414,646	$1,477,237	-$430,378	$35,204,526	$14,150,839	$0	$331,392	$1,039,116	$2,620,000	265,464,074	66,722,745	$25,672,746	$56,039,359	$2,000,000	$569,411,068	$864,194,515	$1,046,860

* Shown for purposes of companson to Direct Testimony.

Cost to Serve LGE&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Values (75% of Congestion Costs) - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 and 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$55,464,898	$15,103,867	$264	-$264	$1,334,550	$0	$0	$0	$0	$0	$16,779,195	$1,837,455	$2,991,738	$1,000,913	$0	$51,131,469	$70,568,765	$0
February	$50,099,007	$16,995,942	$0	$0	$1,716,039	$0	$0	$0	$0	$0	$19,974,024	$3,251,830	$3,113,962	$1,287,029	$0	$44,435,972	$67,094,949	$0
March	$50,488,381	$18,548,545	$10,525	-$3,676	$440,158	$0	$0	$0	$0	$0	$23,645,378	$5,381,475	$2,353,516	$330,119	$0	$43,154,919	$69,036,926	$6,848
April	$50,090,419	$12,072,824	$81,746	-$61,789	$1,594,352	$0	$0	$0	$0	$0	$15,937,736	$4,160,248	$1,242,052	$1,195,764	$0	$45,401,999	$62,163,242	$19,957
May	$54,059,618	$11,900,177	$647,822	-$77,676	$1,122,741	$0	$0	$0	$0	$0	$13,195,036	$1,465,282	$1,693,369	$842,056	$0	$51,922,222	$65,959,795	$570,147
June	$60,385,037	$16,626,146	$141,690	-$90,748	$5,413,153	$0	$0	$0	$0	$0	$20,953,752	$4,944,337	$2,025,520	$4,059,865	$0	$55,436,140	$77,011,183	$50,941
July	$67,724,518	$20,710,053	$665	-$665	$7,277,136	$0	$0	$0	$0	$0	$29,802,680	$10,722,600	$1,675,310	$5,457,852	$0	$58,776,866	$88,434,571	$0
August	$66,299,491	$16,677,432	$558,124	-$186,785	$6,640,429	$0	$0	$0	$0	$0	$22,686,114	$7,115,336	$1,744,882	$4,980,322	$0	$60,577,374	$82,976,924	$371,339
September	$56,145,613	$20,254,484	$0	$0	$4,282,982	$0	$0	$0	$0	$0	$28,454,095	$8,620,569	$1,678,961	$3,212,236	$0	$47,337,787	$76,400,096	$0
October	$48,108,984	$20,820,667	$0	$0	$1,303,174	$0	$0	$0	$0	$0	$32,969,311	$12,375,039	$2,308,078	$977,380	$0	$33,978,056	$68,929,651	$0
November	$48,380,655	$17,200,850	$0	$0	$2,607,906	$0	$0	$0	$0	$0	$21,146,295	$4,287,322	$2,581,094	$1,955,929	$0	$42,506,093	$65,581,505	$0
December	$52,533,249	$17,503,658	$36,402	-$8,774	$1,471,906	$0	$0	$0	$0	$0	$19,920,458	$2,581,252	$2,264,265	$1,103,930	$0	$48,247,789	$70,036,907	$27,628
Total	$659,779,869	$204,414,646	$1,477,237	-$430,378	$35,204,526	$14,150,839	$0	$331,392	$1,039,116	$2,620,000	265,464,074	66,722,745	$25,672,746	$26,403,395	$2,000,000	$599,047,032	$864,194,516	$1,046,860

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Values (75% of Congestion Costs) and Excluding Transmission Revenue Benefits - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 and 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$55,464,898	$15,103,867	$264	-$264	$1,334,550	$0	$0	$0	$0	$0	$16,779,195	$1,837,455	$1,413,364	$1,000,913	$0	$52,709,844	$70,568,765	$0
February	$50,099,007	$16,995,942	$0	$0	$1,716,039	$0	$0	$0	$0	$0	$19,974,024	$3,251,830	$1,609,436	$1,287,029	$0	$45,940,498	$67,094,949	$0
March	$50,488,381	$18,548,545	$10,525	-$3,676	$440,158	$0	$0	$0	$0	$0	$23,645,378	$5,381,475	$2,107,853	$330,119	$0	$43,400,583	$69,036,926	$6,848
April	$50,090,419	$12,072,824	$81,746	-$61,789	$1,594,352	$0	$0	$0	$0	$0	$15,937,736	$4,160,248	$1,476,452	$1,195,764	$0	$45,167,599	$62,163,242	$19,957
May	$54,059,618	$11,900,177	$647,822	-$77,676	$1,122,741	$0	$0	$0	$0	$0	$13,195,036	$1,465,282	$823,634	$842,056	$0	$52,791,957	$65,959,795	$570,147
June	$60,385,037	$16,626,146	$141,690	-$90,748	$5,413,153	$0	$0	$0	$0	$0	$20,953,752	$4,944,337	$1,468,273	$4,059,865	$0	$55,993,388	$77,011,183	$50,941
July	$67,724,518	$20,710,053	$665	-$665	$7,277,136	$0	$0	$0	$0	$0	$29,802,680	$10,722,600	$1,656,630	$5,457,852	$0	$58,794,545	$88,434,571	$0
August	$66,299,491	$16,677,432	$558,124	-$186,785	$6,640,429	$0	$0	$0	$0	$0	$22,686,114	$7,115,336	$1,384,709	$4,980,322	$0	$60,937,547	$82,976,924	$371,339
September	$56,145,613	$20,254,484	$0	$0	$4,282,982	$0	$0	$0	$0	$0	$28,454,095	$8,620,569	$1,986,504	$3,212,236	$0	$47,030,243	$76,400,096	$0
October	$48,108,984	$20,820,667	$0	$0	$1,303,174	$0	$0	$0	$0	$0	$32,969,311	$12,375,039	$2,461,193	$977,380	$0	$33,824,941	$68,929,651	$0
November	$48,380,655	$17,200,850	$0	$0	$2,607,906	$0	$0	$0	$0	$0	$21,146,295	$4,287,322	$1,652,402	$1,955,929	$0	$43,434,785	$65,581,505	$0
December	$52,533,249	$17,503,658	$36,402	-$8,774	$1,471,906	$0	$0	$0	$0	$0	$19,920,458	$2,581,252	$1,540,118	$1,103,930	$0	$48,971,936	$70,036,907	$27,628
Total	$659,779,869	$204,414,646	$1,477,237	-$430,378	$35,204,526	$14,150,839	$0	$331,392	$1,039,116	$2,620,000	265,464,074	66,722,745	$19,580,566	$26,403,395	$2,000,000	$605,139,212	$864,194,516	$1,046,860

* Shown for purposes of comparison to Direct Testimony.

Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	A&G and Reliability Coordination Services Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$55,800,017	$9,529,549	$7,251	-$7,251	$0	$10,281,422	$739,124	$1,413,364	$53,654,781	$65,329,567	$0
February	$50,188,872	$10,252,281	$0	$0	$0	$11,625,643	$1,373,362	$1,609,436	$47,206,074	$60,441,153	$0
March	$50,608,468	$13,238,806	$85	-$85	$0	$15,877,396	$2,638,677	$2,107,853	$45,862,023	$63,847,274	$0
April	$50,434,979	$9,872,687	$107,852	-$107,852	$0	$11,964,903	$2,200,068	$1,476,452	$46,866,312	$60,307,667	$0
May	$54,342,313	$6,495,998	$592,526	-$69,131	$0	$6,912,462	$485,594	$823,634	$53,625,611	$60,838,311	$523,395
June	$60,857,467	$10,205,191	$147,076	-$92,960	$0	$12,729,883	$2,617,652	$1,468,273	$56,918,618	$71,062,658	$54,116
July	$68,350,680	$13,764,686	$0	$0	$0	$19,978,579	$6,213,893	$1,656,630	$60,480,157	$82,115,366	$0
August	$67,432,148	$10,704,446	$336,857	-$55,971	$0	$14,883,710	$4,235,234	$1,384,709	$62,149,063	$78,136,595	$280,886
September	$56,512,577	$12,821,886	$0	$0	$0	$17,414,727	$4,592,841	$1,986,504	$49,933,232	$69,334,463	$0
October	$48,215,937	$14,331,721	$0	$0	$0	$21,343,349	$7,011,628	$2,461,193	$38,743,116	$62,547,658	$0
November	$48,441,830	$9,907,646	$0	$0	$0	$11,152,409	$1,244,763	$1,652,402	$45,544,664	$58,349,476	$0
December	$52,835,492	$9,585,569	$13,833	$11,063	$0	$10,427,383	$830,751	$1,540,118	$50,478,457	$62,421,062	$24,896
Total	$664,020,781	$130,710,467	$1,205,480	-$322,187	$1,840,000	$164,671,870	$34,183,590	$19,580,566	$613,302,105	$794,731,246	$883,293

* Shown for purposes of comparison to Direct Testimony.

Exhibit RRM-
Table 4
Off-System Sales Comparison

	MISO Day 1 Operations	Day 2 LGE in MISO	Day 2 LGE Out of MISO with Conservative Hurdle Rates	Day 2 LGE Out of MISO with Model Benchmarked to Historical Sales Levels
LGE Off-System Sales MWH	10,283,998	14,177,619	9,126,612	4,196,189
Ave. Hourly LGE Gen Price ($/MWH)	$17.67	$18.94	$17.28	$15.13
Volume Weighted Ave. LGE Gen Price ($/MWH)	$18.93	$19.81	$18.50	$16.79
Vol. Weighted Ave. LGE Off-System Sale Price ($/MWH)	$20.64	$18.72	$18.03	$18.89
Off-System Sales Revenues	$191,670,231	$265,464,075	$164,571,870	$79,263,426

Exhibit RRM-
Table 5
Unit 2005 Capacity Factor

	LGE in MISO Regional Dispatch	LGE Out of MISO with Conservative Hurdle Rates (TORC Option)	LGE Out of MISO with Model Benchmarked to Actual Off-System Sales
Brown 1	55%	51%	46%
Brown 2	65%	62%	58%
Brown 3	59%	56%	54%
Brown 6	2%	3%	2%
Brown 7	2%	2%	2%
Brown 8	1%	1%	1%
Brown 9	1%	1%	1%
Brown 10	1%	1%	1%
Brown 11	1%	1%	1%
Cane Run 4	61%	53%	49%
Cane Run 5	82%	70%	58%
Cane Run 6	54%	43%	35%
Cane Run 11	0%	0%	0%
Coleman 1	82%	74%	69%
Coleman 2	71%	65%	61%
Coleman 3	74%	58%	47%
Dix	26%	26%	26%
Ghent 1	72%	63%	52%
Ghent 2	72%	62%	53%
Ghent 3	60%	50%	45%
Ghent 4	62%	53%	46%
Green 1	86%	84%	78%
Green 2	86%	84%	73%
Green River 1	32%	27%	24%
Green River 2	31%	27%	24%
Green River 3	53%	47%	44%
Green River 4	58%	50%	45%
Haefling 1	0%	0%	0%
Haefling 2	0%	0%	0%
Haefling 3	0%	0%	0%
Mill Creek 1	70%	52%	38%
Mill Creek 2	51%	41%	33%
Mill Creek 3	66%	51%	43%
Mill Creek 4	69%	64%	58%
Ohio Falls 8	81%	81%	81%
Paddys Run 11	0%	0%	0%
Paddys Run 12	0%	0%	0%
Paddys Run 13	1%	1%	1%
Reid 1	46%	43%	41%
Reid 2	0%	0%	0%
Trimble County 1	83%	77%	64%
Tyrone 1	0%	0%	0%
Tyrone 2	0%	0%	0%
Tyrone 3	45%	43%	40%
Wilson 1	83%	77%	70%
Waterside 7	0%	0%	0%
Waterside 8	0%	0%	0%
Zorn 1	0%	0%	0%

Exhibit RRM-
Table 6
Summary of Sensitivity Cases

Operator Reliability Coordinator Option

Case / Sensitivity	Illustrative FTR Allocation	Minimum Value for Illustrative FTR Allocation	Very Low FTR Value	Very Low FTR Value & Transmission Revenue Equality
Base Case Comparison	$74,698,825	***$43,891,037***	$14,255,073	$8,162,893
Dispatch Impacts of GFA Carve Out	$71,525,922	$40,623,636	$15,774,198	$8,366,306
Lower than Anticipated Transmission Utilization under Coordinated Dispatch	$72,315,404	$42,056,106	$11,293,138	$5,345,238
Hurdle Rates Base on Benchmarking LGE Transactions More Closely to Historical Levels	$101,933,925	$71,126,137	$41,490,173	$35,397,993
High Fuel Costs	$84,401,274	$47,231,883	$13,966,431	$7,953,443
Low Fuel Costs	$59,923,914	$35,891,356	$13,992,329	$7,824,077

Exhibit RRM -
Table 7
Sensitivity for MISO Transmission Utilization - Results for Annual Net Cost to Serve Control Area Load

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Nominations - LG&E / KU in MISO
Maximum MISO Transmission Utilization Limited to 97% of Flowgate Capacity

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	70,578,855	$0	$1,720,653	$0	$0	$0	$0	$0	$16,709,745.	$2,991,738	4,598,910	$0	$47,999,115
February	66,997,049	$0	$2,001,313	$0	$0	$0	$0	$0	$19,712,622	$3,113,962	3,437,791	$0	$42,733,987
March	68,674,513	$4,897	$693,873	$0	$0	$0	$0	$0	$23,244,744	$2,353,516	4,263,386	$0	$39,511,637
April	61,759,652	$26,007	$2,109,154	$0	$0	$0	$0	$0	$15,511,348	$1,242,052	9,281,149	$0	$37,860,264
May	66,046,599	$550,474	$2,641,663	$0	$0	$0	$0	$0	$13,285,925	$1,693,369	8,956,617	$0	$45,302,826
June	77,274,906	$54,533	$5,624,592	$0	$0	$0	$0	$0	$21,249,481	$2,025,520	12,835,343	$0	$46,843,686
July	89,062,919	$0	$7,481,000	$0	$0	$0	$0	$0	$30,332,005	$1,675,310	20,005,448	$0	$44,531,157
August	83,723,657	$351,790	$7,375,070	$0	$0	$0	$0	$0	$23,413,180	$1,744,882	18,485,048	$0	$47,807,407
September	76,377,605	$0	$4,839,816	$0	$0	$0	$0	$0	$28,272,231	$1,678,961	4,825,961	$0	$46,440,268
October	68,766,480	$0	$1,463,012	$0	$0	$0	$0	$0	$32,529,153	$2,308,078	-1,376,102	$0	$36,768,364
November	65,318,463	$0	$2,716,782	$0	$0	$0	$0	$0	$20,746,629	$2,581,094	2,110,640	$0	$42,596,882
December	69,873,345	$40,019	$2,170,508	$0	$0	$0	$0	$0	$19,664,478	$2,264,265	4,226,154	$0	$45,928,975
Total	$864,454,042	$1,027,721	$40,837,437	$14,150,839	$0	$267,134	$1,113,574	$2,620,000	$264,671,541	$25,672,746	$91,650,345	$2,000,000	$540,476,114

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Allocation and Maximum Counterflow Restoration - LG&E / KU in MISO
Maximum MISO Transmission Utilization Limited to 97% of Flowgate Capacity

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	70,578,855	$0	$1,720,653	$0	$0	$0	$0	$0	$16,709,745	$2,991,738	$3,853,055	$0	$48,744,970
February	66,997,049	$0	$2,001,313	$0	$0	$0	$0	$0	$19,712,622	$3,113,962	$2,031,756	$0	$44,140,022
March	68,674,513	$4,897	$693,873	$0	$0	$0	$0	$0	$23,244,744	$2,353,516	$1,827,968	$0	$41,947,055
April	61,759,652	$26,007	$2,109,154	$0	$0	$0	$0	$0	$15,511,348	$1,242,052	$3,832,827	$0	$43,308,586
May	66,046,599	$550,474	$2,641,663	$0	$0	$0	$0	$0	$13,285,925	$1,693,369	$7,359,892	$0	$46,899,551
June	77,274,906	$54,533	$5,624,592	$0	$0	$0	$0	$0	$21,249,481	$2,025,520	$9,713,368	$0	$49,965,661
July	89,062,919	$0	$7,481,000	$0	$0	$0	$0	$0	$30,332,005	$1,675,310	$14,108,643	$0	$50,427,962
August	83,723,657	$351,790	$7,375,070	$0	$0	$0	$0	$0	$23,413,180	$1,744,882	$12,808,419	$0	$53,484,036
September	76,377,605	$0	$4,839,816	$0	$0	$0	$0	$0	$28,272,231	$1,678,961	$3,369,641	$0	$47,896,588
October	68,766,480	$0	$1,463,012	$0	$0	$0	$0	$0	$32,529,153	$2,308,078	-$2,284,745	$0	$37,677,007
November	65,318,463	$0	$2,716,782	$0	$0	$0	$0	$0	$20,746,629	$2,581,094	$836,050	$0	$43,871,472
December	69,873,345	$40,019	$2,170,508	$0	$0	$0	$0	$0	$19,664,478	$2,264,265	$3,934,173	$0	$46,220,956
Total	$864,454,042	$1,027,721	$40,837,437	$14,150,839	$0	$267,134	$1,113,574	$2,620,000	$264,671,541	$25,672,746	$61,391,047	$2,000,000	$570,735,412

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value - LG&E / KU in MISO
Maximum MISO Transmission Utilization Limited to 97% of Flowgate Capacity

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	70,578,855	$0	$1,720,653	$0	$0	$0	$0	$0	$16,709,745	$2,991,738	$1,290,490	$0	$51,307,535
February	66,997,049	$0	$2,001,313	$0	$0	$0	$0	$0	$19,712,622	$3,113,962	$1,500,985	$0	$44,670,793
March	68,674,513	$4,897	$693,873	$0	$0	$0	$0	$0	$23,244,744	$2,353,516	$520,405	$0	$43,254,618
April	61,759,652	$26,007	$2,109,154	$0	$0	$0	$0	$0	$15,511,348	$1,242,052	$1,581,866	$0	$45,559,547
May	66,046,599	$550,474	$2,641,663	$0	$0	$0	$0	$0	$13,285,925	$1,693,369	$1,981,248	$0	$52,278,195
June	77,274,906	$54,533	$5,624,592	$0	$0	$0	$0	$0	$21,249,481	$2,025,520	$4,218,444	$0	$55,460,585
July	*89,062,919*	*$0*	*$7,481,000*	$0	$0	$0	$0	$0	$30,332,005	$1,675,310	$5,610,750	$0	$58,925,855
August	83,723,657	$351,790	$7,375,070	$0	$0	$0	$0	$0	$23,413,180	$1,744,882	$5,531,302	$0	$60,761,153
September	76,377,605	$0	$4,839,816	$0	$0	$0	$0	$0	$28,272,231	$1,678,961	$3,629,862	$0	$47,636,367
October	68,766,480	$0	$1,463,012	$0	$0	$0	$0	$0	$32,529,153	$2,308,078	$1,097,259	$0	$34,295,003
November	65,318,463	$0	$2,716,782	$0	$0	$0	$0	$0	$20,746,629	$2,581,094	$2,037,587	$0	$42,669,935
December	69,873,345	$40,019	$2,170,508	$0	$0	$0	$0	$0	$19,664,478	$2,264,265	$1,627,881	$0	$48,527,248
Total	**$864,454,042**	**$1,027,721**	**$40,837,437**	**$14,150,839**	**$0**	**$267,134**	**$1,113,574**	**$2,620,000**	**$264,671,541**	**$25,672,746**	**$30,628,079**	**$2,000,000**	**$601,498,380**

Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value and Excluding Transmission Revenue Benefits - LG&E / KU in MISO
Maximum MISO Transmission Utilization Limited to 97% of Flowgate Capacity

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	70,578,855	$0	$1,720,653	$0	$0	$0	$0	$0	$16,709,745	$1,425,144	$1,290,490	$0	$52,874,129
February	66,997,049	$0	$2,001,313	$0	$0	$0	$0	$0	$19,712,622	$1,620,425	$1,500,985	$0	$46,164,330
March	68,674,513	$4,897	$693,873	$0	$0	$0	$0	$0	$23,244,744	$2,089,285	$520,405	$0	$43,518,849
April	61,759,652	$26,007	$2,109,154	$0	$0	$0	$0	$0	$15,511,348	$1,525,703	$1,581,866	$0	$45,275,896
May	66,046,599	$550,474	$2,641,663	$0	$0	$0	$0	$0	$13,285,925	$834,779	$1,981,248	$0	$53,136,784
June	77,274,906	$54,533	$5,624,592	$0	$0	$0	$0	$0	$21,249,481	$1,497,675	$4,218,444	$0	$55,988,430
July	89,062,919	$0	$7,481,000	$0	$0	$0	$0	$0	$30,332,005	$1,691,682	$5,610,750	$0	$58,909,483
August	83,723,657	$351,790	$7,375,070	$0	$0	$0	$0	$0	$23,413,180	$1,408,736	$5,531,302	$0	$61,097,299
September	76,377,605	$0	$4,839,816	$0	$0	$0	$0	$0	$28,272,231	$2,004,835	$3,629,862	$0	$47,310,493
October	*68,766,480*	*$0*	*$1,463,012*	*$0*	*$0*	*$0*	$0	$0	$32,529,153	$2,461,527	$1,097,259	$0	$34,141,553
November	65,318,463	$0	$2,716,782	$0	$0	$0	$0	$0	$20,746,629	$1,625,365	$2,037,587	$0	$43,625,664
December	69,873,345	$40,019	$2,170,508	$0	$0	$0	$0	$0	$19,664,478	$1,539,688	$1,627,881	$0	$49,251,824
Total	**$864,454,042**	**$1,027,721**	**$40,837,437**	**$14,150,839**	**$0**	**$267,134**	**$1,113,574**	**$2,620,000**	**$264,671,541**	**$19,724,846**	**$30,628,079**	**$2,000,000**	**$607,446,281**

Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO
Maximum MISO Transmission Utilization Limited to 97% of Flowgate Capacity

Month	Total Generation Costs	Purchased Power Costs	A&G and Reliability Coordination Services Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load
January	$65,413,601	$0	0	$10,372,839	$1,425,144	$53,615,618
February	$60,525,032	$0	0	$11,682,055	$1,620,425	$47,222,552
March	$63,757,757	$0	0	$15,904,736	$2,089,285	$45,763,735
April	$60,558,112	$0	0	$12,251,945	$1,525,703	$46,780,464
May	$60,837,622	$496,573	0	$7,024,249	$834,779	$53,475,167
June	$71,290,177	$57,771	0	$13,010,649	$1,497,675	$56,839,624
July	$82,563,309	$0	0	$20,565,366	$1,691,682	$60,306,262
August	$78,490,995	$257,429	0	$15,247,488	$1,408,736	$62,092,201
September	$69,420,488	$0	0	$17,578,621	$2,004,835	$49,837,032
October	$62,561,407	$0	0	$21,349,301	$2,461,527	$38,750,578
November	*$58,202,937*	*$0*	*0*	*$10,757,658*	*$1,825,365*	*$45,819,914*
December	$62,415,862	$18,799	0	$10,446,603	$1,539,688	$50,448,370
Total	**$796,037,301**	**$830,571**	**$1,840,000**	**$166,191,508**	**$19,724,846**	**$612,791,518**

Exhibit RRM -
Table 8
GFA Carve Out Sensitivity - Annual Net Cost to Serve Control Area Load

GFA Carve Out Sensitivity - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Nominations - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Off-System Sales Revenue	Off-System Sales Margin*	Less: Distribution of Schedule 1, 7, & 8 Transmission Revenues on Off-System Sales	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$53,798,569	$16,932,325	$0	$0	$1,312,823	$0	$0	$0	$0	$0	$17,313,139	$380,814	$2,991,738	$4,023,259	$0	$47,715,682	70,730,894	0
February	$48,532,753	$18,499,711	$0	$0	$1,687,341	$0	$0	$0	$0	$0	$20,351,381	$1,851,670	$3,113,962	$2,909,865	$0	$42,344,697	67,032,464	0
March	$48,733,019	$20,357,664	$0	$0	$427,055	$0	$0	$0	$0	$0	$24,416,111	$4,058,447	$2,353,516	$3,679,962	$0	$39,068,149	69,090,683	0
April	$48,567,375	$13,496,794	$22,778	-$22,356	$1,431,517	$0	$0	$0	$0	$0	$16,615,314	$3,140,876	$1,242,052	$8,543,658	$0	$37,095,083	62,064,169	422
May	$52,485,563	$13,463,598	$479,356	-$190,237	$2,408,552	$0	$0	$0	$0	$0	$13,699,484	$426,123	$1,693,369	$8,200,516	$0	$45,053,462	65,949,161	289,118
June	$58,657,771	$18,580,010	$254,269	-$244,541	$5,432,283	$0	$0	$0	$0	$0	$22,224,491	$3,889,023	$2,025,520	$12,049,496	$0	$46,380,284	77,237,781	9,728
July	$65,571,667	$22,905,768	$0	$0	$7,155,072	$0	$0	$0	$0	$0	$31,619,304	$8,713,536	$1,675,310	$18,346,019	$0	$43,991,874	88,477,434	0
August	$64,503,607	$18,443,711	$191,495	-$61,967	$6,674,860	$0	$0	$0	$0	$0	$24,266,317	$5,884,573	$1,744,882	$16,067,013	$0	$47,673,493	82,947,317	129,528
September	$54,569,058	$21,957,102	$27,033	-$27,033	$4,192,781	$0	$0	$0	$0	$0	$29,706,407	$7,776,337	$1,678,961	$4,271,729	$0	$45,061,845	76,526,160	0
October	$47,008,337	$21,964,432	$0	$0	$1,305,891	$0	$0	$0	$0	$0	$34,169,272	$12,204,840	$2,308,078	-$1,289,568	$0	$35,090,879	68,972,769	0
November	$46,889,697	$18,696,538	$0	$0	$2,587,844	$0	$0	$0	$0	$0	$21,557,011	$2,860,473	$2,581,094	$2,450,232	$0	$41,686,742	65,586,235	0
December	$50,903,513	$19,295,160	$14,546	-$3,720	$1,575,430	$0	$0	$0	$0	$0	$20,515,438	$1,223,998	$2,264,265	$3,643,127	$0	$45,362,098	70,198,672	10,826
Total	$640,220,928	224,592,812	$989,476	-549,854	$36,191,447	$14,150,839	$0	$342,282	$1,023,266	$2,620,000	$276,453,669	$52,410,711	$25,672,746	$82,895,308	$2,000,000	$532,559,474	$864,813,741	$439,622

* Shown for purposes of comparison to Direct Testimony.

GFA Carve Out Sensitivity - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Allocation and Maximum Counterflow Restoration - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: Distribution of Schedule 1, 7, & 8 Transmission Revenues on Off-System Sales	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$53,798,569	$16,932,325	$0	$0	$1,312,823	$0	$0	$0	$0	$0	$17,313,139	$380,814	$2,991,738	$3,147,231	$0	$48,591,610	70,730,894	0
February	$48,532,753	$18,499,711	$0	$0	$1,687,341	$0	$0	$0	$0	$0	$20,351,381	$1,851,670	$3,113,962	$1,527,476	$0	$43,726,986	67,032,464	0
March	$48,733,019	$20,357,664	$0	$0	$427,055	$0	$0	$0	$0	$0	$24,416,111	$4,058,447	$2,353,516	$1,243,733	$0	$41,504,378	69,090,683	0
April	$48,567,375	$13,496,794	$22,778	-$22,356	$1,431,517	$0	$0	$0	$0	$0	$16,615,314	$3,140,876	$1,242,052	$2,768,833	$0	$42,869,908	62,064,169	422
May	$52,485,563	$13,463,598	$479,356	-$190,237	$2,408,552	$0	$0	$0	$0	$0	$13,699,484	$426,123	$1,693,369	$6,411,159	$0	$46,842,819	65,949,161	289,118
June	$58,657,771	$18,580,010	$254,269	-$244,541	$5,432,283	$0	$0	$0	$0	$0	$22,224,491	$3,889,023	$2,025,520	$9,050,755	$0	$49,379,025	77,237,781	9,728
July	$65,571,667	$22,905,768	$0	$0	$7,155,072	$0	$0	$0	$0	$0	$31,619,304	$8,713,536	$1,675,310	$12,691,385	$0	$49,646,608	88,477,434	0
August	$64,503,607	$18,443,711	$191,495	-$61,967	$6,674,860	$0	$0	$0	$0	$0	$24,266,317	$5,884,573	$1,744,882	$10,890,087	$0	$52,850,419	82,947,317	129,528
September	$54,569,058	$21,957,102	$27,033	-$27,033	$4,192,781	$0	$0	$0	$0	$0	$29,706,407	$7,776,337	$1,678,961	$2,293,371	$0	$47,040,203	76,526,160	0
October	$47,008,337	$21,964,432	$0	$0	$1,305,891	$0	$0	$0	$0	$0	$34,169,272	$12,204,840	$2,308,078	-$2,285,831	$0	$36,087,142	68,972,769	0
November	$46,889,697	$18,696,538	$0	$0	$2,587,844	$0	$0	$0	$0	$0	$21,557,011	$2,860,473	$2,581,094	$1,077,339	$0	$42,958,635	65,586,235	0
December	$50,903,513	$19,295,160	$14,546	-$3,720	$1,575,430	$0	$0	$0	$0	$0	$20,515,438	$1,223,998	$2,264,265	$3,177,484	$0	$45,827,741	70,198,672	10,826
Total	$640,220,928	224,592,812	$989,476	-549,854	$36,191,447	$14,150,839	$0	$342,282	$1,023,266	$2,620,000	$276,453,669	$52,410,711	$25,672,746	$51,993,022	$2,000,000	$563,461,760	$864,813,741	$439,622

* Shown for purposes of comparison to Direct Testimony.

GFA Carve Out Sensitivity - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Values (75% of Congestion Costs) - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: Distribution of Schedule 1, 7, & 8 Transmission Revenues on Off-System Sales	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$53,798,569	$16,932,325	$0	$0	$1,312,823	$0	$0	$0	$0	$0	$17,313,139	$380,814	$2,991,738	$984,617	$0	$50,754,224	70,730,894	0
February	$48,532,753	$18,499,711	$0	$0	$1,687,341	$0	$0	$0	$0	$0	$20,351,381	$1,851,670	$3,113,962	$1,265,505	$0	$43,988,957	67,032,464	0
March	$48,733,019	$20,357,664	$0	$0	$427,055	$0	$0	$0	$0	$0	$24,416,111	$4,058,447	$2,353,516	$320,291	$0	$42,427,820	69,090,683	0
April	$48,567,375	$13,496,794	$22,778	-$22,356	$1,431,517	$0	$0	$0	$0	$0	$16,615,314	$3,140,876	$1,242,052	$1,073,637	$0	$44,665,104	62,064,169	422
May	$52,485,563	$13,463,598	$479,356	-$190,237	$2,408,552	$0	$0	$0	$0	$0	$13,699,484	$426,123	$1,693,369	$1,806,414	$0	$51,447,564	65,949,161	289,118
June	$58,657,771	$18,580,010	$254,269	-$244,541	$5,432,283	$0	$0	$0	$0	$0	$22,224,491	$3,889,023	$2,025,520	$4,074,212	$0	$54,355,568	77,237,781	9,728
July	$65,571,667	$22,905,768	$0	$0	$7,155,072	$0	$0	$0	$0	$0	$31,619,304	$8,713,536	$1,675,310	$5,366,304	$0	$56,971,589	88,477,434	0
August	$64,503,607	$18,443,711	$191,495	-$61,967	$6,674,860	$0	$0	$0	$0	$0	$24,266,317	$5,884,573	$1,744,882	$5,006,145	$0	$58,734,361	82,947,317	129,528
September	$54,569,058	$21,957,102	$27,033	-$27,033	$4,192,781	$0	$0	$0	$0	$0	$29,706,407	$7,776,337	$1,678,961	$3,144,586	$0	$46,188,988	76,526,160	0
October	$47,008,337	$21,964,432	$0	$0	$1,305,891	$0	$0	$0	$0	$0	$34,169,272	$12,204,840	$2,308,078	$979,418	$0	$32,821,893	68,972,769	0
November	$46,889,697	$18,696,538	$0	$0	$2,587,844	$0	$0	$0	$0	$0	$21,557,011	$2,860,473	$2,581,094	$1,840,883	$0	$42,095,091	65,586,235	0
December	$50,903,513	$19,295,160	$14,546	-$3,720	$1,575,430	$0	$0	$0	$0	$0	$20,515,438	$1,223,998	$2,264,265	$1,181,572	$0	$47,823,653	70,198,672	10,826
Total	$640,220,928	224,592,812	$989,476	-549,854	$36,191,447	$14,150,839	$0	$342,282	$1,023,266	$2,620,000	$276,453,669	$52,410,711	$25,672,746	$27,143,584	$2,000,000	$588,311,198	$864,813,741	$439,622

* Shown for purposes of comparison to Direct Testimony.

GFA Carve Out Sensitivity - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Values (65% of Congestion Costs) and Excluding Transmission Revenue Benefits - LG&E / KU in MISO

Month	Generation Costs to Serve Control Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	LGE / KU Control Area Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift
January	$53,798,569	$16,932,325	$0	$0	$1,312,823	$0	$0	$0	$0
February	$48,532,753	$18,499,711	$0	$0	$1,687,341	$0	$0	$0	$0
March	$48,733,019	$20,357,664	$0	$0	$427,055	$0	$0	$0	$0
April	$48,567,375	$13,496,794	$22,778	-$22,356	$1,431,517	$0	$0	$0	$0
May	$52,465,563	$13,463,598	$479,356	-$190,237	$2,408,552	$0	$0	$0	$0
June	$58,657,771	$18,580,010	$254,269	-$244,541	$5,432,283	$0	$0	$0	$0
July	$65,571,667	$22,905,768	$0	$0	$7,155,072	$0	$0	$0	$0
August	$64,503,607	$18,443,711	$191,495	-$61,967	$8,674,860	$0	$0	$0	$0
September	$54,569,058	$21,957,102	$27,033	-$27,033	$4,192,781	$0	$0	$0	$0
October	$47,008,337	$21,964,432	$0	$0	$1,305,891	$0	$0	$0	$0
November	$46,889,697	$18,696,538	$0	$0	$2,587,844	$0	$0	$0	$0
December	$50,903,513	$19,295,160	$14,546	-$3,720	$1,575,430	$0	$0	$0	$0
Total	$640,220,928	224,592,812	$989,476	-649,854	$36,191,447	$14,150,839	$0	$342,282	$1,023,266

Month	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Off-System Sales Margin*	Less: Distribution of Schedule 1, 7, & 8 Transmission Revenues on Off-System Sales	Less: FTR Revenues	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	$0	$17,313,139	$380,814	$1,566,329	$853,335	$0	$52,310,916	70,730,894	0
February	$0	$20,351,381	$1,851,670	$1,767,162	$1,096,771	$0	$45,504,491	67,032,464	0
March	$0	$24,416,111	$4,058,447	$2,293,406	$277,586	$0	$42,630,635	69,090,683	0
April	$0	$16,615,314	$3,140,876	$1,720,212	$930,486	$0	$44,230,095	62,064,169	422
May	$0	$13,699,484	$426,123	$961,370	$1,565,559	$0	$52,420,417	65,949,161	289,118
June	$0	$22,224,491	$3,889,023	$1,669,478	$3,530,984	$0	$55,254,839	77,237,781	9,728
July	$0	$31,619,304	$8,713,536	$1,878,787	$4,650,797	$0	$57,483,619	88,477,434	0
August	$0	$24,266,317	$5,884,573	$1,587,807	$4,338,659	$0	$59,558,923	82,947,317	129,528
September	$0	$29,708,407	$7,776,337	$2,203,338	$2,725,308	$0	$46,083,889	76,526,160	0
October	$0	$34,169,272	$12,204,840	$2,710,809	$848,829	$0	$32,549,751	68,972,769	0
November	$0	$21,557,011	$2,860,473	$1,839,248	$1,682,098	$0	$43,095,722	65,586,235	0
December	$0	$20,515,438	$1,223,998	$1,686,052	$1,024,029	$0	$48,559,409	70,198,672	10,826
Total	$2,620,000	$276,453,669	$52,410,711	$21,883,997	$23,524,441	$2,000,000	$595,719,090	$864,813,741	$439,622

* Shown for purposes of comparison to Direct Testimony.

GFA Carve Out Sensitivity - Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO

Month	Generation Costs to Serve Contrtol Area Load	Incremental Generation Costs to Support Off-system Sales	Purchased Power Costs to Serve Control Area Load	Incremental Purchased Power Costs to Support Off-System Sales	A&G and Reliability Coordination Services Costs	Less: Revenue from Off-System Sales Net of Transmission Charges
January	$54,062,746	$10,340,333	$14,142	-$14,142	$0	$9,449,350
February	$48,701,488	$10,897,355	$0	$0	$0	$11,008,283
March	$48,967,965	$14,164,167	$0	$0	$0	$15,497,095
April	$48,720,424	$11,377,246	$84,079	-$84,079	$0	$12,345,790
May	$52,594,750	$7,356,273	$438,791	-$212,003	$0	$8,270,369
June	$58,729,289	$11,687,375	$222,999	-$222,999	$0	$12,792,130
July	$65,889,639	$15,692,804	$0	$0	$0	$20,801,806
August	$65,248,207	$12,208,344	$131,943	-$50,430	$0	$15,347,148
September	$54,814,739	$14,181,680	$7,638	-$7,638	$0	$17,846,448
October	$47,047,008	$15,333,006	$0	$0	$0	$21,911,198
November	$47,015,278	$10,839,519	$0	$0	$0	$10,788,994
December	$51,206,434	$10,274,479	$6,596	-$6,596	$0	$9,470,845
Total	$642,997,968	$144,352,580	$906,187	-$597,886	$1,840,000	$163,529,456

Month	Off-System Sales Margin*	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load	Total Generation Costs	Total Purchased Power Costs
January	-$876,841	$1,566,329	$53,387,399	$64,403,078	$0
February	$110,928	$1,767,162	$46,823,398	$59,598,843	$0
March	$1,332,928	$2,293,406	$45,341,632	$63,132,132	$0
April	$1,052,623	$1,720,212	$46,031,668	$60,097,670	$0
May	-$873,901	$961,370	$52,946,072	$59,951,023	$226,788
June	$1,327,754	$1,669,478	$55,955,067	$70,416,665	$0
July	$5,109,002	$1,878,787	$58,901,850	$81,582,443	$0
August	$3,189,234	$1,587,807	$60,603,109	$77,456,551	$81,512
September	$3,672,407	$2,203,338	$48,946,632	$68,996,418	$0
October	$6,578,192	$2,710,809	$37,758,007	$62,380,014	$0
November	-$50,525	$1,839,248	$45,226,556	$57,854,798	$0
December	-$797,038	$1,686,052	$50,324,016	$61,480,913	$0
Total	$19,774,762	$21,883,997	$604,085,396	$787,350,648	$308,301

Exhibit RRM -
Table 9
High Fuel Cost Sensitivity Analysis - Cost to Serve Control Area Load

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO Day 1 Operations

Month	Generation Costs	Purchased Power Costs	Schedule 10 Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Net Cost to Serve Control Area Load
January	$72,570,680	$1,254	$0	$10,569,999	$2,991,738	$59,010,198
February	$69,724,167	$0	$0	$15,573,147	$3,113,962	$51,037,058
March	$72,950,940	$848	$0	$19,858,136	$2,353,516	$50,740,136
April	$67,540,298	$9,244	$0	$14,267,482	$1,242,052	$52,040,007
May	$68,337,905	$917,650	$0	$8,498,977	$1,693,369	$59,063,209
June	$80,991,971	$56,722	$0	$16,847,744	$2,025,520	$62,175,428
July	$95,906,002	$914	$0	$28,402,547	$1,675,310	$65,829,060
August	$90,862,019	$450,111	$0	$20,994,619	$1,744,882	$68,572,630
September	$80,623,351	$0	$0	$24,640,021	$1,678,961	$54,304,370
October	$72,537,574	$0	$0	$28,281,723	$2,308,078	$41,947,773
November	$68,227,343	$0	$0	$16,380,412	$2,581,094	$49,265,837
December	$70,761,202	$54,828	$0	$12,654,817	$2,264,265	$55,896,948
Total	$911,033,453	$1,491,571	$7,078,924	$216,969,625	$25,672,746	$676,961,578

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Nominations - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	80,016,660	$0	$1,591,286	$0	$0	$0	$0	$0	$19,473,427	$2,991,738	5,304,519	$0	$53,838,263
February	75,780,081	$0	$2,002,596	$0	$0	$0	$0	$0	$22,916,500	$3,113,962	3,872,748	$0	$47,879,467
March	78,050,690	$8,118	$455,247	$0	$0	$0	$0	$0	$27,242,952	$2,353,516	4,911,285	$0	$44,006,301
April	69,126,411	$43,744	$2,099,950	$0	$0	$0	$0	$0	$17,632,765	$1,242,052	9,876,397	$0	$42,518,890
May	73,482,685	$734,478	$2,705,915	$0	$0	$0	$0	$0	$14,704,309	$1,693,369	11,124,422	$0	$49,400,978
June	86,124,642	$145,855	$6,518,423	$0	$0	$0	$0	$0	$23,705,440	$2,025,520	15,256,610	$0	$51,801,350
July	99,170,909	$427	$8,196,777	$0	$0	$0	$0	$0	$33,718,818	$1,675,310	21,365,032	$0	$50,608,954
August	93,032,519	$490,035	$7,824,797	$0	$0	$0	$0	$0	$25,882,232	$1,744,882	20,131,884	$0	$53,588,352
September	85,527,844	$0	$5,034,257	$0	$0	$0	$0	$0	$32,015,731	$1,678,961	5,449,064	$0	$51,418,345
October	77,969,932	$0	$1,871,299	$0	$0	$0	$0	$0	$38,281,131	$2,308,078	-1,430,495	$0	$40,482,517
November	74,080,694	$0	$3,037,842	$0	$0	$0	$0	$0	$24,326,076	$2,581,094	2,473,639	$0	$47,737,727
December	79,107,051	$26,947	$1,958,899	$0	$0	$0	$0	$0	$22,763,774	$2,264,265	4,422,703	$0	$51,642,155
Total	$971,470,118	$1,449,603	$43,097,287	$14,150,839	$0	$343,471	$1,205,179	$2,620,000	$302,663,155	$25,672,746	$102,757,808	$2,000,000	$601,242,788

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Allocation and Maximum Counterflow Restoration - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	80,016,660	$0	$1,591,286	$0	$0	$0	$0	$0	$19,473,427	$2,991,738	$4,208,925	$0	$54,933,857
February	75,780,081	$0	$2,002,596	$0	$0	$0	$0	$0	$22,916,500	$3,113,962	$2,212,731	$0	$49,539,484
March	78,050,690	$8,118	$455,247	$0	$0	$0	$0	$0	$27,242,952	$2,353,516	$1,884,412	$0	$47,033,174
April	69,126,411	$43,744	$2,099,950	$0	$0	$0	$0	$0	$17,632,765	$1,242,052	$3,214,590	$0	$49,180,697
May	73,482,685	$734,478	$2,705,915	$0	$0	$0	$0	$0	$14,704,309	$1,693,369	$8,853,465	$0	$51,671,935
June	86,124,642	$145,855	$6,518,423	$0	$0	$0	$0	$0	$23,705,440	$2,025,520	$11,461,918	$0	$55,596,042
July	99,170,909	$427	$8,196,777	$0	$0	$0	$0	$0	$33,718,818	$1,675,310	$14,648,560	$0	$57,325,426
August	93,032,519	$490,035	$7,824,797	$0	$0	$0	$0	$0	$25,882,232	$1,744,882	$13,824,024	$0	$59,896,212
September	85,527,844	$0	$5,034,257	$0	$0	$0	$0	$0	$32,015,731	$1,678,961	$3,119,044	$0	$53,748,365
October	77,969,932	$0	$1,671,299	$0	$0	$0	$0	$0	$38,281,131	$2,308,078	-$2,684,310	$0	$41,736,332
November	74,080,694	$0	$3,037,842	$0	$0	$0	$0	$0	$24,326,076	$2,581,094	$966,657	$0	$49,244,709
December	79,107,051	$26,947	$1,958,899	$0	$0	$0	$0	$0	$22,763,774	$2,264,265	$3,878,401	$0	$52,186,457
Total	$971,470,118	$1,449,603	$43,097,287	$14,150,839	$0	$343,471	$1,205,179	$2,620,000	$302,663,155	$25,672,746	$65,588,417	$2,000,000	$638,412,179

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	80,016,660	$0	$1,591,286	$0	$0	$0	$0	$0	$19,473,427	$2,991,738	$1,193,465	$0	$57,949,317
February	75,780,081	$0	$2,002,596	$0	$0	$0	$0	$0	$22,916,500	$3,113,962	$1,501,947	$0	$50,250,268
March	78,050,690	$8,118	$455,247	$0	$0	$0	$0	$0	$27,242,952	$2,353,516	$341,435	$0	$48,576,151
April	69,126,411	$43,744	$2,099,950	$0	$0	$0	$0	$0	$17,632,765	$1,242,052	$1,574,962	$0	$50,820,325
May	73,482,685	$734,478	$2,705,915	$0	$0	$0	$0	$0	$14,704,309	$1,693,369	$2,029,436	$0	$58,495,964
June	86,124,642	$145,855	$6,518,423	$0	$0	$0	$0	$0	$23,705,440	$2,025,520	$4,888,818	$0	$62,169,142
July	99,170,909	$427	$8,196,777	$0	$0	$0	$0	$0	$33,718,818	$1,675,310	$6,147,583	$0	$65,826,403
August	93,032,519	$490,035	$7,824,797	$0	$0	$0	$0	$0	$25,882,232	$1,744,882	$5,668,598	$0	$67,851,638
September	85,527,844	$0	$5,034,257	$0	$0	$0	$0	$0	$32,015,731	$1,678,961	$3,775,692	$0	$53,091,717
October	77,969,932	$0	$1,671,299	$0	$0	$0	$0	$0	$38,281,131	$2,308,078	$1,253,474	$0	$37,798,548
November	74,080,694	$0	$3,037,842	$0	$0	$0	$0	$0	$24,326,076	$2,581,094	$2,278,381	$0	$47,932,985
December	79,107,051	$26,947	$1,958,899	$0	$0	$0	$0	$0	$22,763,774	$2,264,265	$1,469,174	$0	$54,595,684
Total	$971,470,118	$1,449,603	$43,097,287	$14,150,839	$0	$343,471	$1,205,179	$2,620,000	$302,663,155	$25,672,746	$32,322,965	$2,000,000	$671,677,631

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value and Excluding Transmission Revenue Benefits - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	80,016,660	$0	$1,591,286	$0	$0	$0	$0	$0	$19,473,427	$1,410,130	$1,193,465	$0	$59,530,924
February	75,780,081	$0	$2,002,596	$0	$0	$0	$0	$0	$22,916,500	$1,619,972	$1,501,947	$0	$51,744,258
March	78,050,690	$8,118	$455,247	$0	$0	$0	$0	$0	$27,242,952	$2,126,912	$341,435	$0	$48,802,756
April	69,126,411	$43,744	$2,099,950	$0	$0	$0	$0	$0	$17,632,765	$1,419,677	$1,574,962	$0	$50,642,700
May	73,482,685	$734,478	$2,705,915	$0	$0	$0	$0	$0	$14,704,309	$814,005	$2,029,436	$0	$59,375,328
June	86,124,642	$145,855	$6,518,423	$0	$0	$0	$0	$0	$23,705,440	$1,448,104	$4,888,818	$0	$62,746,559
July	99,170,909	$427	$8,196,777	$0	$0	$0	$0	$0	$33,718,818	$1,670,453	$6,147,583	$0	$65,831,259
August	93,032,519	$490,035	$7,824,797	$0	$0	$0	$0	$0	$25,882,232	$1,404,926	$5,668,598	$0	$68,191,594
September	85,527,844	$0	$5,034,257	$0	$0	$0	$0	$0	$32,015,731	$2,013,096	$3,775,692	$0	$52,757,581
October	77,969,932	$0	$1,671,299	$0	$0	$0	$0	$0	$38,281,131	$2,505,391	$1,253,474	$0	$37,601,235
November	74,080,694	$0	$3,037,842	$0	$0	$0	$0	$0	$24,326,076	$1,689,857	$2,278,381	$0	$48,824,222
December	79,107,051	$26,947	$1,958,899	$0	$0	$0	$0	$0	$22,763,774	$1,537,235	$1,469,174	$0	$55,322,713
Total	$971,470,118	$1,449,603	$43,097,287	$14,150,839	$0	$343,471	$1,205,179	$2,620,000	$302,663,155	$19,659,758	$32,322,965	$2,000,000	$677,690,619

High Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO

Month	Total Generation Costs	Purchased Power Costs	A&G and Reliability Coordination Services Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load
January	$73,968,035	$2,580	$0	$12,048,786	$1,410,130	$60,511,698
February	$68,342,745	$0	$0	$13,774,927	$1,619,972	$52,947,846
March	$72,355,619	$0	$0	$18,692,711	$2,126,912	$51,535,996
April	$67,526,610	$489	$0	$13,824,184	$1,419,677	$52,283,238
May	$67,937,064	$772,113	$0	$7,986,004	$814,005	$59,909,168
June	$79,650,945	$206,411	$0	$14,772,309	$1,448,104	$63,636,943
July	$92,527,604	$0	$0	$23,190,965	$1,670,453	$67,666,186
August	$88,108,069	$430,658	$0	$17,688,797	$1,404,926	$69,445,004
September	$78,288,490	$0	$0	$20,749,293	$2,013,096	$55,526,100
October	$71,165,284	$0	$0	$26,081,146	$2,505,391	$42,578,748
November	$66,042,969	$0	$0	$13,483,633	$1,689,657	$50,889,479
December	$70,559,575	$52,914	$0	$12,201,598	$1,537,235	$56,873,656
Total	$896,473,007	$1,465,165	$1,840,000	$194,474,353	$19,659,758	$685,644,062

Exhibit RRM -
Table 10
Low Fuel Cost Sensitivity Analysis - Cost to Serve Control Area Load

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO Day 1 Operations

Month	Generation Costs	Purchased Power Costs	Schedule 10 Costs	Less: Off-System Sales Revenue	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Net Cost to Serve Control Area Load
January	$55,207,025	$454	$0	$7,134,112	$2,991,738	$45,081,629
February	$53,435,115	$0	$0	$10,788,760	$3,113,962	$39,532,393
March	$55,744,584	$35	$0	$14,143,779	$2,353,516	$39,247,324
April	$53,231,102	$0	$0	$10,930,868	$1,242,052	$41,058,182
May	$53,835,649	$430,714	$0	$6,224,734	$1,693,369	$46,348,260
June	$63,295,434	$20,654	$0	$12,080,317	$2,025,520	$49,210,251
July	$74,208,308	$0	$0	$20,634,144	$1,675,310	$51,898,854
August	$70,771,911	$64,572	$0	$15,633,875	$1,744,882	$53,457,727
September	$62,396,891	$0	$0	$17,326,961	$1,678,961	$43,390,969
October	$54,904,128	$0	$0	$18,788,065	$2,308,078	$33,807,985
November	$51,745,230	$0	$0	$10,574,050	$2,581,094	$38,590,086
December	$53,846,955	$18,430	$0	$8,215,685	$2,264,265	$43,385,436
Total	**$702,622,331**	**$534,860**	**$7,078,924**	**$152,475,351**	**$25,672,746**	**$532,088,018**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Nominations - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Power Sales Outside LG&E	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0	$1,116,004	$0	$0	$0	$0	$0	$14,657,021	$2,991,738	3,421,936	$0	$41,606,555
February	58,507,744	$0	$1,370,051	$0	$0	$0	$0	$0	$17,278,761	$3,113,962	2,566,584	$0	$36,916,468
March	59,858,269	$4,875	$280,571	$0	$0	$0	$0	$0	$20,247,121	$2,353,516	3,262,375	$0	$34,280,703
April	54,826,921	$0	$1,428,315	$0	$0	$0	$0	$0	$13,889,023	$1,242,052	7,340,340	$0	$33,783,820
May	58,173,119	$395,695	$1,957,467	$0	$0	$0	$0	$0	$11,547,246	$1,693,369	6,147,681	$0	$41,137,985
June	67,893,661	$50,241	$4,546,405	$0	$0	$0	$0	$0	$18,413,968	$2,025,520	9,833,993	$0	$42,216,826
July	77,497,130	$0	$5,487,951	$0	$0	$0	$0	$0	$25,782,731	$1,675,310	15,012,017	$0	$40,515,023
August	73,164,400	$216,737	$5,801,595	$0	$0	$0	$0	$0	$20,030,929	$1,744,882	13,232,837	$0	$44,174,084
September	67,261,501	$0	$3,485,011	$0	$0	$0	$0	$0	$24,534,050	$1,678,961	3,499,291	$0	$41,034,210
October	59,942,366	$0	$944,231	$0	$0	$0	$0	$0	$27,981,010	$2,308,078	-973,775	$0	$31,571,285
November	56,993,945	$0	$2,155,310	$0	$0	$0	$0	$0	$17,624,589	$2,581,094	2,005,687	$0	$36,937,885
December	61,014,894	$24,005	$1,439,358	$0	$0	$0	$0	$0	$17,048,305	$2,264,265	3,091,821	$0	$40,073,867
Total	**$756,695,195**	**$691,553**	**$30,012,269**	**$14,150,839**	**$0**	**$359,473**	**$846,737**	**$2,620,000**	**$229,034,754**	**$25,672,746**	**$68,440,787**	**$2,000,000**	**$480,227,779**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Illustrative FTR Allocation and Maximum Counterflow Restoration - LG&E / KU in MISO

Month	*Total Generation* Costs	*Purchased* Power Costs	*LG&E Congestion* Costs	*Schedule 10, 16 &* 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Power Sales Outside LG&E	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0	$1,116,004	$0	$0	$0	$0	$0	$14,657,021	$2,991,738	$2,799,081	$0	$42,229,410
February	58,507,744	$0	$1,370,051	$0	$0	$0	$0	$0	$17,278,761	$3,113,962	$1,408,673	$0	$38,076,399
March	59,858,269	$4,875	$280,571	$0	$0	$0	$0	$0	$20,247,121	$2,353,516	$1,194,977	$0	$36,348,101
April	54,826,921	$0	$1,428,315	$0	$0	$0	$0	$0	$13,889,023	$1,242,052	$2,826,964	$0	$38,297,196
May	58,173,119	$395,695	$1,957,467	$0	$0	$0	$0	$0	$11,547,246	$1,693,369	$4,896,745	$0	$42,388,921
June	67,893,661	$50,241	$4,546,405	$0	$0	$0	$0	$0	$18,413,968	$2,025,520	$7,655,246	$0	$44,395,573
July	77,497,130	$0	$5,487,951	$0	$0	$0	$0	$0	$25,782,731	$1,675,310	$10,527,569	$0	$44,999,471
August	73,164,400	$216,737	$5,801,595	$0	$0	$0	$0	$0	$20,030,929	$1,744,882	$9,228,281	$0	$48,178,640
September	67,261,501	$0	$3,485,011	$0	$0	$0	$0	$0	$24,534,050	$1,678,961	$2,172,928	$0	$42,360,573
October	59,942,366	$0	$944,231	$0	$0	$0	$0	$0	$27,981,010	$2,308,078	-$1,800,604	$0	$32,398,114
November	56,993,945	$0	$2,155,310	$0	$0	$0	$0	$0	$17,624,589	$2,581,094	$760,210	$0	$38,183,362
December	61,014,894	$24,005	$1 439,358	$0	$0	$0	$0	$0	$17,048,305	$2,264,265	$2,738,159	$0	$40,427,529
Total	**$756,695,195**	**$691,553**	**$30,012,269**	**$14,150,839**	**$0**	**$359,473**	**$846,737**	**$2,620,000**	**$229,034,754**	**$25,672,746**	**$44,408,229**	**$2,000,000**	**$504,260,337**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Power Sales Outside LG&E	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561.246	$0	$1,116,004	$0	$0	$0	$0	$0	$14,657,021	$2,991,738	$837,003	$0	$44,191,488
February	58,507,744	$0	$1,370,051	$0	$0	$0	$0	$0	$17,278,761	$3,113,962	$1,027,538	$0	$38,457,534
March	59,858,269	$4,875	$280,571	$0	$0	$0	$0	$0	$20,247,121	$2,353,516	$210,428	$0	$37,332,650
April	54,826,921	$0	$1.428,315	$0	$0	$0	$0	$0	$13.889,023	$1,242,052	$1,071,236	$0	$40,052,924
May	58,173,119	$395,695	$1,957,467	$0	$0	$0	$0	$0	$11.547,246	$1,693,369	$1,468,101	$0	$45,817,565
June	67,893.661	$50,241	$4,546,405	$0	$0	$0	$0	$0	$18.413,968	$2,025,520	$3,409,804	$0	$48,641,015
July	77.497,130	$0	$5,487,951	$0	$0	$0	$0	$0	$25,782,731	$1,675,310	$4,115,963	$0	$51,411,077
August	73,164.400	$216,737	$5,801.595	$0	$0	$0	$0	$0	$20,030,929	$1,744,882	$4,351,196	$0	$53,055,725
September	67,261,501	$0	$3,485,011	$0	$0	$0	$0	$0	$24,534,050	$1,678,961	$2,613,758	$0	$41,919,743
October	59,942,366	$0	$944.231	$0	$0	$0	$0	$0	$27,981.010	$2,308,078	$708,173	$0	$29,889,337
November	56,993.945	$0	$2,155,310	$0	$0	$0	$0	$0	$17,624,589	$2,581,094	$1,616,483	$0	$37,327,089
December	61,014,894	$24,005	$1,439,358	$0	$0	$0	$0	$0	$17,048,305	$2,264,265	$1,079,519	$0	$42,086,169
Total	**$756,695,195**	**$691,553**	**$30,012,269**	**$14,150,839**	**$0**	**$359,473**	**$846,737**	**$2,620,000**	**$229,034,754**	**$25,672,746**	**$22,509,202**	**$2,000,000**	**$526,159,364**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load under MISO EMT with Very Low FTR Allocation Value and Excluding Transmission Revenue Benefits - LG&E / KU in MISO

Month	Total Generation Costs	Purchased Power Costs	LG&E Congestion Costs	Schedule 10, 16 & 17 Costs	Schedule 21 Costs	Option B GFA Uplift	Narrow Constrained Area Uplift	A & G Costs Associated with RTO Membership	Less: Revenue from Power Sales Outside LG&E	Less: MISO Distribution of Schedule 1, 7, & 8 Transmission Revenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61.561,246	$0	$1,116,004	$0	$0	$0	$0	$0	$14,657,021	$1,413,901	$837,003	$0	$45,769,325
February	58,507,744	$0	$1,370,051	$0	$0	$0	$0	$0	$17,278,761	$1,585,566	$1,027,538	$0	$39,985,929
March	59,858,269	$4,875	$280,571	$0	$0	$0	$0	$0	$20,247,121	$2,131,441	$210,428	$0	$37,554,725
April	54,826,921	$0	$1,428,315	$0	$0	$0	$0	$0	$13,889,023	$1,538,495	$1,071,236	$0	$39,756,482
May	58,173,119	$395,695	$1,957,467	$0	$0	$0	$0	$0	$11,547,246	$851,811	$1,468,101	$0	$46,659,123
June	67,893,661	$50,241	$4,546,405	$0	$0	$0	$0	$0	$18,413,968	$1.504,602	$3,409,804	$0	$49,161,934
July	77.497,130	$0	$5,487,951	$0	$0	$0	$0	$0	$25,782,731	$1,625,988	$4.115,963	$0	$51,460,398
August	73,164,400	$216,737	$5,801,595	$0	$0	$0	$0	$0	$20,030,929	$1,412,113	$4,351,196	$0	$53,388,494
September	67,261,501	$0	$3,485,011	$0	$0	$0	$0	$0	$24,534,050	$1,998,651	$2,613,758	$0	$41,600,052
October	59,942,366	$0	$944,231	$0	$0	$0	$0	$0	$27,981,010	$2,429,502	$708,173	$0	$29,767,912
November	56,993,945	$0	$2,155,310	$0	$0	$0	$0	$0	$17,624,589	$1,558,567	$1,616,483	$0	$38,349,616
December	61,014,894	$24,005	$1,439,358	$0	$0	$0	$0	$0	$17,048,305	$1,453,857	$1,079,519	$0	$42,896,577
Total	**$756,695,195**	**$691,553**	**$30,012,269**	**$14,150,839**	**$0**	**$359,473**	**$846,737**	**$2,620,000**	**$229,034,754**	**$19,504,494**	**$22,509,202**	**$2,000,000**	**$532,327,616**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO

Month	Total Generation Costs	Purchased Power Costs	A&G and Reliability Coordination Services Costs	Less: Revenue from Power Sales Outside LG&E	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load
January	$56,577.225	$0	$0	$8,493.366	$1,413,901	$46,669,957
February	$52,432,305	$0	$0	$9,449,802	$1,585,566	$41,396,937
March	$55,531,541	$0	$0	$13,386,986	$2,131,441	$40,013,114
April	$52,991,787	$0	$0	$10,365,621	$1,538,495	$41,087,672
May	$53,577,328	$322,737	$0	$5,874,139	$851,811	$47,174,115
June	$62,484.264	$35,020	$0	$10,688,242	$1,504,602	$50,326,440
July	$71,278,889	$0	$0	$16,093,055	$1,625,988	$53,559,846
August	$68,356,698	$51,095	$0	$12,374,670	$1,412,113	$54,621,009
September	$60,620,472	$0	$0	$14,148,787	$1,998,651	$44,473,034
October	$54,144,328	$0	$0	$17,218,748	$2,429,502	$34,496,077
November	$50,394,467	$0	$0	$8,587,991	$1,558,567	$40,247,909
December	$53,889,303	$8,627	$0	$8,198,490	$1,453,857	$44,245,583
Total	**$692,278,606**	**$417,479**	**$1,840,000**	**$134,879,898**	**$19,504,494**	**$540,151,693**

Exhibit RRM -
Table 11
Sensitivity for Benchmarked LG&E Hurdle Rate - Results for Annual Net Cost to Serve Control Area Load

Cost to Serve LG&E / KU Control Area Load with LG&E / KU Outside MISO
LG&E / KU Hurdle Rate Increased by $6 / MWH to More Closely Match Modeled LG&E Out of MISO Sales to Historical Levels

Month	Total Generation Costs	Purchased Power Costs	A&G and Reliability Coordination Services Costs	Less: Revenue from Off-System Sales Net of Transmission Charges	Less: Transmission Revenue from Off-System Sales	Net Cost to Serve Control Area Load
January	$56,910,142	$0	$0	$1,107,950	$177,889	**$55,624,303**
February	$53,285,768	$0	$0	$3,474,178	$550,218	**$49,261,372**
March	$56,537,739	$691	$0	$7,101,758	$1,058,700	**$48,377,972**
April	$56,084,210	$0	$0	$6,430,315	$866,148	**$48,787,748**
May	$55,831,559	$518,813	$0	$1,491,127	$218,411	**$54,640,834**
June	$66,208,984	$59,211	$0	$6,484,233	$844,667	**$58,939,295**
July	$76,751,162	$0	$0	$12,668,194	$1,051,989	**$63,030,979**
August	$73,843,433	$535,409	$0	$8,889,453	$845,567	**$64,643,822**
September	$65,246,553	$0	$0	$10,885,934	$1,433,979	**$52,926,640**
October	$59,301,195	$0	$0	$14,866,855	$2,024,560	**$42,409,781**
November	$52,332,027	$0	$0	$4,024,174	$707,292	**$47,600,560**
December	$54,605,512	$10,506	$0	$1,839,255	$322,864	**$52,453,900**
Total	**$726,938,285**	**$1,124,630**	**$1,840,000**	**$79,263,426**	**$10,102,284**	**$640,537,205**

Dispatch, LMP's, FTR's and Settlement

September 22, 2003

Ron McNamara

Section 1: The Basics

The purpose of this section is to introduce and reinforce basic concepts that are fundamental to electricity market design.

MISO

Physics

- Two important Laws:
  - Ohm's Law:
    - *The current (i.e. amps) through a conductor, under constant conditions, is proportional to the difference of potential (i.e. the voltage) across the conductor, and*
  - Kirchoff's 2nd Law:
    - *In any closed circuit, the algebraic sum of the products of the current and the resistance of each part of the circuit is equal to the resultant electro magnetic force in the circuit.*
- Why are these important?
  - Because you can't fool Mother Nature. Power flows according to the laws of physics and not by commercial desire, government decree, or market design!

MISO

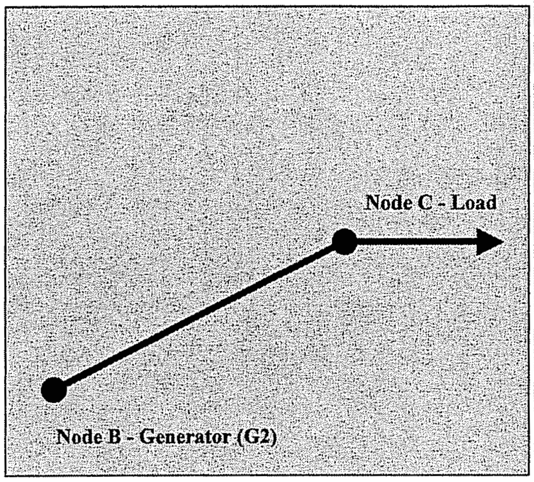
Economics

- Electricity has several important economic characteristics
  - Difficulty/impossibility of storing electricity.
    - Within tight bounds, supply and demand must always be equal.
  - Network production
    - Can't establish/define property rights on an interconnected grid.
    - Can't separate the commodity (electricity) from delivery (dispatch).
  - Network externalities
    - Decisions about reliability cannot be totally separated from "energy."
- Why are these important?
  - Failure to recognize/incorporate these characteristics into the market design leads to market inefficiencies and/or collapse.

MISO

Illustrating the basics – Step 1

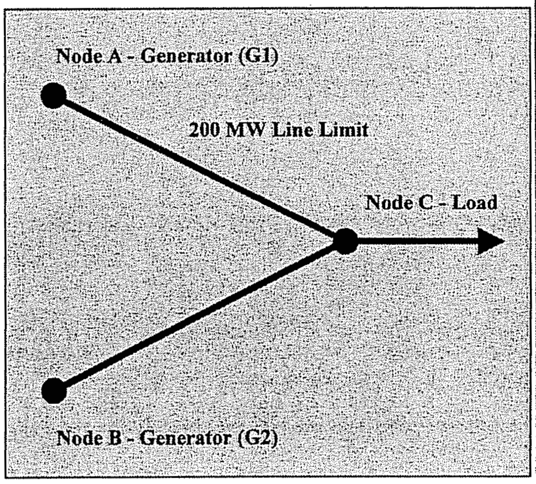
- Start with the simplest model:
  - 2 nodes (B and C)
  - 1 transmission line (BC).
  - 1 generator (G2)
  - 1 load
- Not very representative but:
  - No such thing as "redispatch"
    - Nothing to redispatch!
    - Great deal of risk!



MISO

Illustrating the basics – Step 2

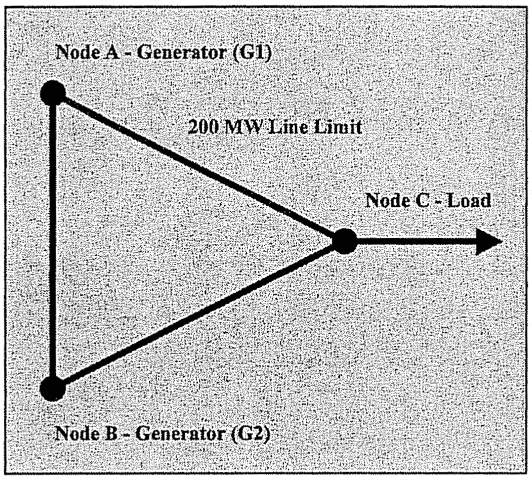
- Make the model a little more complicated:
  - 3 nodes.
  - 2 transmission lines with equal impedance and of equal length.
  - 1 thermally constrained transmission line (line AC)
    - Line AC is constrained to no more than 200 MW.
    - Lines BC has unlimited MW capacity.
  - 2 generators (G1 and G2)
  - 1 load



MISO

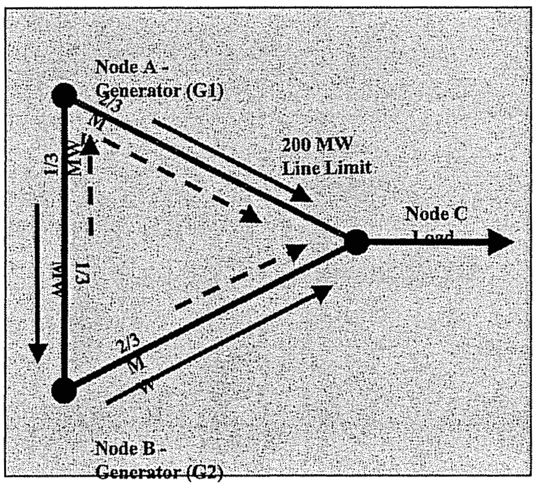
Illustrating the basics – Step 3

- Add "loop" flow:
  - 3 interconnected nodes.
  - 3 transmission lines with equal impedance and of equal length.
  - 1 thermally constrained transmission line (line AC)
    - Line AC is constrained to no more than 200 MW.
    - Lines AB and BC have unlimited MW capacity.
  - 2 generators (G1 and G2)
  - 1 load



Illustrating the basics – the physics

- Based on physics:
  - If G1 injects 1 MW (at Node A) - 2/3 MW flows along AC and 1/3 MW flows along AB and then BC.
  - Likewise, if G2 injects 1 MW (at Node B) – 2/3 MW flows along BC and 1/3 MW flows along BA and then AC.
  - **WHY?**
    - Given our assumptions:
    - For G1 the flow on AC (2/3 MW) must equal the algebraic sum of the flow on the other lines, i.e. AB and BC (1/3 + 1/3).



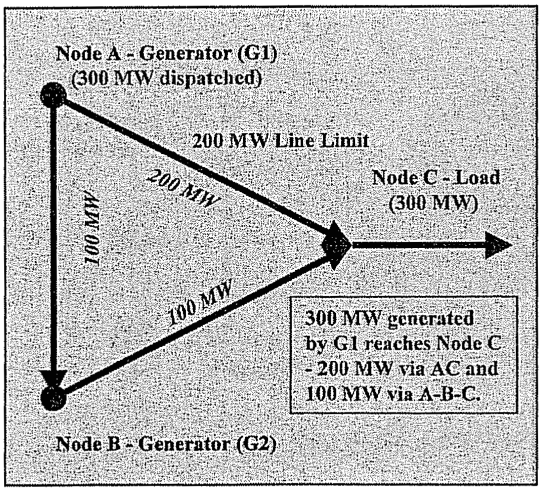
Illustrating the basics – defining capacity

- Defining the capacity of a transmission system is problematic.
  - Not like natural gas!
- Orders 888/889 are underpinned by the belief that transmission capacity can be defined in advance.
  - Total Transfer Capability (TTC), Available Transfer Capability (ATC)
- Leads to the (complicated) physically based scheduling and reservation process we have today. Also resulted in the creation of certain transmission services (i.e. point-to-point, etc).

MISO

If load is 300MW...

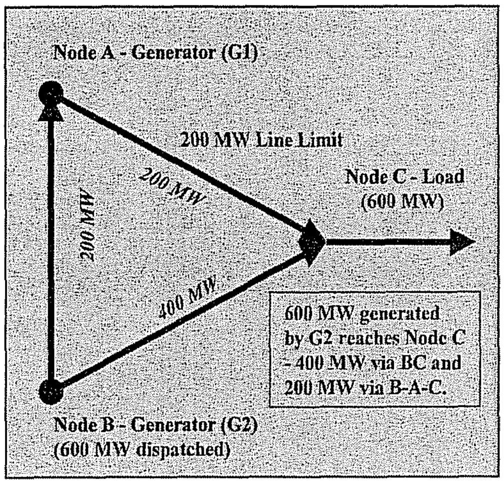
- *IF*, load at Node C is 300 MW
  - Then it is possible for G1 to meet all the load
    - Depends on offer curves.
  - But…if G1 does produce 300MW then G2 cannot produce anything.
- *IF*, G1 produces 300MW then the Total Transfer Capability (TTC) is 300MW
  - Neither G1 or G2 can produce more output without violating line limits.



MISO

But if load is 600MW...

- *IF*, load at Node C is 600 MW
  - Then it is possible for G2 to meet all the load
  - Assuming G2 does produce 600MW then G1 cannot produce anything.
- *IF*, G2 produces 600MW then the TTC is 600MW
  - Neither G1 or G2 can produce more output.



Miso

Conclusion – transmission capacity fact or fiction?

- The two previous examples illustrate the difficulty in defining physical property rights on an interconnected electricity grid.
  - Neither generator can have physical capacity rights over line AC without knowledge of what the other is doing - and what load is. The combined generation from A and B cannot have physical capacity rights to meet load at C (and beyond) because, depending on the dispatch pattern, the transfer limit is anywhere between 300 MW and 600MW.
  - In the world of Orders 888/889 we tried to get around these two issues by defining and selling transmission capacity beforehand.
- ***In essence, create and sell hypothetical capacity based on expected outcomes. BUT, what happens when expected and actual outcomes deviate?***
  - ***Defining capacity is useful for transmission system plan... real time operations!***

Miso

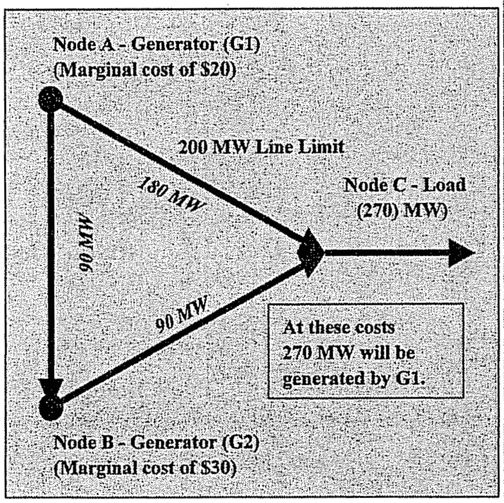
Illustrating the basics – separating "energy" from reliability

- Energy is…just…energy…regardless of whether it keeps the lights on, provides regulation, alleviates a constraint etc…
- …or whether it is scheduled energy or imbalance energy…
- …or whether it is bilateral energy or spot energy.
- …or whether it is "grandfather" energy or OATT energy.
- The primary job of real time operations is to coordinate instantaneous power flows – *in performing this task, operators do not distinguish between different categories of energy.*
- However, historical utility practice (and even Order 888) codifies the myth that energy can be differentiated
  - ***"Don't run an energy market"***

MISO

Illustrating the basics - separating energy from reliability

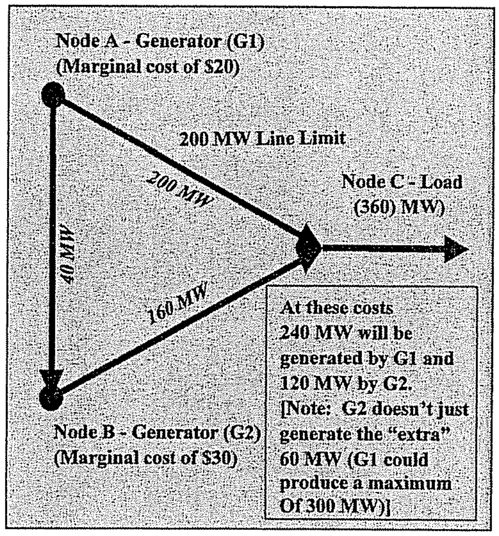
- Congestion is a type of transmission constraint and is a reliability issue.
- **Redispatch example**:
  - If load at C is 270MW and the marginal costs are $20 and $30 for G1 and G2 respectively, then the entire load should be served by G1.

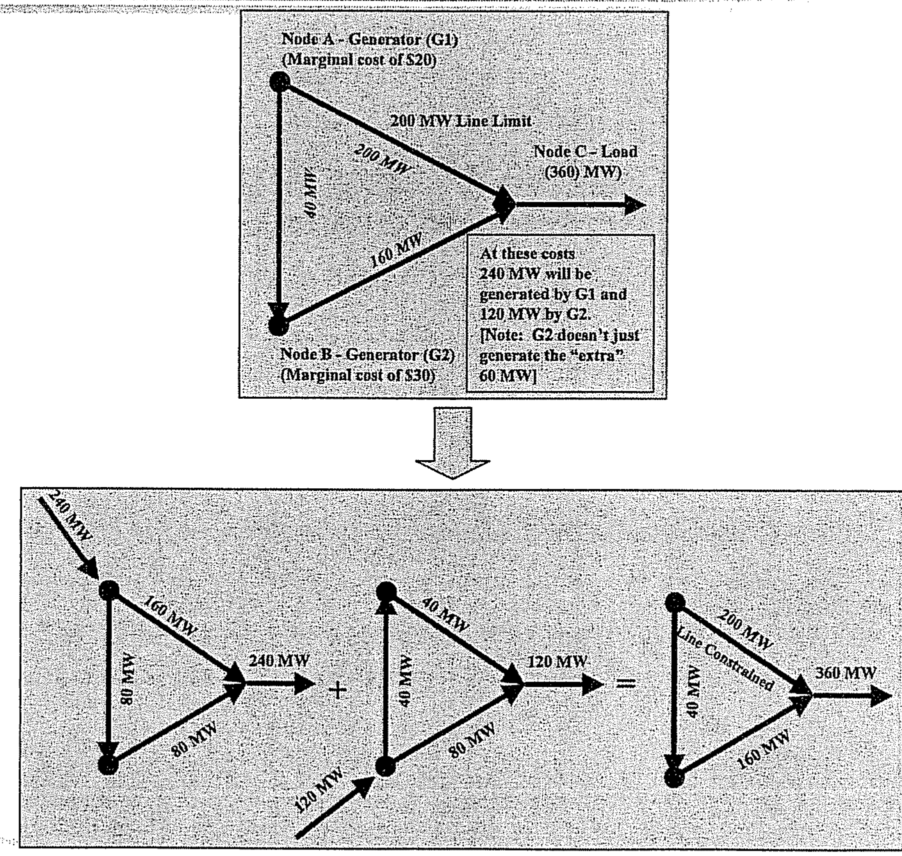


MISO

Redispatch Example

- Suppose that load is 360 rather than 270 then:
  - Efficient (i.e. least cost) dispatch would require G1 to produce 240MW and G2 to produce 120MW.
  - What physically happens is shown on the next slide.





Conclusion - separating energy from reliability is a myth

- In real time all electrical energy is indistinguishable…there is no difference between energy used to solve a congestion constraint (or any other transmission constraint) from that used to light a bulb.
  - Differentiation comes from accounting (i.e settlements) and not from physical operation.
- All the energy in a network is a single integrated physical pool and it must be managed accordingly.
  - Important for market design!

Miso

Section 1 – Concluding Remarks

- Current operations are based on:
  - Defining transmission capacity for purposes of daily operations/commercial transactions (as opposed to transmission planning). Deviations between actual and expected are handled through the "Transmission Loading Relief" (TLR) process – which is a physical and not financial rationing mechanism, i.e a transaction is "cut" or not allowed to take place.
    - Dispatch is not as efficient as it could be.
  - Redispatch takes place largely outside of the "market".
    - Creates uncertainty about price. Increases financial risk.
  - Artificial distinction maintained between reliability and energy.
    - "Liberal" use of Network Service.

Miso

Section 2: Real Time

Real time refers to the activities focused on coordinating instantaneous power flows. The purpose of this section is to explain how this will be accomplished.

Miso

How big is the "gorilla"?

- The nature of dispatch on a physically interconnected grid means that there will always be a "gorilla" in the middle of the market.
  - ***There can only be a single air traffic controller at an airport!***
- The question is not so much how to get rid of it, but rather how to:
  - Minimize the size and scope, and
  - Make it transparent, auditable, and replicable
    - Needed for integrity of the process which is important under open access.

Miso

LMP minimizes the gorilla

- Under an LMP regime, the dispatcher uses the same "tools" to match supply and demand that are used to establish prices.
- Thus there is a match between dispatch and prices or, put another way the market price provides a good indicator of what happened in the physical system.
  - ***The economics and the physics are aligned!***
- This minimizes the need for the ISO to manage the difference between what people thought would happen and what actually did happen.
  - In the first year of ERCOT's operation, AEP with approximately 12% of the generation, had over 600,000 "OOM" (out of merit) calls. "OOM" events are one way to measure the disconnect between the market rules and operation of the system.

MISO

What is LMP?

- A "tool" for coordinating power flows.
  - Relies on price signals to "direct" generator output.
- In its simplest form nodal pricing:
  - Is the "cost" of electricity at the generator bus and the cost of moving the electricity from the generator to the consumer.
- Nodal pricing is based on the notion that *place* and *time* are important characteristics of electricity.
  - In essence, energy delivered to a different place and/or at a different time is a different good and should be priced accordingly in order to achieve economic efficiency.
- Recognizes the effects of joint production of energy for delivery and energy for consumption.
- ***NOT NEW. Utilities have been doing economic dispatch for years!***

MISO

Definition: Locational marginal price (LMP)

- The marginal cost of supplying the next increment of electric demand at a specific location (node) on the electric power network, taking into account both generation marginal cost and the physical aspects of the transmission system.

Miso

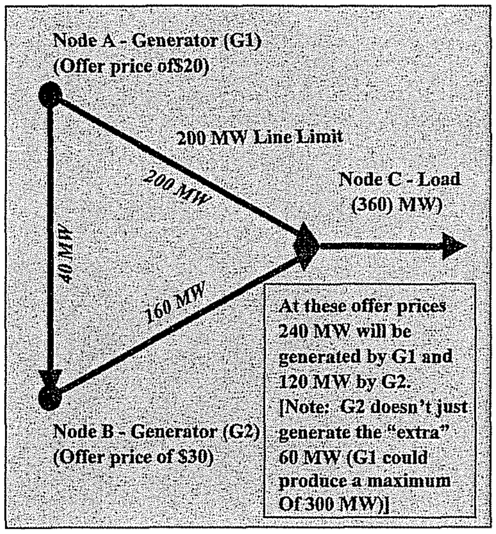
Overview of real time market design

- LMP is an approach to running a real-time energy market and pricing system that overcomes the limitations inherent in physical rights systems (i.e. TLR based systems)
- There are three primary elements of an LMP system:
  - Uses security constrained economic **(re)dispatch** based on market participant offers.
  - Calculates market **prices** (LMPs) from this dispatch and uses them for energy market **settlements**.
  - Provides redispatch and balancing market services to anyone willing to pay the energy market/redispatch prices.

Miso

Example of Dispatch and LMP Price Calculation

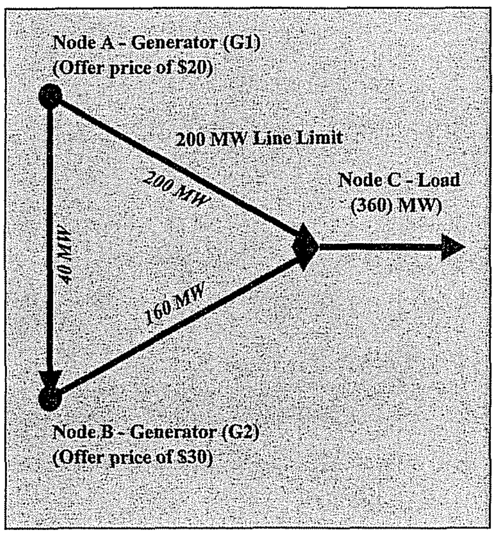
- As we saw:
  - If load is 270 and the "offers" from G1 and G2 were $20 and $30 respectively, then the efficient (and feasible) dispatch would all be from G1 (this is the unconstrained case).
  - But if load is 360 MW then efficient dispatch is 240 MW from G1 and 120 MW from G2 (this is the constrained case).



MISO

Price Derivation - Nodes A and B

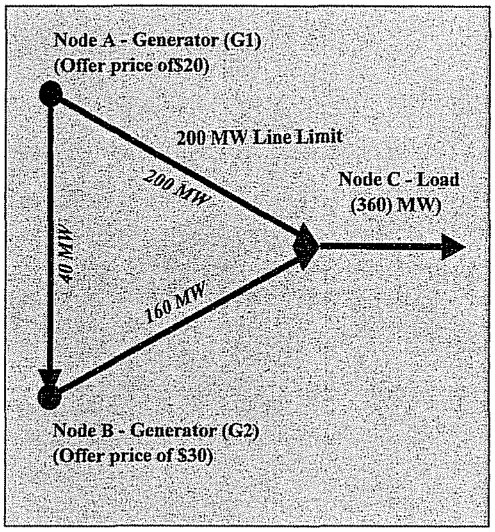
- The LMP is the lowest (re)dispatch cost (based on bids from generators) of supplying energy to the next increment of load at a specific location on the transmission grid, while observing all security limits.
- **The LMP at A is $20/MWh.** An increment of load at A can be met at lowest bid cost by dispatching the generator at A at a price of $20.
- **The LMP at B is $30/MWh.** An increment of load at B can be met at lowest bid cost by dispatching the generator at B at a price of $30. Incremental generation at A cannot serve load at B, because part of it would flow on the line from A to C, violating the limit on this line.



MISO

Price Derivation - Node C

- **The LMP at C is $40/MWh.**
- The $40 LMP at location C occurs because the least-cost (re)dispatch to meet an increment of load there, while meeting the thermal limit, is to increase generation by 2 MW at node B and to decrease it by 1 MW at node A
- (2MW *$30 – 1MW * $20 = $40).



Miso

Price derivation summary

- Based on actual flow of energy
- Based on the actual system operating conditions.
  - *Prices mirror exactly what happened in dispatch.*
- When the transmission system is unconstrained, LMPs are equal at all locations
  - *If losses are included then LMPs will vary even if system is unconstrained.*
- Under constrained conditions, LMPs vary by location

Miso

Section 3: Settlements

The purpose of this section is to explain how real time dispatch is linked to settlement.

MISO

Settlements

- Under an LMP system:
  - Generators are paid the LMP at their transmission bus for balancing energy.
  - LSEs pay the LMP at their location (node or zone) for schedule imbalances.
  - Transmission users pay transmission congestion charges. The transmission congestion charge is the difference between the LMP at the withdrawal location for the transaction less the LMP at the injection location. This is the lowest cost redispatch (based on bids) that reliably accommodates the transaction, on margin.
  - **LMPw - LMPi = Congestion Charge**

MISO

Settlement prices consistent with reliability

- A key characteristic of LMP is that the prices used for balancing market settlements fully reflect the impact of congestion on:
  - The value of incremental generation at different locations.
  - The bid-based cost of serving incremental load at different locations.
  - The bid-based cost of the redispatch required to reliably accommodate an incremental transaction between two locations.
- **Using LMP for balancing market settlements provides incentives for market participants to make voluntary decisions that are consistent with maintaining reliability.**
  - Thus, LMP is a way to use market prices, rather than administrative restrictions and balancing penalties, to manage transmission congestion and maintain reliability.

MISO

Generation settlement - simple case

- Under an LMP system:
  - Generators are paid the LMP at their transmission bus for balancing energy.
    - Thus the generator at A (G1) will get paid - ***from the pool:***
      - $20 * 240 MW = $4,800
    - The generator at B (G2) will get paid - ***from the pool:***
      - $30 * 120 MW = $3,600
    - Total dollars paid ***from the pool*** to generators = $8,400

MISO

Load settlement - simple case

- Under an LMP system:
  - LSEs pay the LMP at their location (node or zone).
    - Total dollars paid ***to the pool*** by load, $40 * 360 = $14,400.
- Whenever there is a transmission constraint (or if losses are included in the price determination), the RTO will over collect.
  - In this example, generators received $8,400 and load paid $14,400…$6,000
  - ***What happens to this money? We will come back to this…***

MISO

Settlement with a bilateral contract

- Suppose that G1 and the load at C had a bilateral contract for 200MW at $30/MW – how would that settle?
  - The 200MW would not transact at LMP. Whoever submits the "schedule" pays the congestion costs.
  - Payments to generators would be:
    - G1: $20 * 40 MW = $800
    - G2: $30 * 120 MW = $3,600
    - Total = $4,400
  - Payments from load would be:
    - Load at C: $40 * 160 MW = $6,400
    - Schedule A-C: $20 * 200 MW = $4,000
    - Total = $10,400
  - Excess collection = $6,000 ***exactly the same as before!***
- As the market matures, these contracts will take the form of a "CfD' or Contract for Difference rather than "physical" bilaterals.

MISO

An aside…

- If we assume for the moment constant marginal costs = to the offer bid and both generators have the same owner:
  - Then the total variable cost of producing the 360MW is:
    - (\$20 * 240) + (\$30 * 120) = \$8,400
    - Average cost = \$23.33 MW
  - Notice that having the load "pay" \$23.33 MW rather than \$40 MW doesn't really solve anything.
    - The generator has to redistribute the revenue internally. To cover the costs.
    - ***We still have to discuss what to do with the excess revenue collected under LMP.***
  - BUT most importantly that price does not cover the costs of G1 and it undervalues the effect of congestion.

MISO

Section 4: "FTR's"

What to do with the extra revenue!

MISO

Settlement and FTRs

- Remember the RTO "overcollects" from the load compared to what they pay to the generators. The RTO must return this money and does so by issuing financial transmission rights (FTRs) to parties.
- An FTR is a financial instrument.
  - The instrument has three components that make up its value.
    - Volume - defined as MW.
    - Price - defined as the price difference between points A & B.
    - Term - defined in months or years.
- The holder of the FTR is entitled to the hourly cashflows for the term of the instrument.

  Hourly cashflows = volume $\times$ ΔP

  where $\Delta P = (LMP_B - LMP_A)$

MISO

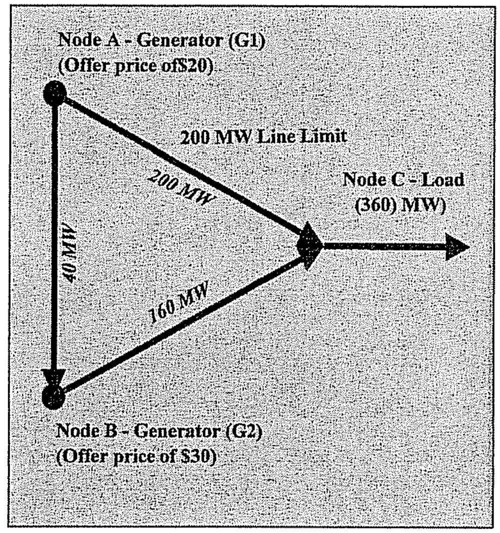
Settlement and FTRs

- The challenge for the RTO is creating the number of FTRs that ensure it returns $6,000 to the holders.
  - If it returns less than $6,000 then who gets the extra money?
  - If it returns more than $6,000 then where does the money come from?
- It resolves this problem by running simultaneous feasibility tests (SFTs)
  - An SFT determines the "exact" number of FTRs to issue for a given generation pattern so that the RTO returns all the money.

MISO

Simultaneous Feasibility using the Example

- The output of the constrained LMP solution is used to determine the set of simultaneously feasible FTRs that the RTO can offer.
  - 200 FTRs from AC
  - 40 FTRs from AB
  - 160 FTRs from BC
- A complete settlement run can now be performed.
- Load @ C pays $14,400
  - G1 receives $4,800
  - G2 receives $3,600
  - FTR (AC) receives $4,000
  - FTR (AB) receives $400
  - FTR (BC) receives $1,600



MISO

Section 5: A Full Allocation of FTRs

How many FTRs does load need to have a full allocation?

MISO

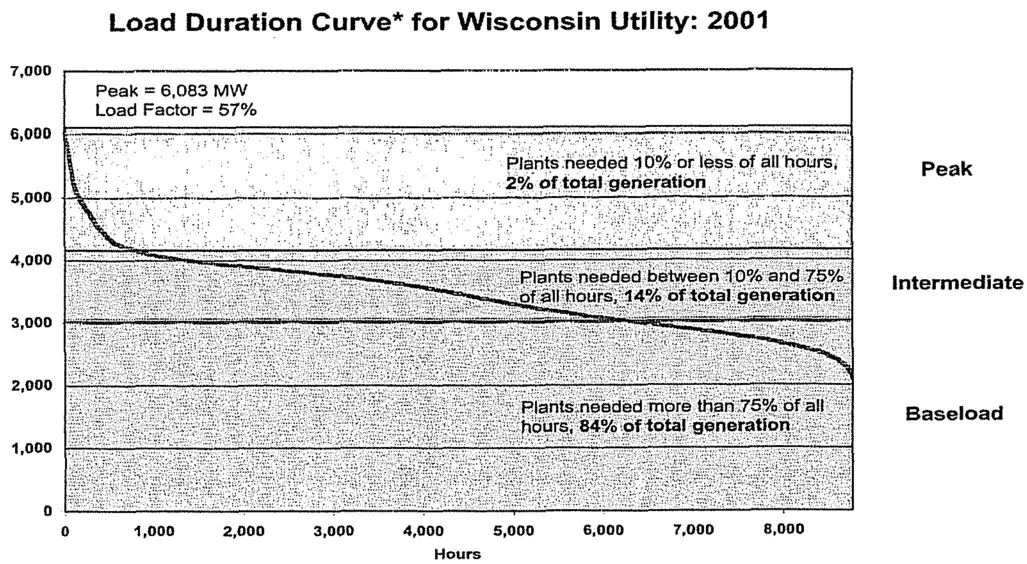
A "Full" Allocation of FTR's

Financial Transmission Rights (FTR) provide a hedge for congestion costs that may occur between generation source and load sink.

- A "full allocation" is one that leaves existing customers in the same ***financial*** position as under physical rights.
- FTRs have value in all hours, whether or not generation is on-line or scheduled.

MISO

Load Duration Curve



MISO

A "Full" Allocation of FTR's

- A full FTR allocation would provide expected FTR revenue from an FTR portfolio sufficient to offset expected aggregate congestion cost for a generation portfolio, on an annual basis, to the extent congestion costs are hedged today under physical service.
  - Within the year, congestion cost may be <=> than FTR revenue in any single hour.
  - Over the year, congestion cost may be <=> than FTR revenue for schedules from any single unit to load.
  - In a single year, congestion cost may be <=> than FTR revenue to the extent system/market conditions vary from those expected.
    - Mitigated by ongoing FTR portfolio evaluation and adjustment.

Appendix B: Analysis of Locational Pricing Patterns Within LG&E

In many hours of our simulation of energy markets in the LG&E/KU areas, the market value of LG&E generation is, on the average, greater than the market cost of LG&E load. This pattern reflects the impact of regional power flows on the operation of transmission and generation in the LG&E/KU system.

A look at two hours in which this occurs provides insight as to how congestion in the LG&E region causes this "reversal" of the expected pattern of congestion costs.

Hour 20 of April 1, 2005, shows the following LMPs in and around LG&E:

Location	LMP ($/MWh)
LG&E Load Zone	17.5
Brown (bus 27009)	24.2
Cane Run (bus 27048)	13.8
Ghent (bus 27138)	27.4
Green River (bus 27144)	23.6
Haeflin (bus 27155)	26.2
Mill Creek (bus 27253)	13.0
Paddys Run (bus 27332)	13.6
Trimble (bus 27409)	13.3
Tyrone (bus 27413)	26.4
Waterside (bus 27433)	9.6
Petersburg (Indiana)	41.1
Tanners Creek (Ohio)	30.9

In this hour, the primary constraint affecting LG&E/KU prices is from Northside to Clifty Creek (Louisville area into Indiana). This constraint depresses prices from (Trimble County southwest to Cane Run, affecting much of the load in the Louisville area. Large generators to the east and downstream of this constraint given an overall west to east power flow, such as Ghent, Brown, Haeflin, Green River, and Tyrone, have significantly higher LMPs. The pattern of LMPs and location of constraints are graphically displayed in Figures 1 and 2 (attached).

Hour 12 on August 20, 2005, shows similar behavior of LMPs, but due to a different constraint. In this hour, the Blue Lick transformer to the south and east of Louisville is highly constraining on the west to east flow of power, resulting in the following LMPs:

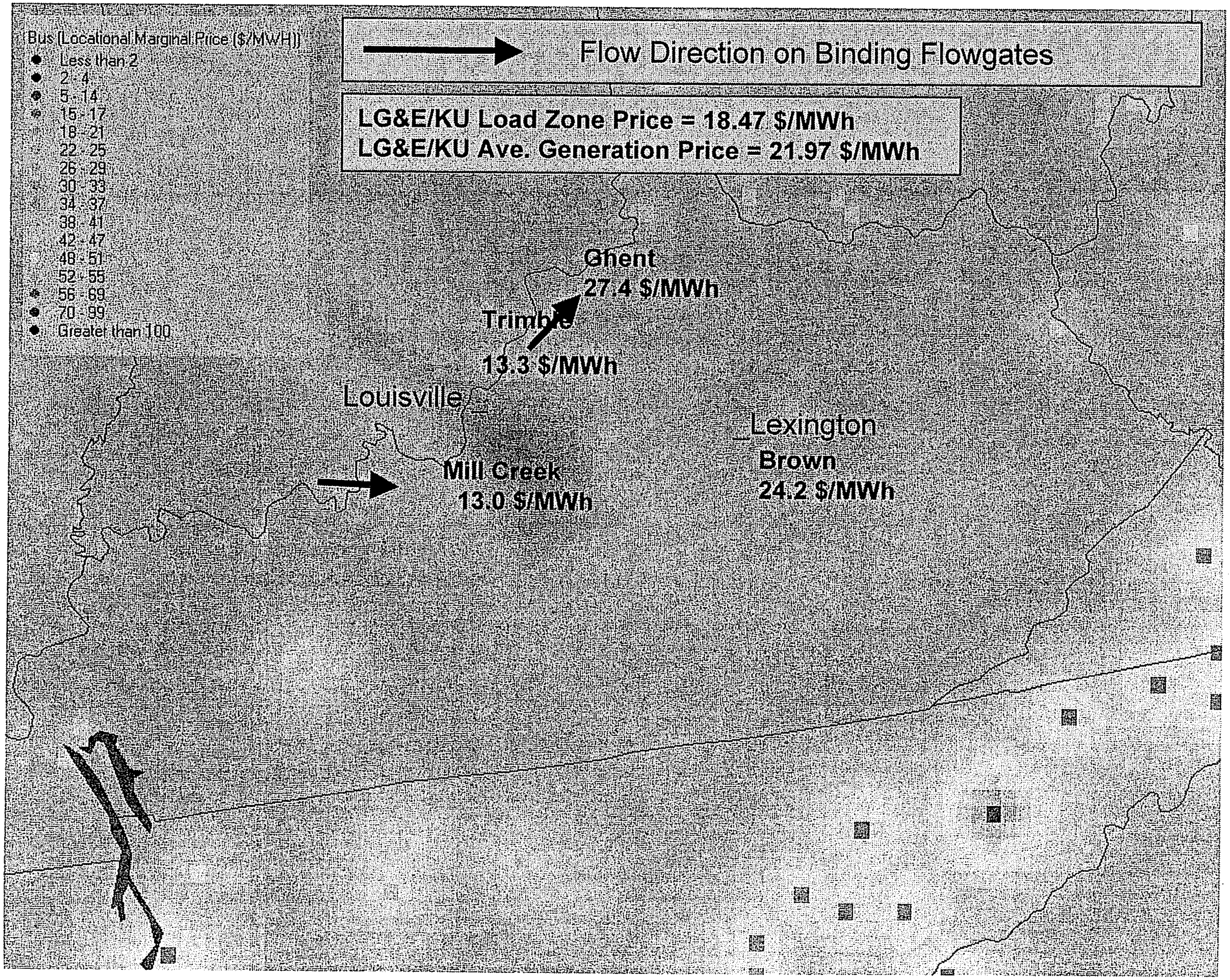
Location	**LMP ($/MWh)**
LG&E Load Zone	32.2
Brown (bus 27009)	47.9
Cane Run (bus 27048)	10.0
Ghent (bus 27138)	31.4
Green River (bus 27144)	45.4
Haeflin (bus 27155)	43.3
Mill Creek (bus 27253)	2.5
Paddys Run (bus 27332)	11.6
Trimble (bus 27409)	12.6
Tyrone (bus 27413)	47.4
Waterside (bus 27433)	12.3
Petersburg (Indiana)	16.4
Tanners Creek (Ohio)	21.6

In this hour, the Blue Lick constraint depresses prices to the northwest, again covering the Louisville load area from Trimble County on the northeast to Mill Creek on the southwest. But again, the larger LG&E /KU generators to the east end up with higher LMPs. The pattern of LMPs and location of constraints for this hour are displayed in Figures 3 and 4 (attached).

When loop flows through the LG&E / KU system are considered, power generated at some LG&E/KU generators can have a location specific market value that is up to 4 to 19 times greater than the market value of generation at other LG&E/KU facilities. If the LG&E/KU was operated in accordance with regional security-constrained economic dispatch and purchased and sold power in regional LMP markets, the Companies could in some hours significantly reduce the cost to serve load and earn premium prices by selling power from facilities downstream of frequently occurring transmission constraints.

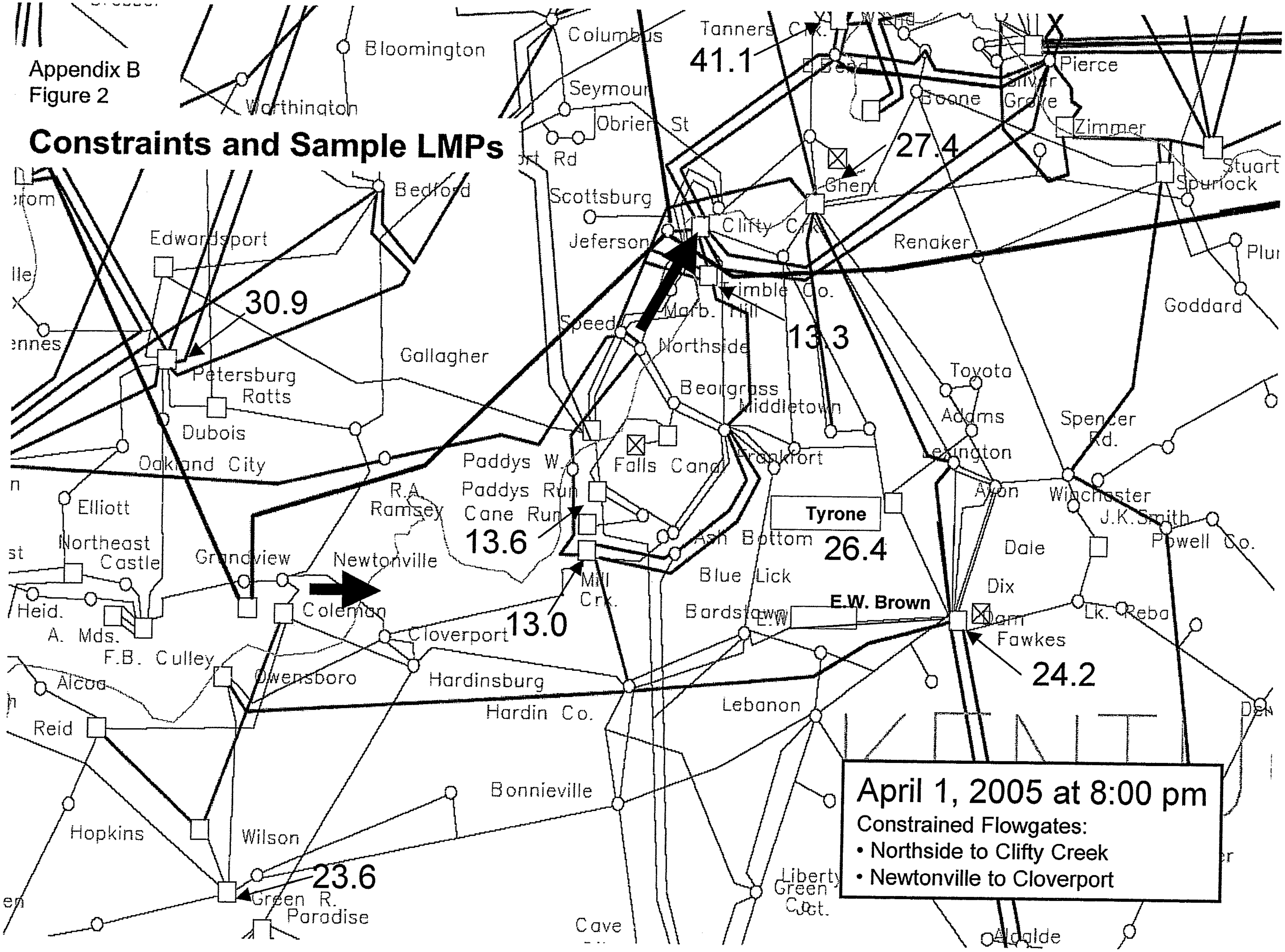
Appendix B
Figure 1

April 1, 2005 at 8:00 pm



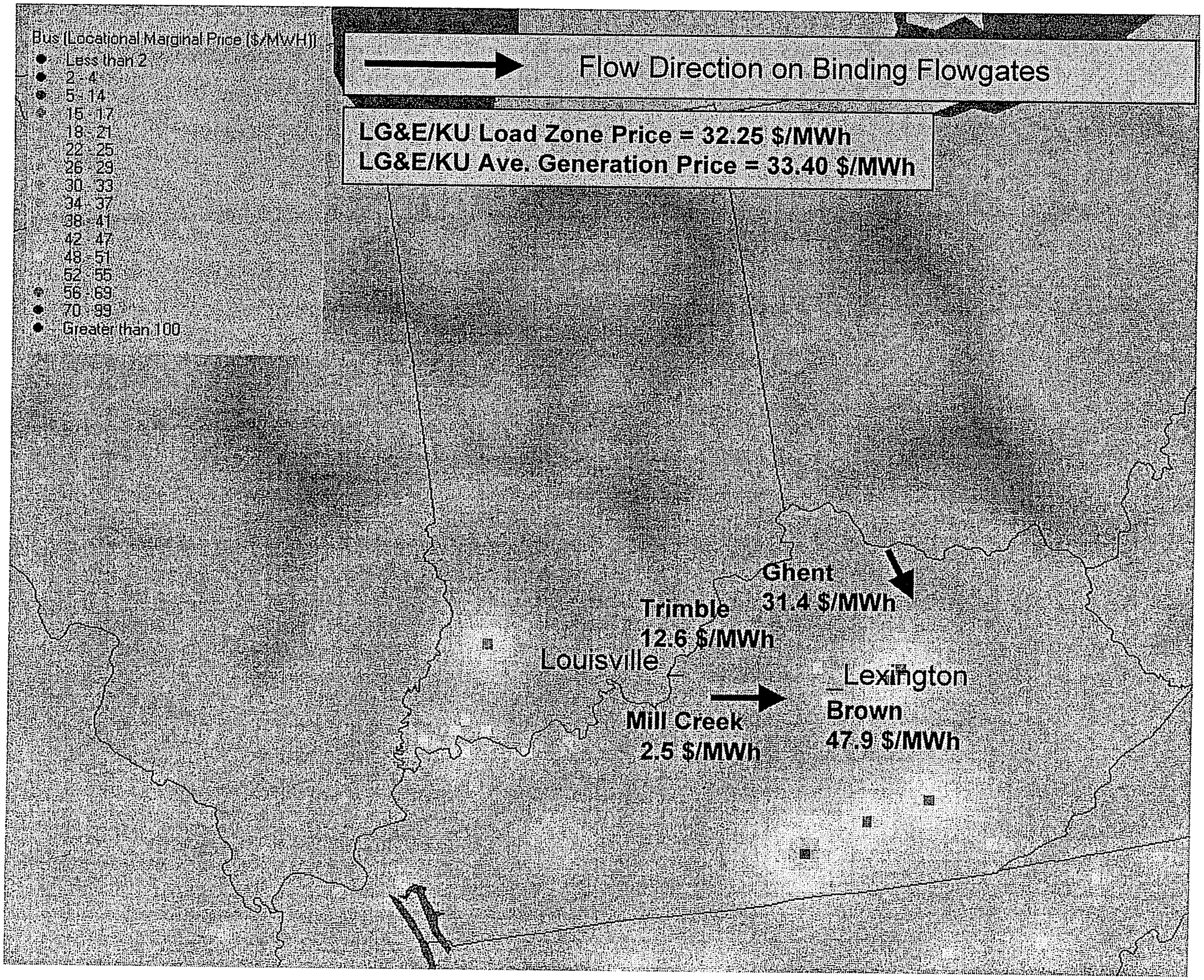
Appendix B
Figure 2

Constraints and Sample LMPs



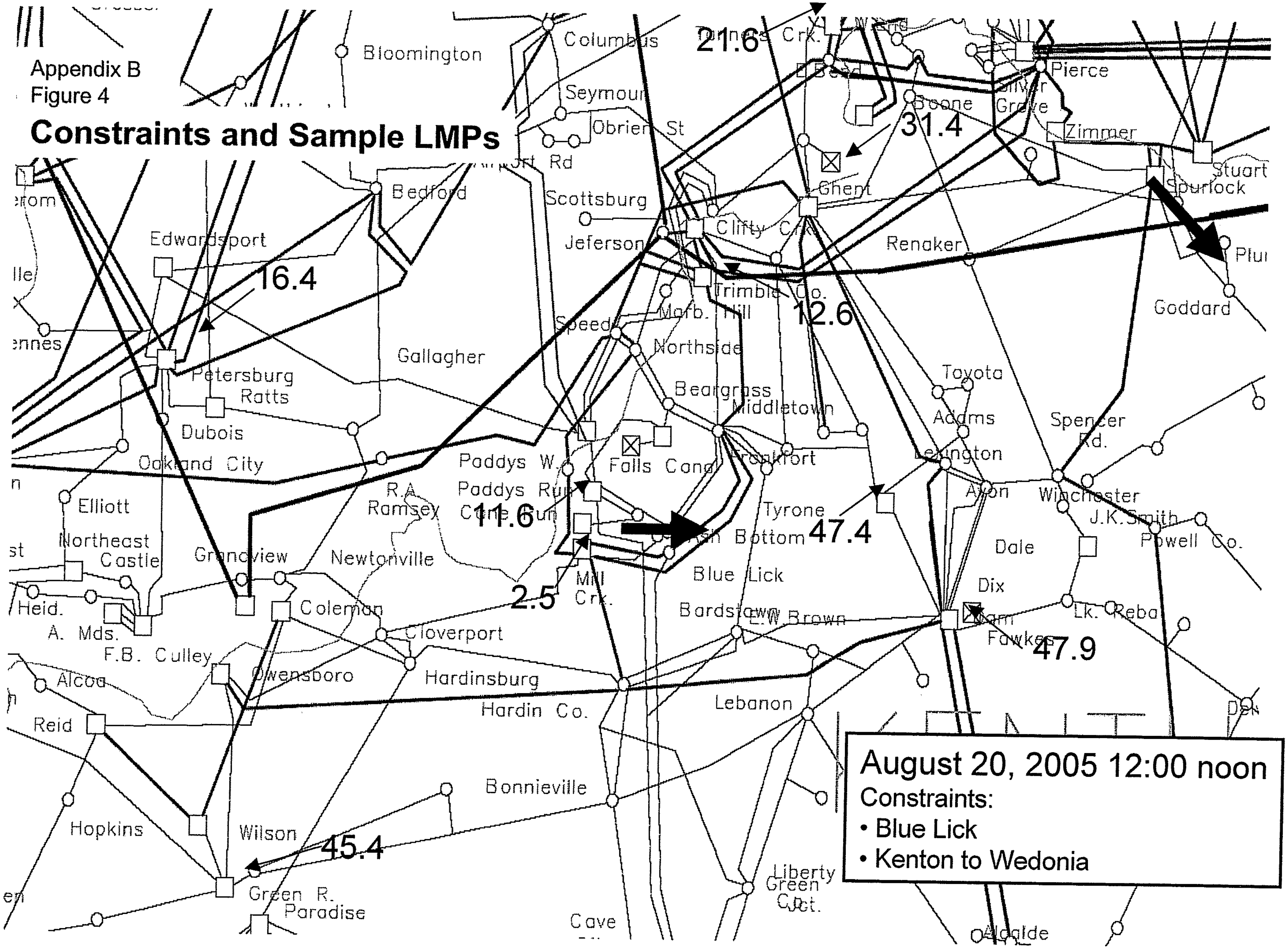
Appendix B
Figure 3

August 20, 2005 at 12:00 Noon



Appendix B
Figure 4

Constraints and Sample LMPs



Appendix C: Production Cost and Power Flow Study of LG&E/KU Options for Transmission Operations

MISO conducted an analysis of the economic impacts of alterative approaches for LG&E/KU to operate their transmission system. This analysis builds upon the study and report attached to the Direct Testimony of Ronald R. McNamara in this proceeding. As in the initial study, this analysis which was prepared to respond to the Supplemental Testimony being filed by LG&E/KU was based on a simulation of transmission system operations and regional power markets using the PROMOD IV® production costing and power flow model. The model was used to project hourly production costs and location-specific market clearing prices.

PROMOD IV® includes an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a wide variety of operating constraints. PROMOD IV® integrates chronological production costing and detailed power flow analysis. The model represents power system operations in the Eastern Interconnect, including representations of the operation of the 5,000 generating units that are 1 MW or larger, 40,000 transmission buses, and 50,000 transmission lines. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations.

The model captures the dynamics of transmission system operations and in the cases simulating the operation of MISO's TEMT an LMP market that will be fully integrated with transmission operations. The selected approach is able to represent the effects of power flows and transmission congestion, as well as fuel costs, generator availability, load patterns, and other factors on market prices. PROMOD IV® performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV® forecasts hourly energy prices, unit generation, revenues and fuel consumption, bus-bar and zonal energy market prices, external market transactions, transmission flows, losses, and congestion prices.

Unit Commitment and Dispatch

The unit commitment logic is based on a marginal scheduling algorithm that models generator constraints for minimum runtime and minimum downtime and considers the start-up costs and variable operating costs of each generating unit to develop a unit commitment schedule. This process starts with an initial unit commitment order for the week, and then performs an iterative improvement of the unit commitment schedule for each day of the week, considering the location-specific replacement cost of energy at each generator bus and opportunities to make off-system sales. Checking for violations of minimum runtime and minimum downtime constraints on each unit, the logic looks for alternative commitment decisions that improve the economic performance of the system.

Once the unit commitment schedule is developed, security constrained economic dispatch is performed by loading incremental unit segments in bid order, subject to operational constraints. PROMOD IV® dispatches the power system in each hour to minimize total variable production costs. For generating units, these costs include fuel costs (applied to the heat rate profile for each unit), variable O&M costs, and emissions costs based on forecasted SO_2 emission allowance and, where applicable, NO_x emission credit prices. Each unit's cost is scaled by a dynamic transmission loss factor that is calculated each hour during the dispatch, reflecting the unit's incremental effect on total system transmission losses. The unit dispatch procedure simulates detailed hourly chronological dispatch subject to ramp rate limits on maximum hour-to-hour changes and a Monte Carlo simulation of generating unit outages.

Economy transfers from one area to another area are considered in dispatch and reflect a hurdle rate incorporating transmission prices and transaction and opportunity costs for that buyer/seller pair.

A few unit types are assigned specific generation profiles. For example, river-based hydro are represented as the combination of flat run-of-the-river profile up to its minimum loading level, plus a peaking profile for remaining monthly energy. Pumped storage hydro is assumed to operate with 70% overall efficiency and dispatched on an economic bases as peak shaving. An hourly profile for wind generation was developed based on historical operating data for large wind farms in southwest Minnesota.

Mathematical Formulation of Security-Constrained Dispatch

Within each hour, PROMOD IV® performs a simulated economic dispatch of the power system such that all of the designated flowgate constraints are simultaneously satisfied. This operation is a large but straightforward Linear Program optimization problem, and PROMOD IV®'s implementation of this problem is conceptually comparable to the way the existing LMP markets schedule the dispatch and calculate LMPs.

The mathematical formulation of the security-constrained dispatch can be expressed as follows:

Minimize generation costs

$$\sum_i c_i \times g_i$$

where g_i is the generation and bus i, and c_i is the variable cost of the generation at bus i, including such components as:

- Fuel cost
- Heat rate of the generator
- Variable O&M cost
- Emissions cost
- Dynamic penalty for transmission losses

such that the system demand D is satisfied by the generators:

$$D = \sum_i g_i$$

and that each flowgate k stays within its flow limit F_k:

$$F_k \geq \sum_i sf_{ik} \times (g_i - d_i)$$

where d_i is the demand at bus i, and sf_{ik} is the dc powerflow shift factor for how much of the net injection at bus i (generation at the bus minus demand at the bus) affects the flow on flowgate k. These shift factors are calculated from the characteristics of the ac powerflow data.

The actual optimization problem solved by PROMOD IV® is somewhat more complicated, taking into account spinning reserve constraints, heat rate curves for the generators, minimum generation and ramp rate constraints for the generators, scheduling of phase shifting transformers, and scheduling of interchange among RTOs and control areas, recognizing the transfer cost (or hurdle rate) for interchange between the parties.

Power Flows & the Transmission System

Transmission system configurations, capabilities, and power flow distributions were based on a 2005 power flow case. The 2005 case was developed based on updating the Midwest ISO's 2004 peak power flow case to reflect transmission improvements, topology changes, and load growth for 2005. Data was provided by transmission owners in the course of MISO market studies and by the MISO transmission planning group. Data provided by these organizations was incorporated in the development of the updated and more detailed power flow case. Additionally, MISO has performed a full AC power flow analysis using the MUST model to identify any additional elements that might be placed at risk due to changes in power flows in market environment and specified additional flowgates where necessary.

PROMOD IV® represents the full power flow case in standard PSSE version 26 format and implements a linearized solution to the power flow. Shift factors are calculated to represent the redistribution of power flows associated with changes in generator output or load at specific locations.

The model optimizes the dispatch of the system, subject to a set of transmission constraints that represent the financially significant constraints that might be binding on the system dispatch. These transmission constraints comprise both base flow constraints, representing path based flowgate limits, and contingency constraints, reflecting limits based on the flows that would occur in the event of a failure of one or more other specified transmission elements. Contingency constraints occur where the failure of the secondary element(s) would increase flows over the primary flowgate to levels in excess of its security limit. The resulting economic dispatch will be such that, if any of those specified contingencies were to occur, the power flow would still be feasible. The list of potentially binding constraints used in this analysis includes limits on power flows for more than 1100 flowgates.

Transactions and Hurdle Rates

To take into account existing inefficiencies in bilateral power trading and prevent the PROMOD IV® model from over optimizing transactions in comparison to historical market experience, hurdle rates were applied to transactions between dispatch pools. These hurdle rates may include two components:

- The incremental transmission charge associated with purchasing power from another area to serve load within the dispatch pool; and
- A transaction and lost opportunity cost component to reflect the inherent inefficiencies of relying on a bilateral market.

The incremental tariff charge for transactions within MISO was set to zero to reflect the ability of Load Serving Entities (LSEs) to use network integration service. Similarly, the tariff component was set to zero for transactions between MISO and PJM, reflecting an elimination of through and out rates between these two RTOs. Applicable hourly non-firm point-to-point hourly transmission charges for exports were applied to transfers between other dispatch pools in the model.

The transaction and lost opportunity cost portion of the hurdle rate was generally set at \$3/MWH for transactions between pools that were not part of the same energy market.[1] It was applied in the dispatch of generation. A separate hurdle rate was not applied to unit commitment, although the model does commit generation, in part, based on anticipated sales given the dispatch hurdle rate. The selection of the \$3 per MWH amount for transaction and lost opportunity costs was based on a conservative study design that was intended to ensure that the results did not overstate the costs of TORC operation. It reflects an historical bench-marking analysis which analysis indicated that at this level the model would implement cost-effective transactions in excess of those actually identified and implemented in the real world market. A subsequent sensitivity case was run in which LG&E/KU TORC hurdle rates were allowed to increase to a level at which modeled transactions for 2003 would approximate the actual historical level of LG&E/KU off-system sales. In this sensitivity the cost of TORC operations was significantly greater than in our base case simulations.

PROMOD IV® is an optimization model. In the absence of specifying hurdle rates, the model would optimize power transfers between dispatch pools ignoring the effects of transmission rates and effectively assuming the pools would coordinate unit commitment and dispatch with perfect information. This would be an unrealistic representation of bilateral markets.

The transmission charge portion of the hurdle rate reflects the incremental charges that would affect the generation vs. power purchase choices of an LSE. The hurdle rates used in the study reflect rates for non-firm hourly service for the transfer of power out of an adjacent system. This is a conservative assumption in that actual transmission costs could be higher where firm or longer-term transmission service is purchased or where the contract path involves more than one transmission provider.

The transaction and opportunity cost portion of the hurdle rate was selected to reflect the cumulative impact of several inherent inefficiencies in bilateral contract markets, including:

- Participants in a bilateral market that is not closely integrated with the operation of the transmission system simply never see many of the opportunities to make cost effective trades that reflect the location specific pricing impacts of dynamic flows and transmission constraints.
- Current utility practice tends to reflect a bias, which may be appropriate given the lack of a liquid spot market, towards commitment of each utility's own generation to serve its native load.
- Existing scheduling procedures limit market participants to whole hour or longer transactions. By contrast, MISO energy markets will be able to optimize the operation of generation across member utilities at least every five-minutes.

[1] To recognize the impact of ATC redispatch procedures that affect some but not all TLR events, the hurdle rate within ATC was reduced to \$2.50 per MWH when the ATC companies are not in the MISO Energy Market. A modest reduction to the hurdle was used to represent ATC redispatch because ATC redispatch procedures appear to be in effect for a minority of TLR events and the initially selected hurdle rate is already conservative when compared to generally accepted practice.

- Finding a cost-effective mix of purchases and sales requires bilateral negotiations with multiple other market participants. Such negotiations and the resulting transactions impose transaction costs related to the search for cost-effective transactions, negotiations, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution. These transaction costs are a direct cost to bilateral market participants. They are either largely avoided (i.e. search, negotiations, contracting, and dispute resolution) or covered by MISO charges (i.e. scheduling, settlement, and counter-party risk management) under MISO's TEMT.
- In such power trading negotiations, each participant has an incentive to limit its disclosures to counter parties to capture as large a portion of the benefits from the transactions as possible. Given imperfect information and a non-transparent market, identifying a cost-effective mix of transactions takes time and not all economic transactions will be discovered.
- Given a lack of transparency, geographic price spreads occur in bilateral markets that do not reflect genuine differences in locational marginal costs. These spreads create misleading operating incentives that may fail to mitigate and in some cases exacerbate transmission congestion. The lack of transparency has direct cost impacts and secondary cost impacts through its failure to efficiently alleviate transmission congestion.
- Power markets are highly dynamic. Given the transaction costs and the time involved in completing bilateral transactions, the utilities' generation, purchases and sales are seldom fully optimized given continuously changing conditions. This failure to optimize the operation of generation across entities increases total generation costs.

The transaction and opportunity cost portion of the hurdle rate was conservatively set at $3/MWH a level that is significantly below that used in the levels commonly used in comparable studies.

Representation of Congestion Management

Rated flowgate capacities were reduced in each scenario to reflect expected flowgate utilization during high power flow periods. This adjustment was required to prevent the model from over optimizing and to accurately represent operating performance under a TLR system of congestion management based on what has actually been observed. To reflect the impacts of TLR management, specific adjustments were made to flowgate capacities based on the location of the flowgate and case being analyzed. These adjustments reflect a comprehensive evaluation of actual flowgate utilization during Level 3 or higher TLR events in different portions of the MISO footprint.

Generating Unit Characteristics

The primary data sources include data reported by the utilities to the Federal Energy Regulatory Commission or U.S. Energy Information Administration (EIA) and published by those agencies, information filed by the utilities with U.S. Environmental Protection Agency (EPA) including submissions to meet their Continuous Emissions Monitoring System (CEMS) reporting requirements, the NERC Energy Supply and Demand database and Generating Availability Data System (GADS), and New Energy Associates' PowerBase® database.

PowerBase® draws data in large part from Platt's (formerly Resource Data International), a division of McGraw Hill, which are subject to review and adjustments by New Energy Associates. PowerBase is New Energy's regional database and the associated programs to process and format the data for use in PROMOD IV®. Data items supplied by these sources include generator name, location (area assignment), summer/winter capacity, primary and secondary fuels, GADS category, operating & maintenance (O&M) costs, heat rates, projected capacity changes, projected retirement dates, and average monthly hydro energy. Detailed operational data from the CEMS is used to derive multiple capacity states with associated incremental heat rate data. Defaults values for forced outage rates, forced outage durations, and scheduled maintenance requirements are taken from the NERC GADS. Emission production rates for SO_2, NO_x, and CO_2 are taken from documents published by the EPA. Where appropriate, we have reflected in the inputs comments on LG&E/KU data provided by the Companies during the earlier portion of this proceeding.

Data for nuclear planned refueling outage schedules and nuclear forced outage rates are supplied through Platt's by an independent consultant, Koppe Consultants. Forecasted prices for SO_2 allowances along with the associated forecast for unit specific emissions reduction technology upgrades are supplied by Platt's consulting organization or public sources. Market prices for NO_x credits reflect published forward prices for 2005. Other operational modeling parameters such as unit minimum runtime, minimum downtime, contribution to spinning reserve, must-run status, etc., needed for simulation accuracy are based on experience and knowledge of the models.

Load Forecast

Load and demand forecasts represent forecasted control area load and demand. Initial forecasts were developed based on the combination of the Form EIA 714 filings, NERC Energy Supply & Demand (ES&D) data, and NERC regional summer/winter assessments. Control area peak and energy forecasts within a NERC sub-region are scaled to match the total sub-region monthly peak and energy forecast provided in the NERC ES&D database. This scaling is done based on the relative peak and energy values provided in the Form EIA 714 forecasts. This preserved the relative forecasted growth rates of different areas within a sub-region while still recognizing the NERC sub-region forecast which has broader acceptance and credibility.

This scaling also is applied to the location specific load profiles in the power flow case to determine loads assigned to specific buses.

Forecasted loads include average transmission losses. For purposes of calculating LMP, marginal losses will be calculated by the model.

Forecasted Gas and Oil Prices

The gas and oil fuel price forecasts were developed using two components. The first component is a general market price forecast based on futures prices at specific trading hubs. The second is a basis differential to reflect geographic differences between hub prices and delivered costs and, for oil, the relationship between the delivered fuel costs to utilities and crude oil futures prices. The basis differential was established based on a three month rolling average of the historical relationships of historical spot prices to historical state (for natural gas) or sub-region (for oil) specific delivered fuel costs.

Natural Gas Price Forecast

The forecasted market price component for natural gas is based on the June 7, 2004 NYMEX forward prices for natural gas at Henry Hub for delivery in each month of 2005.

Locational basis differentials for the delivered cost of natural gas to utilities in each state were determined by taking the difference between the average delivered price of natural gas in each state over the period January 1999 through December 2002 and the average daily spot price at the Henry Hub for delivery in that same month. The natural gas basis differentials tend to widen in the winter when deliveries on the pipeline system can be capacity constrained. The basis differentials were set on a monthly basis based on three month rolling averages of historical basis differentials so as to reflect these seasonal patterns.

The delivered cost data used to calculate basis differentials are the costs reported by utilities for spot and interruptible gas on the Form EIA 423. This survey is designed to capture cost data that includes both interstate pipeline and local distribution company transportation charges. These data are aggregated by state and published by EIA in Electric Power Monthly, and the underlying data are available in an on-line database. After December 2002, the published data no longer distinguish between the cost of spot, interruptible, and contract gas purchases.

In general, state level average natural gas costs were used to calculate the natural gas basis differentials. However, EIA did not publish any delivered cost of gas data for selected states and data from adjacent states was used to calculate locational basis differentials in these cases.

In a small number of instances, EIA gas costs include anomalous data that appear to reflect data entry errors by the submitting company or EIA. Anomalies were investigated by reviewing the disaggregated company Form EIA 423 data. In a few cases, the data entries were judged to very likely reflect some kind of data error, and the state average was recalculated excluding this observation.

In additional cases, historical delivered costs exhibited significant month-to-month volatility. To ensure the use of representative values, basis differentials for each month were calculated using a three-month rolling average of historical values, e.g. the differential for September was calculated from the historical differentials for August, September, and October.

#2 Fuel Oil Price Forecast

A similar methodology is used to develop forecasted prices for the #2 fuel oil. The price forecast component for #2 oil price is the June 7, 2004 NYMEX futures price for #2 oil delivered in New York harbor during each month of January – September 2005. At the time our fuel forecast was developed, futures contracts for #2 oil were not traded on NYMEX past September 2005. To continue the series through December 2005, month-to-month percentage changes in #2 oil prices were assumed to equal the month-to-month percentage changes in the price of NYMEX futures for light, sweet crude oil. Historically there has been a reasonably consistent relationship between #2 and light, sweet crude prices.

Sub-regional locational basis differentials relative to the New York Harbor futures market price were calculated using the costs reported by utilities for spot purchases of #2 oil on Form EIA 423. As in the case of natural gas, this survey is designed to capture delivered costs including transportation charges. State level average #2 oil prices were utilized to calculate locational basis differentials. Basis differentials for each month were calculated using a three-month rolling average of historical values.

A small number of anomalous data reporting entries were identified and excluded from the analysis.

Residual Fuel Oil Price Forecast

The residual oil forecast is based on a comparable methodology to that used for natural gas and #2 fuel oil prices. The price forecast component of the residual oil price was based on the June 7, 2004 NYMEX futures price for light, sweet crude during each month of 2005. The futures market price for crude oil is utilized because there is no 2005 forward commodity market for residual oil, and residual oil prices are reasonably well linked to crude oil prices. The basis differential for residual oil is calculated in essentially the same manner as for #2 Fuel Oil, using the differential between the delivered residual oil costs reported by utilities on the Form EIA 423 and the spot price of crude oil. Basis differentials are applied to the NYMEX forward price for light, sweet crude delivered to the pipeline at Cushing, OK in order to develop forward projections for residual oil prices that reflect both locational price differences and the price difference between crude and residual oil. Data from representative states was used to calculate sub-regional basis differentials.

Forecasted Coal and Uranium Prices

Coal and uranium price forecasts were taken from Powerbase and derived from facility specific information for the delivered cost of coal and representative regional nuclear fuel costs reported by Platt's.