MISO Congestion Management System

Two-Settlement Systems in PJM and New York

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August 2, 2001

TOPICS

- Rationale
- Mechanics
- Examples
- Details

RATIONALE

Day-ahead markets and two-settlement systems were developed to provide performance incentives for day-ahead schedules in decentralized electricity markets while avoiding administrative penalties for non-performance.

- System operators in decentralized, vertically disintegrated electricity markets want reliable day-ahead schedules for security analysis.
- Absent performance incentives, vertically disintegrated market participants with short or long positions in the real-time energy market will have an incentive to provide day-ahead schedules that do not reflect their operating intentions.

RATIONALE

One approach to attaching performance incentives to day-ahead schedules is to disallow changes to day-ahead schedules and/or impose administrative penalties for deviations from day-ahead schedules.

Reliance on administrative restrictions and penalties to provide performance incentives has several limitations:

- Restrictions on schedule changes can prevent market participants from responding to changes in load, outages, or fuel supply, exacerbating price volatility.
- Restrictions on schedule changes will not necessarily prevent gaming and may even increase its competitive impact.
- Restrictions on schedule changes can raise the cost of meeting load and thus raise the average price level.

The introduction of a two-settlement system in conjunction with locational marginal pricing provides grid users with additional flexibility in structuring transactions and enables the ISO to reduce reliance on administrative rules and penalties. A two-settlement system:

- Allows market-driven performance incentives to replace administrative penalties for non-performance.
- Reduces the need for administrative rules intended to limit gaming by introducing market-driven pricing and financial commitments to schedules.
- Allows all grid users to buy and sell energy at LMP prices to cover their “shorts” or dispose of their “longs.”
- Creates a day-ahead market in which FTR owners can sell unneeded transmission rights and grid users lacking FTRs can lock in the cost of transmission day ahead.

Non-Delivery Penalties -- OATT Attachment K, Sheet 124

1.6.5c A Market Seller offering an External Resource on a resource-specific basis that does not deliver energy as scheduled by the Office of the Interconnection shall be assessed a non-delivery charge as specified below, unless the resource being offered has suffered a Generator Forced Outage.

1.6.5d Subject to the conditions specified in this paragraph, the non-delivery charge for External Resources that do not deliver energy as scheduled shall be calculated hourly as follows: Pro-rated start-up plus hourly no-load fees specified in the Offer Data + [offered minimum dispatch level x (Unconstrained Market Clearing Price - offered energy price) X 110%]. For purposes of the foregoing calculation: (i) if the Unconstrained Market Clearing Price less the offered energy price is less than zero, this difference shall be set to zero; and (ii) start-up and no-load fees shall be subject to the requirements of Section 1.5.7(b). Payments or credits for non-delivery charges shall be used by the Office of the Interconnection to reduce or offset PJM Control Area costs for Operating Reserves.

Failure to Take Delivery -- OATT Attachment K, Sheet 124

1.6.6d An External Buyer that does not take delivery of the amounts of energy specified in its request to purchase shall be assessed a non-delivery charge. The non-delivery charge shall be calculated as the Unconstrained Market Clearing Price times the amount of energy not taken each hour. The non-delivery charge shall not apply to deliveries curtailed in accordance with Section 1.6.6(c) of this Schedule, or for periods when the Dispatch Rate exceeds the maximum value specified by the External Market Buyers in accordance with Section 1.6.1(b). Payments or credits for non-delivery charges shall be used by the Office of the Interconnection to reduce or offset PJM Control Area costs for Operating Reserves.

The original PJM tariff included administrative penalties for non-performance. These penalties were needed to deter various gaming strategies.

The current NEPOOL tariff includes restrictions on the scheduling of real-time imports, real-time exports and self-scheduling generation in real time that deter gaming within the one-settlement system but also greatly restrict market participant choices.

A two-settlement system allows administrative penalties to be replaced with market-driven performance incentives.

The need for administrative penalties can be greatly reduced under an LMP-based two-settlement system.

- Financial commitments in the day-ahead market would make non-performance unprofitable to the extent that non-performance affects market prices.
- Non-performance that has no impact on the market would incur no penalties.

These performance incentives will exist to the extent that constraints are reflected in the pricing system. Exceptions can exist for units providing reactive power and inertia.

Under locational marginal pricing and a two-settlement system, transmission customers that do not schedule use of their FTRs (or who are not, in effect, scheduled to use them in the ISO's day-ahead scheduling process), in effect, sell the use of this transmission capacity in the day-ahead market.

- Absent a day-ahead settlement process for unscheduled transmission rights, transmission rights holders would have an incentive to submit schedules matching their unsold rights holdings, regardless of their operating intentions.
- The ISO's day-ahead scheduling process also, in effect, prices and reconfigures point-to-point FTRs to meet the needs of other customers.

A two-settlement system also allows generators, loads and transmission customers to lock in prices in the day-ahead market. Under a one-settlement system, all energy sold through the pool and all transmission not hedged by FTRs would be settled at real-time prices.

- Misforecasts by load or non-performance by generators that raise or lower real-time prices affect the costs and profitability of all generators and loads, not only those who deviated from schedule.
- Generators and loads can seek to hedge price volatility through longer-term bilateral contracts, including contracts for differences (CFDs).

Generators with bilateral contracts cannot hedge themselves under a one-settlement system by relying on the ISO's day-ahead scheduling process.

- Generators with bilateral contracts that are not scheduled to run (because of low forecast demand day ahead) would be exposed to price risk if real-time demand is above forecast.
- Generators with bilateral contracts therefore must either self-schedule themselves to run or enter into bilateral purchases in order to hedge themselves against high real-time prices, if they are not scheduled to operate by the ISO.

Under a two-settlement system, a generator with a bilateral contract can bid both its generation resource and its contractual obligation in the day-ahead market and thereby lock in the cost of covering its contract whether it is scheduled to run or not.

Day-ahead markets can also provide a mechanism for generators to schedule fuel supply that is consistent with their operating schedules.

- Gas-fired generation with explicit forward contracts for energy can schedule gas to support their day-ahead sales.
- Day-ahead gas scheduling can be particularly important during winter periods in which daily gas balancing rules are in effect and unscheduled gas may be very expensive.

Absent transmission constraints, the short-term price hedging functions of a day-ahead market could also be achieved through bilateral trades.

- The fundamental rationale for a centralized day-ahead market process is to coordinate intended usage of the transmission system prior to unit commitment for both reliability purposes and economic efficiency goals.
- Coordination of transmission usage based on schedules is unworkable, however, unless those schedules reflect actual operating intentions.
- Day-ahead markets and two-settlement systems are essentially mechanisms for attaching financial consequences to day-ahead schedules for transmission usage.
- Day-ahead energy markets are actually just the most convenient mechanism for coordinating day-ahead transmission markets.

TWO-SETTLEMENT MECHANICS

A two-settlement system consists of a day-ahead market (forward market) and a real-time dispatch market (spot market). In each market settlements for energy and transmission are at the market-clearing LMP price determined by the ISO.

A two-settlement system has four major phases:

1. The day-ahead bidding and scheduling process.
2. The hour-ahead bidding and scheduling process.
3. The real-time dispatch.
4. The day-after accounting.

Prior to the dispatch day, at a time fixed by the ISO, the ISO receives bids from flexible load and generation, schedules from self-scheduled generation and bids and/or schedules from transmission-only customers.

- Flexible generators would submit running cost, start-up cost and minimum load cost bids.
- Flexible loads would submit load quantities and reservation prices.
- Flexible transmission customers would submit transmission schedules with incremental and decremental bids for every hour of the dispatch day.
- Inflexible generators, loads and transmission customers would submit the location and amount of their net injections for each hour of the dispatch day.

The ISO uses all the information available on system conditions at this time combined with load and generation bids to determine a least-cost schedule subject to all reliability requirements.

- The ISO will forecast load, compare this forecast to the scheduled loads of grid users and schedule additional reserves if appropriate.
- The ISO will schedule flexible generation to meet scheduled and flexible loads and accommodate transmission schedules at least cost over the dispatch day while ensuring that there are enough reserves available (spinning or quick-start) to meet the ISO’s load forecast and reliability rules for the dispatch day.
- The ISO will provide generators, loads and transmission customers with day-ahead schedules.

The ISO calculates day-ahead LMP prices based on the day-ahead schedule and the bids of all flexible generation, transmission and loads scheduled by the ISO.

- These day-ahead prices are posted on the ISO Oasis.
- These schedules and prices would define binding financial commitments for day-ahead purchases and sales and day-ahead transmission for the “first settlement” for those participating in the day-ahead forward market.

Prior to the real-time dispatch, at a time fixed by the ISO, there would be an opportunity for market participants to make adjustments to their day-ahead schedules.

- Generators would inform the ISO of the bilateral or self-scheduling of generation segments not scheduled with the ISO day ahead.
- Loads and transmission customers scheduled day-ahead could submit adjustments to their existing schedules.
- Flexible generators, loads and transmission customers not scheduled by the ISO in the day-ahead scheduling process to either operate or provide reserves could submit bids to provide additional generation or load, and could submit additional transmission schedules with incremental and decremental bids.

- Flexible generators scheduled by the ISO in the day-ahead scheduling process to either operate or provide reserves could adjust their bid prices (relative to those submitted day ahead).
- Inflexible generators, loads and transmission customers could submit schedules for additional generation, load and bilateral transactions.

In real time, conditions may vary from the forecast necessitating changes in the dispatch.

- The ISO would dispatch flexible generation, loads and transmission customers to meet actual loads at least as-bid cost during the dispatch hour, based on the hour-ahead bids and schedules.
- Generators would operate as directed by the ISO in real time, loads would consume power, transmission customers would inject and withdraw power per their schedules and directions from the ISO.
- The ISO would calculate real-time LMP prices for each location based on the actual real-time dispatch and the bids of the flexible generation, loads and transmission customers.

Settlements for Day-Ahead Schedules:

- Generators and loads scheduled day-ahead would pay and be paid the day-ahead LMP for the energy that they were scheduled to provide or consume in the day-ahead dispatch.
- Transmission scheduled day ahead would be charged for congestion based on the difference in day-ahead LMP prices for scheduled transmission.
- FTR holders would be paid congestion credits based on the differences in day-ahead LMP prices.

Settlements for Real-Time Imbalances:

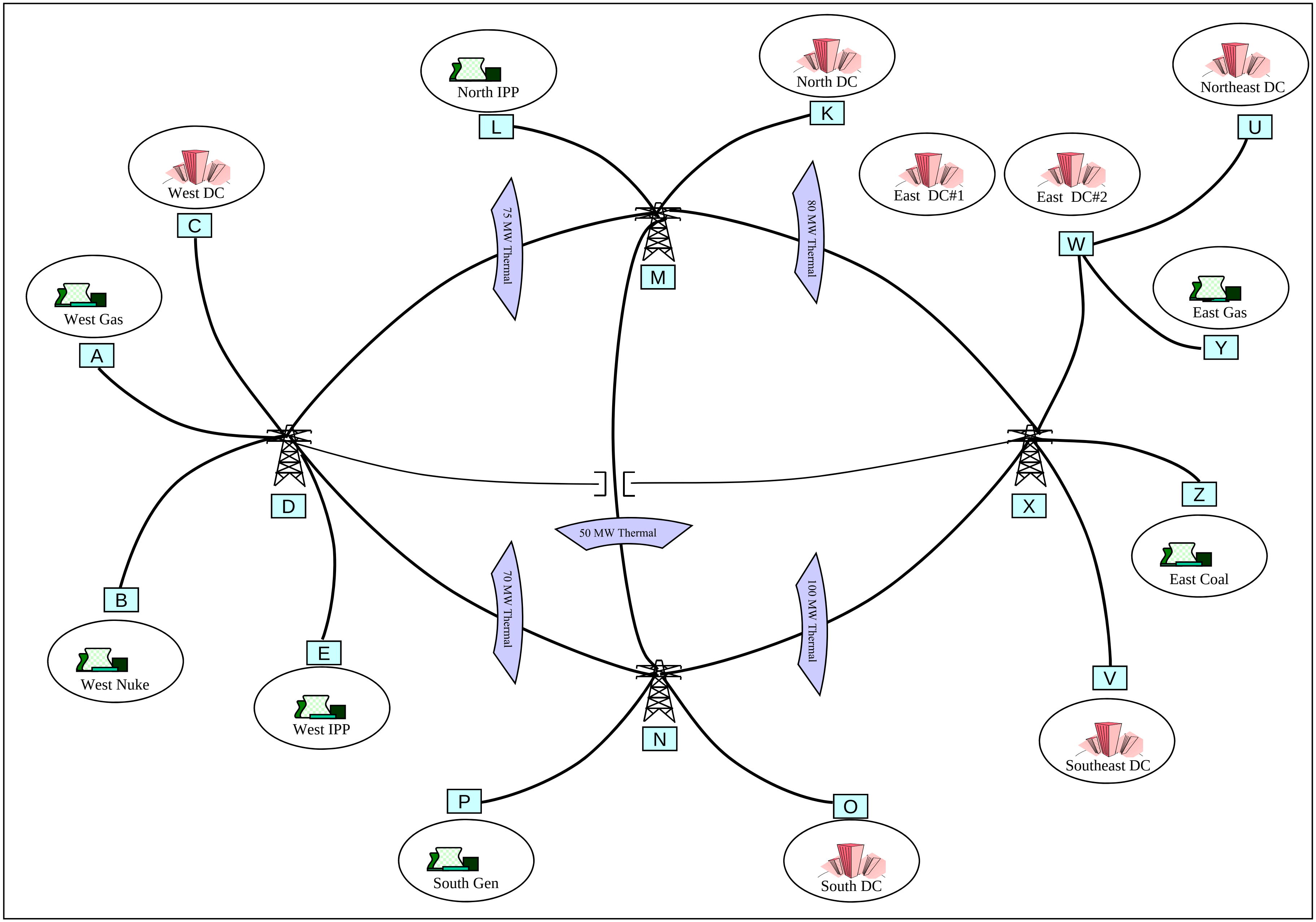
- Flexible generators that were instructed by the ISO to increase or decrease generation (compared to the day-ahead schedule) would settle these deviations from the day-ahead schedule at real-time prices.
- Generators that failed to perform as scheduled would cover their day-ahead financial obligation to deliver power by buying power at the real-time price.
- Loads would settle deviations from their day-ahead schedules at real-time prices.

Settlements for Real-Time Imbalances:

- Internal transmission customers would settle any deviations from their day-ahead schedules at real-time prices.
- External transmission customers would settle differences between their day-ahead and hour-ahead transmission schedules at the difference in real-time prices.
- Generators committed by the ISO that fail to recover their as-bid costs (including no-load and start-up costs) in either their day-ahead or real-time schedule valued at LMP prices (computed separately for each schedule) would recover the balance in uplift.

Illustrative Examples

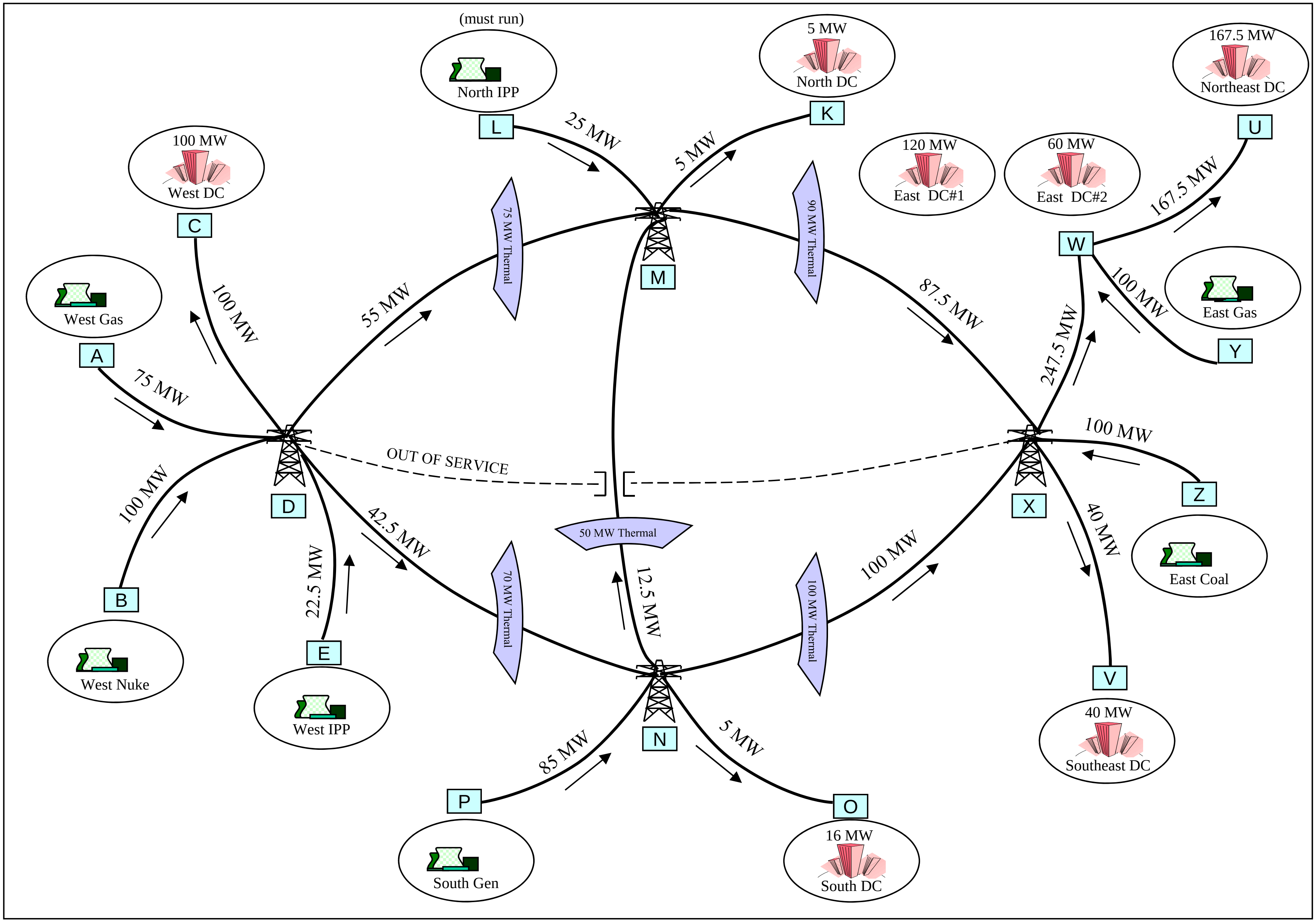
ILLUSTRATIVE GRID



The examples below illustrate the operation of an LMP-based two-settlement system using the hypothetical grid shown above. For simplicity, all of the examples are based on a single day-ahead schedule, but three different real-time dispatches are utilized to illustrate particular features of an LMP-based two-settlement system.

- LSEs scheduling their loads day ahead pay day-ahead prices to meet their load.
- LSEs that over- or underforecast their loads cover their imbalances at real-time prices.
- Generators are paid day-ahead prices for the output scheduled day ahead.
- Generators that are redispatched or fail to perform settle their imbalances at real-time prices.

LOAD FLOW FOR FTR ALLOCATION

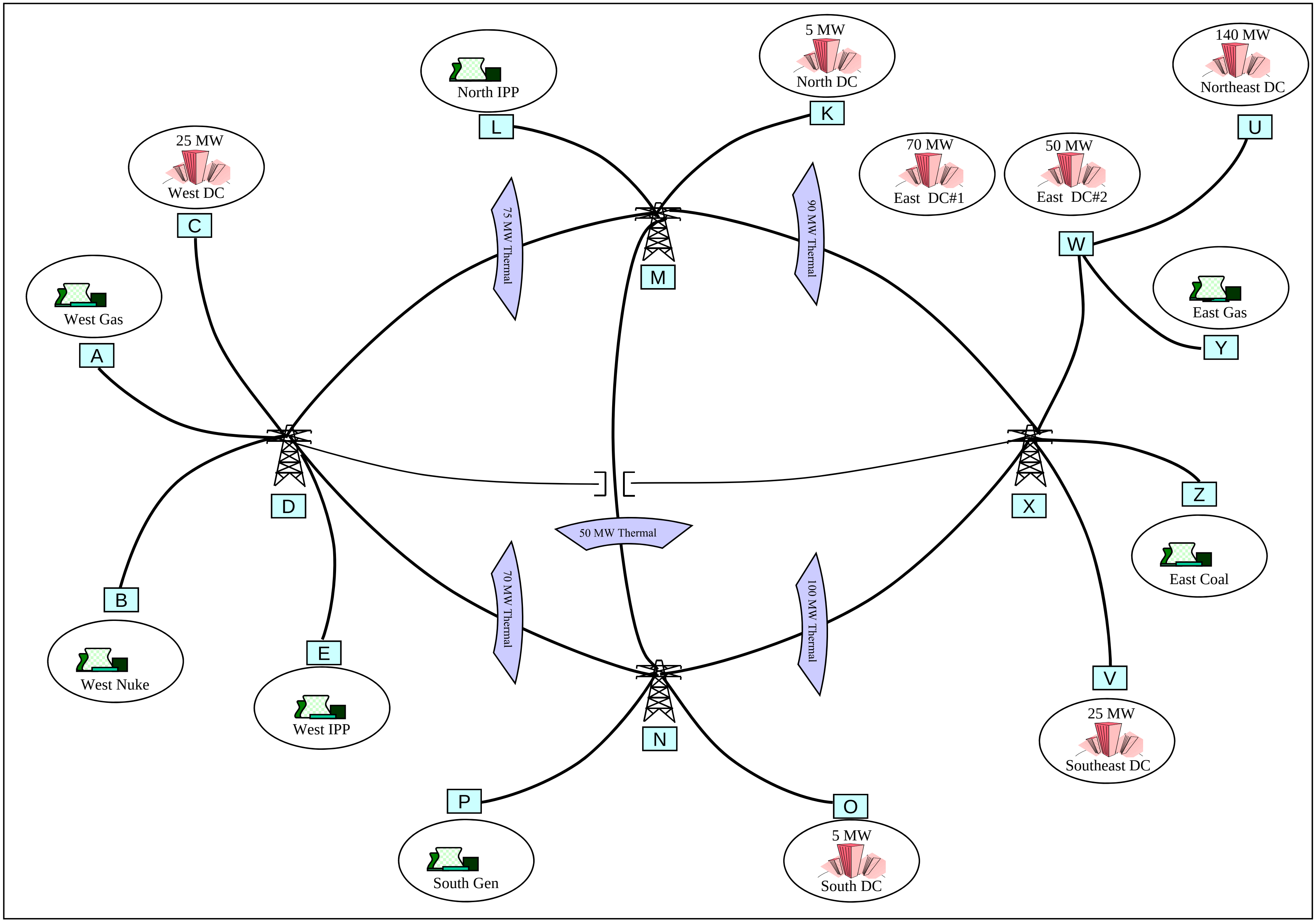


For these examples, we have assumed ownership of FTRs as shown below. As the figure above indicates, these FTRs are simultaneously feasible. The ownership of these FTRs by individual LSEs is described in the specific examples.

Loads	**From __ to Bus**	**FTR (MW)**
Northeast DC Loads	E-U	22.5
	Y-U*	50
	P-U	70
	Z-U*	25
North DC Loads	B-K	5
Southeast DC Loads	L-V	10
	Y-V*	15
	Z-V*	15
West DC Loads	B-C*	25
	A-C*	75
East DC 1 Loads	B-W	70
	Y-W*	30
East DC 2 Loads	Z-W*	60
	L-W	15
	Y-W*	5
South DC Loads	P-O*	16

* These FTRs always have a zero value in the examples below and are omitted from subsequent tables.

DAY-AHEAD LOADS

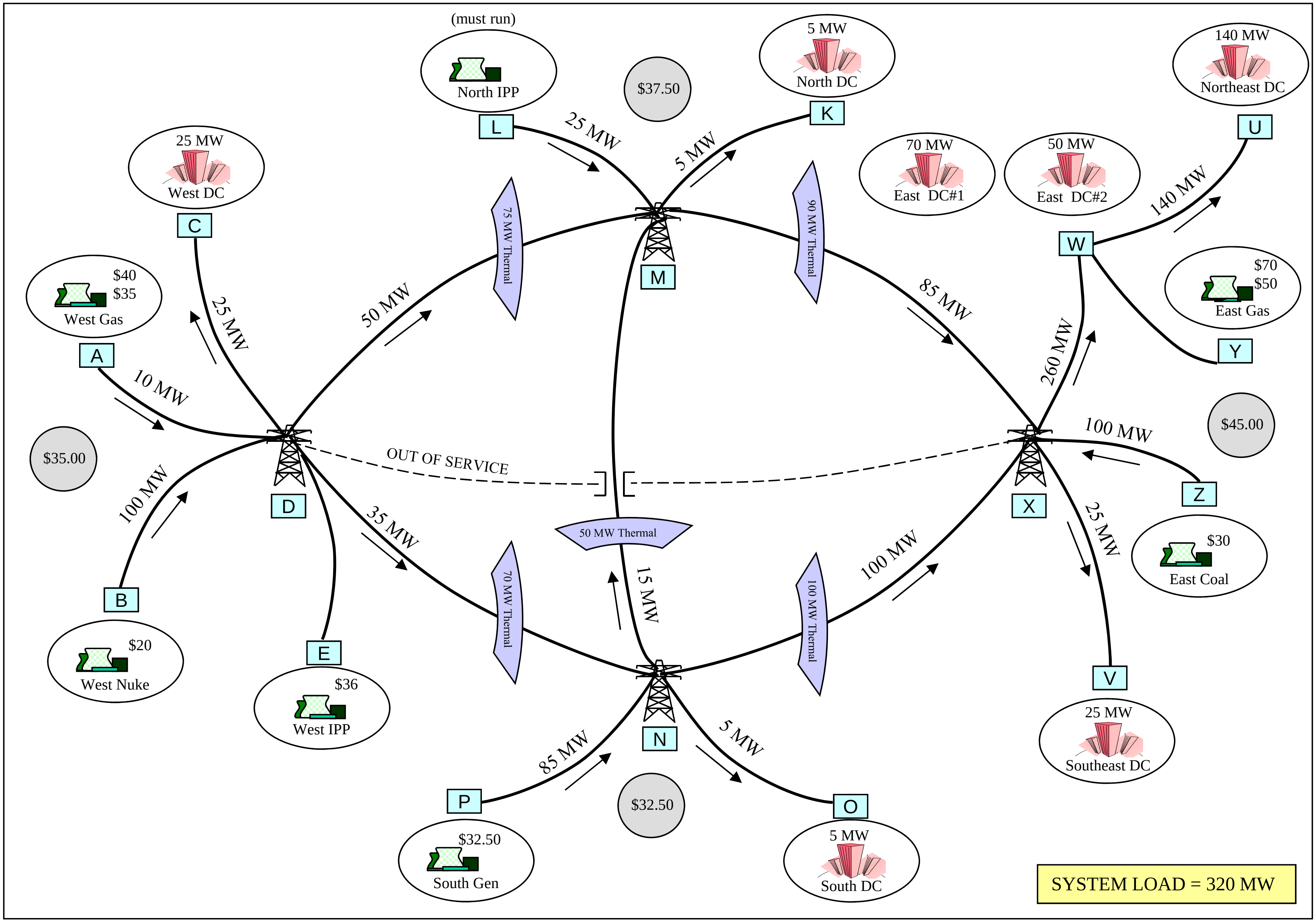


Generators and loads not covered by bilateral contracts bid into the ISO coordinated dispatch, making the bids listed in the table below in the day-ahead market. The bilateral contract participants could provide fixed schedules to the ISO.

BIDS INTO DAY-AHEAD SCHEDULE						
	Bids			Bilateral Schedules		
		Generator Bid			Generator Bid	
Bidder	Load Bid[1] (MW)	Running Cost ($/MWh)	Capacity (M)	Load Bid[1] (MW)	Running Cost ($/MWh)	Capacity (MW)
West IPP		40.00	50			
West Gas 1		35.00	50			
West Gas 2		40.00	50			
West Nuke		20.00	100			
West DC Loads	25					
North IPP #1					Must-run	25
North DC Loads	5					
South Gen		32.50	90			
South DC Loads	5					
East DC #1 Loads	70					
East DC #2 Loads	35			15		
Northeast DC Loads	140					
East Gas 1		50.00	50			
East Gas 2		70.00	175			
East Coal		30.00	100			
Southeast DC Load	15			10		

[1] All loads bid inflexibility in this example.

DAY-AHEAD DISPATCH

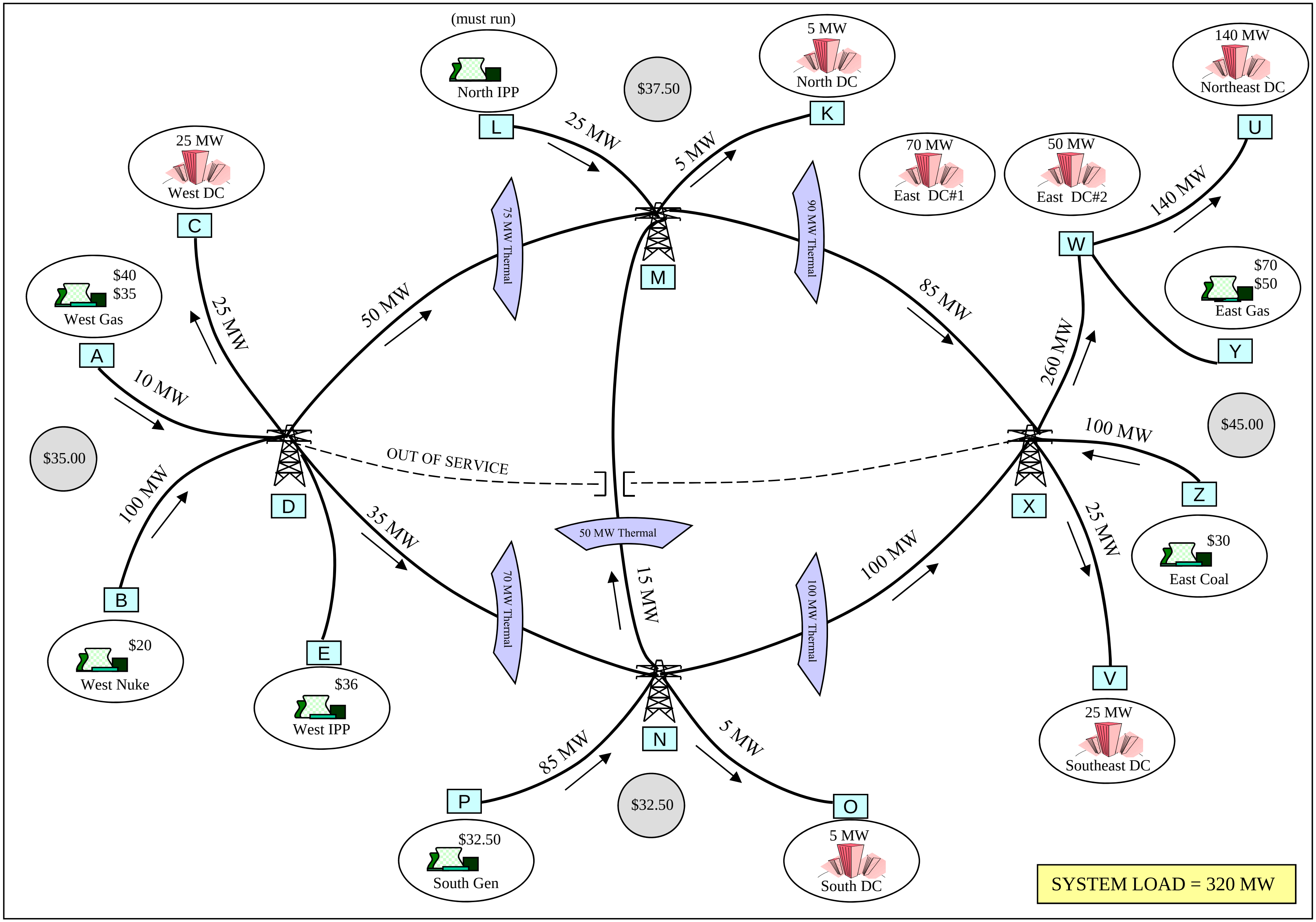


Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

The ISO takes the day-ahead bids and transmission schedules, determines the security-constrained unit commitment and schedules generation to meet the bid in loads and provide the requested transmission service at least cost. These bids yield the day-ahead schedules and LMPs illustrated above. The ISO would coordinate the following day-ahead settlements:

- Generators would be paid the day-ahead LMP for their scheduled sales.
- Loads would pay the day-ahead LMP for their scheduled purchases.
- Transmission customers would pay the day-ahead transmission congestion charges for their scheduled transmission.

DAY-AHEAD DISPATCH



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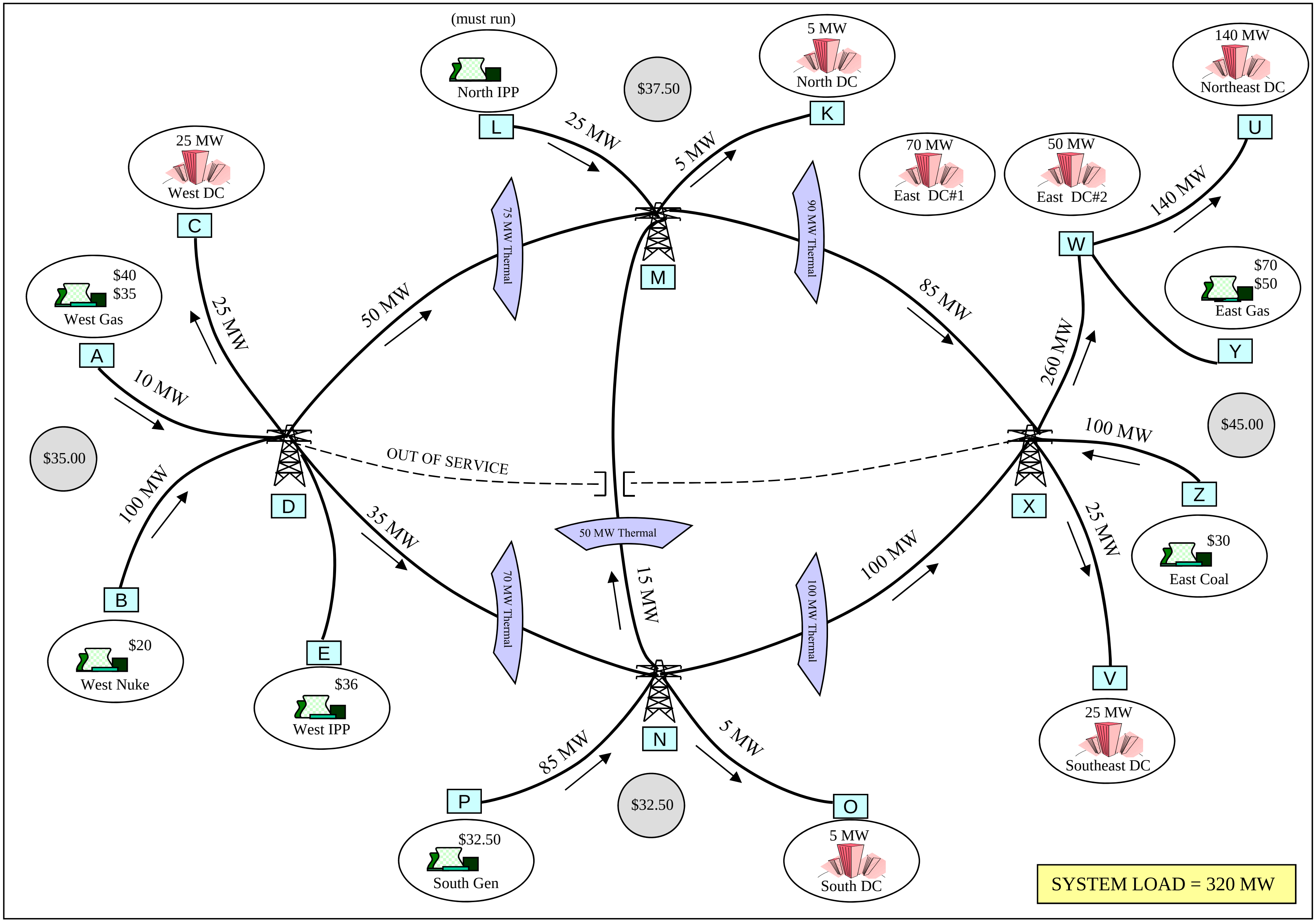
The ISO would settle with FTR holders based on the congestion charges in the day-ahead market.

DAY-AHEAD DISPATCH



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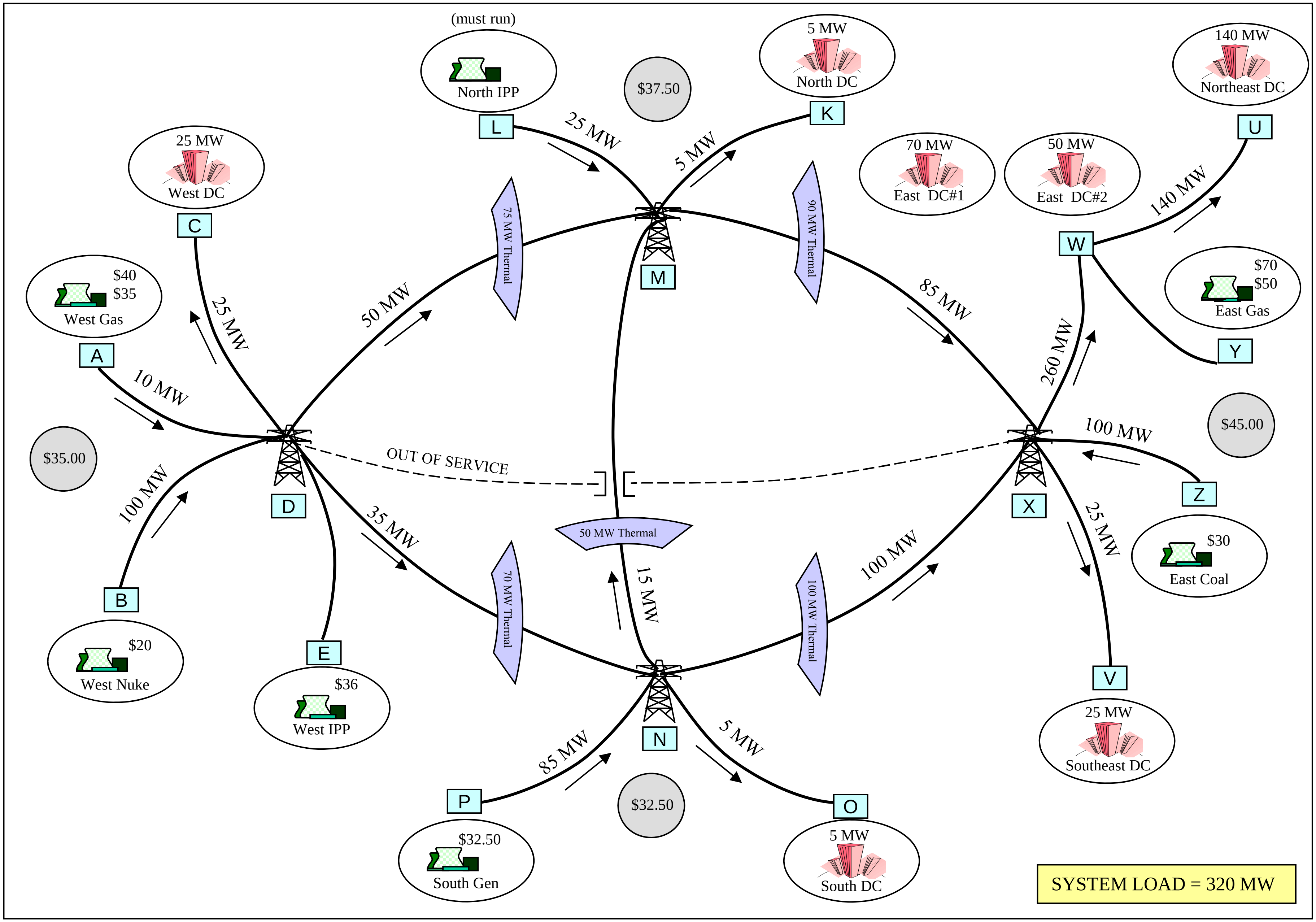
Generators that bid into the day-ahead market and are scheduled by the ISO would be paid the day-ahead LMP for the energy the generators are scheduled to produce (excluding energy scheduled to serve bilateral contracts). This would yield the following revenue for generators bidding into the day-ahead market.

GENERATION REVENUES IN DAY-AHEAD DISPATCH				
	Energy Revenue			
Generators	**At Bus**	**Day-Ahead LMP ($/MWh)**	**Scheduled Generation (MWh)**	**Total Revenue ($)**
West Gas	A	35.00	10	350.00
West Nuke	B	35.00	100	3,500.00
South Gen	P	32.50	85	2,762.50
East Gas	Y	45.00	0	0.00
East Coal	Z	45.00	100	4,500.00
West IPP	E	35.00	0	0.00
North IPP	L	37.50	0	0.00
Total			295	11,112.50

Generators purchasing transmission for sales under bilateral contracts would be paid for energy through their bilateral contracts.

DAY-AHEAD DISPATCH



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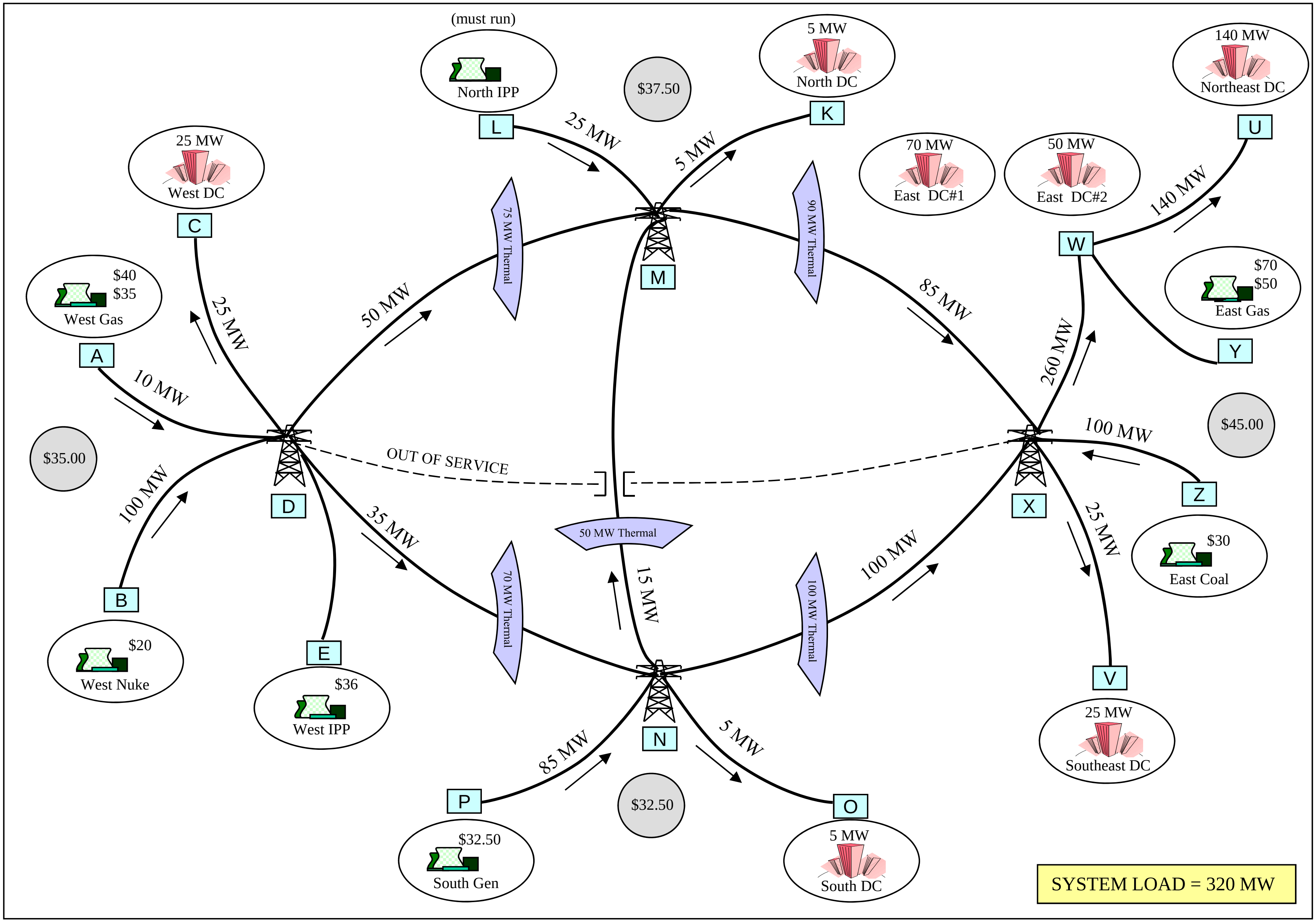
LSEs will pay the day-ahead LMP for all load that is scheduled day ahead. In the example, LSEs would pay $12,925 for load scheduled day ahead.

LSE COSTS IN DAY-AHEAD DISPATCH			
Customers	**Day-Ahead LMP ($/MWh)**	**Load (MWh)**	**Total Charge ($)**
West DC LSEs	35.00	25	875.00
North DC LSEs	37.50	5	187.50
South DC LSEs	32.50	5	162.50
Northeast DC LSEs	45.00	140	6,300.00
East DC #1 LSEs	45.00	70	3,150.00
East DC #2 LSEs	45.00	35	1,575.00
Southeast DC LSEs	45.00	15	675.00
Total		295	12,925.00

Southeast DC and East DC #2 LSEs that have bilateral contracts with North IPP units would not be charged for their scheduled load. The participants in the bilateral transactions would be charged for transmission, however, and customers served under bilateral contracts would pay a contract price for energy.

DAY-AHEAD DISPATCH



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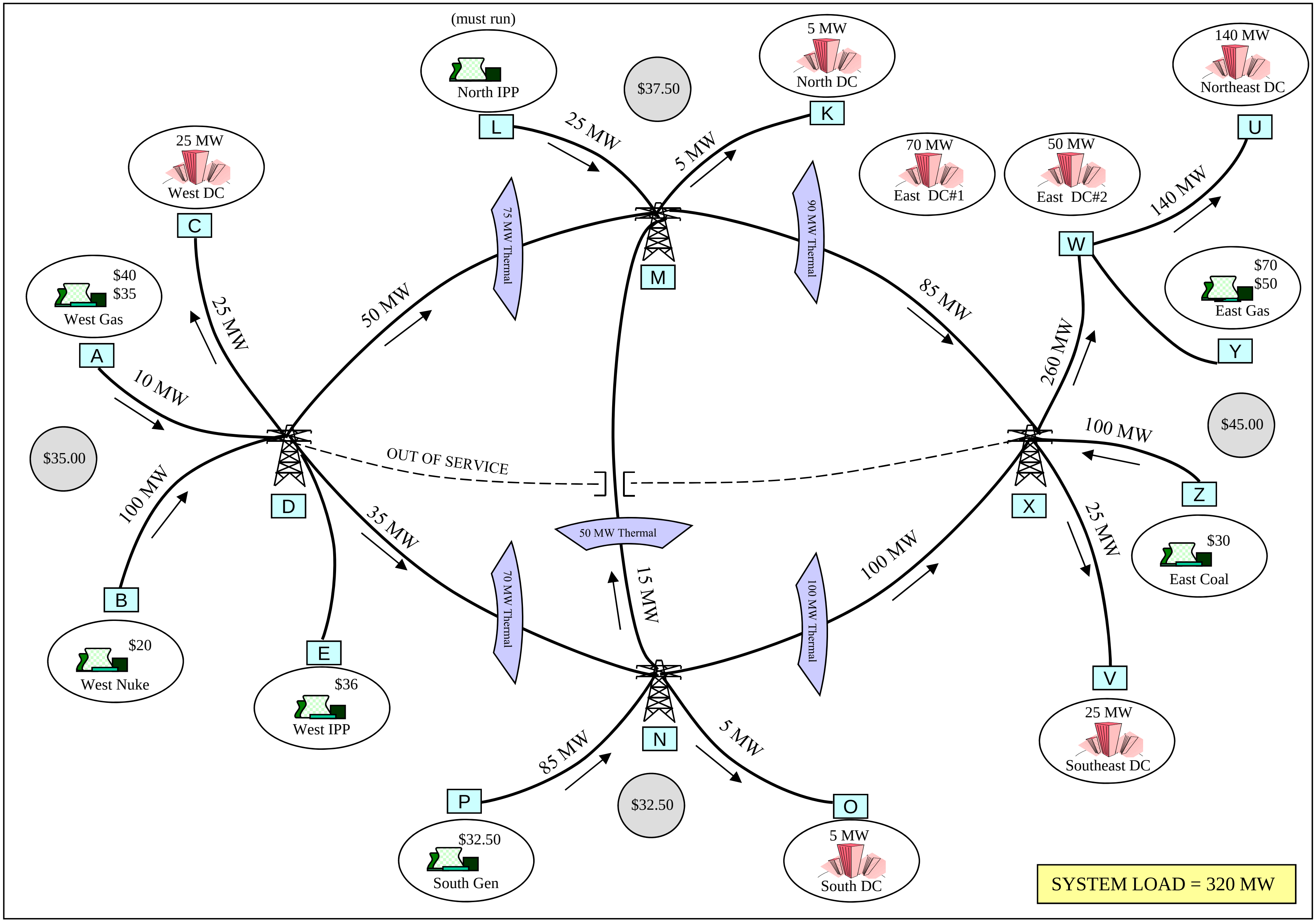
The transmission congestion charge is the difference between the LMP at the delivery bus specified under the contract and the LMP at the receipt bus. It reflects the cost of transmission congestion between these locations.

As the table below illustrates, the ISO would collect transmission congestion charges from participants in pool transactions as part of the price of energy, while an explicit transmission charge would be collected from participants in bilateral transactions.

GRID OPERATOR DAY-AHEAD SETTLEMENT COSTS AND REVENUES				
Transaction	MWh	LMP ($/MWh)	Revenue ($)	Cost ($)
Payments by LSEs				
West DC LSEs	25	35.00	875.00	
North DC LSEs	5	37.50	187.50	
South DC LSEs	5	32.50	162.50	
Northeast DC LSEs	140	45.00	6,300.00	
East DC #1 LSEs	70	45.00	3,150.00	
East DC #2 LSEs	35	45.00	1,575.00	
Southeast DC LSEs	15	45.00	675.00	
Total	295		12,925.00	
Payments by Transmission-Only Customers				
North IPP/Southeast DC LSEs	10	45.00 – 37.50 = 7.50	75.00	
North IPP/East DC #2 LSEs	15	45.00 – 37.50 = 7.50	112.50	
Total	25		187.50	
Payments to Generators				
West Gas	10	35.00		350.00
West Nuke	100	35.00		3,500.00
South Gen	85	32.50		2,762.50
East Gas	0	45.00		--
East Coal	100	45.00		4,500.00
West IPP	0	35.00		--
North IPP	0	37.50		--
Total	295			11,112.50
ISO Residual Collection			2,000.00	
Note: Figures may not sum due to rounding.				

DAY-AHEAD DISPATCH



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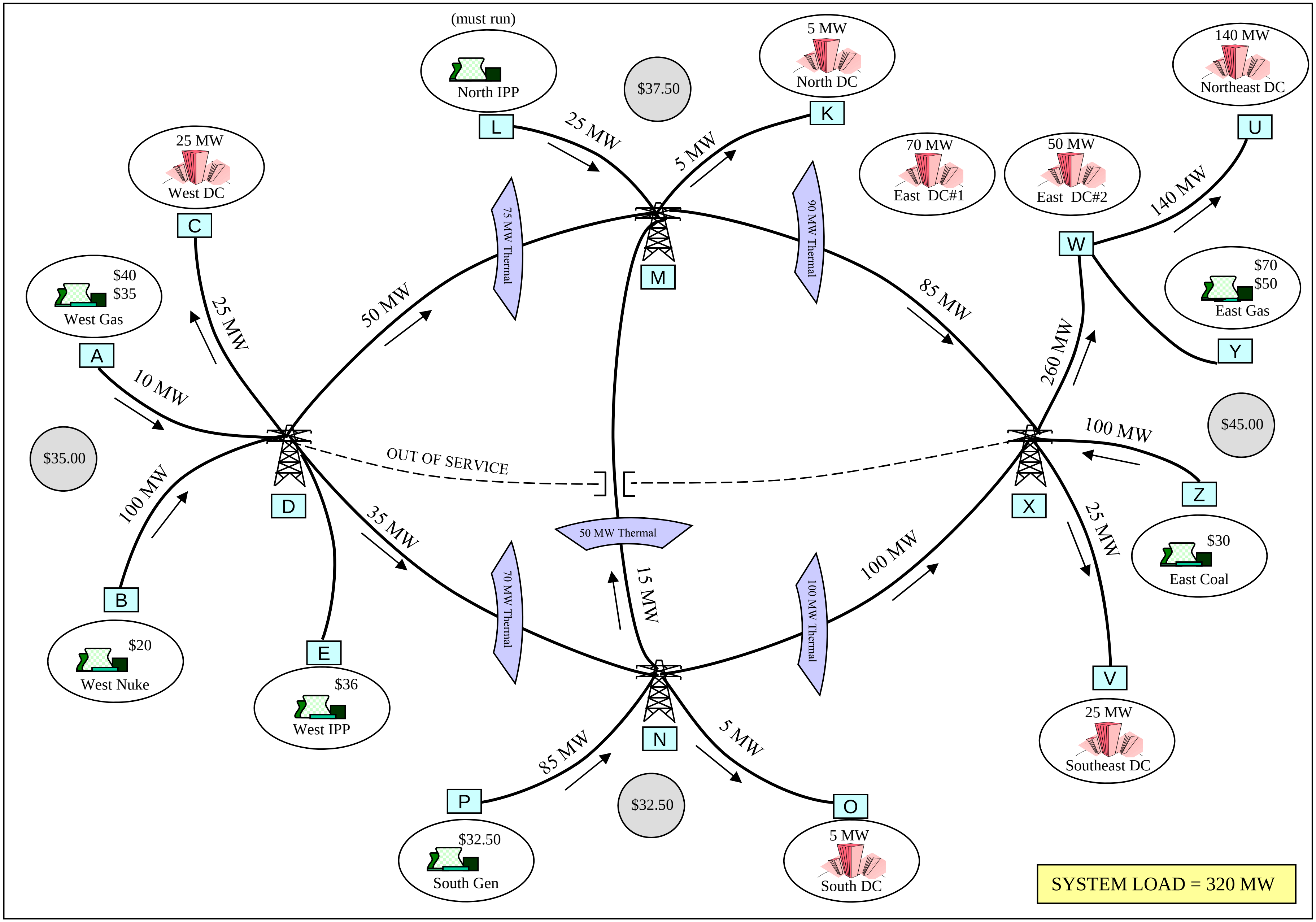
FTR holders would receive the following congestion credits, given this day-ahead schedule.

CONGESTION CREDITS TO HOLDERS OF FTRs IN THE DAY-AHEAD SETTLEMENT UNDER TWO-SETTLEMENT SYSTEM							
				Congestion Costs ($/MWh)			
LSE	**MW**	**Injection Bus**	**Withdrawal Bus**	**LMP at Withdrawal Bus**	**LMP at Injection Bus**	**Difference ($/MWh)**	**FTR Credit ($)**
Southeast DC LSEs	10.0	L	V	45.00	37.50	7.50	75.00
North DC LSEs	5.0	B	K	37.50	35.00	2.50	12.50
Northeast DC LSEs	22.5	E	U	45.00	35.00	10.00	225.00
Northeast DC LSEs	70.0	P	U	45.00	32.50	12.50	875.00
East DC #1 LSEs	70.0	B	W	45.00	35.00	10.00	700.00
East DC #2 LSEs	15.0	L	W	45.00	37.50	7.50	112.50
Total Congestion Rents Paid to Owners of Transmission Congestion Contracts							**2,000.00**
Note: Figures may not sum due to rounding.							

DAY-AHEAD DISPATCH



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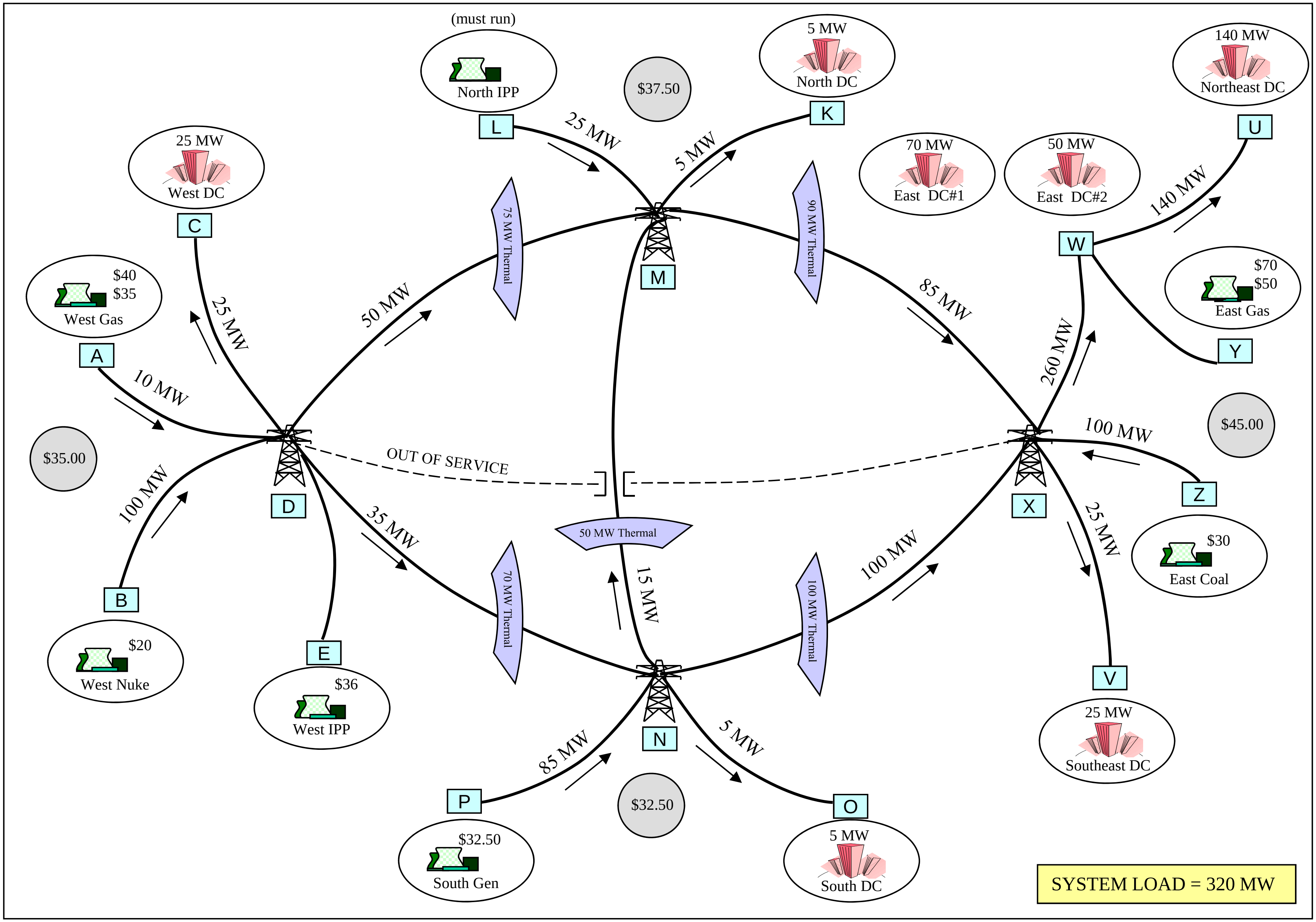
In this hour, the congestion charges collected day ahead by the ISO would just cover the congestion credits it would distribute to FTR holders.

CONGESTION CHARGES RETAINED BY ISO	
Total Payments by LSEs for Energy	$12,925.00
Bilateral Transmission Charges	187.50
Total Payments to Generation for Energy	11,112.50
Congestion Rents Collected by ISO	2,000.00
Total ISO FTR Payments	2,000.00
Congestion Charges Retained by ISO	$0.00

DAY-AHEAD DISPATCH



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The operation of the two-settlement system is illustrated by focusing on the operations of five hypothetical LSEs (Blue, Red, Tan, Yellow and Green) serving loads with real-time meters located in Northeast DC and Southeast DC.

FTRs			
	MW	**Injection Bus**	**Withdrawal Bus**
Blue	2	E	U
	2	P	U
	1	Z	U
Red	2	E	U
	2	P	U
	1	Z	U
Tan	5	Z	U
Yellow	5	L	V
Green	5	Z	V

BLUE AND RED TRANSMISSION CONGESTION CREDITS ($/MWh)						
MW	**Injection Bus**	**Withdrawal Bus**	**LMP at Withdrawal Bus**	**LMP at Injection Bus**	**Difference**	**Value**
2	E	U	45	35	10	20
2	P	U	45	32.5	12.5	25
1	Z	U	45	45	0	0
Total						45

BLUE AND RED ENERGY COSTS						
	Day-Ahead Schedule (MW)	**Day-Ahead Price ($/MW)**	**Day-Ahead Energy Cost ($)**	**FTR Value ($)**	**Net Cost ($)**	**Average Cost ($/MW)**
Blue	5	45	225	45	180	36
Red	5	45	225	45	180	36

Blue, Red and Tan all serve loads in Northeast DC and schedule purchases of 5 MW each in the day-ahead market. All three retailers pay $45/MWh for the energy they purchase day ahead (the LMP price at Bus U), but the net cost to Blue and Red would be reduced by their FTR ownership.

The average cost of energy to Blue and Red is therefore $36/MWh, while the average cost to Tan is $45/MWh.

TRANSMISSION USAGE CHARGES					
	MW	**$/MW**	**Cost ($)**	**FTR Value ($)**	**Net Cost ($)**
Yellow	5	7.50	32.50	32.50	0.00
Greet	5	7.50	32.50	0.00	32.50

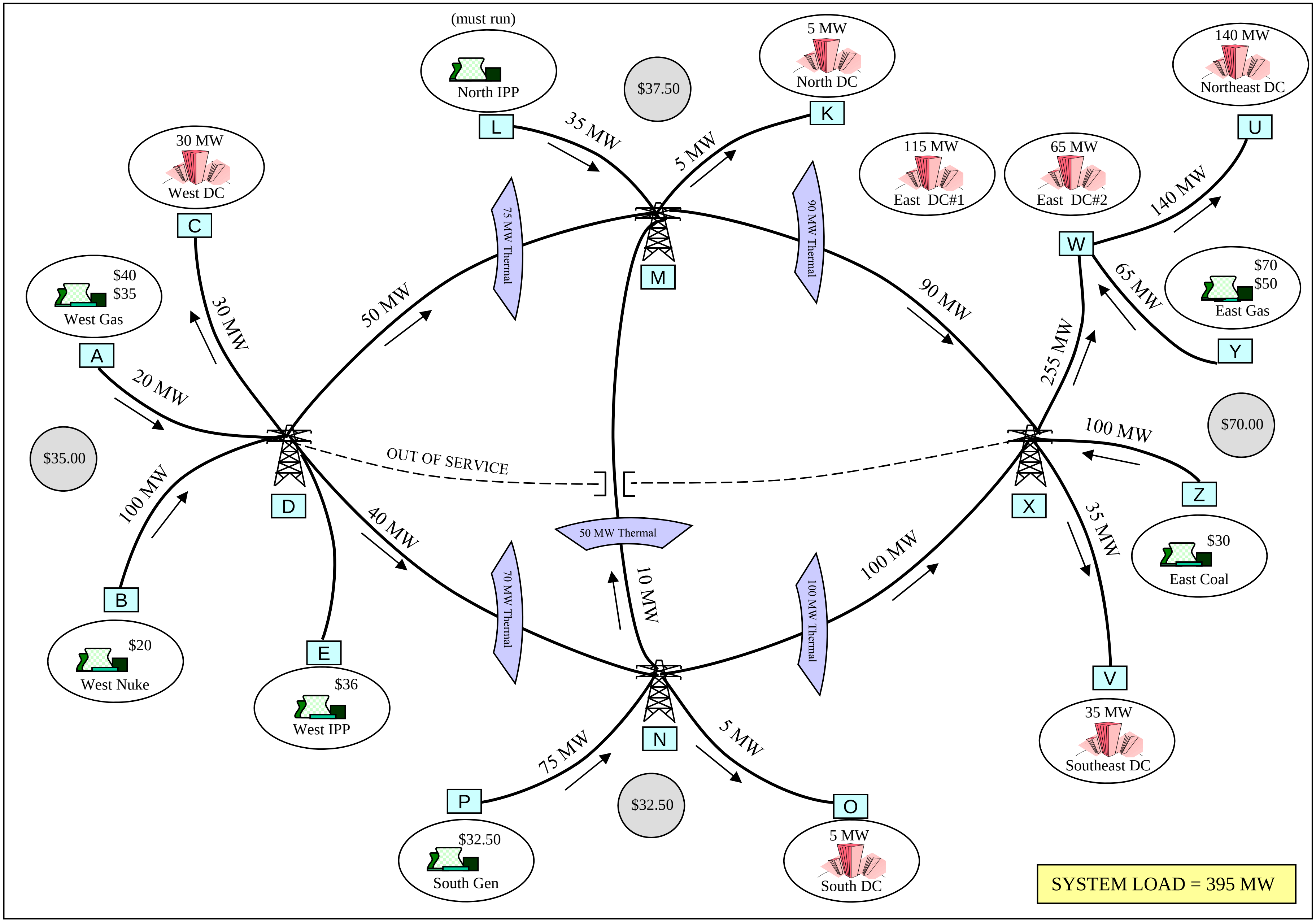
FTR VALUES			
	Delivery Price ($)	**Receipt Price ($)**	**FTR Value ($)**
L-V	45.00	37.50	7.50
Z-V	45.00	45.00	0.00

Yellow and Green are LSEs serving load in Southeast DC but they do not schedule any purchases of energy from the pool. Instead, they each purchase 5 MW of energy from North IPP in a bilateral transaction and schedule transmission from L to V. Each LSE pays \$7.50/MWh in congestion charges for 5 MWh of transmission from L to V (\$45 - \$37.50).

Yellow receives \$7.50/MWh in transmission credits for the 5 MW of L to V FTRs it owns, so it does not incur any net transmission costs for its day-ahead schedule.

Green owns FTRs from Z to V, which neither hedge its purchase nor have any value due to congestion in the hour-ahead schedule, so it incurs net transmission costs of \$7.50/MWh.

REAL-TIME DISPATCH 1

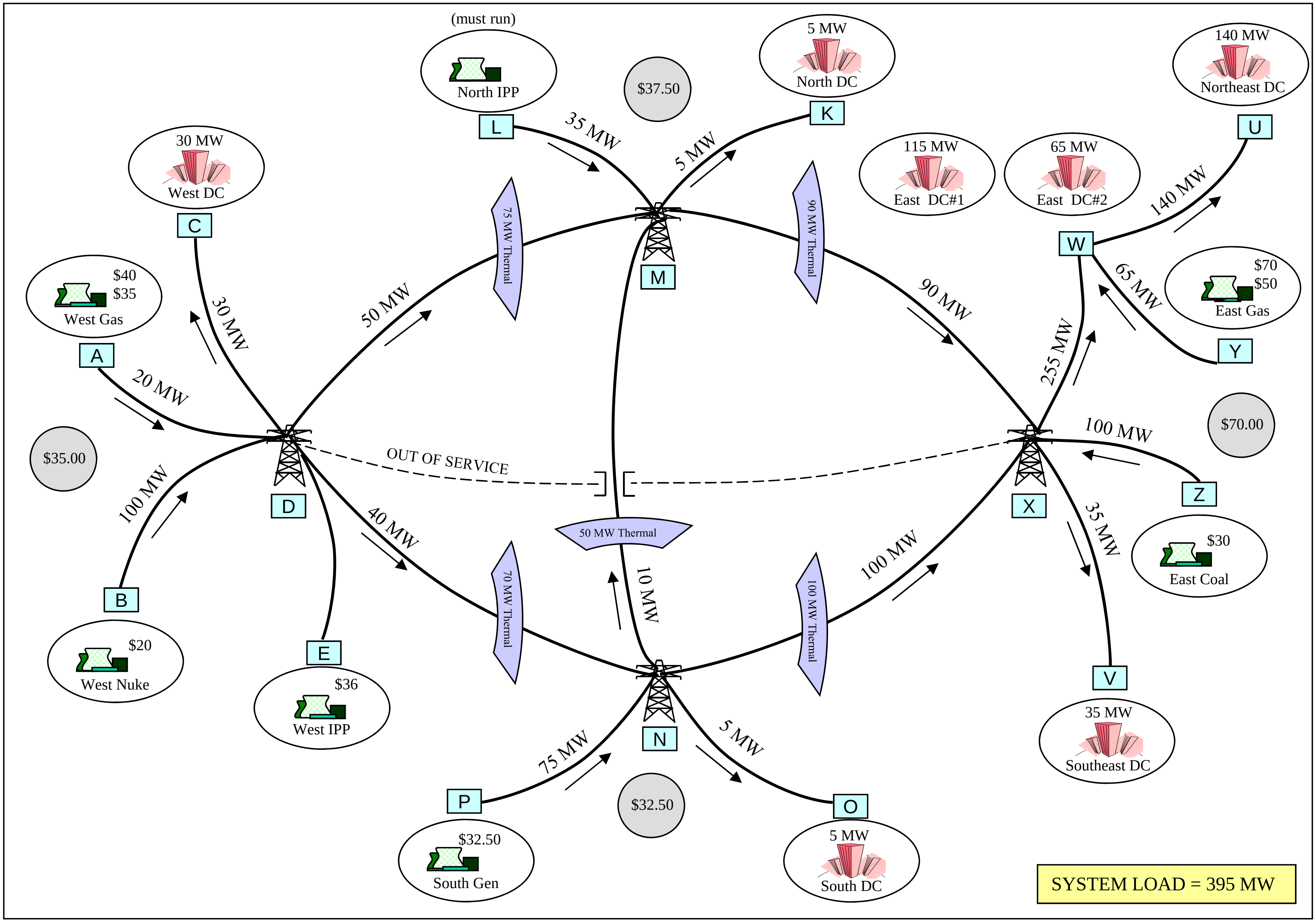


Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

To illustrate the operation of the proposed two-settlement system, it is assumed that total system load in the balancing dispatch is greater than the load that was scheduled day ahead and that transmission congestion increases between the day-ahead schedule and balancing dispatch.

Under the proposed two-settlement system, LSEs would pay the day-ahead LMP at their location for energy consumed that was scheduled day ahead. They would get credits for any FTRs they hold, settled at the day-ahead prices. They would pay the real-time dispatch LMP at their bus only for load in excess of the scheduled amount, while they would receive the real-time LMP at their bus for all power purchased a day ahead but not consumed in the real-time dispatch.

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

REAL-TIME DISPATCH 1 LSEs

Consider first Blue, who scheduled 5 MWh of load at Northeast DC in the day-ahead market and whose customers consumed 5 MWh of energy in real time.

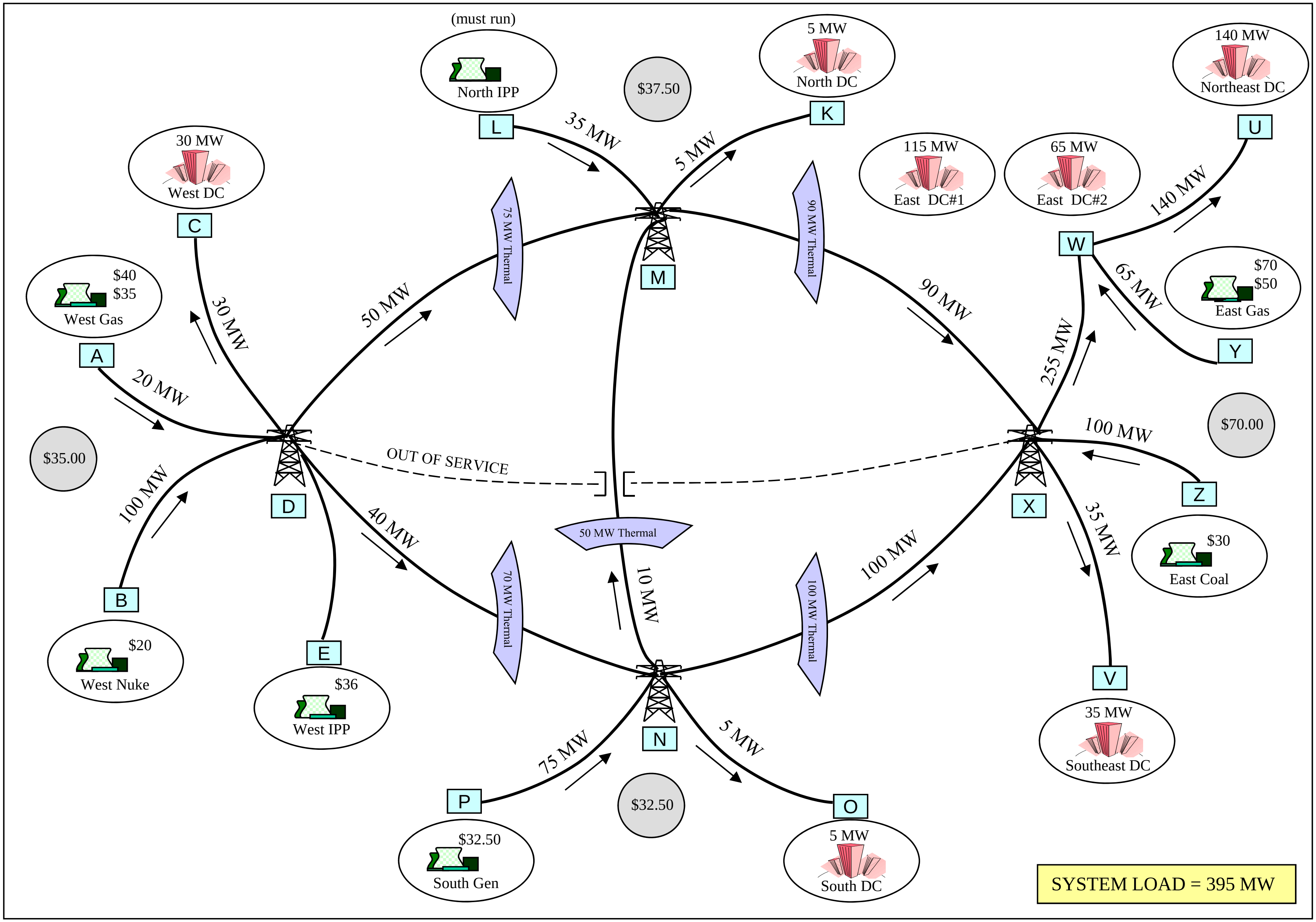
Because Blue's real-time consumption matches it day-ahead schedule, its cost of meeting load is unaffected by real-time prices.

COST OF MEETING LOAD UNDER TWO-SETTLEMENT SYSTEM										
	DAY-AHEAD DISPATCH				REAL-TIME DISPATCH					
LSE	**Scheduled Load (MWh)**	**LMP ($/MWh)**	**Cost ($)**	**FTR Credits ($)**	**Load (MWh)**	**Load Deviation (MWh)**	**LMP ($)**	**Cost ($)**	**Net Cost of Load ($)**	**Average Net Cost of Load ($/MW)**
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Blue	5	45.00	225.00	45.00	5	0	70.00	--	180.00	36.00

Equations:

[4] = [2] * [3]
[7] = [6] – [2]
[9] = [8] * [7]
[10] = [9] – [5] + [4]
[11] = [10] / [2]

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

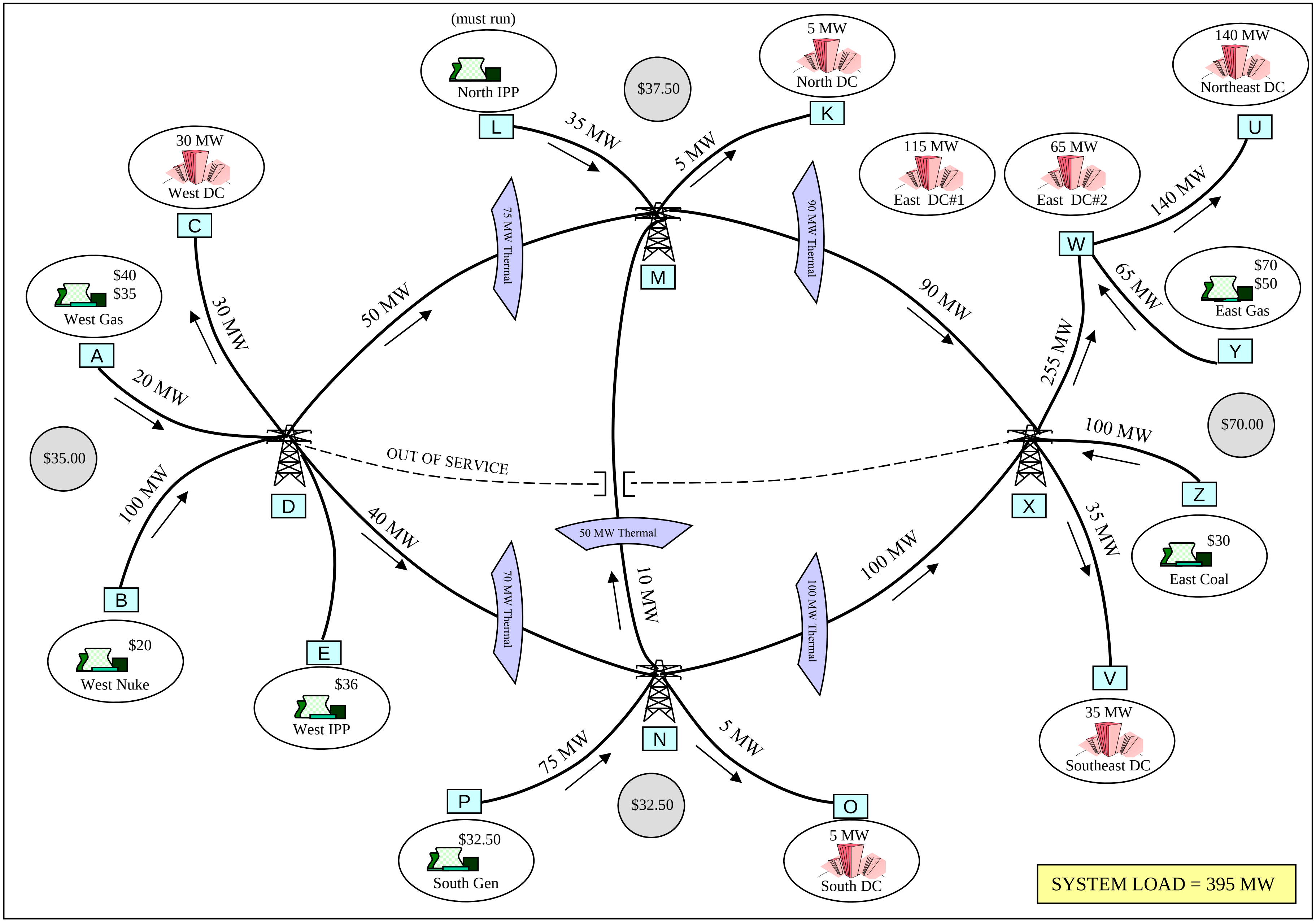
Under a one-settlement system, Blue's costs would have been somewhat higher because it would have paid the higher real-time prices for the load not hedged by FTRs from West to East.

COST OF MEETING LOAD UNDER ONE-SETTLEMENT SYSTEM						
LSE	**Load (MWh)**	**LMP ($MWh)**	**Energy Cost ($)**	**FTR Credits ($)**	**Net Cost of Load (MWh)**	**Average Net Cost of Load ($/MW)**
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Blue	5	70.00	350.00	145.00	205.00	41.00

Equations:

[4] = [2] * [3]
[5] 2 MW * [70–35] + 2 MW * [70-32.5] = 145
[6] = [4] – [5]
[7] = [6] / [2]

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Next, consider Red, who scheduled 5 MWh of load in Northeast DC in the day-ahead market and whose customers consumed 6 MWh of energy in real time.

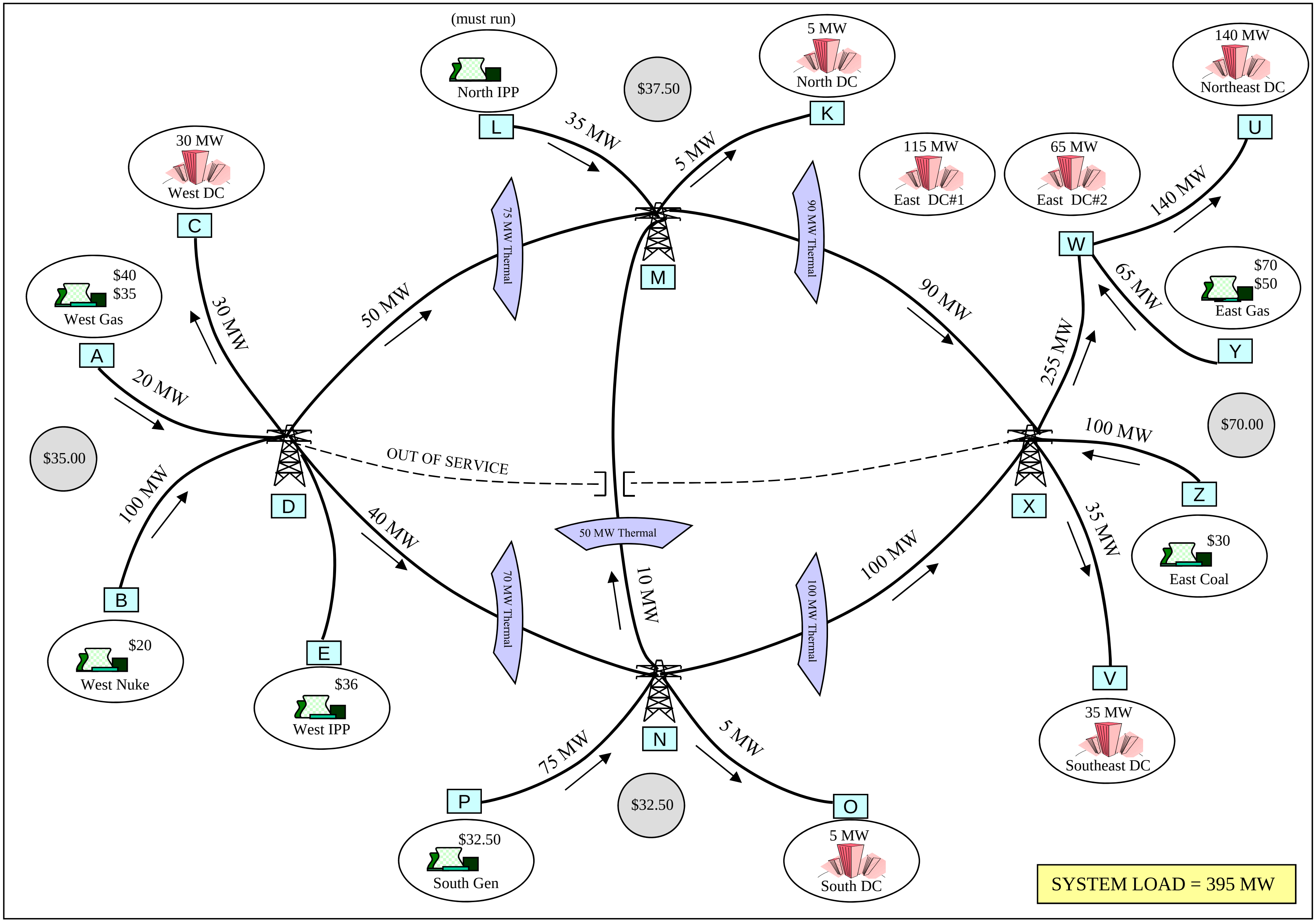
Under a two-settlement system, Red would cover the imbalance between its day-ahead schedule and real-time consumption by purchasing energy in the real-time spot market. Red would therefore buy 5 MWh at day-ahead prices and 1 MWh at real-time prices.

COST OF MEETING LOAD UNDER TWO-SETTLEMENT SYSTEM										
	DAY-AHEAD DISPATCH				REAL-TIME DISPATCH					
LSE	Scheduled Load (MWh)	LMP ($/MWh)	Cost ($)	FTR Credits ($)	Load (MWh)	Load Deviation (MWh)	LMP ($)	Cost ($)	Net Cost of Load ($)	Average Net Cost of Load ($/MW)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Red	5	45.00	225.00	45.00	6	1	70.00	70.00	250.00	41.67

Equations:

[4] = [2] * [3]
[5] 2 MW * [70–35] + 2 MW * [70-32.5] = 145
[7] = [6] – [2]
[9] = [8] * [7]
[10] = [9] – [5] + [4]
[11] = [10] / [6]

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Although Red underforecast its load day ahead, its net cost of meeting load would be lower under a two-settlement system because it would have locked in the cost of meeting most of its load at day-ahead prices.

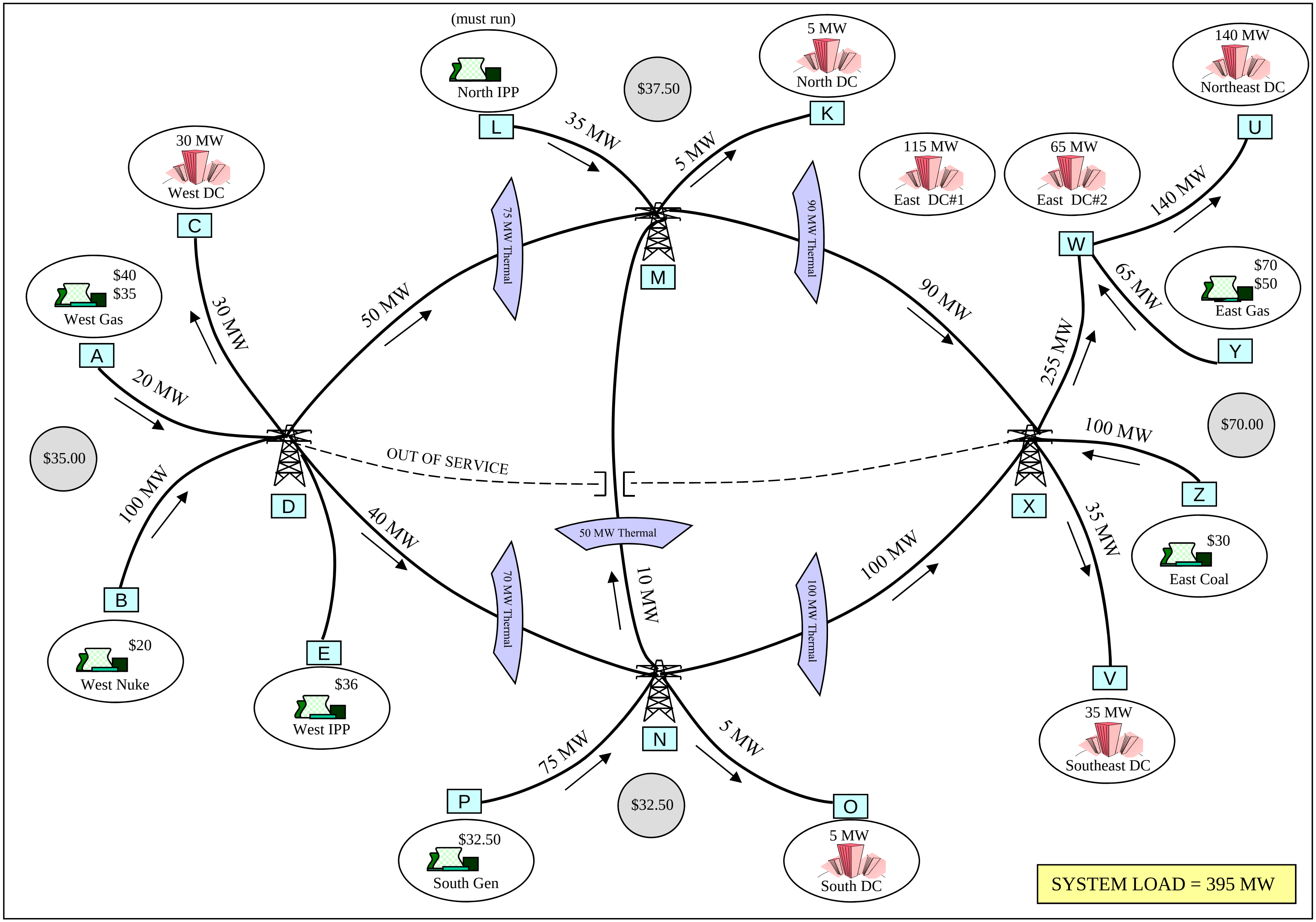
Under a one-settlement system, Red would have paid real-time prices for all its load not hedged by FTRs from West to East.

COST OF MEETING LOAD UNDER ONE-SETTLEMENT SYSTEM						
LSE	**Load (MWh)**	**LMP ($MWh)**	**Cost ($)**	**FTR Credits ($)**	**Net Cost of Load (MWh)**	**Average Net Cost of Load ($/MW)**
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Red	6	70.00	420.00	145.00	275.00	45.83

Equations:

[4] = [2] * [3]
[5] 2 MW * [70–35] + 2 MW * [70-32.5] = 145
[6] = [4] – [5]
[7] = [6] \ [2]

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

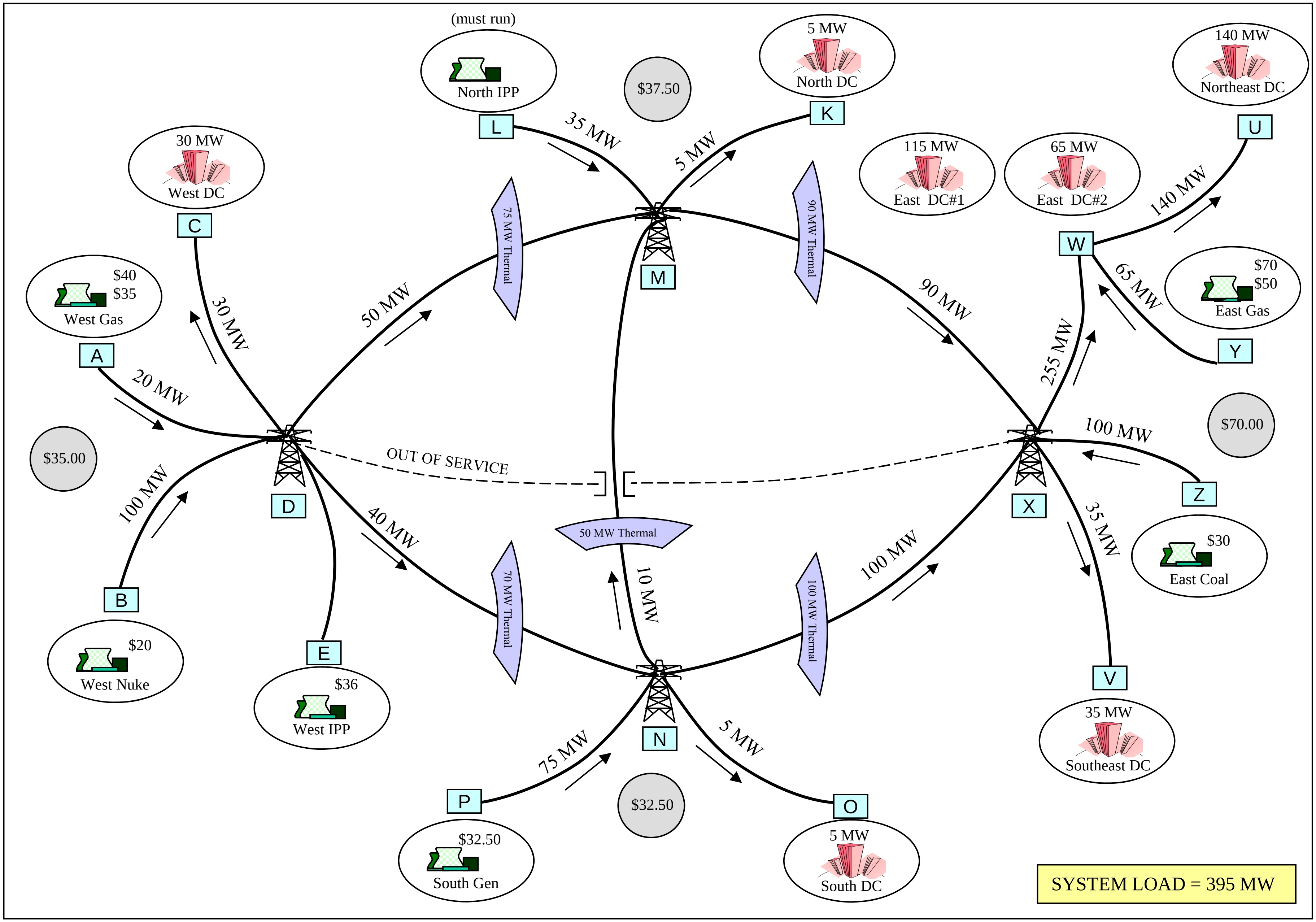
Next, we consider Tan, who also scheduled 5 MWh of load in Northeast DC in the day-ahead market, owns no valuable FTRs and whose customers consumed 6 MWh of energy in real time. Tan would buy 5 MWh at day-ahead prices and 1 MWh at real-time prices.

COST OF MEETING LOAD UNDER TWO-SETTLEMENT SYSTEM										
	DAY-AHEAD DISPATCH				REAL-TIME DISPATCH					
LSE	Scheduled Load (MWh)	LMP ($/MWh)	Cost ($)	FTR Credits ($)	Load (MWh)	Load Deviation (MWh)	LMP ($)	Cost ($)	Net Cost of Load ($)	Average Net Cost of Load ($/MW)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Tan	5	45.00	225.00	--	6	1	70.00	70.00	295.00	49.17

Equations:

[4] = [2] * [3]
[7] = [6] – [2]
[9] = [8] * [7]
[10] = [9] – [5] + [4]
[11] = [10] / [6]

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

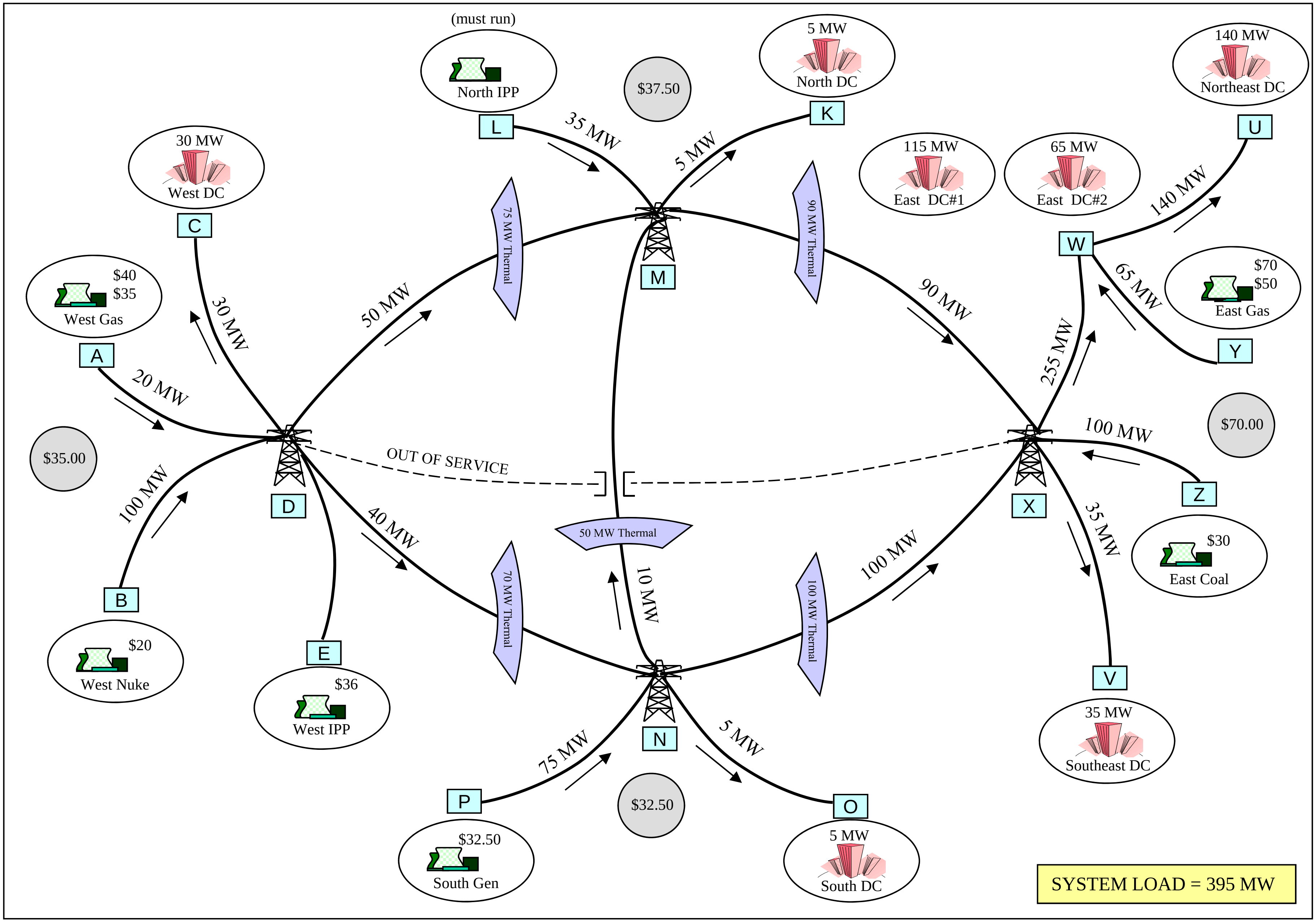
Once again, although Tan underforecast its load day-ahead, its net cost of meeting load would be lower under a two-settlement system because it would meet most of its load at day-ahead prices. Under the one-settlement system, Tan would have paid real-time prices for all of its load unhedged by any FTRs.

COST OF MEETING LOAD UNDER ONE-SETTLEMENT SYSTEM						
LSE	**Load (MWh)**	**LMP ($MWh)**	**Cost ($)**	**FTR Credits ($)**	**Net Cost of Load (MWh)**	**Average Net Cost of Load ($/MW)**
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Tan	6	70.00	420.00	--	420.00	70.00

Equations:

[4] = [2] * [3]
[6] = [4] – [5]
[7] = [6] \ [2]

REAL-TIME DISPATCH 1



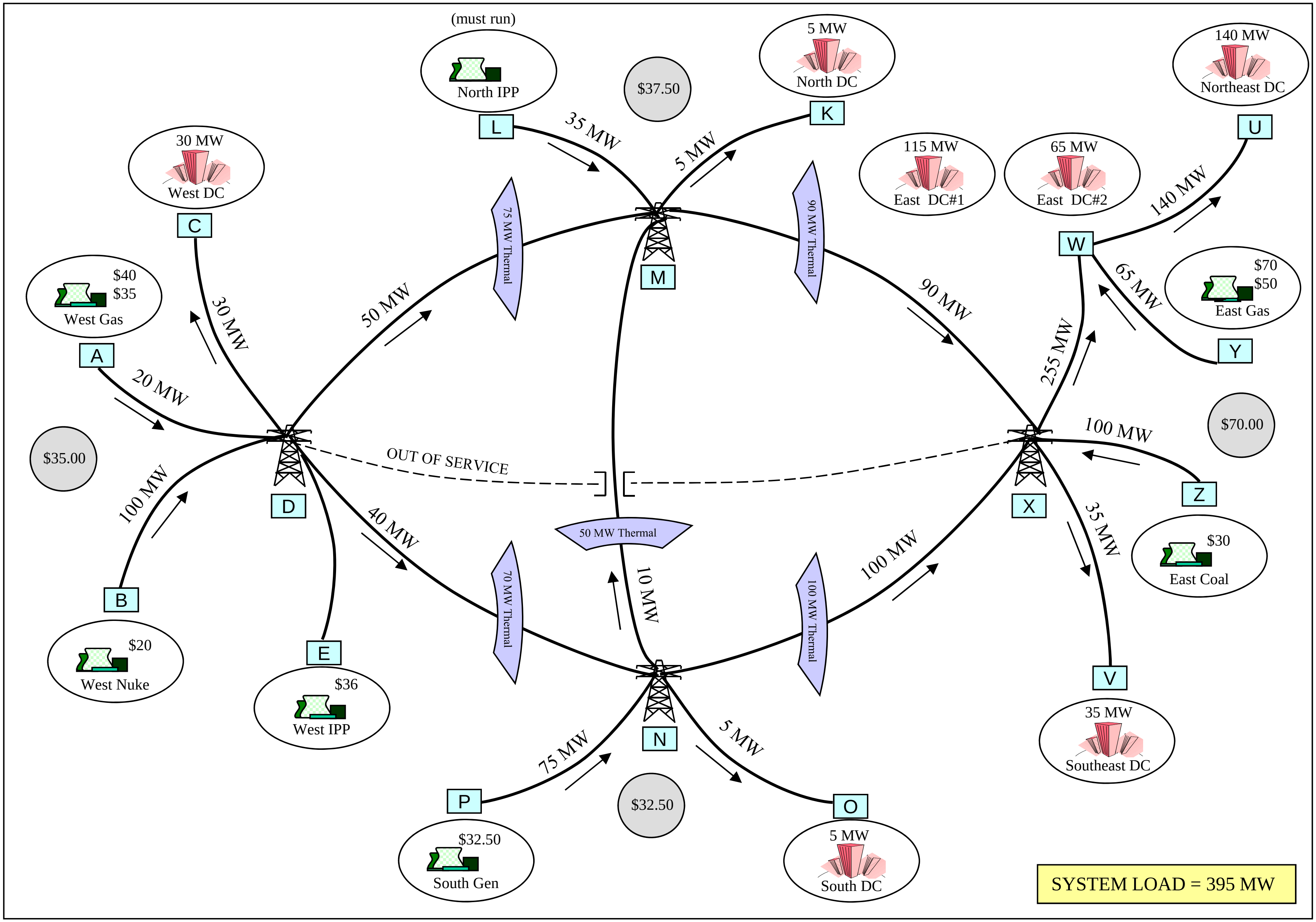
Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Next, we consider Yellow, who did not schedule any energy purchases in the day-ahead market but instead scheduled 5 MW of transmission to cover its bilateral purchase from North IPP. This transmission schedule is hedged day ahead by Yellow's FTR ownership.

In real time, however, Yellow's load consumed 6 MWh of energy, so Yellow buys 1 MWh of energy at real-time prices to cover its imbalance.

COST OF MEETING LOAD UNDER TWO-SETTLEMENT SYSTEM						
	Day-Ahead Schedule		**Real-Time Dispatch**			
	Transmission Congestion Charges	**Transmission Congestion Credits**	**Load (MWh)**	**Load Deviation (MWh)**	**LMP ($/MWh)**	**Net Cost ($)**
Yellow	37.50	37.50	6	1	70	70

REAL-TIME DISPATCH 1

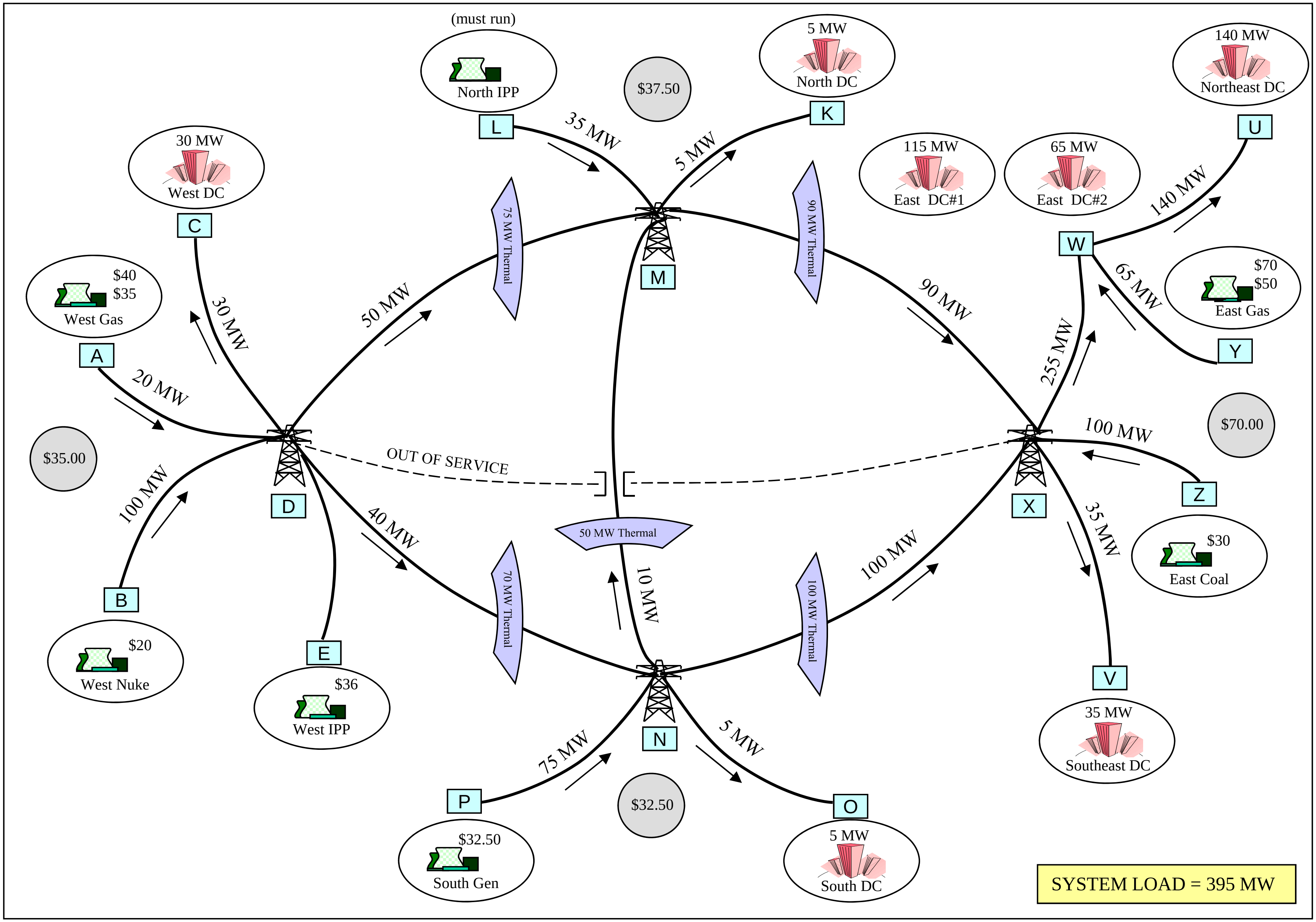


Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Because Yellow's transmission schedule is completely hedged by FTRs for West to East, its cost of serving its retail loads would be the same under a one- or two-settlement system.

COST OF MEETING LOAD UNDER ONE-SETTLEMENT SYSTEM			
Transmission Congestion Charges	**Transmission Congestion Credits**	**Energy Purchases**	**Net Cost**
162.50	162.50	$70.00	$70.00

REAL-TIME DISPATCH 1



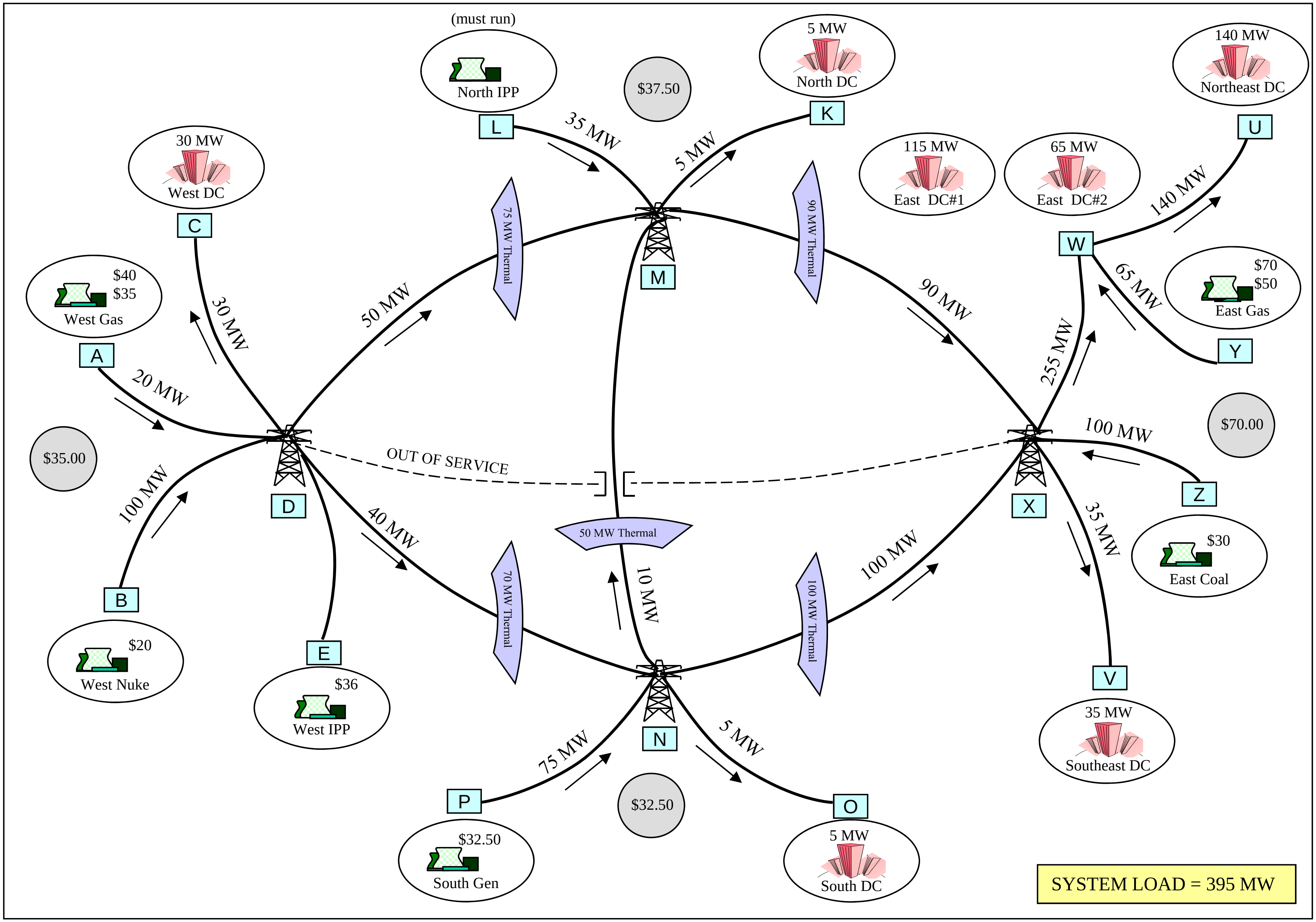
Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Finally, we consider Green, who also scheduled 5 MW of transmission day ahead to cover its bilateral purchase from North IPP. Green, however, owns FTRs from Z to V so its FTR ownership does not hedge its transmission schedule.

In real time, Green's loads responded to the high spot prices in the East by reducing consumption to only 4 MWh, so Green sold one of the MWh it scheduled day ahead into the real-time market.

COST OF MEETING LOAD UNDER TWO-SETTLEMENT SYSTEM							
	Day-Ahead Schedule		**Real-Time Dispatch**				
	Transmission Congestion Charges	**Transmission Congestion Credits**	**Load (MWh)**	**Load Deviation (MWh)**	**LMP ($/MWh)**	**Net Cost ($)**	**Net Cost ($)**
Green	37.50	0.00	4	-1	70.00	-70.00	-32.50

REAL-TIME DISPATCH 1

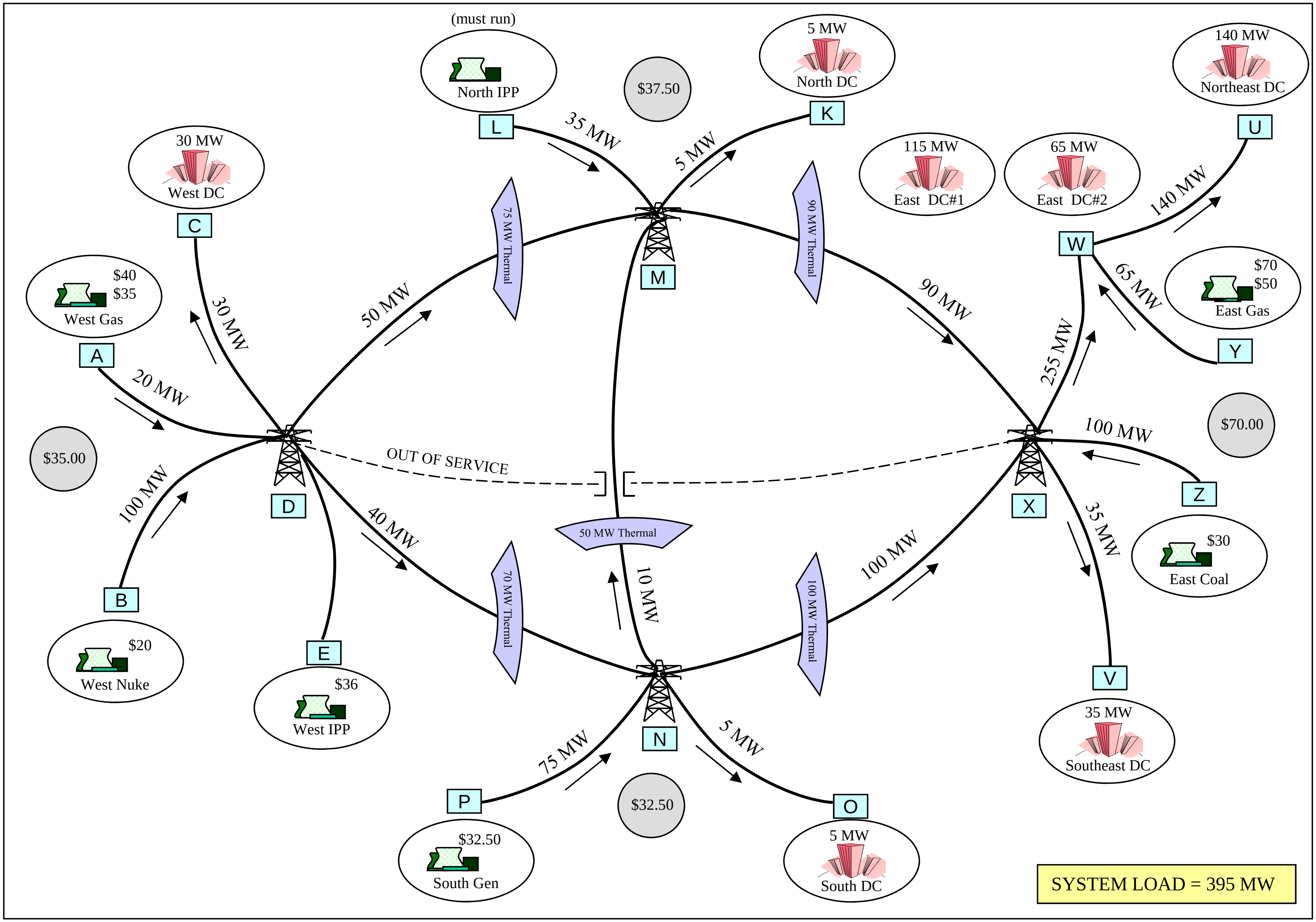


Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Green's cost of meeting load would have been considerably higher under a one-settlement system because it would have paid real-time prices for its transmission service.

COST OF MEETING LOAD UNDER ONE-SETTLEMENT SYSTEM			
Transmission Congestion Charges	**Transmission Congestion Credits**	**Energy Sale**	**Net Cost**
162.50	0.00	-$70.00	$92.50

REAL-TIME DISPATCH 1



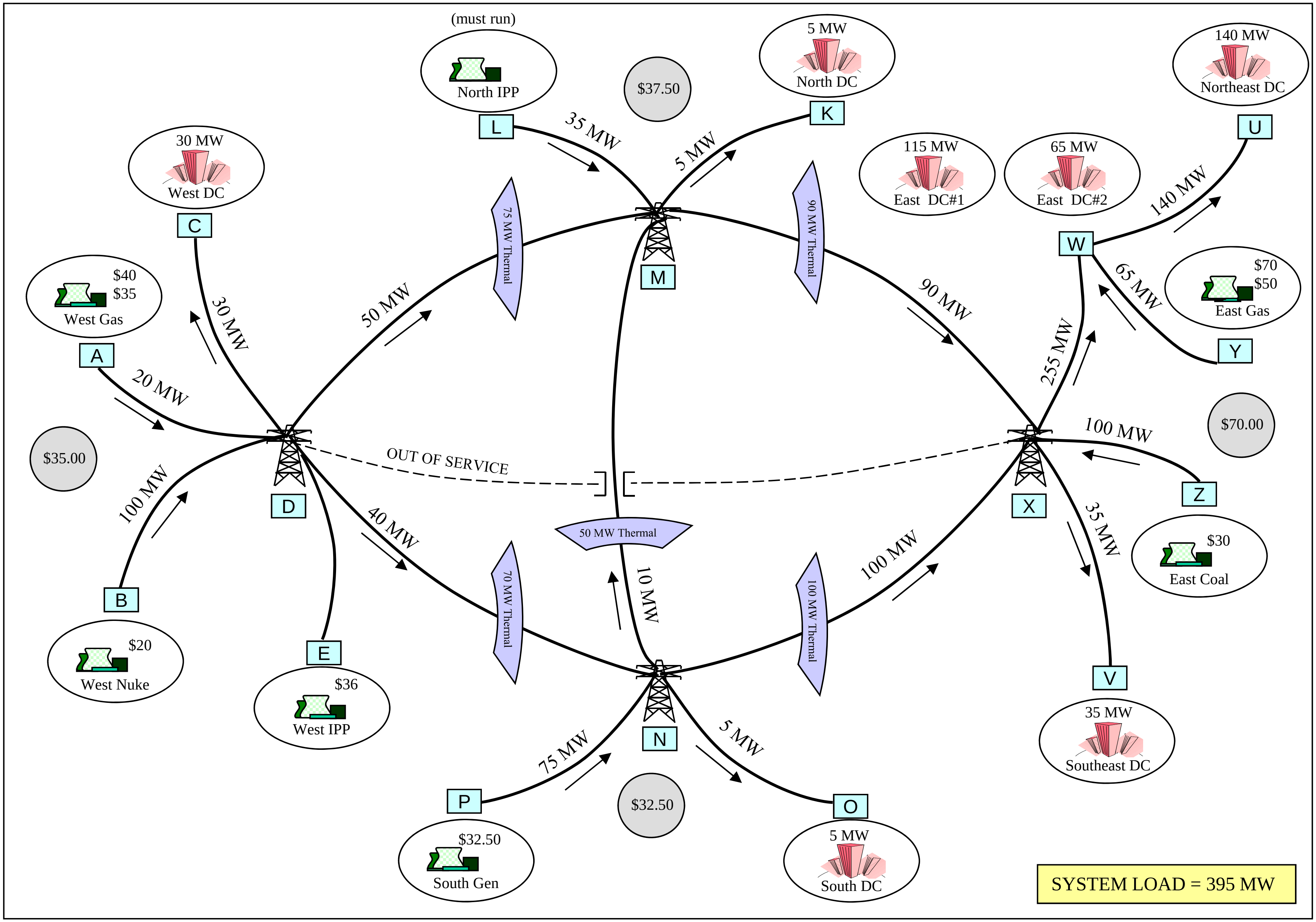
Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

In this example, the two-settlement system lowers the cost of meeting load relative to a one-settlement system. This is because the prices in this example are higher in real time than day ahead and the LSEs meet most of their loads at day-ahead prices.

If the real-time load were lower than expected and real-time prices were lower than day-ahead prices, then the two-settlement system would benefit generators by enabling them to sell part of their generation at the higher day-ahead prices.

The advantage of a two-settlement system is not that it raises or lowers price for any particular class of grid users but that it provides additional flexibility and hedging ability to all grid users.

REAL-TIME DISPATCH 1



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Because generators are redispatched by the ISOs in real time based on their bids, the schedule changes arising from the dispatch are either profitable or profit-neutral for generators.

GENERATOR MARGINS UNDER TWO-SETTLEMENT SYSTEM

	Day-Ahead Dispatch			Real-Time Dispatch					
Generators	**Scheduled Generation (MWh)**	**LMP ($/MWh)**	**Revenue ($)**	**Generation (MWh)**	**Generation Deviation (MWh)**	**LMP ($/MWh)**	**Revenue ($)**	**As-Bid Costs ($)**	**Net Real-Time Margin ($)**
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
West Gas 1	10	35.00	350.00	20	10	35.00	350.00	350.00	--
West Nuke	100	35.00	3,500.00	100	--	35.00	--	--	--
South Gen	85	32.50	2,762.50	75	(10)	32.50	(325.00)	(325.00)	--
East Gas 1	--	45.00	--	50	50	70.00	3,500.00	2,500.00	1,000.00
East Gas 2	--	45.00	--	15	15	70.00	1,050.00	1,050.00	--
East Coal	100	45.00	4,500.00	100	--	70.00	--	--	--
West IPP	--	35.00	--	--	--	35.00	--	--	--
North IPP	--	37.50	--	10	10	37.50	375.00	--	375.00
Total	295		11,112.50	370			4,950.00	3,575.00	1,375.00

Equations:

[4] = [2] * [3]
[6] = [5] – [2]
[8] = [6] * [7]
[10] = [8] - [9]

Real-Time Dispatch 1

ISO REAL-TIME SETTLEMENT COSTS AND REVENUES						
Transaction	**Scheduled MWh**	**Actual (MWh)**	**Deviation (MWh)**	**LMP ($/MWh)**	**Revenue ($)**	**Cost ($)**
Payments by LSEs						
West DC LSEs	25	30	5	35.00	175.00	
North DC LSEs	5	5	0	37.50	--	
South DC LSEs	5	5	0	32.50	--	
Northeast DC LSEs	140	140	0	70.00	--	
East DC #1 LSEs	70	115	45	70.00	3,150.00	
East DC #2 LSEs	35	50	15	70.00	1,050.00	
Southeast DC LSEs	15	25	10	70.00	700.00	
Total	295	370	75		5,075.00	
Payments by Transmission-Only Customers						
North IPP/Southeast DC LSEs	10	10	0	70.00 – 37.50 = 32.50		
North IPP/East DC #2 LSEs	15	15	0	70.00 – 37.50 = 32.50		
Total	25	25				
Payments to Generators						
West Gas	10	20	10	35.00		350.00
West Nuke	100	100	0	35.00		--
South Gen	85	75	-10	32.50		(325.00)
East Gas	0	65	65	70.00		4,550.00
East Coal	100	100	0	70.00		--
West IPP	0	0	0	35.00		--
North IPP	0	10	10	37.50		375.00
Total	295	370	75			4,950.00
ISO Residual Collection					125.00	
Note: Figures may not sum due to rounding.						

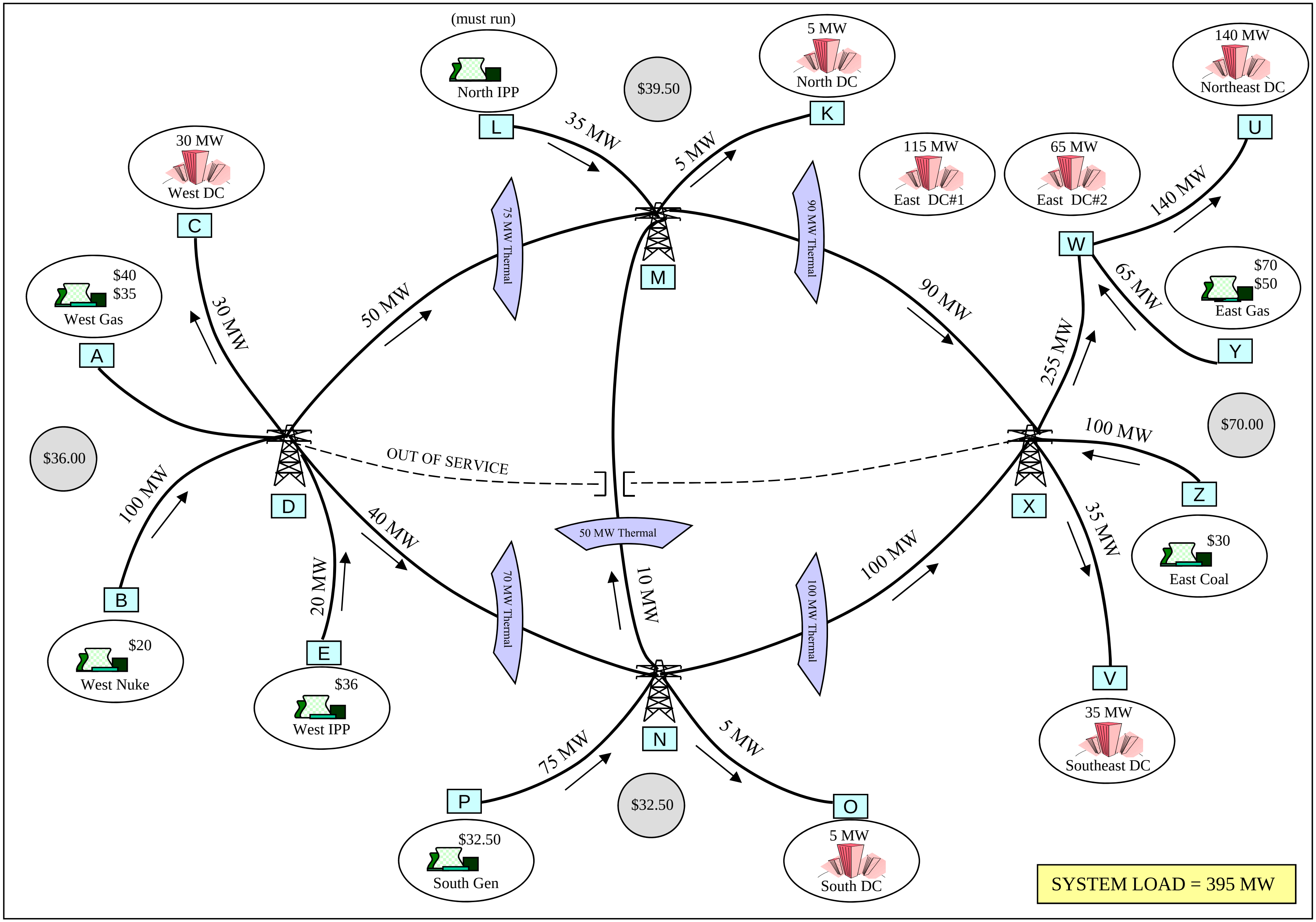
The ISO does not take a commercial position under an LMP-based two-settlement system but merely clears the market. The ISO therefore does not lose money as prices change between the day-ahead and real-time markets, although it may collect additional congestion rents.

The two-settlement system also provides generators with market-driven performance incentives, reducing the need for administrative penalties that are likely to be both too small and too large.

Under the two-settlement system, generators that fail to perform as scheduled cover their imbalances at real-time prices. If a failure to perform has little impact on market prices, the failure will have little financial impact on the generator, while outages that significantly affect market prices will have a significant financial impact on the generator.

These properties of a two-settlement system are illustrated by real-time dispatches #2 and #3.

REAL-TIME DISPATCH 2



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Real-time dispatch 2 is similar to real-time dispatch 1 except that West Gas has had a forced outage. It is assumed in this example that there is sufficient time to start West IPP to replace West Gas and the price of power in the West rises only to $36 in real time. If West Gas bid its costs day-ahead, its failure to perform in real time would cost it only $10 in this hour.

WEST GAS REAL-TIME SETTLEMENTS					
	Real-Time Dispatch 2				
Day-Ahead Schedule (MWh)	**Actual Output (MWh)**	**Deviation from Schedule (MWh)**	**LMP ($/MWh)**	**As-Bid Costs ($/MWh)**	**Losses per MWh**
10	0	10	36	35	1

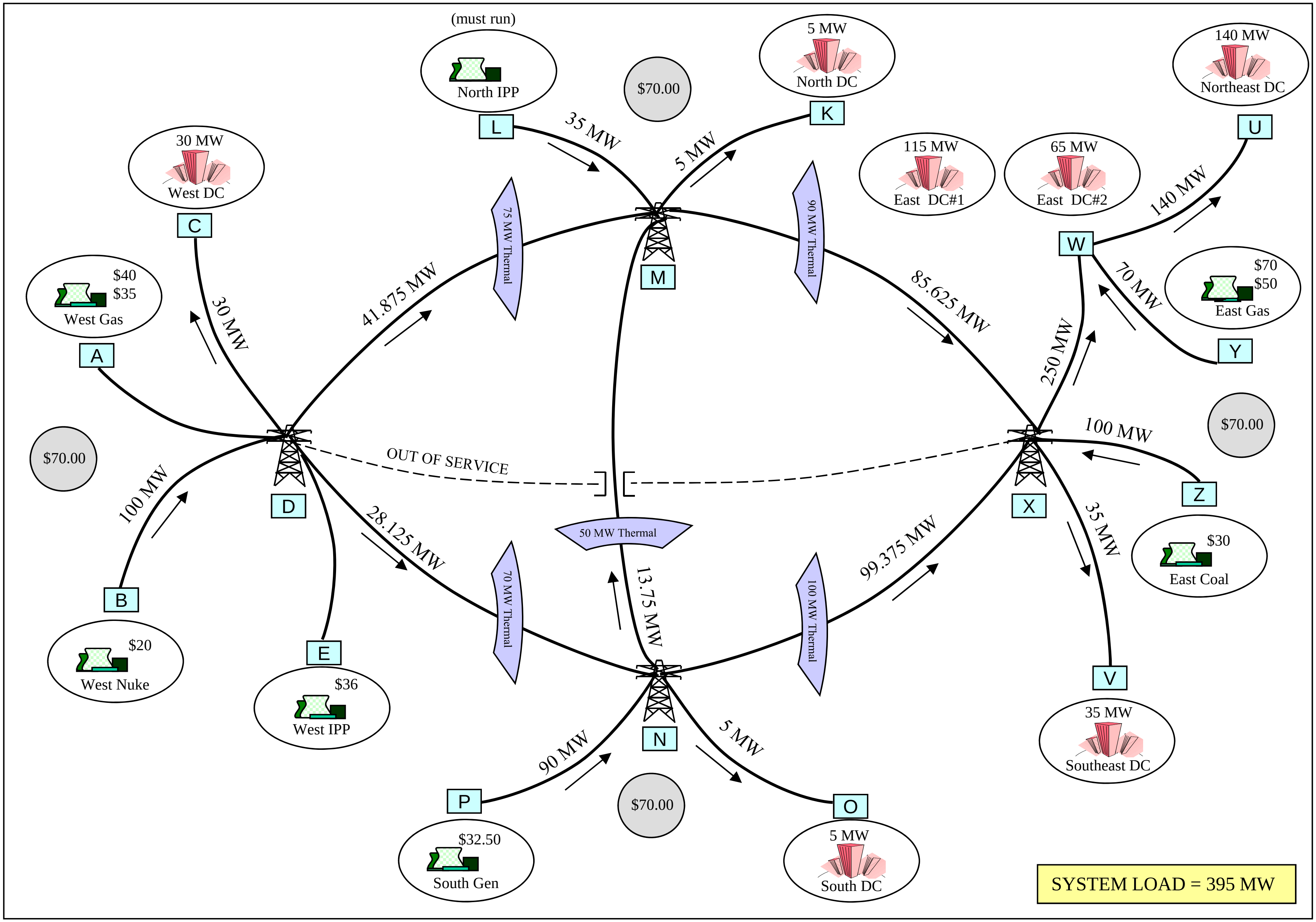
Real-Time Dispatch 2

ISO REAL-TIME SETTLEMENT COSTS AND REVENUES						
Transaction	**Scheduled MWh**	**Actual (MWh)**	**Deviation (MWh)**	**LMP ($/MWh)**	**Revenue ($)**	**Cost ($)**
Payments by LSEs						
West DC LSEs	25	30	5	36.00	180.00	
North DC LSEs	5	5	0	39.50	--	
South DC LSEs	5	5	0	32.50	--	
Northeast DC LSEs	140	140	0	70.00	--	
East DC #1 LSEs	70	115	45	70.00	3,150.00	
East DC #2 LSEs	35	50	15	70.00	1,050.00	
Southeast DC LSEs	15	25	10	70.00	700.00	
Total	295	370	75		5,080.00	
Payments by Transmission-Only Customers						
North IPP/Southeast DC LSEs	10	10	0	70.00 – 39.50 = 30.50		
North IPP/East DC #2 LSEs	15	15	0	70.00 – 39.50 = 30.50		
Total	25	25				
Payments to Generators						
West Gas	10	0	-10	36.00		(360.00)
West Nuke	100	100	0	36.00		--
South Gen	85	75	-10	32.50		(325.00)
East Gas	0	65	65	70.00		4,550.00
East Coal	100	100	0	70.00		--
West IPP	0	20	20	36.00		720.00
North IPP	0	10	10	39.50		395.00
Total	295	370	75			4,980.00
ISO Residual Collection					100.00	
Note: Figures may not sum due to rounding.						

Because the ISO would not take a financial position in the energy markets, the generator outage would not impose losses on the ISO nor create a need for uplift.

- The payments to West IPP to replace the output of West Gas would be offset by payments by West Gas to cover its imbalances.
- The payments to generators for energy to meet additional real-time load would be covered by payments by the real-time loads.

REAL-TIME DISPATCH 3

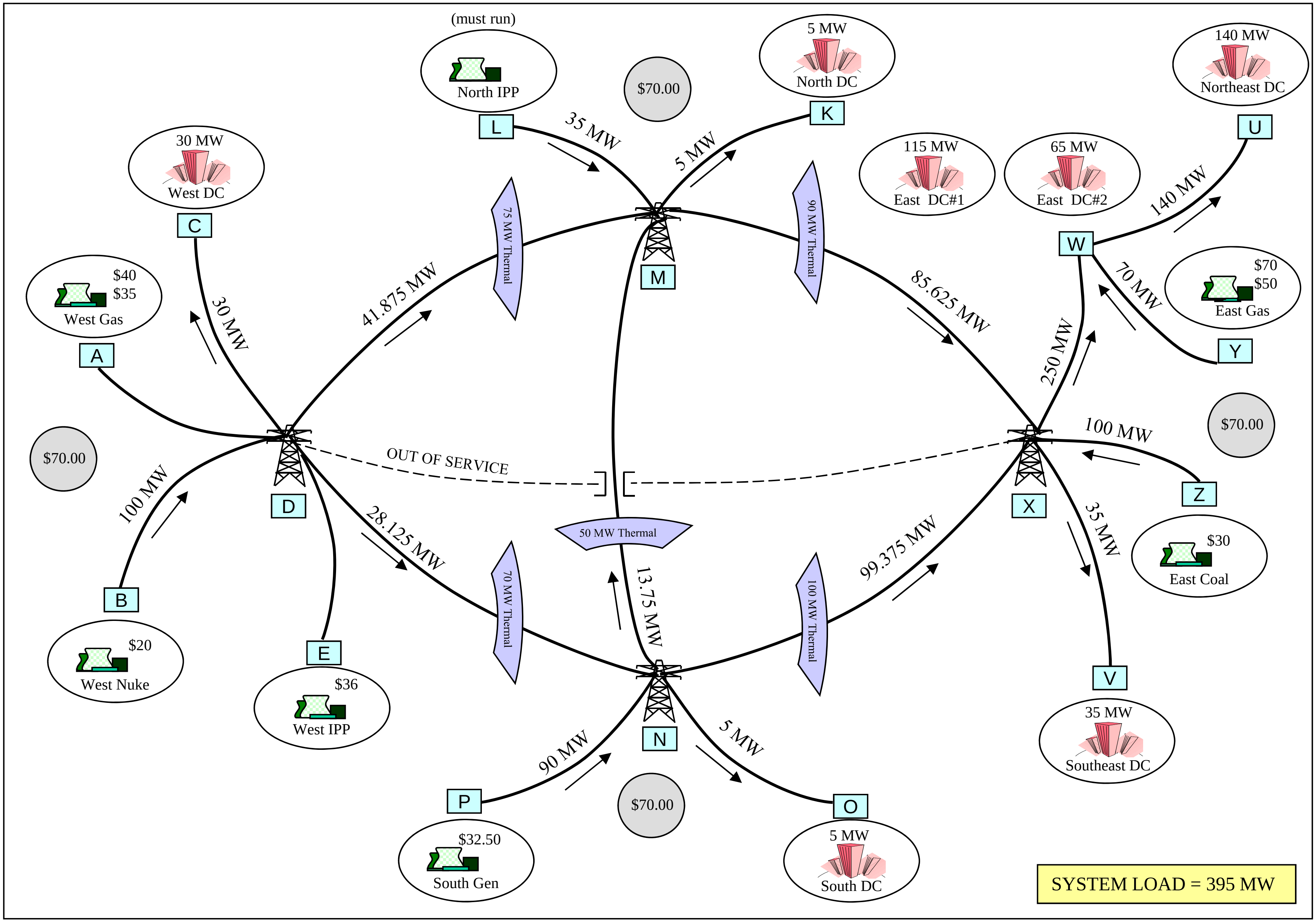


Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Real-time dispatch 3 again assumes that West Gas has had an outage but in this dispatch it is assumed that there was not enough time to start West IPP, so West Gas output is replaced by East Gas. Real-time prices in the West rise to $70/MWh and congestion disappears. In this case, the West Gas outage would have a large impact on prices and would impose significant costs on West Gas for its failure to perform.

WEST GAS REAL-TIME SETTLEMENTS					
	Real-Time Dispatch 2				
Day-Ahead Schedule (MWh)	Actual Output (MWh)	Deviation from Schedule (MWh)	LMP ($/MWh)	As-Bid Costs ($/MWh)	Losses per MWh
10	0	10	70	35	35

REAL-TIME DISPATCH 3



Generator Capacities: West Nuke, 100 MW; West Gas #1, 50 MW; West Gas #2, 50 MW; West IPP, 50 MW; North IPP, 35 MW; South Gen, 90 MW; East Gas #1, 50 MW; East Gas #2, 175 MW; East Coal, 100 MW

Despite the substantial change in prices, the outage would not impose any losses on the ISO or create uplift.

Real-Time Dispatch 3

ISO REAL-TIME SETTLEMENT COSTS AND REVENUES						
Transaction	**Scheduled MWh**	**Actual (MWh)**	**Deviation (MWh)**	**LMP ($/MWh)**	**Revenue ($)**	**Cost ($)**
Payments by LSEs						
West DC LSEs	25	30	5	70.00	350.00	
North DC LSEs	5	5	0	70.00	--	
South DC LSEs	5	5	0	70.00	--	
Northeast DC LSEs	140	140	0	70.00	--	
East DC #1 LSEs	70	115	45	70.00	3,150.00	
East DC #2 LSEs	35	50	15	70.00	1,050.00	
Southeast DC LSEs	15	25	10	70.00	700.00	
Total	295	370	75		5,250.00	
Payments by Transmission-Only Customers						
North IPP/Southeast DC LSEs	10	10	0	70.00 – 70.00 = 0		
North IPP/East DC #2 LSEs	15	15	0	70.00 – 70.00 = 0		
Total	25	25				
Payments to Generators						
West Gas	10	0	-10	70.00		(700.00)
West Nuke	100	100	0	70.00		--
South Gen	85	90	5	70.00		350.00
East Gas	0	70	70	70.00		4,900.00
East Coal	100	100	0	70.00		--
West IPP	0	0	0	70.00		
North IPP	0	10	10	70.00		700.00
Total	295	370	75			5,250.00
ISO Residual Collection					--	
Note: Figures may not sum due to rounding.						

	PJM	New York
Security-Constrained Unit Commitment	Yes	Yes
Reliability Commitment Against ISO Load Forecast	Yes	Yes
Reliability Commitment Minimizes Uplift, Not Energy Cost	Yes	Yes
Pricing	LMP	LMP
Energy Bid Structure	3-Part	3-Part
Bid Production Cost Guarantee	Yes	Yes
Physical Parameters	Yes	Yes
Balanced Schedule Requirement	No	No
Maximum Bid	$1,000	$1,000
Price Capped Load Bids	Nodal/Zonal	Zonal

	PJM	New York
Self-Scheduling	Yes	Yes
Self-Schedule Bid	0	-$1,000
Reserve Markets	No	Yes
Locational Reserve Constraints	No	Yes
Two-Settlement System for Reserves	No	No
Reserve Targets		
Spin	X	.5X
Total	3X	1.5X
Bid Mitigation	Advance	in SCUC
Forecast Load Commitment Included in Price Calculation	No	Yes
Commitment Optimizes Regulation	No	Yes
Virtual Load and Supply Bids	Yes	No/Fall 2001