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November 29, 2004
VIA U.P.S

Elizabeth O'Donnell, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Ms. O'Donnell:

Enclosed please find eleven replacement copies for Table 10, Appendix A, and Figures 1-4 (part of Appendix B) of the Rebuttal Testimony of Dr. Ronald R. McNamara, filed on behalf of Midwest Independent Transmission System Operator, Inc. on November 19, 2004. These copies should replace the corresponding pages and attachments in the copies of Dr. McNamara's testimony initially filed with the Commission. Due to a copying error, the second page of Table 10 included with some of the copies filed and served is unreadable; in addition, Appendix A and Figures 1-4, originally filed with the Commission and served on the parties, are not color copies and are thus difficult to read. There is no substantive change between the initially filed copies of Table 10, Appendix A, and Figures 1-4 and the replacement copies enclosed with this letter.

An additional set of these replacement copies is also enclosed. Please stamp this set with the date of filing/receipt and return it in the enclosed self-addressed, stamped envelope. Thank you for your assistance in this matter.

Sincerely,

Ben Allen

Benjamin D. Allen

Enclosures

Dispatch, LMP's, FTR's and Settlement

RECEIVED

NOV 3 0 2004

PUBLIC SERVICE
COMMISSION

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.

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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!

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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.

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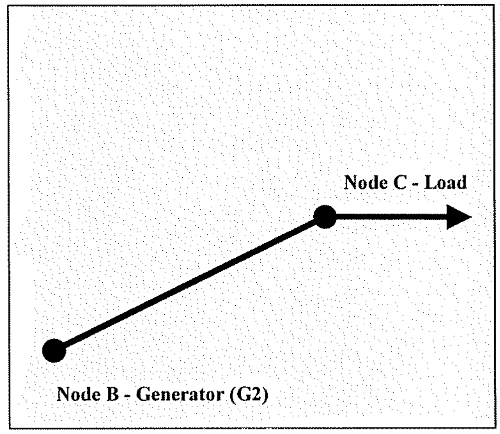
Illustrating the basics – Step 1

- 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!



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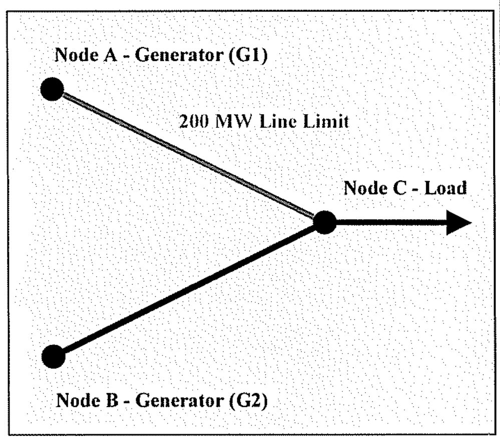
Illustrating the basics – Step 2

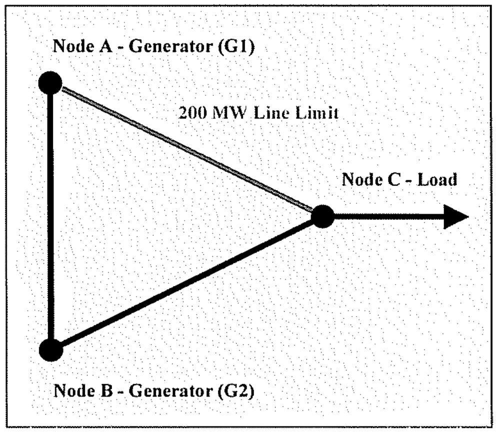
- Make the model a little more complicated:
  - 3 nodes.
  - 2 transmission lines with equal impedance and of equal length.
  - 1 thermally constrained transmission line (line AC)
    - Line AC is constrained to no more than 200 MW.
    - Lines BC has unlimited MW capacity.
  - 2 generators (G1 and G2)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



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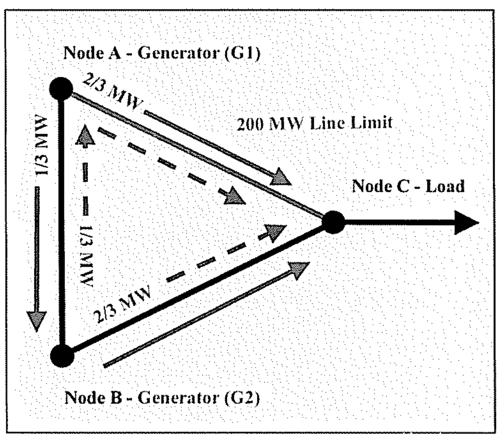
Illustrating the basics – the physics

- 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).



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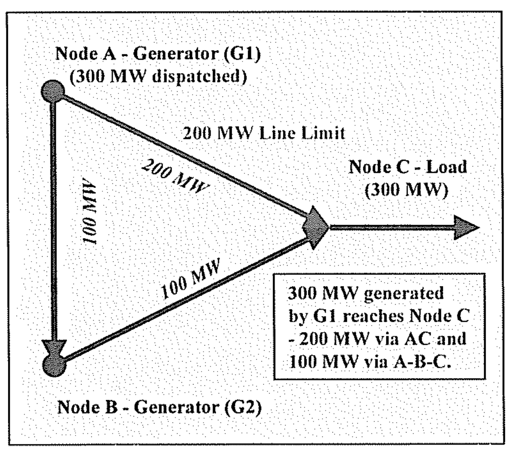
Illustrating the basics – defining capacity

- 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...

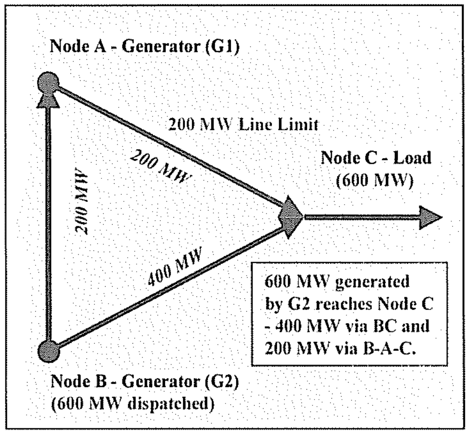
- *IF*, load at Node C is 300 MW
  - Then it is possible for G1 to meet all the load
    - Depends on offer curves.
  - But…if G1 does produce 300MW then G2 cannot produce anything.
- *IF*, G1 produces 300MW then the Total Transfer Capability (TTC) is 300MW
  - Neither G1 or G2 can produce more output 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.



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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 planning not real time operations!***

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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"

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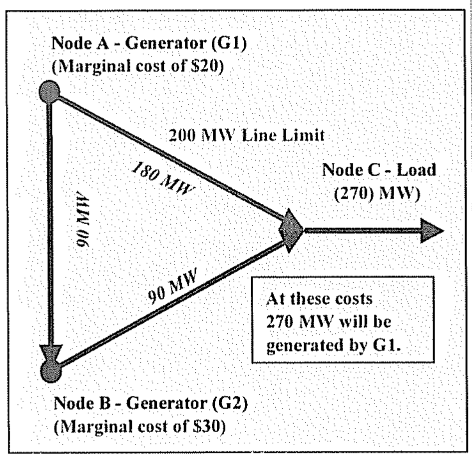
Illustrating the basics - separating energy from reliability

- 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.



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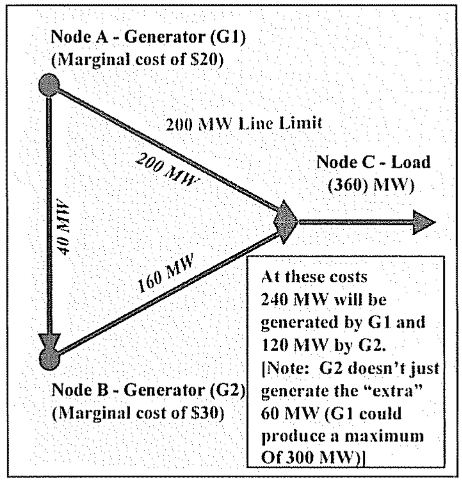
Redispatch Example

- 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.



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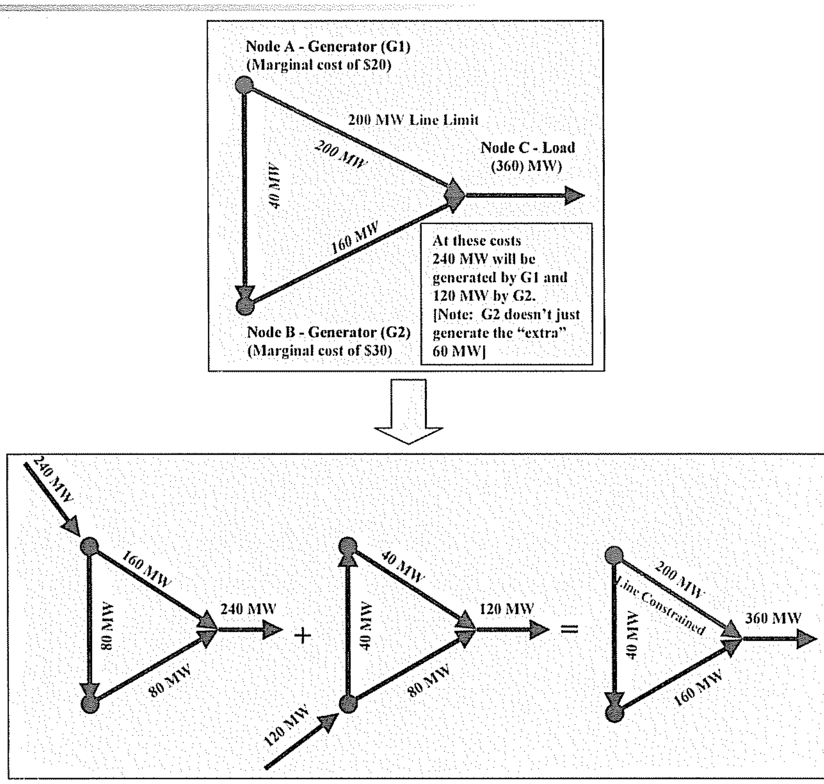

Conclusion - separating energy from reliability is a myth

- 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!

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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.

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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.

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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.

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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.

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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!***

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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.

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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.

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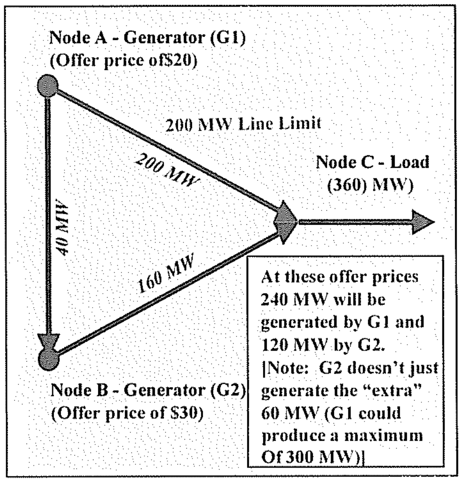
Example of Dispatch and LMP Price Calculation

- 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).



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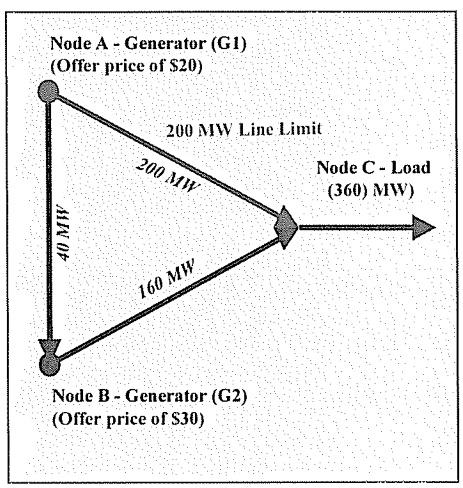
Price Derivation - Nodes A and B

- 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.



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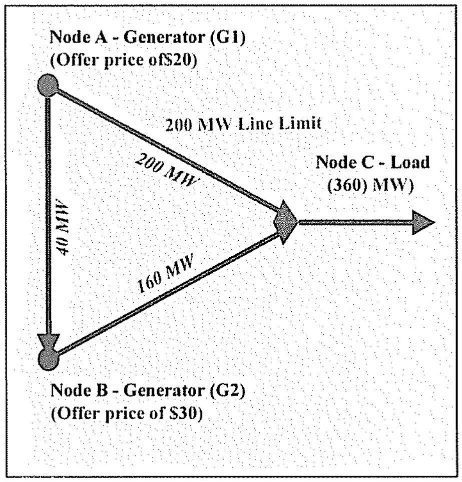
Price Derivation - Node C

- **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).



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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

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Section 3: Settlements

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

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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

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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.

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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

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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…***

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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.

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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.

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Section 4: "FTR's"

What to do with the extra revenue!

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Settlement and FTRs

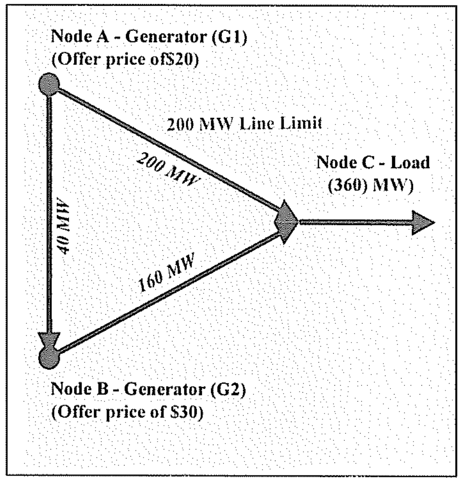
- Remember the RTO "overcollects" from the load compared to what they pay to the generators. The RTO must return this money and does so by issuing financial transmission rights (FTRs) to parties.
- An FTR is a financial instrument.
  - The instrument has three components that make up its value.
    - 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 Δ ΔP
  - where $\Delta P = (LMP_B - LMP_A)$

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.

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



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Section 5: A Full Allocation of FTRs

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

MISO

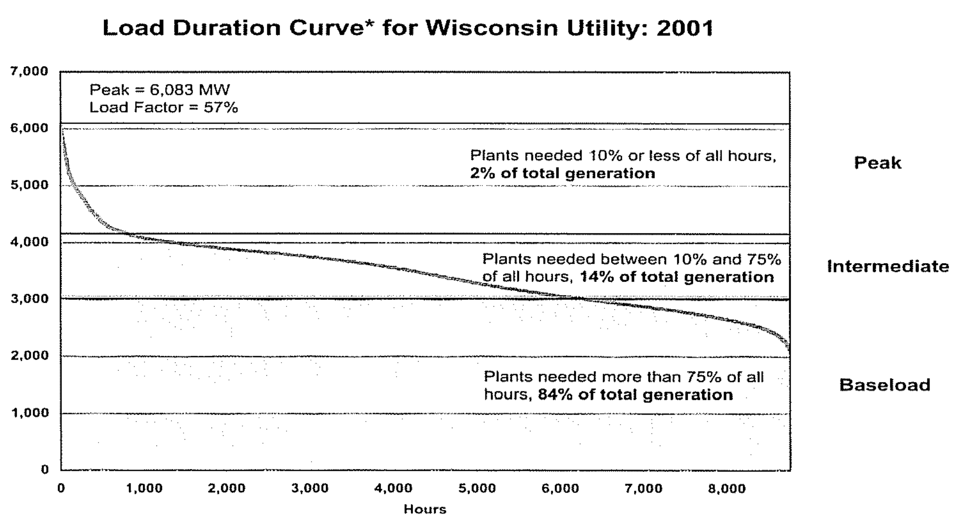
A "Full" Allocation of FTR's

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



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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.

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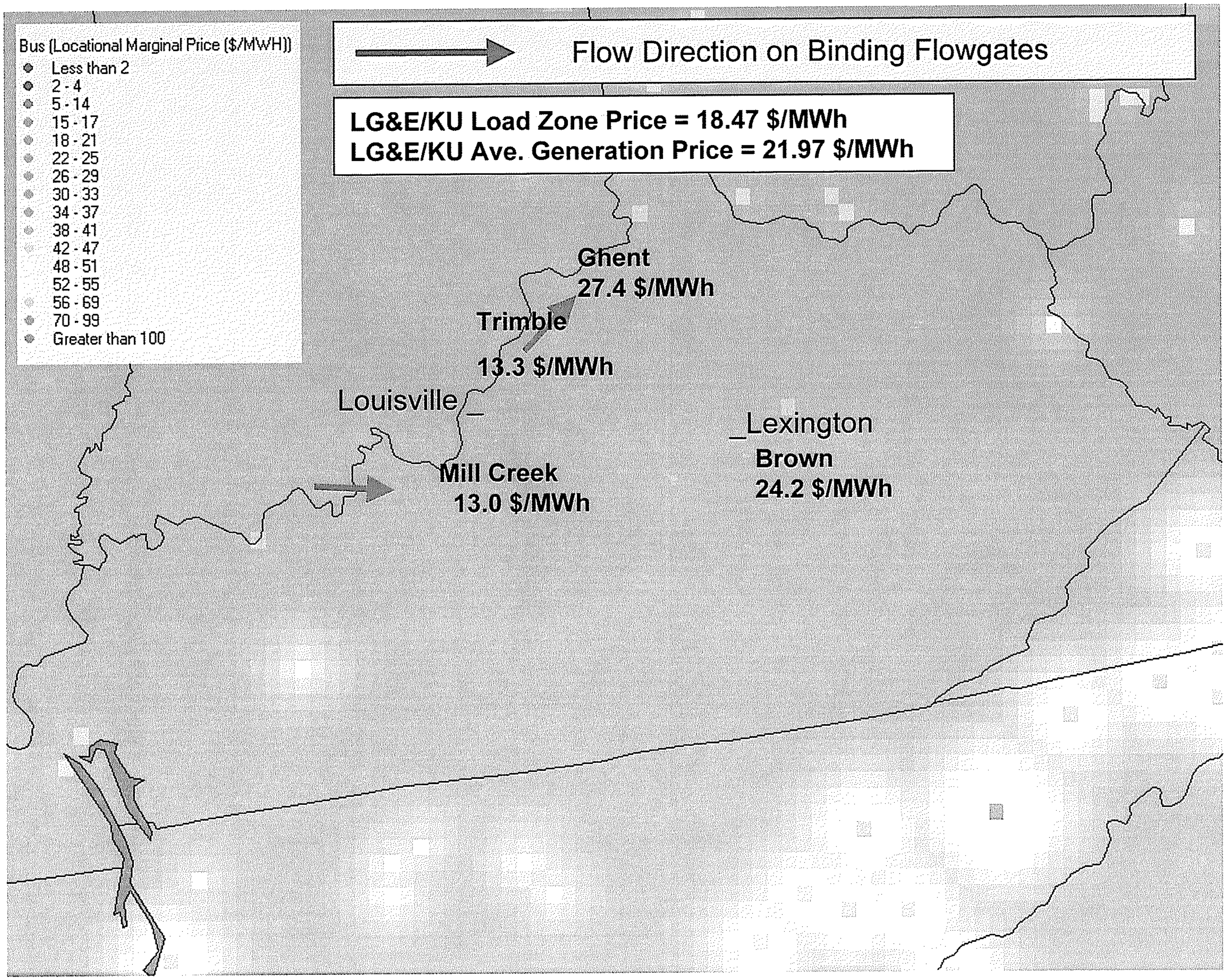
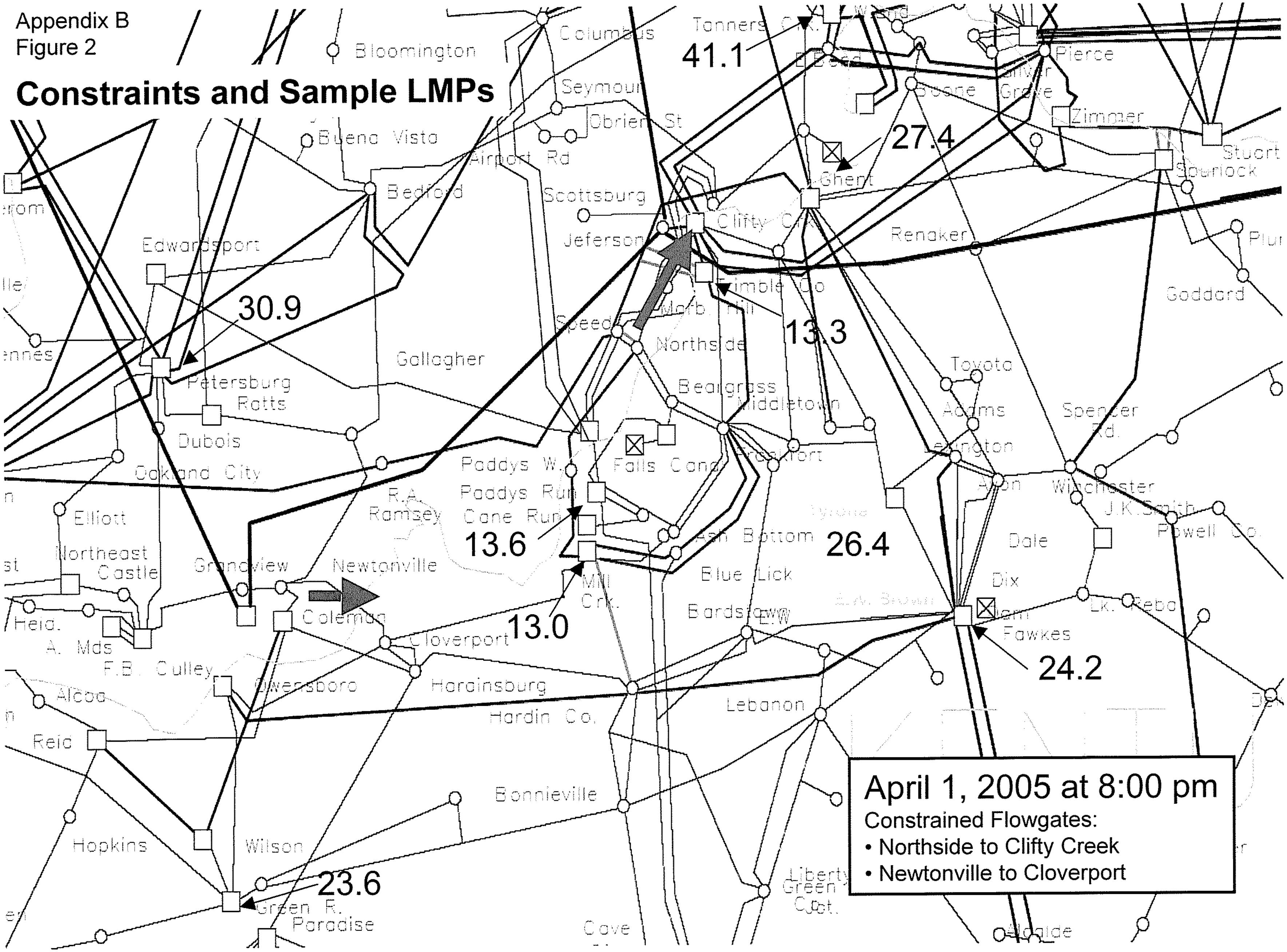
Appendix B
Figure 1

April 1, 2005 at 8:00 pm



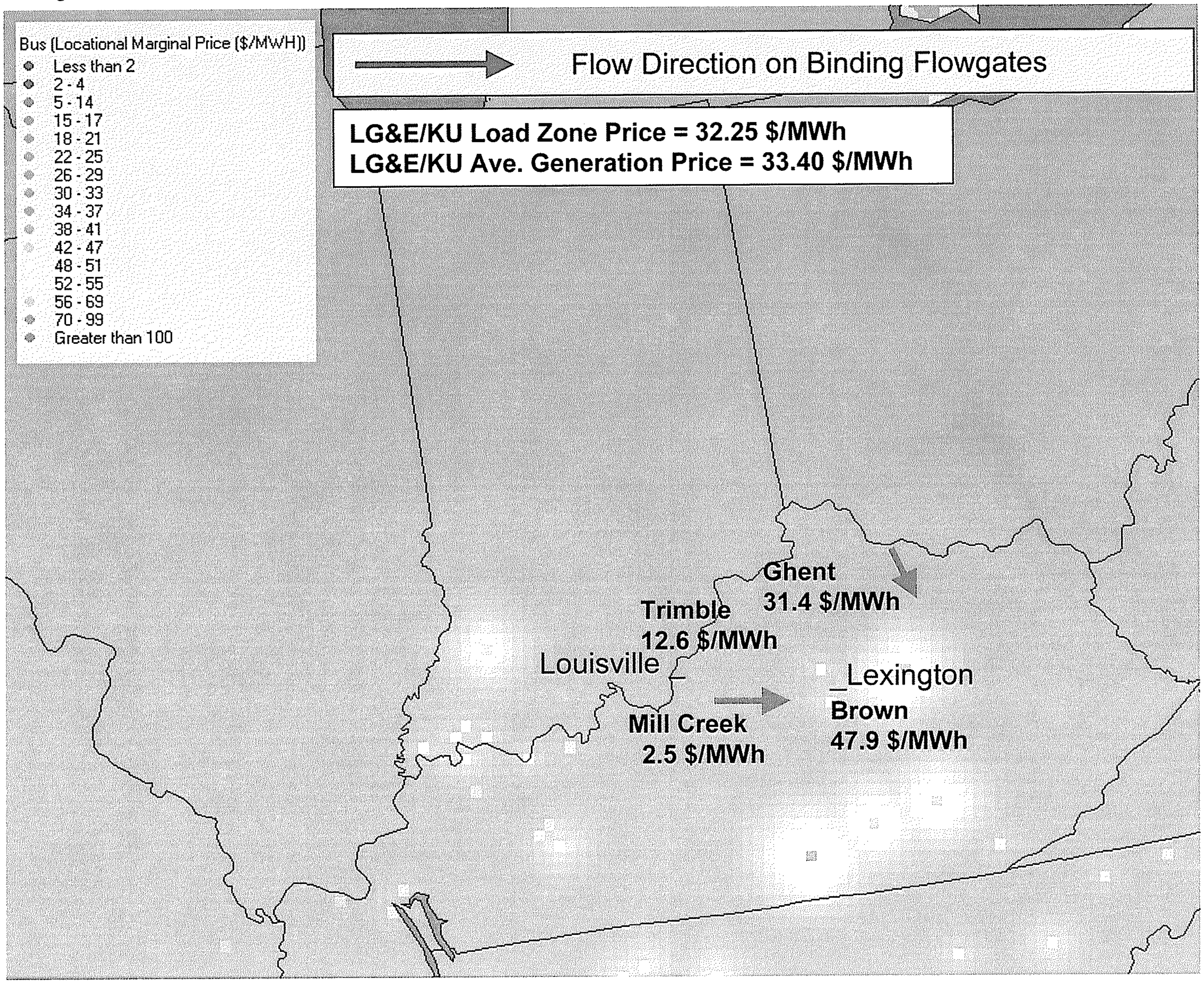
Appendix B
Figure 2

Constraints and Sample LMPs



Appendix B
Figure 3

August 20, 2005 at 12:00 Noon



Appendix B
Figure 4

Constraints and Sample LMPs

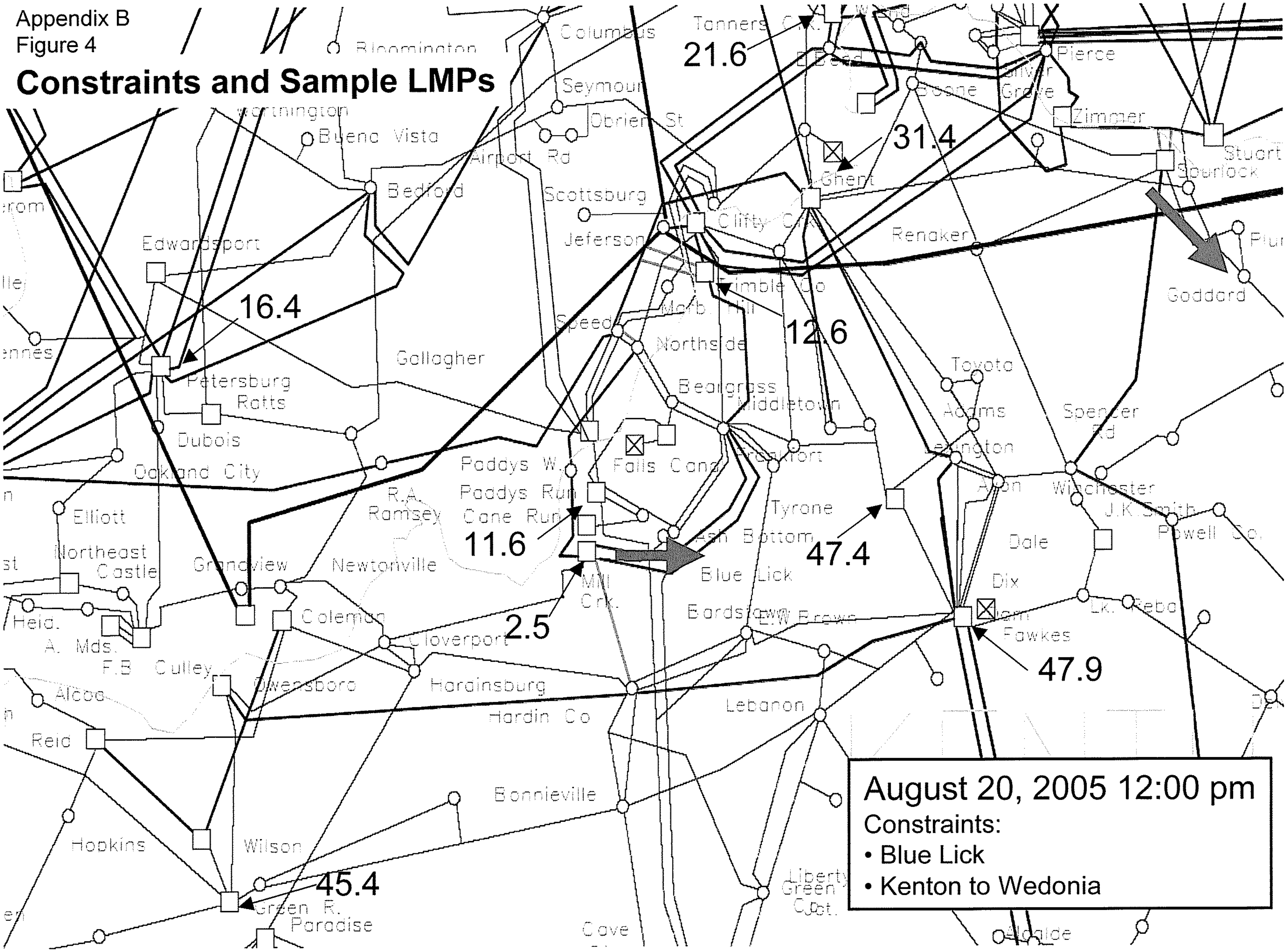


Exhibit RRM -
Table 10
Low Fuel Cost Sensitivity Analysis - Cost to Serve Contro

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E /

Month	Generation Costs	Purchased Power Costs	Schedu
January	$55,207,025	$454	
February	$53,435,115	$0	
March	$55,744,584	$35	
April	$53,231,102	$0	
May	$53,835,649	$430,714	
June	$63,295,434	$20,654	
July	$74,208,308	$0	
August	$70,771,911	$64,572	
September	$62,396,891	$0	
October	$54,904,128	$0	
November	$51,745,230	$0	
December	$53,846,955	$18,430	
Total	**$702,622,331**	**$534,860**	

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E /

Month	Total Generation Costs	Purchased Power Costs	LG&E C Costs	tribution of 8 evenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0		$2,991,738	3,421,936	$0	**$41,606,555**
February	58,507,744	$0		$3,113,962	2,566,584	$0	**$36,918,488**
March	59,858,269	$4,875		$2,353,516	3,262,375	$0	**$34,280,703**
April	54,826,921	$0		$1,242,052	7,340,340	$0	**$33,783,820**
May	58,173,119	$395,695		$1,693,369	6,147,681	$0	**$41,137,985**
June	67,893,661	$50,241		$2,025,520	9,833,993	$0	**$42,216,826**
July	77,497,130	$0		$1,675,310	15,012,017	$0	**$40,515,023**
August	73,164,400	$216,737		$1,744,882	13,232,837	$0	**$44,174,084**
September	67,261,501	$0		$1,678,961	3,499,291	$0	**$41,034,210**
October	59,942,366	$0		$2,308,078	-973,775	$0	**$31,571,285**
November	56,993,945	$0		$2,581,094	2,005,687	$0	**$36,937,885**
December	61,014,894	$24,005		$2,264,265	3,091,821	$0	**$40,073,867**
Total	**$756,695,195**	**$691,553**		**$25,672,746**	**$68,440,787**	**$2,000,000**	**$480,227,779**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / I

Month	Total Generation Costs	Purchased Power Costs	LG&E Co Costs	tribution of 8 evenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0		$2,991,738	$2,799,081	$0	**$42,229,410**
February	58,507,744	$0		$3,113,962	$1,408,673	$0	**$38,076,399**
March	59,858,269	$4,875		$2,353,516	$1,194,977	$0	**$36,348,101**
April	54,826,921	$0		$1,242,052	$2,826,964	$0	**$38,297,196**
May	58,173,119	$395,695		$1,693,369	$4,896,745	$0	**$42,388,921**
June	67,893,661	$50,241		$2,025,520	$7,655,246	$0	**$44,395,573**
July	77,497,130	$0		$1,675,310	$10,527,569	$0	**$44,999,471**
August	73,164,400	$216,737		$1,744,882	$9,228,281	$0	**$48,178,640**
September	67,261,501	$0		$1,678,961	$2,172,928	$0	**$42,360,573**
October	59,942,366	$0		$2,308,078	-$1,800,604	$0	**$32,398,114**
November	56,993,945	$0		$2,581,094	$760,210	$0	**$38,183,362**
December	61,014,894	$24,005		$2,264,265	$2,738,159	$0	**$40,427,529**
Total	**$756,695,195**	**$691,553**		**$25,672,746**	**$44,408,229**	**$2,000,000**	**$504,260,337**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E /

Month	Total Generation Costs	Purchased Power Costs	LG&E C Costs	ribution of 8 evenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0		$2,991,738	$837,003	$0	**$44,191,488**
February	58,507,744	$0		$3,113,962	$1,027,538	$0	**$38,457,534**
March	59,858,269	$4,875		$2,353,516	$210,428	$0	**$37,332,650**
April	54,826,921	$0		$1,242,052	$1,071,236	$0	**$40,052,924**
May	58,173,119	$395,695		$1,693,369	$1,468,101	$0	**$45,817,565**
June	67,893,661	$50,241		$2,025,520	$3,409,804	$0	**$48,641,015**
July	77,497,130	$0		$1,675,310	$4,115,963	$0	**$51,411,077**
August	73,164,400	$216,737		$1,744,882	$4,351,196	$0	**$53,055,725**
September	67,261,501	$0		$1,678,961	$2,613,758	$0	**$41,919,743**
October	59,942,366	$0		$2,308,078	$708,173	$0	**$29,889,337**
November	56,993,945	$0		$2,581,094	$1,616,483	$0	**$37,327,089**
December	61,014,894	$24,005		$2,264,265	$1,079,519	$0	**$42,086,169**
Total	**$756,695,195**	**$691,553**		**$25,672,746**	**$22,509,202**	**$2,000,000**	**$526,159,364**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E /

Month	Total Generation Costs	Purchased Power Costs	LG&E C Costs	ribution of 8 evenues	Less: FTR Revenue	Less: FTR Auction Revenues	Net Cost to Serve Control Area Load
January	61,561,246	$0		$1,413,901	$837,003	$0	**$45,769,325**
February	58,507,744	$0		$1,585,566	$1,027,538	$0	**$39,985,929**
March	59,858,269	$4,875		$2,131,441	$210,428	$0	**$37,554,725**
April	54,826,921	$0		$1,538,495	$1,071,236	$0	**$39,756,482**
May	58,173,119	$395,695		$851,811	$1,468,101	$0	**$46,659,123**
June	67,893,661	$50,241		$1,504,602	$3,409,804	$0	**$49,161,934**
July	77,497,130	$0		$1,625,988	$4,115,963	$0	**$51,460,398**
August	73,164,400	$216,737		$1,412,113	$4,351,196	$0	**$53,388,494**
September	67,261,501	$0		$1,998,651	$2,613,758	$0	**$41,600,052**
October	59,942,366	$0		$2,429,502	$708,173	$0	**$29,767,912**
November	56,993,945	$0		$1,558,567	$1,616,483	$0	**$38,349,616**
December	61,014,894	$24,005		$1,453,857	$1,079,519	$0	**$42,896,577**
Total	**$756,695,195**	**$691,553**		**$19,504,494**	**$22,509,202**	**$2,000,000**	**$532,327,616**

Low Fuel Cost Sensitivity Analysis - Cost to Serve LG&E / I

Month	Total Generation Costs	Purchased Power Costs	A&G and Coordina Services
January	$56,577,225	$0	
February	$52,432,305	$0	
March	$55,531,541	$0	
April	$52,991,787	$0	
May	$53,577,328	$322,737	
June	$62,484,264	$35,020	
July	$71,278,889	$0	
August	$68,356,698	$51,095	
September	$60,620,472	$0	
October	$54,144,328	$0	
November	$50,394,467	$0	
December	$53,889,303	$8,627	
Total	**$692,278,606**	**$417,479**	