# Electric System Economics
# How ISOs Work

NCAC PJM Tour
2010 November 11
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# Electric System Economics

- Screening between Technologies
- Real time cost minimization
- Uniform pricing
- Imbalances
- Transmission

- Screening—making gross planning decisions as to which types of generators to build
- Optimization—running power plants jointly such that total costs are minimized, occurs when all units are operating at the same short run marginal costs, as adjusted for losses and constraints
- Pricing—many ISOs extend equalized marginal costs to equalized prices
- Imbalances—auctions are forwards/futures contracts. Need different pricing model to handle spot differences
- Transmission—related costs result in prices being geographically differentiated

# Screening between Technologies

- Fixed costs ($/KW-Year)
  - Capital investment
    - Return
    - Depreciation
    - Taxes
  - Operations (manpower)
- Variable costs ($/KWH)
  - Maintenance
  - Fuel
- Jerk ($/KW differential)

- Most analyses differentiate costs between fixed and variable. Part of the variable costs can also treated as the cost of jerking the system around.
- Fixed costs are frequently stated as being proportional to the size of the generator, expressed as $/KW-Year or $/KW-Month. Having a second generator will double the fixed costs even if the output is not changed.
- Some costs vary based on the amount that the generator is run, especially fuel costs.
- Jack rabbit starts and stops worsen a cars fuel economy. Similarly starting and stopping a generator worsens its fuel economy and cause it to break down more frequently.

# Fixed Costs

- Economies of scale
  - 7/10ths Power rule on capital costs
  - Labor costs not proportional to size (24x7)
- Depreciation
  - Annual
  - Units of production
  - Economic
  - Declining balance

- Electric generating equipment is subject to economies of scale. One approximation is that capital costs increase at the $7/10^{th}$ power of the size of the unit. Thus, if a 100 MW coal plant costs $1000/KW, a 200 MW coal plant would cost only $812/MW, a 500 MW coal plant would only cost $617/MW, and a 1000 MW coal power plant would cost only $501/MW. Man power to operate the plant are subject to even greater economies of scale.
- The allocation of fixed costs to annual periods is a depreciation decision. Several methods have been used. GAAP seems to favor annual.

# Fixed Costs (pt 2)

- Interest
- Return
- Taxes OTI
- Income Taxes
  - Tax Credits
  - Production credits (KWH)

# Comments on Previous Slide

- The various fixed costs can be lumped together and then spread across time as a fixed charge rate, under an assumption of net present value concepts.

# Variable Costs

- Maintenance
- Fuel
  - Heat rate of generating unit (steady state)
    - Size
    - Operating level
  - Unit cost of fuel

- We get the oil changed in our car every 3,000 miles. Other planned maintenance items are at similarly fixed intervals, generally based on mileage, though perhaps on time.
- The heat rate of generating units depends on their construction, with more money being spent to make very large generating units more efficient. Heat rates are generally expressed as Btu/KWH. Note that this is the reciprocal of miles per gallon. A low heat rate is good. A low miles per gallon is bad.
- The heat rate of a generating unit varies depending on how much power is being produced. The best production level is generally at full load. Hydro Tasmania cites the efficiency of a turbine operating at 10% of rated capacity uses four times as much water per unit of output as the same turbine running at full load. We will see examples of this later.
- The cost of fuel in the US is generally expressed as $/Mbtu. Multiplying the heat rate times the unit cost of fuel produces the unit cost of electricity. Conversely, the cost of gasoline for a car has to be divided by the miles per gallon to get the cost of fuel per mile.

# Jerk

- Metal fatigue
- Inefficiencies associated with jack rabbit starts

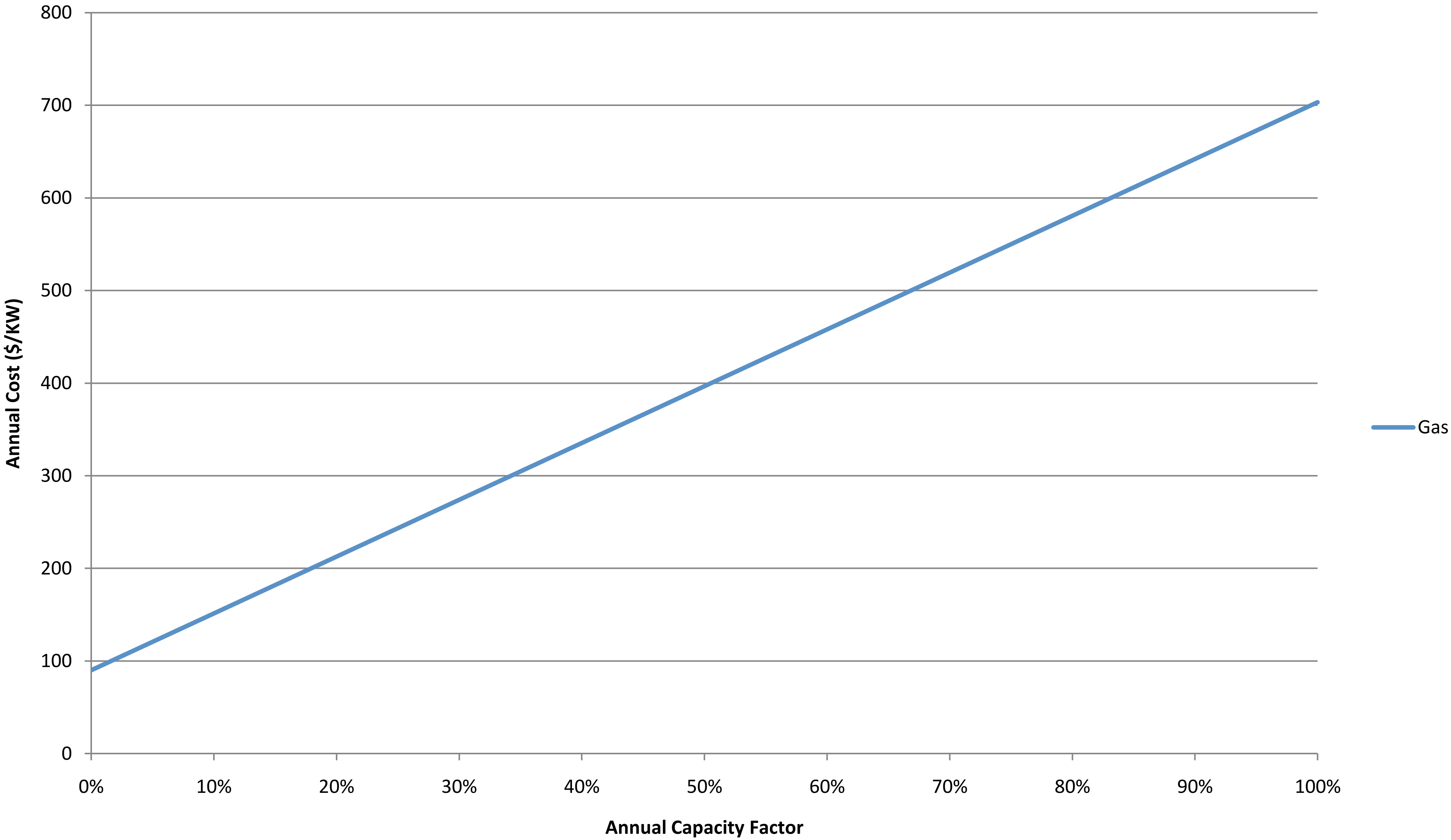
- Rapidly increasing and decreasing the operating level of a generator will cause it to wear out more quickly and result in a less efficient use of fuel.  This concept is important to determine the price for imbalances.  Very difficult to measure or even to estimate.

# Unit Costs
# Planning Issues

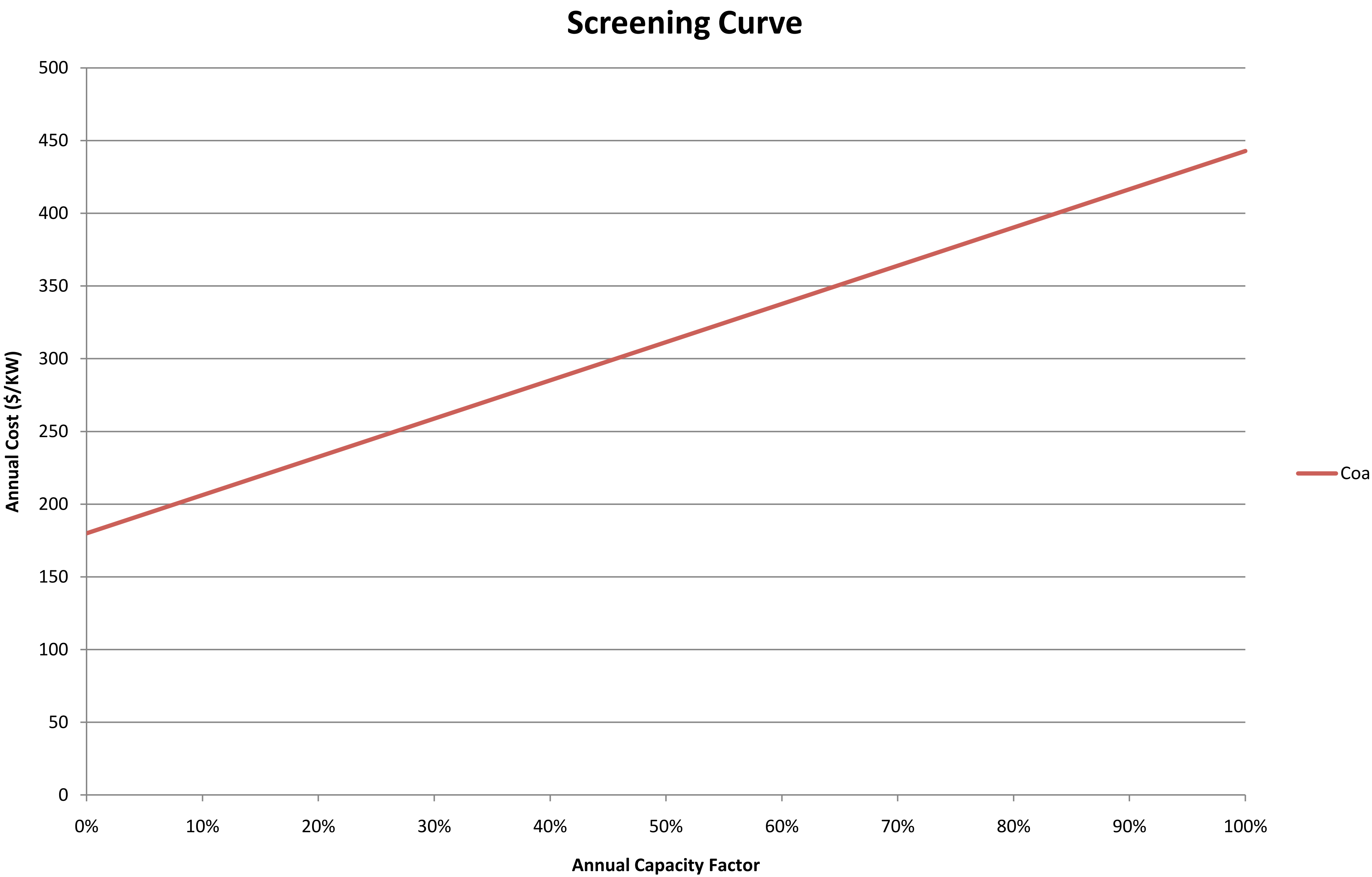
| | Installed Cost ($/KW) | Annual Cost ($/KW-Yr) | Fuel Cost ($/MWH) |
|---|---|---|---|
| Gas | 600 | 90 | 70 |
| Coal | 1200 | 180 | 30 |
| Nuclear | 2000 | 300 | 10 |

- The unit costs in this table are only illustrative. Gas turbines are generally much cheaper to own than are coal units. Coal units are cheaper to own than are nuclear units.
- A uniform fixed charge rate of 15% has been used to convert the installed costs into an annual fixed costs. Fixed labor costs could be added to these numbers.
- The fuel cost might include variable operating costs.

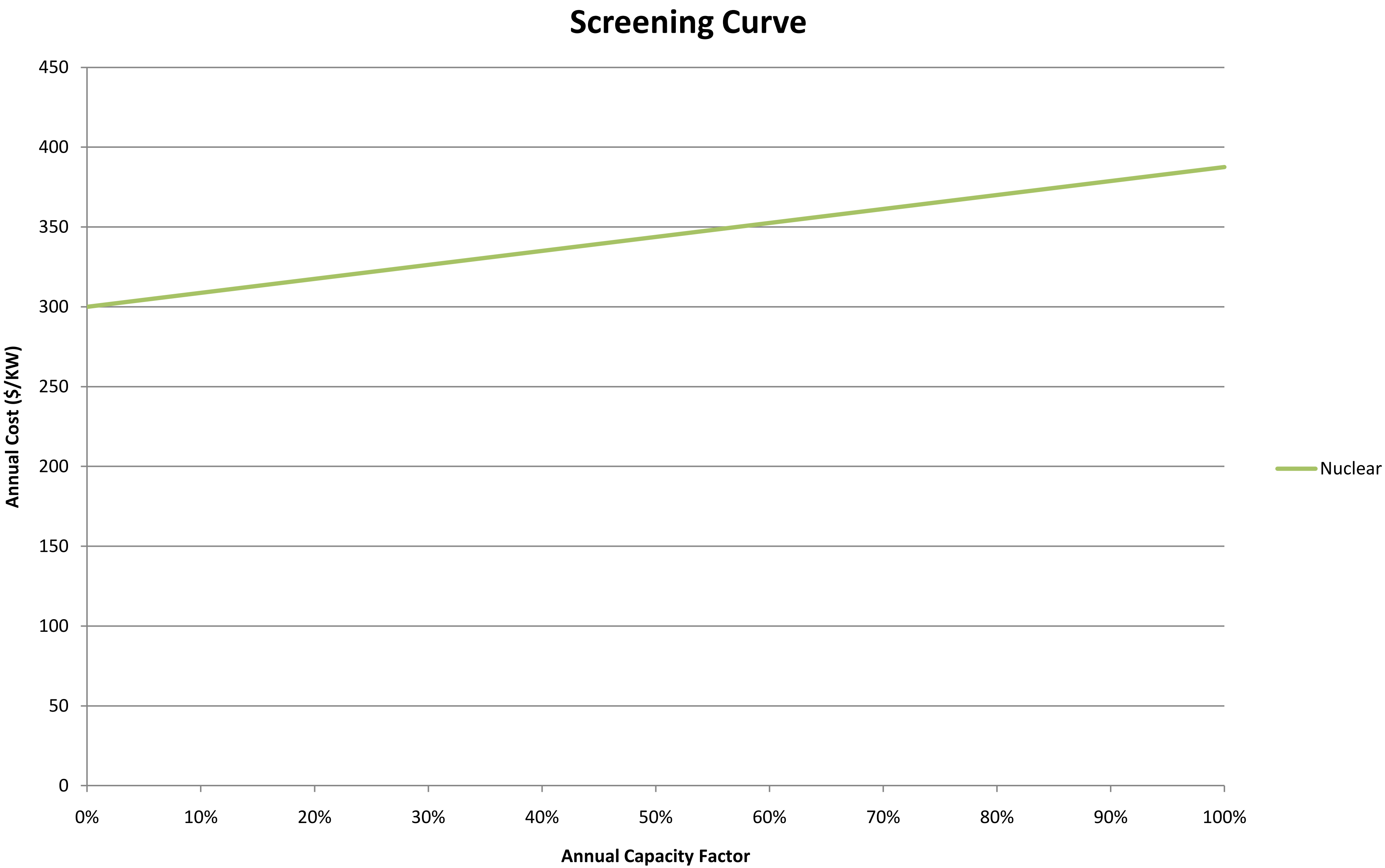
## Screening Curve



- The screening curve shows the total unit costs of owning and operating a generating unit at various annual capacity factors. Just owning the gas generator incurs an annual cost of $90/KW, even if no electricity is produced. At $70/MWH for fuel, the cost of running the plant 24x7 throughout the year is just over $700/KW.

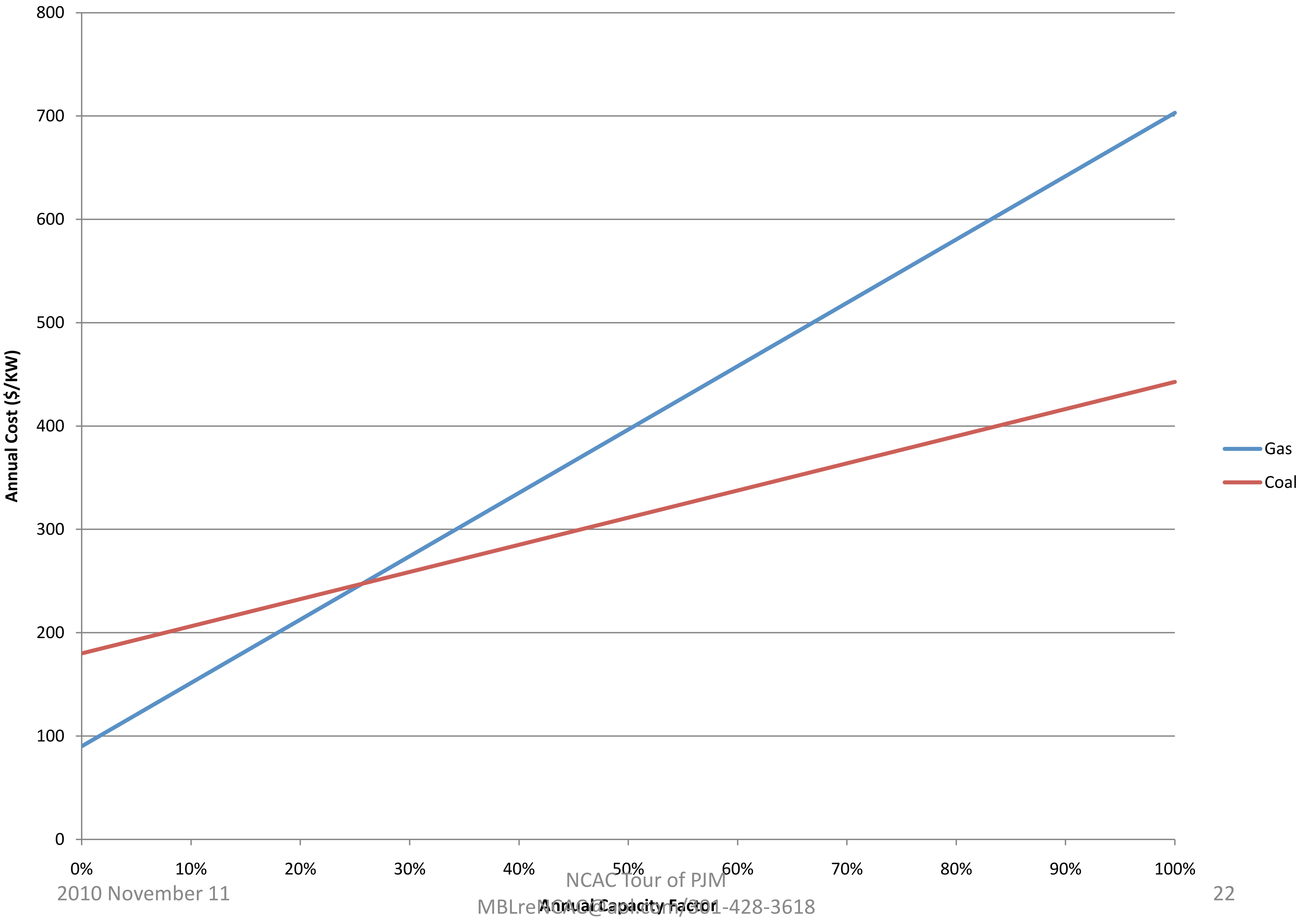

Screening Curve
500
450
400
350
300
250
200
150
100
50
0
Annual Cost ($/KW)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Annual Capacity Factor
Coal

- The screening curve for a coal plant is flatter in these examples than the screening curve for a gas plant because the unit cost of fuel for the coal plant is only $30/MWH instead of $70/MWH. Just owning the coal plant and not operating the plant incurs a cost of $180/KW. At $30/MWH for fuel, the cost of running the plant 24x7 throughout the year is just under $450/KW.

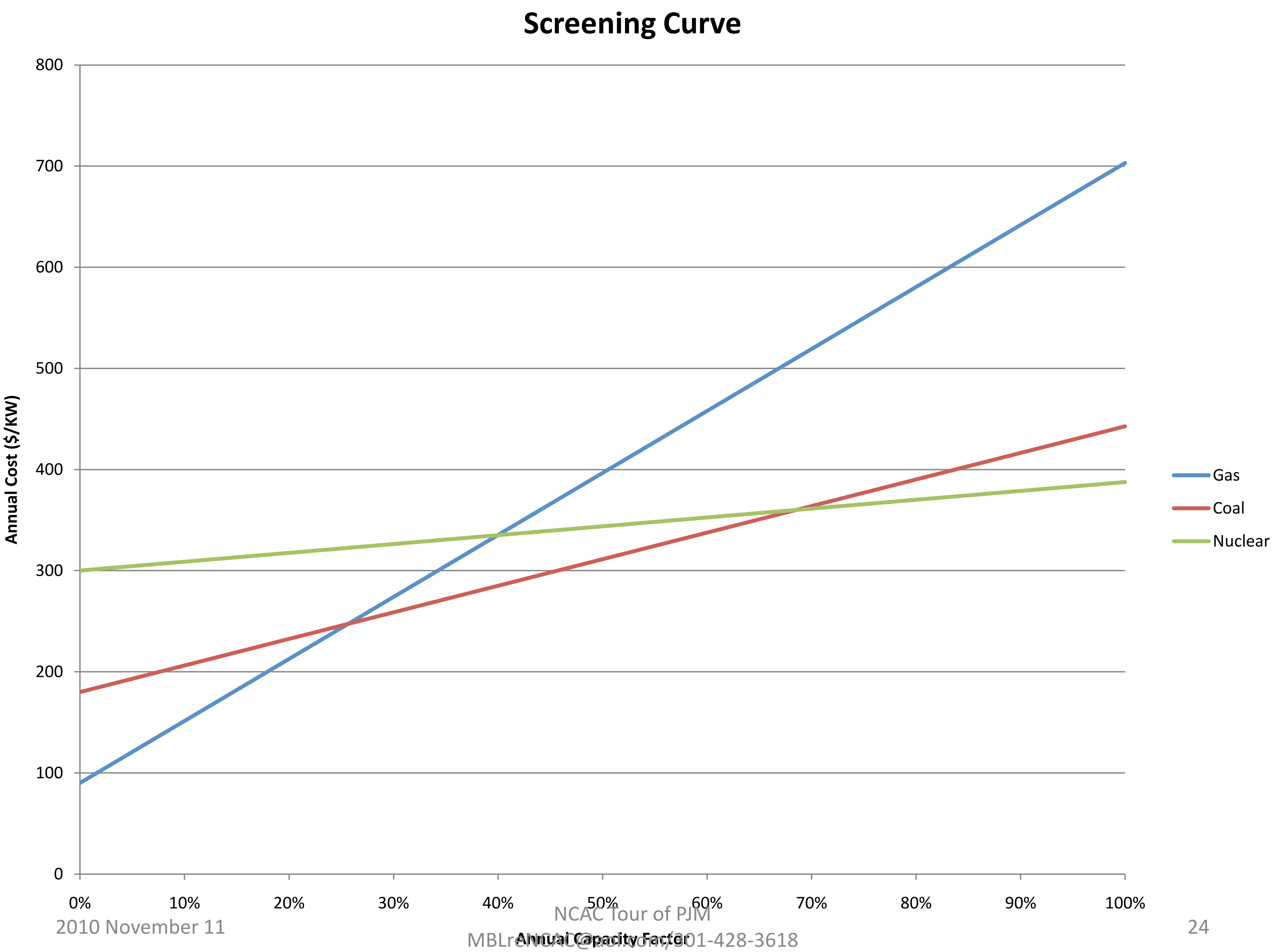

Screening Curve
450
400
350
300
250
200
150
100
50
0
Annual Cost ($/KW)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Annual Capacity Factor
Nuclear

- The screening curve for a nuclear plant is even flatter in these examples than the screening curve for a gas plant or a coal plant because the unit cost of fuel for the nuclear plant is only $10/MWH instead of $70/MWH or $30/MWH.  Just owning the nuclear plant and not operating the plant incurs a cost of $300/KW. At $10/MWH for fuel, the cost of running the plant 24x7 throughout the year is just under $390/KW.

# Screening Curve

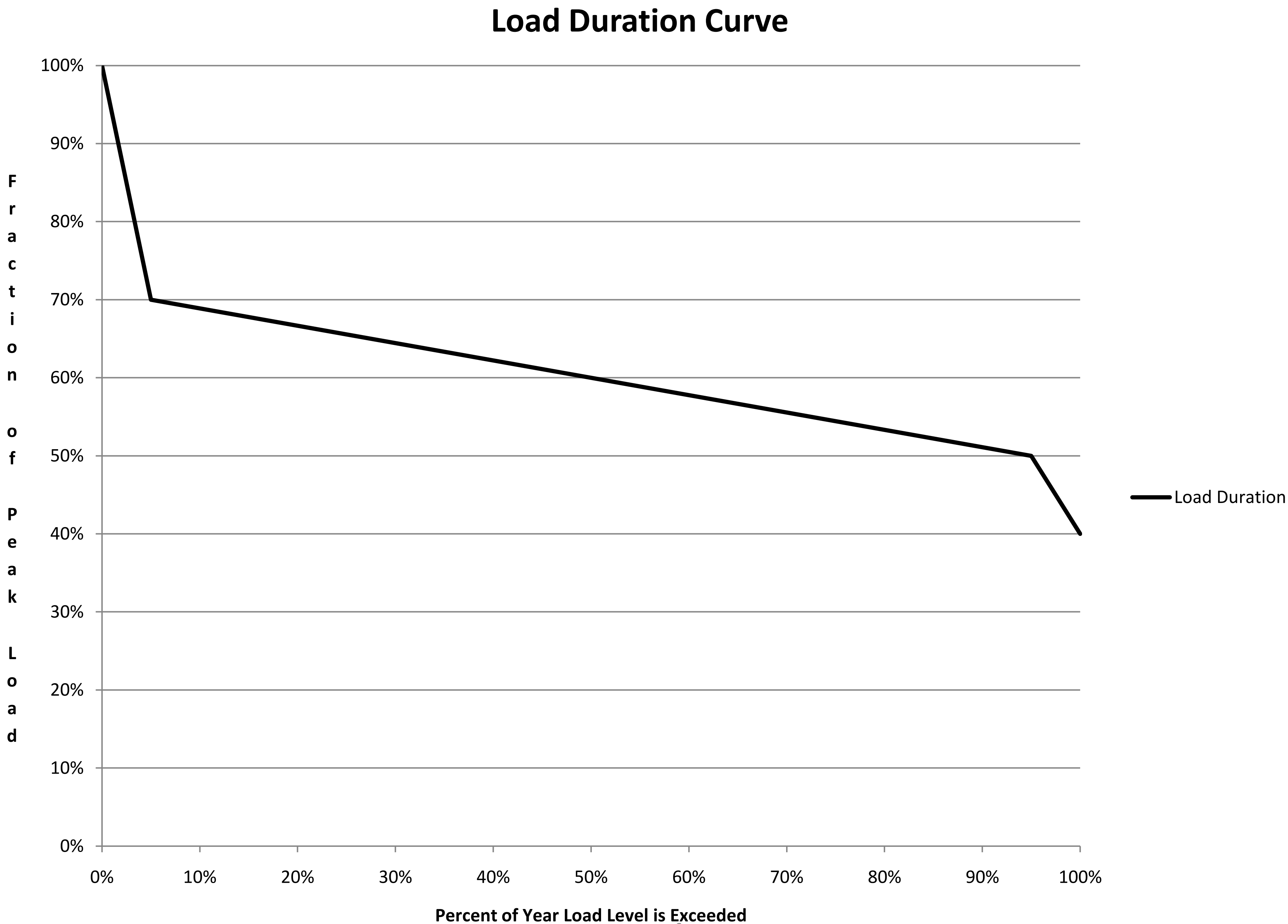


- We can combine the screening curves for gas plants and coal plants to see how the plants match up depending on the length of time that they are expected to be operated.  Under the numbers including in this series of graphs, the breakeven point is about 26% (25.68%).  Below that capacity factor, it will be cheaper to own and operate the gas plant.  Above that capacity factor, it will be cheaper to own and operate the coal plant.

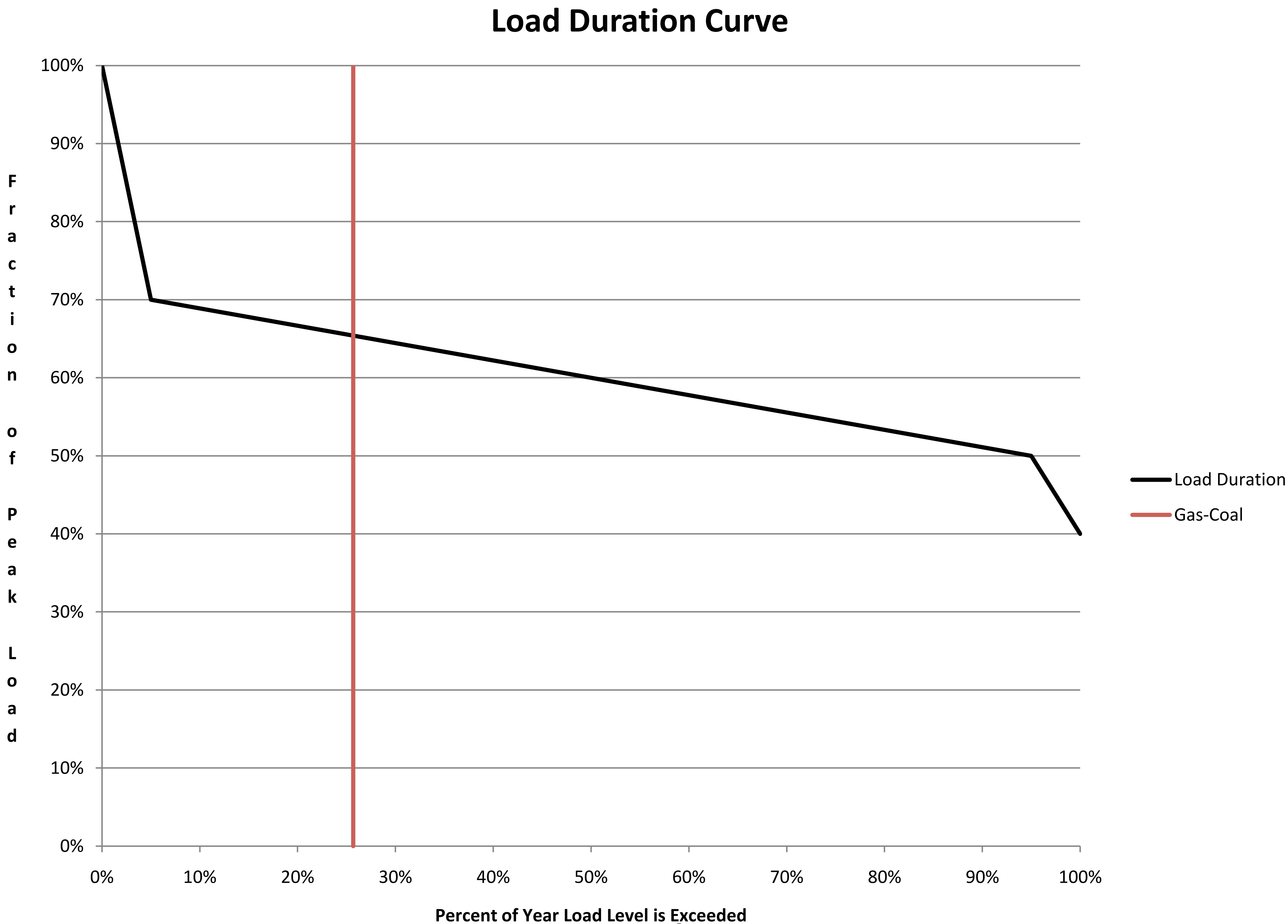

Screening Curve
Annual Cost ($/KW)
800
700
600
500
400
300
200
100
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Annual Capacity Factor
Gas
Coal
Nuclear

Comments on Previous Slide

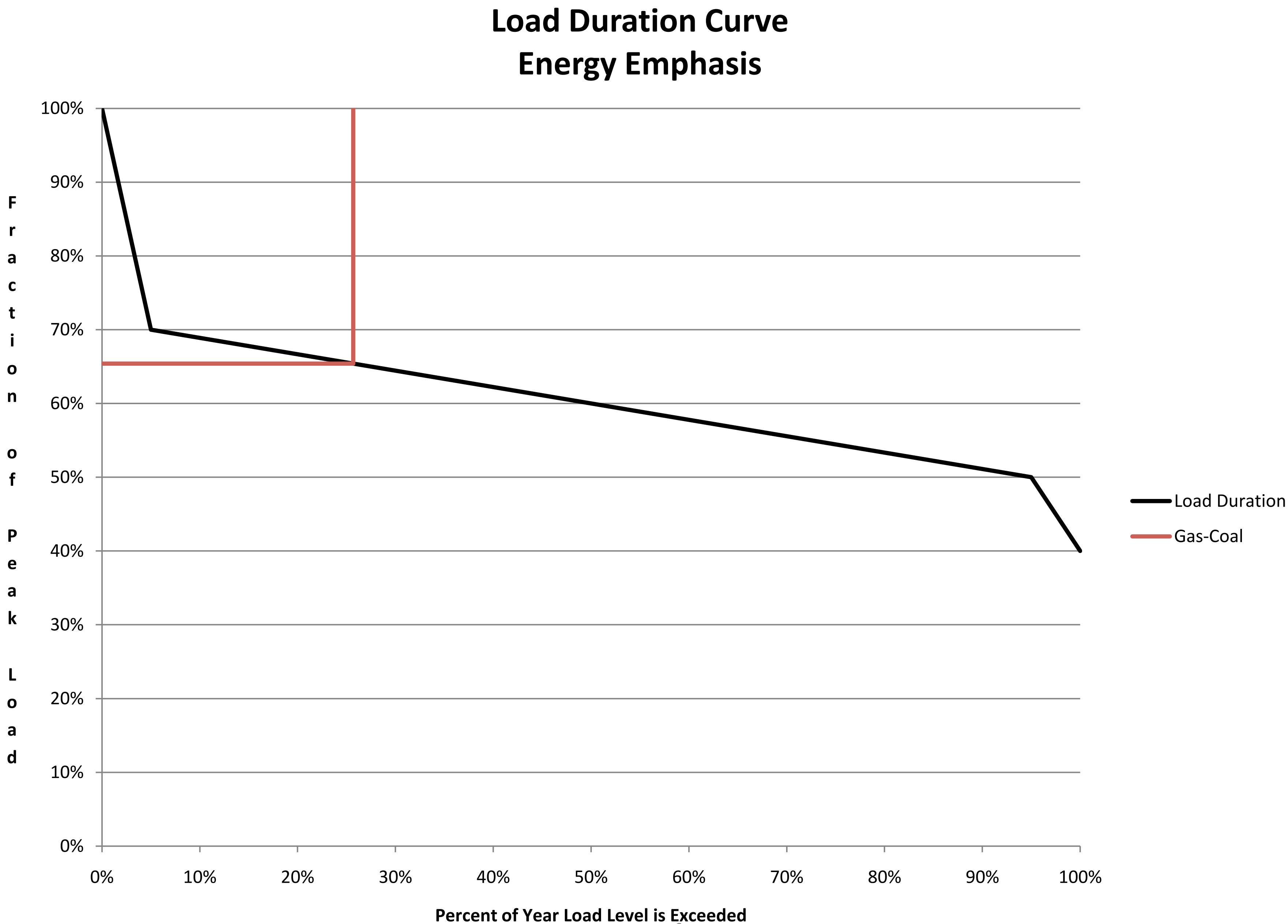
- The three screening curves can be combined. Note that a carbon tax will increase the slopes of gas and coal lines with little or no effect on the nuclear line.


Load Duration Curve
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Fraction of Peak Load
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Year Load Level is Exceeded
Load Duration

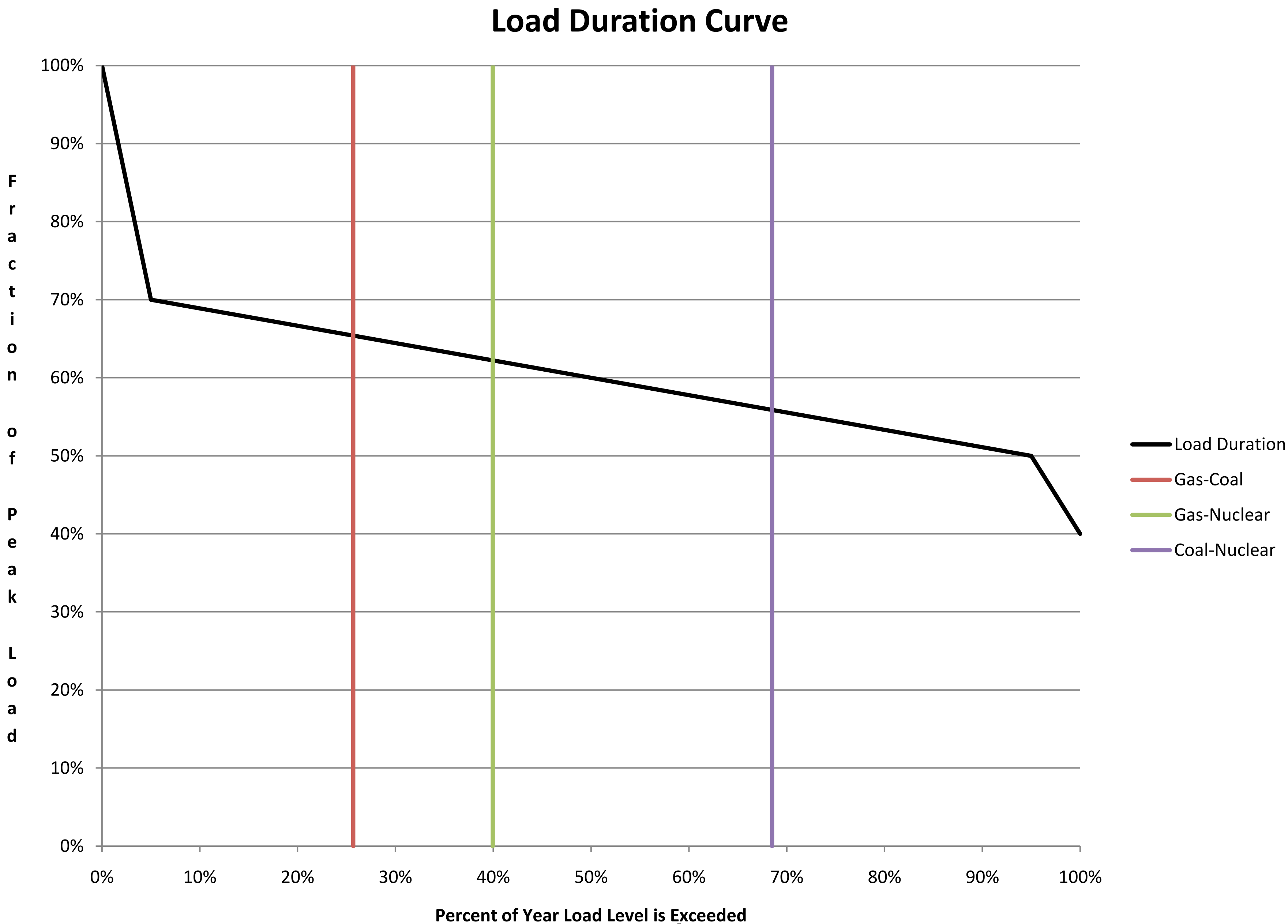
- A load duration curve is a numerical sorting by size of all of the hourly loads that a utility experiences during a year. For the vast majority of the year (95% of the time in this example), only about 70% of the generating capacity is needed in this example. During the other very few hours (5% of the time in this example), the utility needs peaking capacity, generation that can be jerked up and down relatively easily. Gas turbines fit this concept. There are also a few hours when very little generation is needed.


Load Duration Curve
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Fraction of Peak Load
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Year Load Level is Exceeded
Load Duration
Gas-Coal

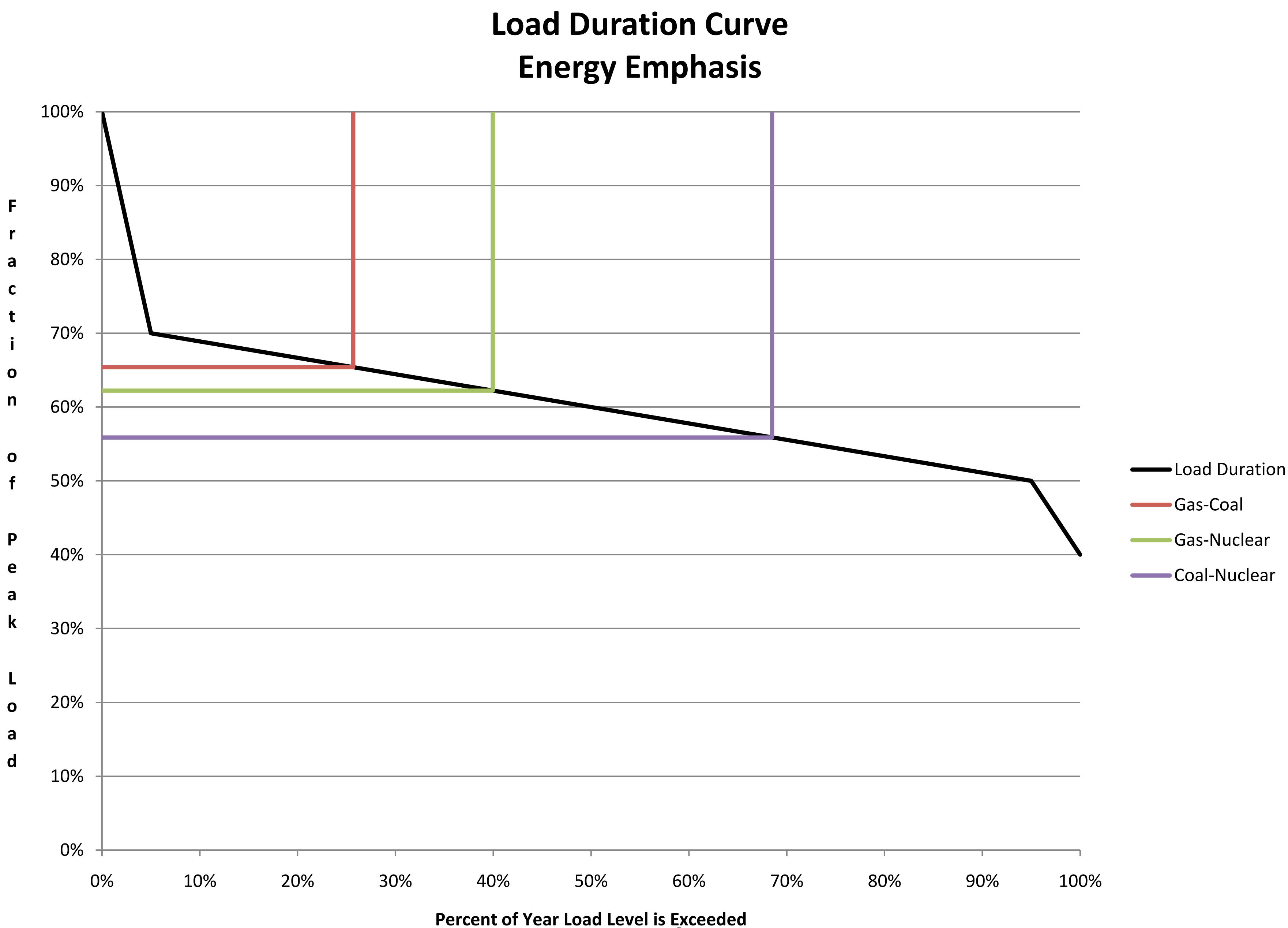
- The breakeven points identified in the screening curve can be put onto the load duration curve, the gas-coal break even point in this example.


Load Duration Curve
Energy Emphasis
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Fraction of Peak Load
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Year Load Level is Exceeded
Load Duration
Gas-Coal

- Under ideal situations, the gas turbine would only be operated to provide energy above the red line above. Though the gas turbines in the example would make up about 35% of the generating fleet and be expected to be available up to 26% of the time, they will provide only a miniscule amount of energy.
- Situations are never ideal. The expectation of having to back down generation at the tail end of the load duration curve at the right may require some gas turbines to be on all the time such that they can provide the back down service.



Load Duration Curve
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Fraction of Peak Load
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Year Load Level is Exceeded
Load Duration
Gas-Coal
Gas-Nuclear
Coal-Nuclear



Load Duration Curve
Energy Emphasis
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Fraction of Peak Load
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Year Load Level is Exceeded
Load Duration
Gas-Coal
Gas-Nuclear
Coal-Nuclear

# Unit Costs
# Static Operating Basis

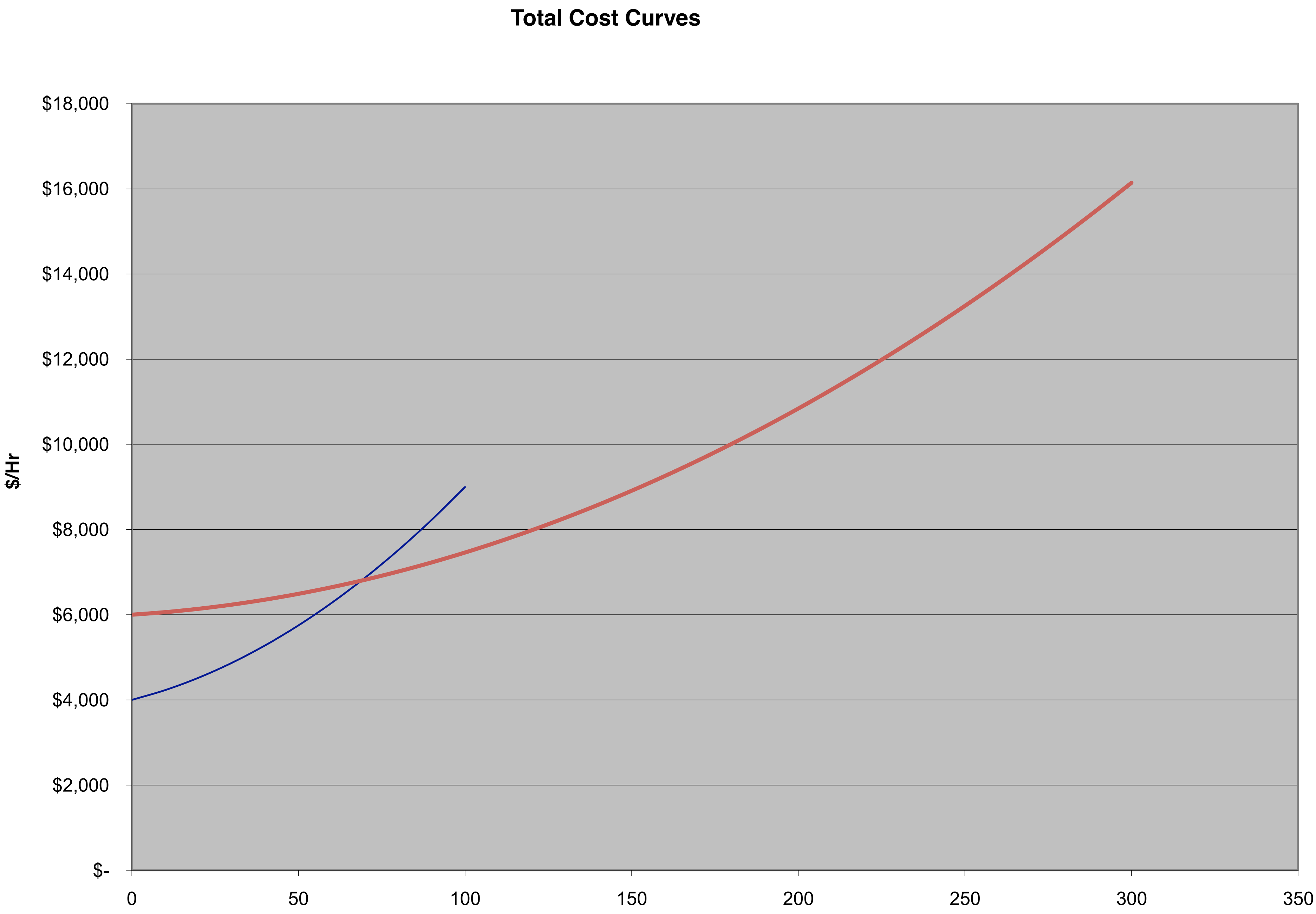
- Quadratic Total Cost Curve
  - TC ($/hour) = $A * MW^2 + B * MW + C$
- Linear Marginal Cost Curve
  - MC ($/MWH) = $2 * A * MW + B$
- Average Cost Curve
  - MC ($/MWH) = $A * MW + B + C/MW$

- We can model the real time steady state cost of operating a fossil fired generating plant with a quadratic cost function.  More complex cost functions can be used, but for purposes of this demonstration a quadratic total cost function illustrates several concepts nicely.
- Simple calculus can produce the marginal cost curve for the same unit.  The derivative of a quadratic total cost curve produces a linear marginal cost curve.
- The average cost curve is simply the total cost curve divided by the output.

# Co-Optimizing Two Generators

| | Small | Large |
|---|---|---|
| Capacity | 100 | 300 |
| A ($/hour) | 4,000 | 6,000 |
| B ($/MWH) | 20 | 5 |
| C ($/MWH/MW) | 0.3 | 0.096 |

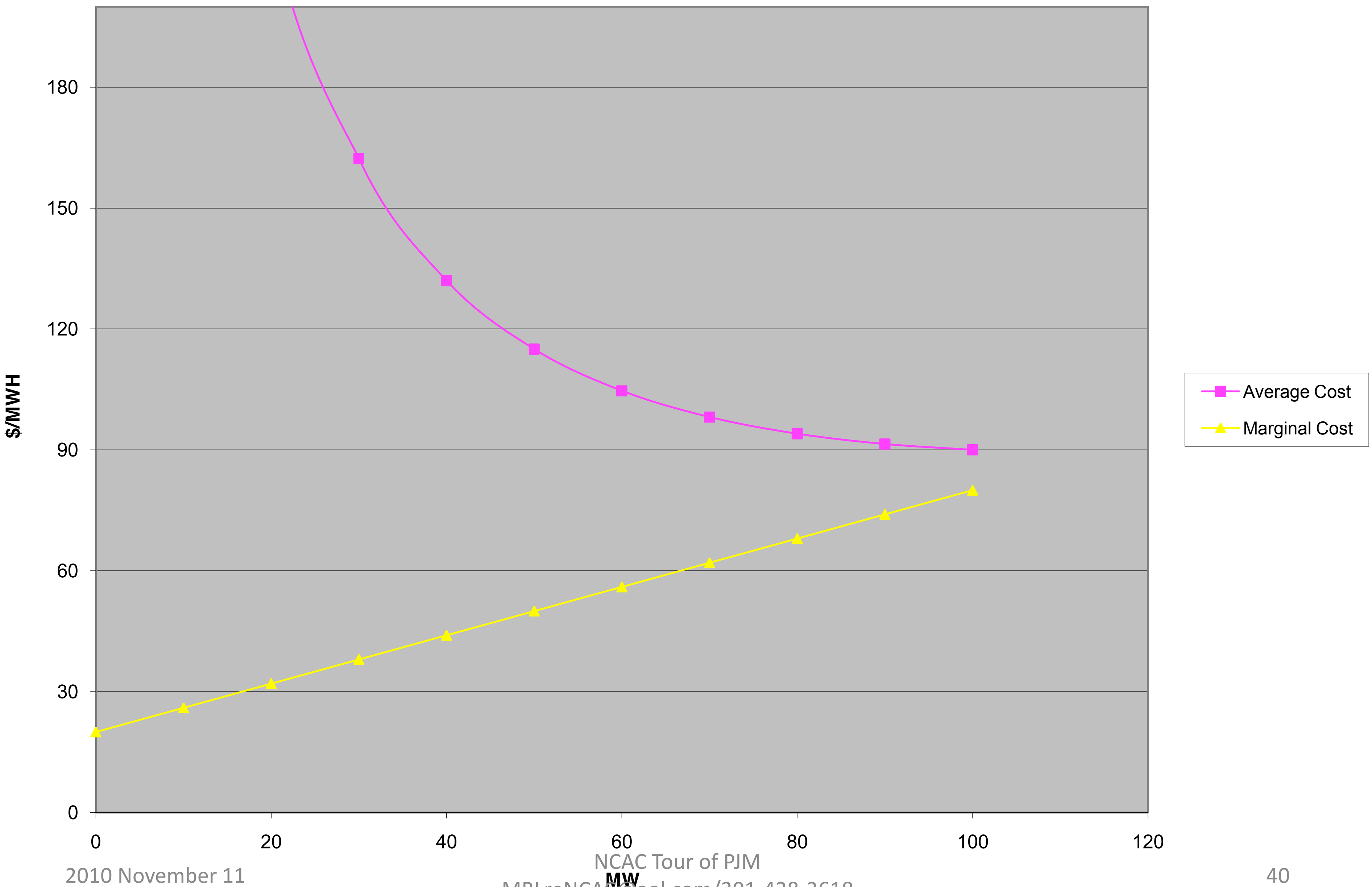
- For simplicity, we will do an optimization using two units, called just small and large. The relevant assumptions are in the table so that the following graphs can be reproduced by those interested in the process.



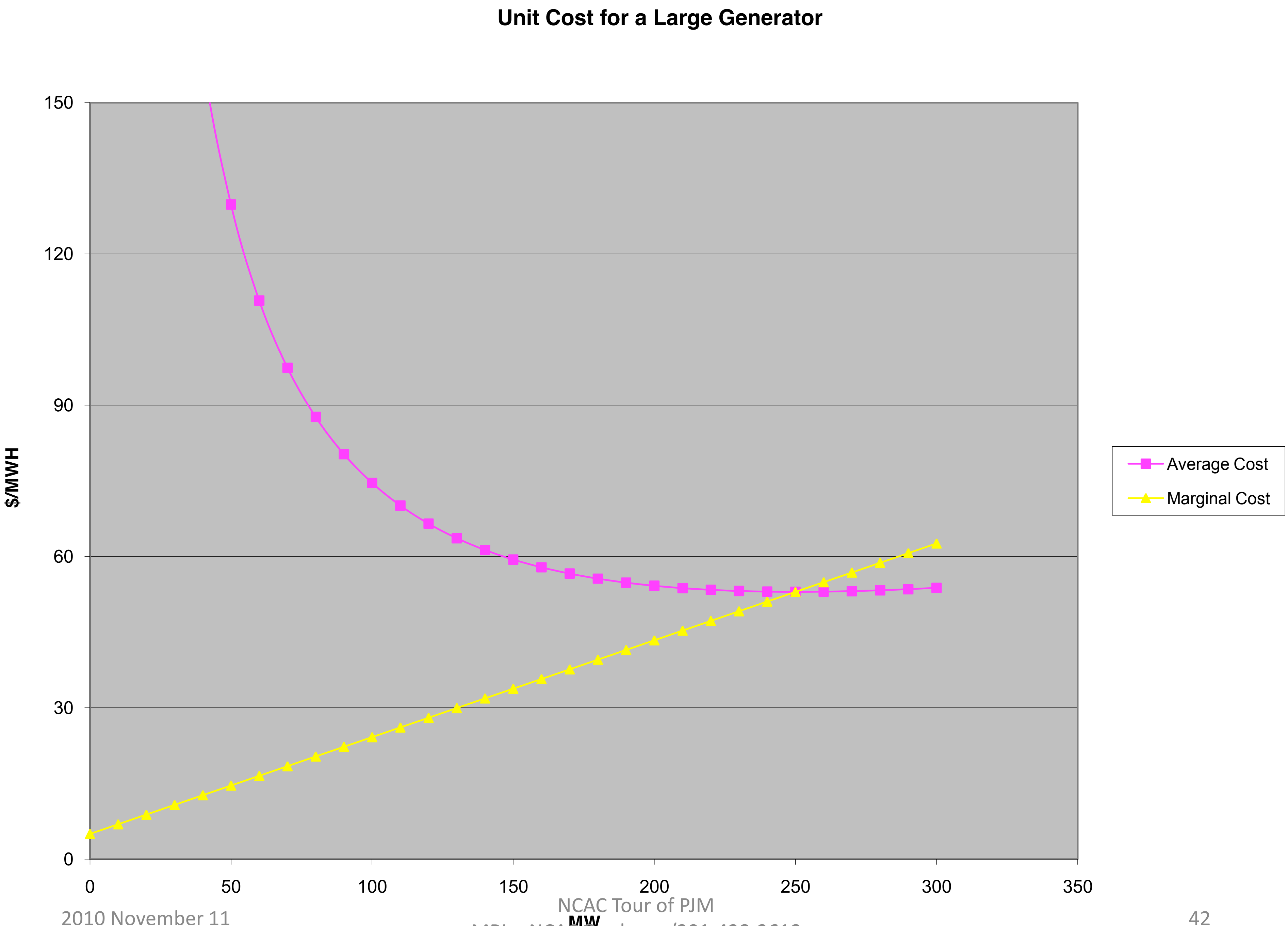
Total Cost Curves
$/Hr
$18,000
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$-
0
50
100
150
200
250
300
350
MW

- The total cost curves are the quadratic curves specified by the coefficients (numbers) in the previous table. If one can instantaneously switch back and forth between the two units, we would want to use the small unit until the power level reached about 69 MW, then the larger unit would be turned on instantly, since its total operating costs would be less, and the smaller unit would be turned off instantly. Unfortunately, generating units can't be turned on and off instantly, so one generator must be selected. If the load is expected to be above the 100 MW capacity of the smaller unit, then the larger unit must be operated. But we are interested in joint dispatch, not choosing being one or the other.

## Unit Cost for a Small Generator

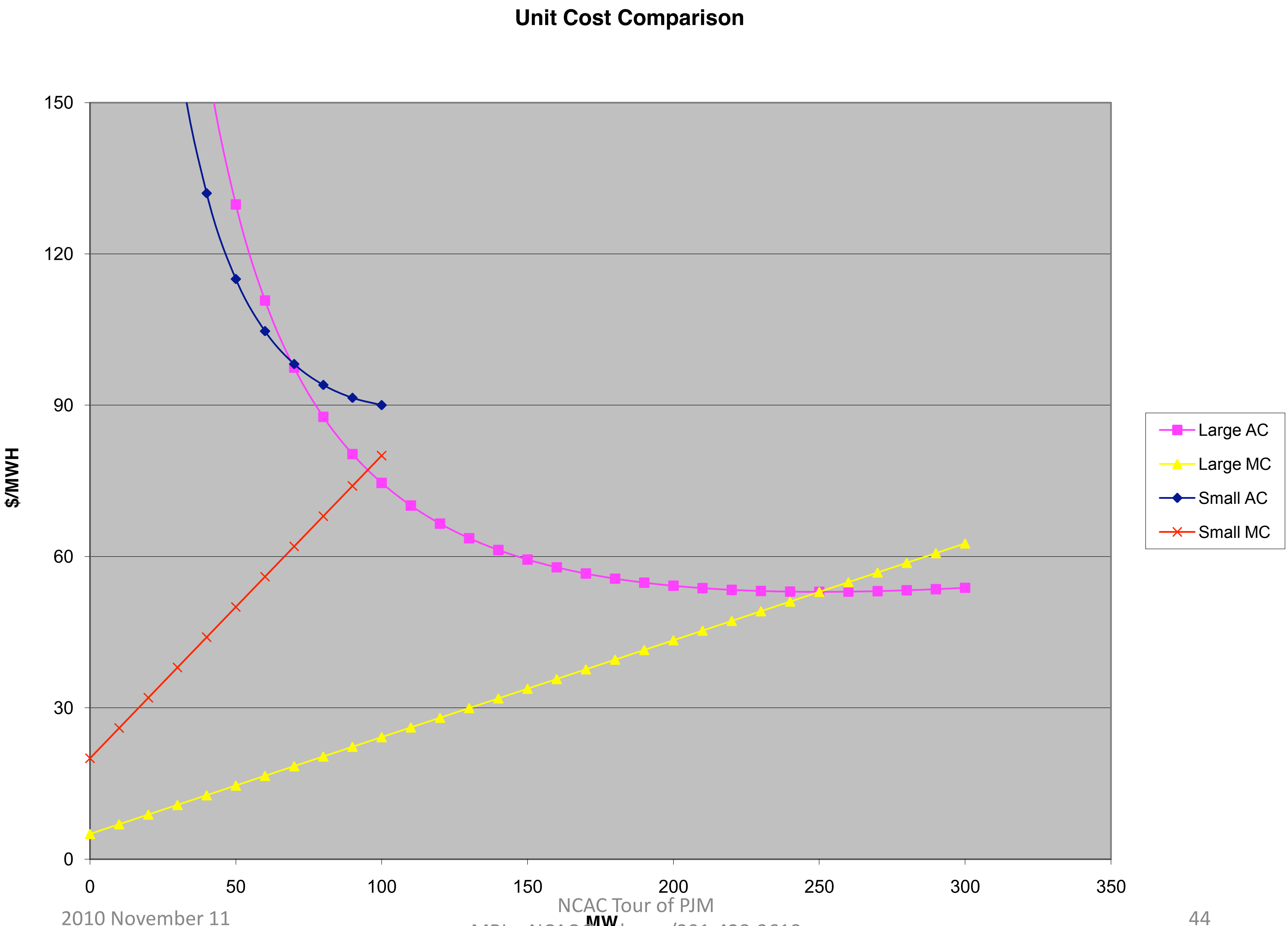


- The unit cost curves for the smaller unit shows how the marginal costs increase as the power level of the unit increases. In contrast, the average unit cost declines over the posted range. In regard to the previous comment from Hydro Tasmania, the average cost at 20 MW, $226/MWH is about 2 ½ times the average cost at 100 MW, full load for this unit. This supports the concept that operating at low power levels results in outlandish average unit costs. At 10 MW, which is 10% of full load, the average cost is $575/MWH, about 6 times the average cost at full load.

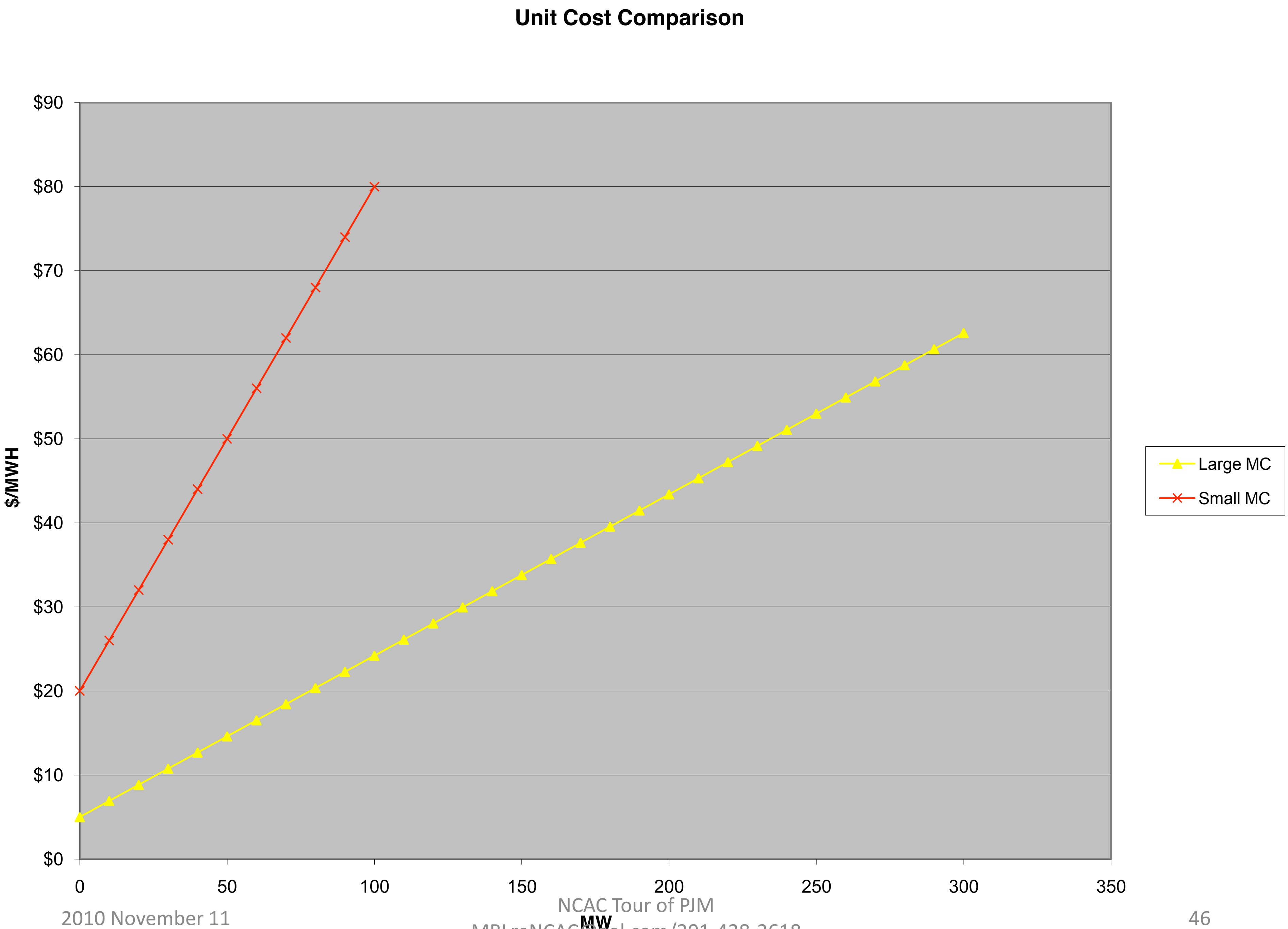


Unit Cost for a Large Generator
150
120
90
60
30
0
$/MWH
0
50
100
150
200
250
300
350
MW
Average Cost
Marginal Cost

- The unit cost curves for the larger unit shows how the marginal costs increase as the power level of the unit increases. In contrast, the average unit cost declines over the posted range, at least until the two curves cross. It is not obvious because of the scale of the graph, but above the crossing point, the average cost slowing increases. In regard to the previous comment from Hydro Tasmania, the average cost at 50 MW, $139/MWH is about 2 ½ times the average cost at 300 MW, full load for this unit. This supports the concept that operating at low power levels results in outlandish average unit costs. At 30 MW, which is 10% of full load, the average cost is $208/MWH, about 4 times the average cost at full load.

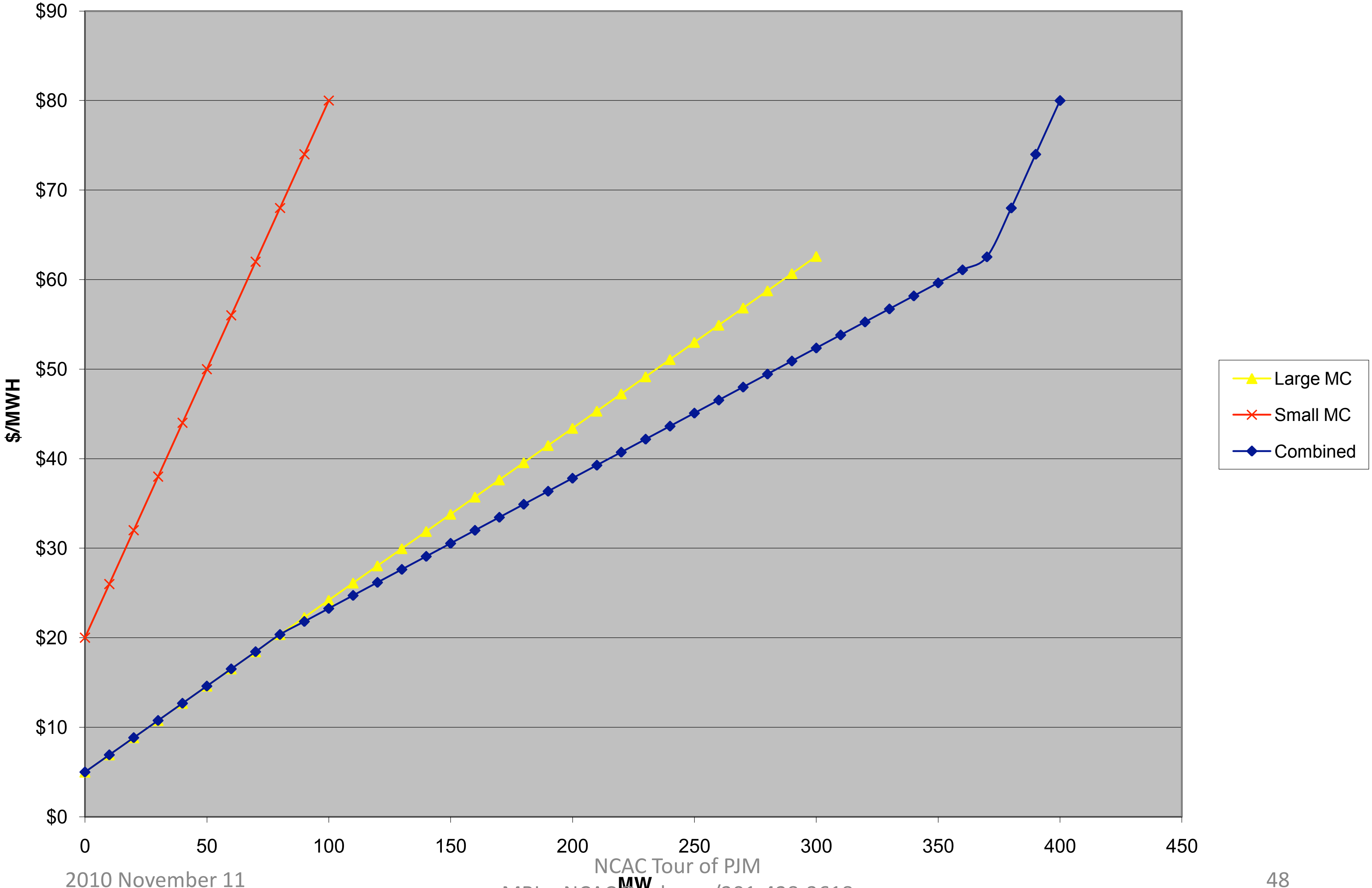

Unit Cost Comparison
150
120
90
60
30
0
0
50
100
150
200
250
300
350
$/MWH
MW
Large AC
Large MC
Small AC
Small MC

- The four cost curves illustrate two different results for generating plants. Sometimes the average cost curve and the marginal cost curve cross, as is the case for the large unit and sometimes the average cost curve and the marginal cost curve don't cross as is the case for the small unit. When they do cross, the crossing point is likely to be near full load, just over 80% in the case of the large unit in these examples.


Unit Cost Comparison
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
$/MWH
0
50
100
150
200
250
300
350
MW
Large MC
Small MC

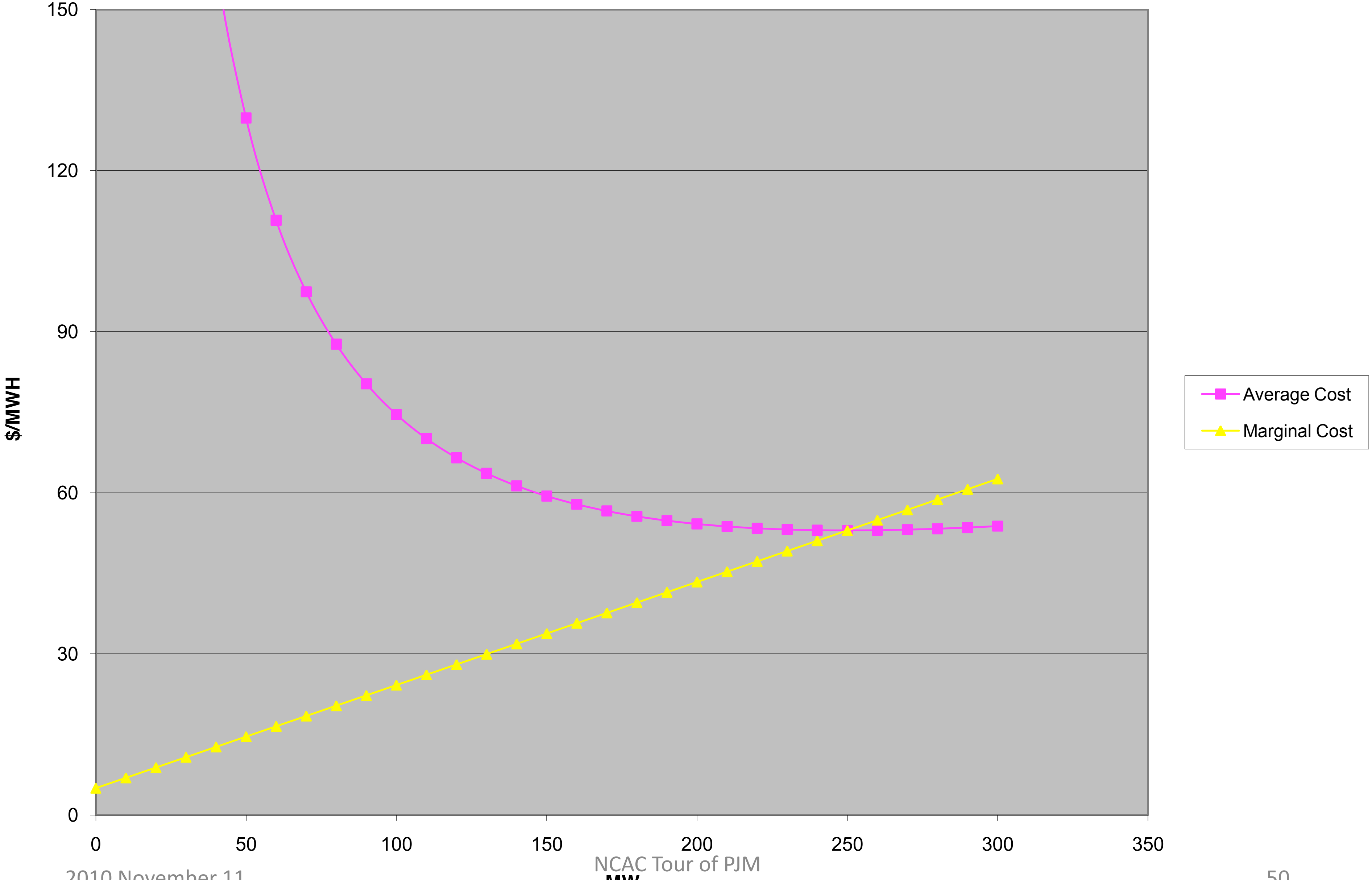
- Lagrange showed that costs can be minimized by examining marginal costs and setting the marginal costs equal.

# Unit Cost Comparison



- The marginal cost curves can be combined by adding the capacities associated with each marginal cost. For those marginal costs which are less than the lowest marginal cost of the small unit, the combined marginal cost curve overlays the marginal cost curve of the large unit. For those marginal costs which are common to both generators, the operating levels of the two generators are added to determine the combined operating level. For those marginal costs which are greater than the marginal cost of the large unit, the combined operating level is the operating level of the small unit plus the total capacity of the larger unit.

## Unit Cost for a Large Generator



- Unit operations may be optimized by operating a generating unit at less than its capacity, but this incurs a form of penalty in that the average cost will be substantially above marginal cost.

# Marginal Cost

- Good way to dispatch several units jointly
- Start-up (low load) costs not handled well
  - Stronger emphasis in Europe on unit commitment
- Profits come from operating at some one else's marginal cost above one's own
- Some ISOs have uplift charges to compensate for start-up costs
- Some ISOs have capacity/demand auctions

# ISO Auctions

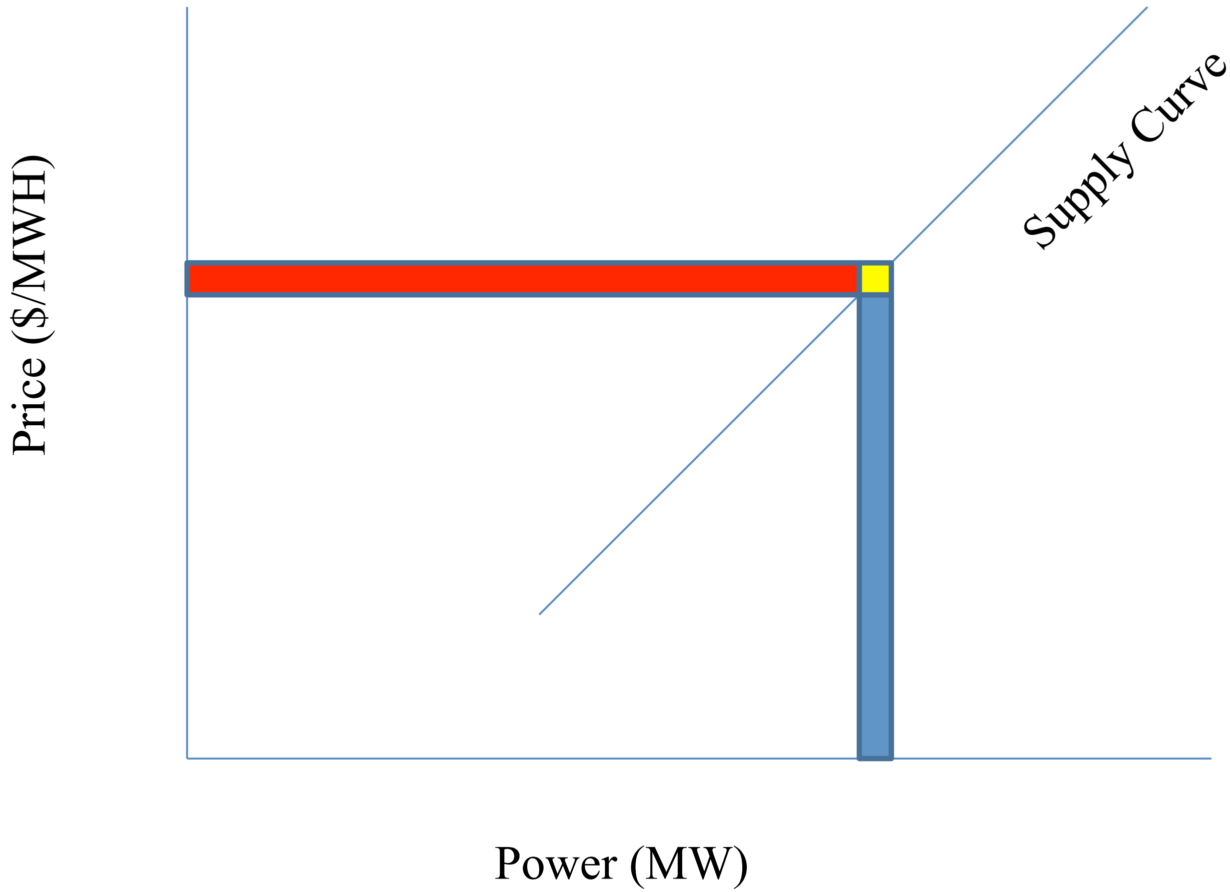
- Two sided-supply and demand
- Future periods
  - Day ahead
  - Hour ahead
  - 15 minutes ahead

- The supply curves are created using the technique shown above for combining the marginal cost of two units. A converse method is used to determine a demand curve, though the demand curve is almost vertical.
- ISO auctions are for a future period and can be considered to be a forwards market.

# Uniform Price Auction

- Joint Dispatch to equalized Lambdas following concept of Langrange
- Adjusted for transmission losses
- Reflecting system transmission constraints
- Price variance can dwarf volume variance
  - Exacerbated effect of Enron gaming of California market in 2000/2001

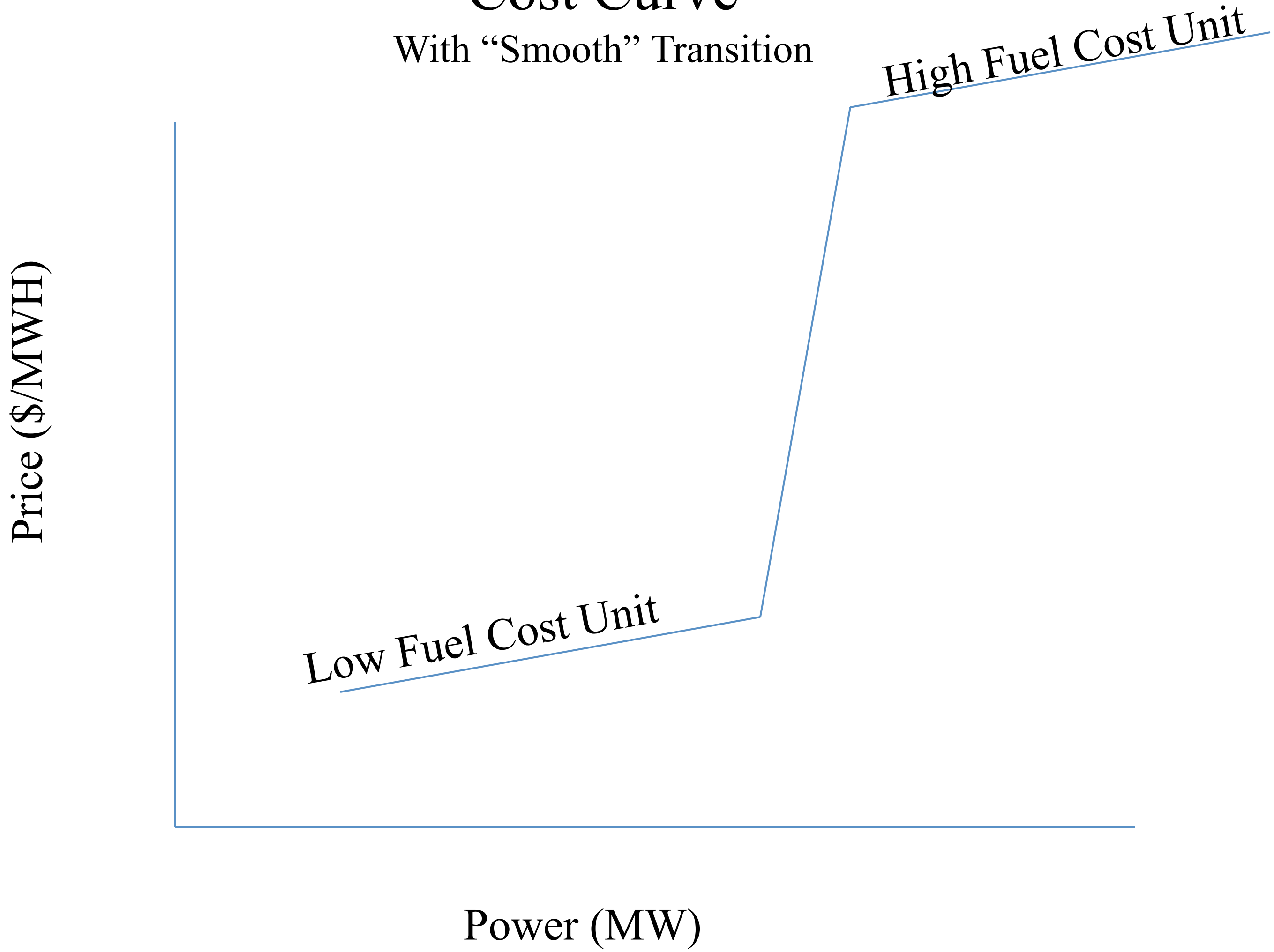
# Revenue Due to Change in Demand



- The supply curve is upward sloping. A slight change in the power level will increase the price. Under a uniform price auction, all of the capacity to the left of the supply curve gets re-priced, as is illustrated by the horizontal rectangle. Some accountants will call the vertical rectangle a volume variance and the horizontal rectangle a price variance. The price variance, when it involves re-pricing all power can be very expensive.

# Cost Curve

With "Smooth" Transition



- The low and high parts of the cost curve might be the slow increase in marginal cost associated with increasing the output of a particular unit. The middle part of the cost curve might be a transition between a low fuel cost unit and a high fuel cost unit, as shown in the diagram. In some systems, the middle part of the cost curve might be a discontinuity where the costs jump suddenly from one level to another. The slopes of the cost curves are expressed in $/MWH/MW, the vertical units divided by the horizontal units. In the following example the lower two slopes will be 0.0001 and 0.4000, while the kink occurs at 50,000 MW (which is much smaller than PJM) and $50.00/MWH.

# ISO Revenue Effect of Demand Change

(above and below kink in supply curve)

| Power | Rate | Revenue | Delta Revenue |
|---|---|---|---|
| 49,999 | $49.9999 | $ 2,499,945.00 | |
| | | | $ 55.00 |
| 50,000 | $50.0000 | $ 2,500,000.00 | |
| | | | $ 20,050.40 |
| 50,001 | $50.4000 | $ 2,520,050.40 | |

In this numeric example there is a kink in the supply curve that occurs at 50,000 MW and $50.00/MWH.  Below that kink, the supply curve was increasing at a very slow $0.0001/MWH/MW.  Thus, at 1 MW below 50,000 MW, the rate has dropped by $0.0001/MWH to $49.9999/MWH.  Above that kink, the supply curve was increasing at a fast $0.4000/MHW/MW.  Thus, at 1 MW above 50,000 MW, the rate has increased by $0.4000 to $50.4000/MWH.  The MW increase in the supply curve to get from 49,999 MW to 50,000 MW cost the consumers $55.00/hour.  The additional MW increase in the supply curve to get from 50,000 MW to 50,001 MW cost the consumers $20,0050.40.  The math shows the that volume variance is approximately the rate, $50 or $50.4. The price variance is $5 in the first instance and $20,000 in the second instance.  The supply curve was much steeper during the California crisis of 2000/2001.

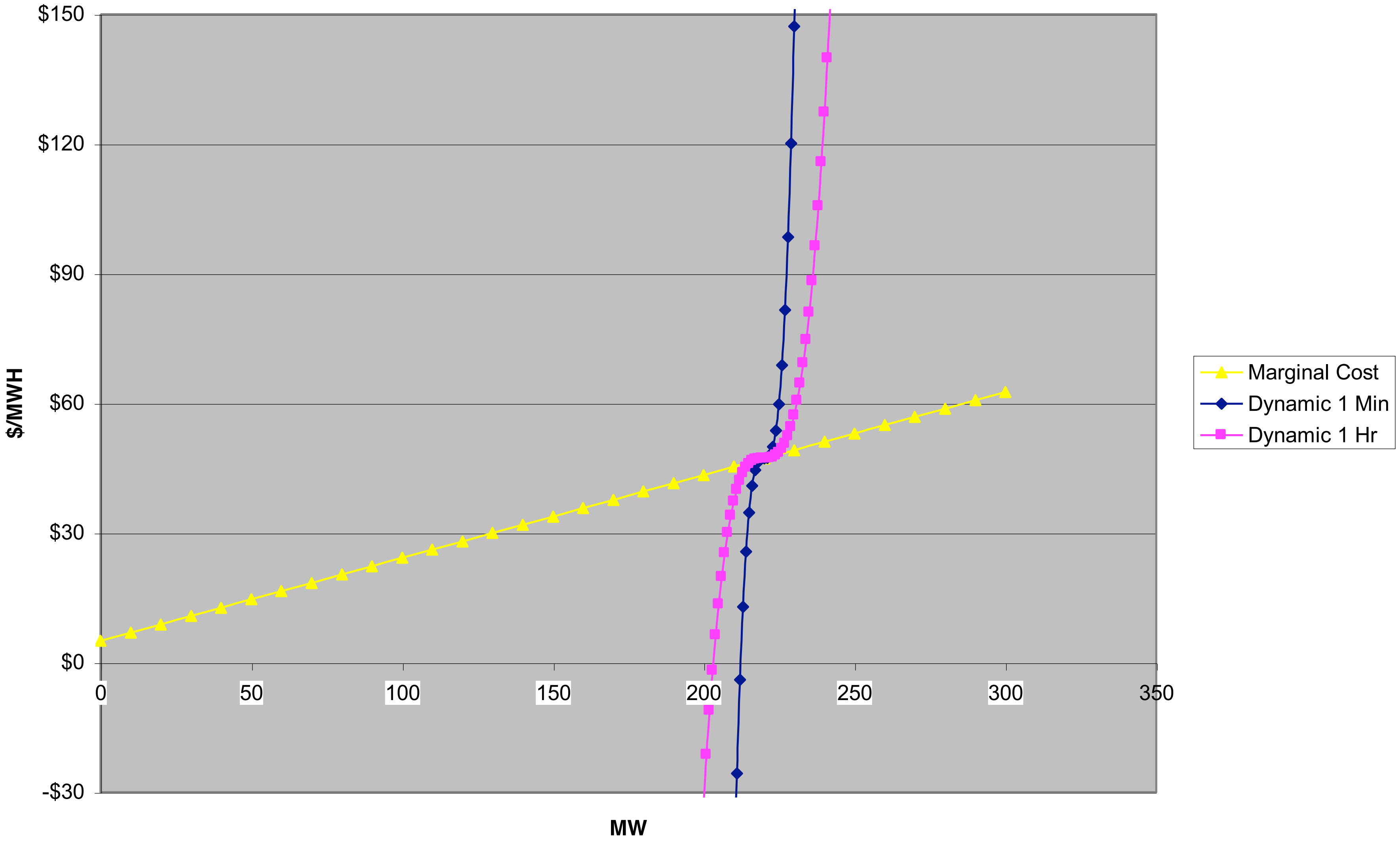
# Electricity is continuous

- Electricity is delivered second by second with demand equal to supply
- Meters can measure to many decimal places

but

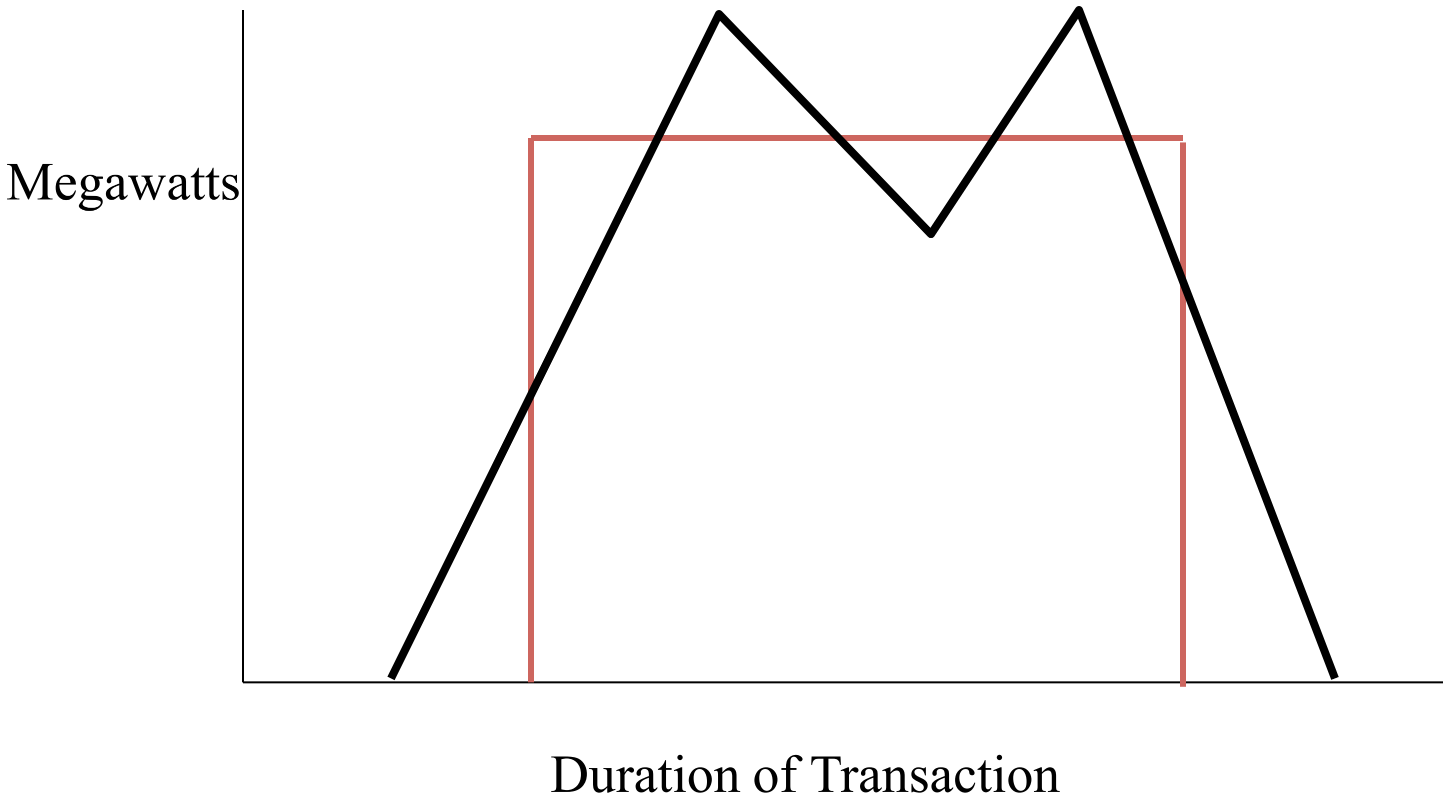
- Auctions are cumbersome for longer periods of time
- Auctions are for discrete amounts, one or two significant digits

## Unit Cost for a Large Unit



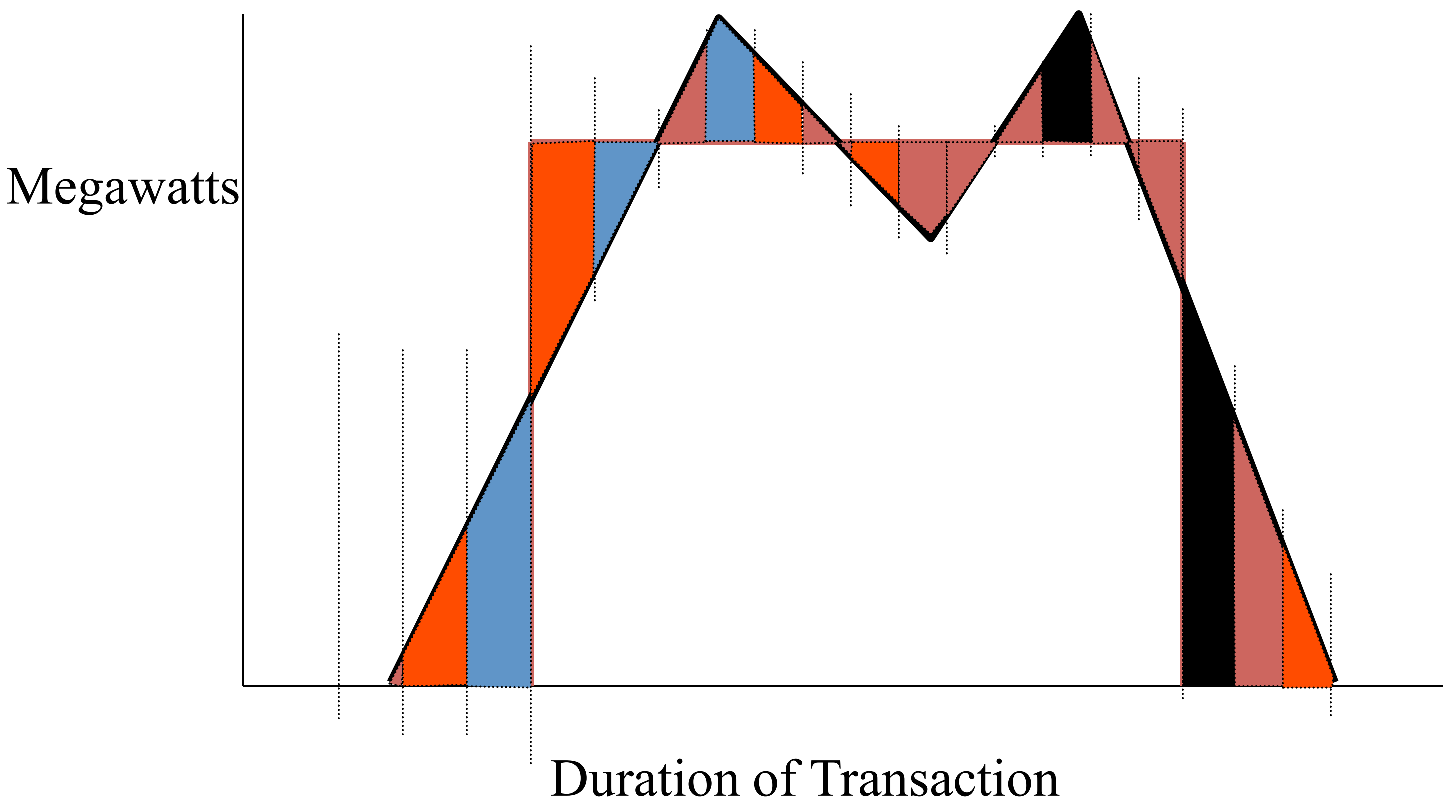
- The previous cost curves were for static conditions, running at a particular generation level for an extended period of time to allow the conditions to settle. But when generators are forced to change their output rapidly, marginal costs depart from the stated cost curves. In this graph, the dynamic marginal cost curves are shown as departing from the static cost curves using cubic functions. The dynamic marginal cost curves depend on how rapidly the units are forced to change their output. Dynamic costs are difficult to measure or even to estimate. Dynamic pricing can reduce the need for such measurement or estimation on a centralized basis. Note that the marginal cost is modeled as going negative for extreme decreases in the output.

# Scheduled vs Delivered Power



- Though electricity is a continuously delivered commodity, the practicalities of running an auction will generally result in a rectangular commitment, a specific number of MWs for a specific time duration.  The actual requirement will be slightly different and generators will be redispatched second by second to fill the differences.

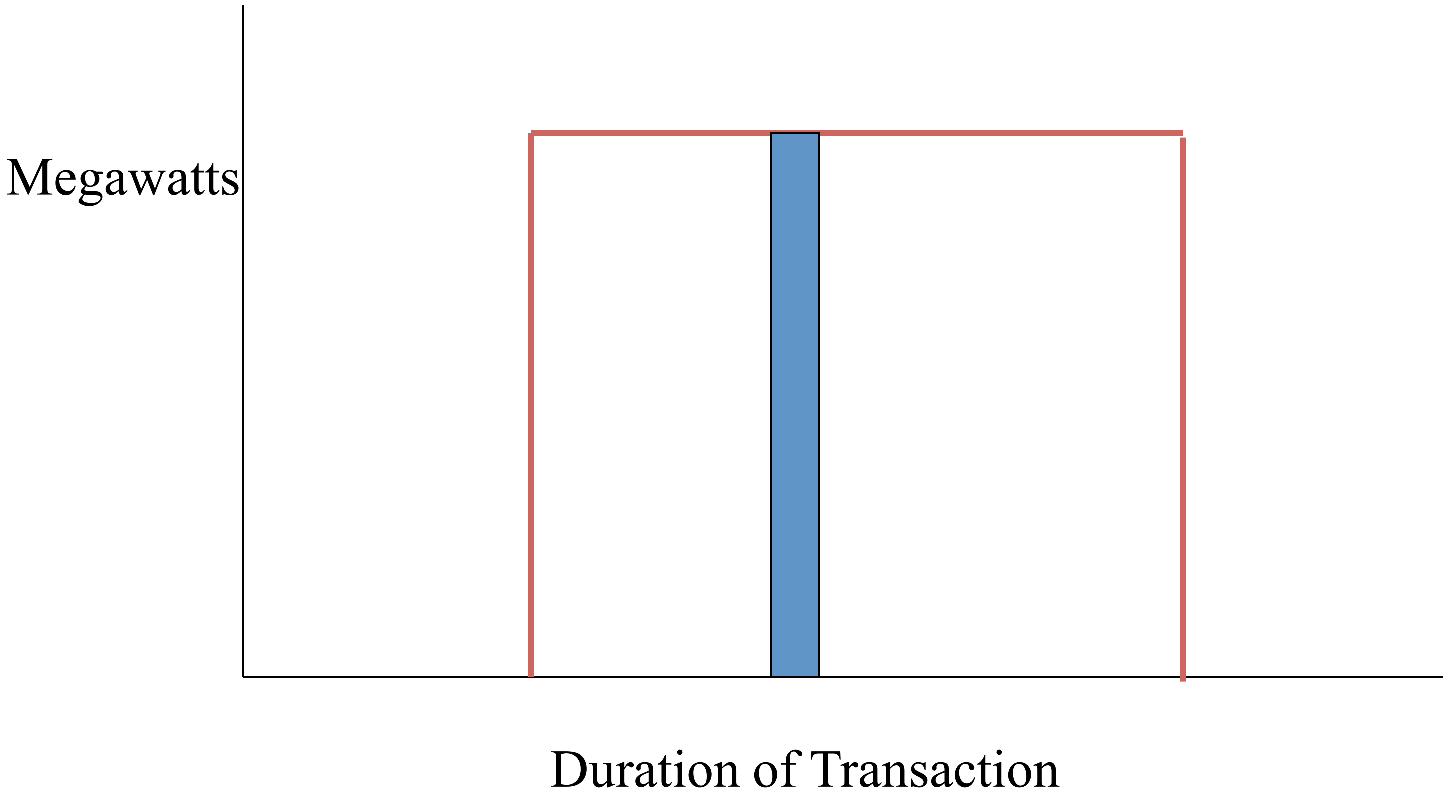
# Delivering Active Power



Comments on Previous Slide

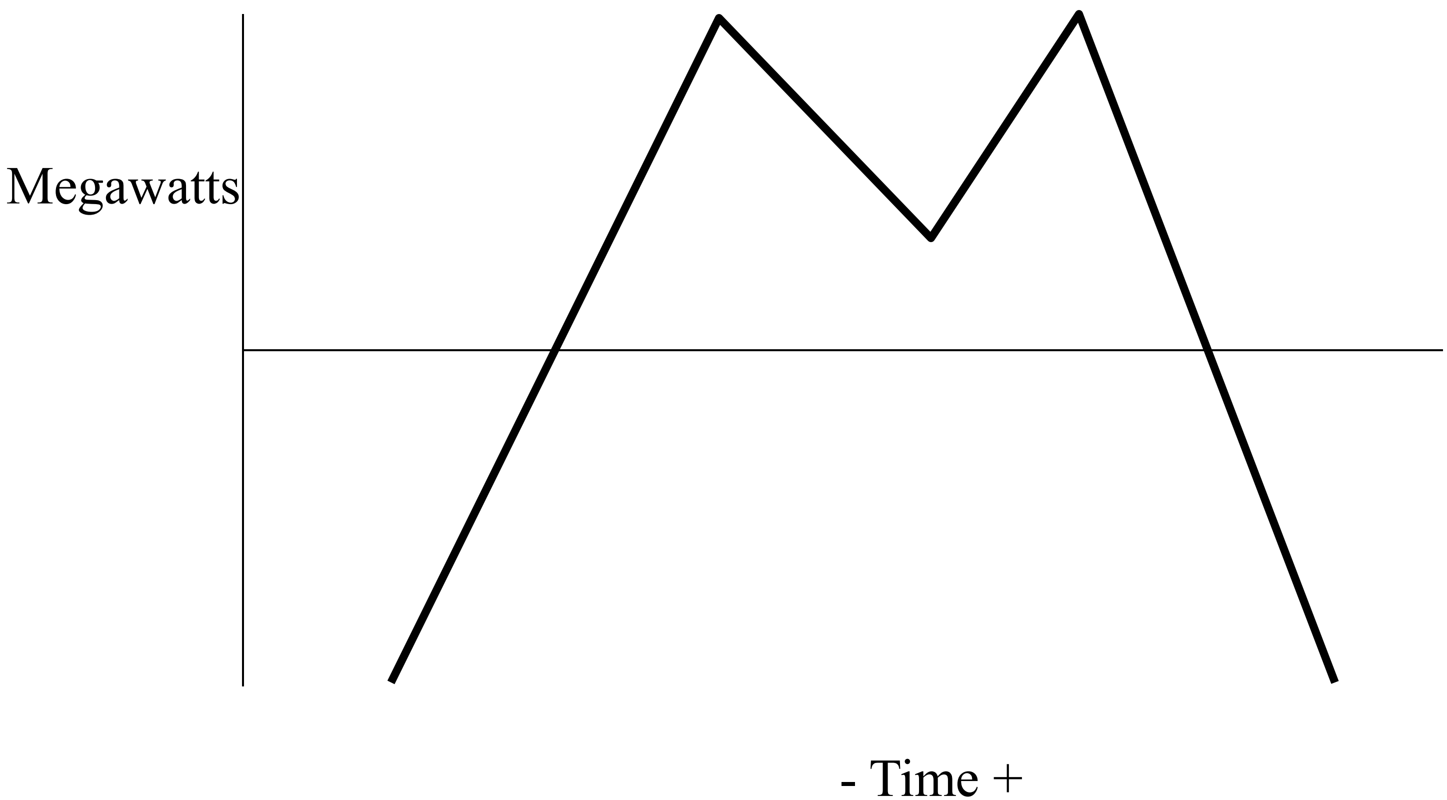
- The forwards auction will result in a single price for the rectangular commitment. The value of the instantaneous differences between the metered delivery and the rectangular delivery will vary, and can be priced according to that value. The value would be determined by the dynamic cost curves indicated previously.

# Delivering Active Power
## Load Management



- When a utility (or an ISO) is short of power, the utility might shut off consumer load.  In California during 2000/2001, there were rotating blackouts where entire neighborhoods went black.  A more sophisticated approach is to shut off specific loads behind a consumers meter, such as water heaters, air conditioner compressors, or pool pumps.  Some steel mills can shut of arc furnaces.  Some aluminum smelters can shut off pot lines.  This should become more common with the Smart Grid, but that will require some Smart Pricing to get consumers to allow the utility to reach through the meter to the customer’s loads.

# ISO Imbalance
# Area Control Error (ACE)



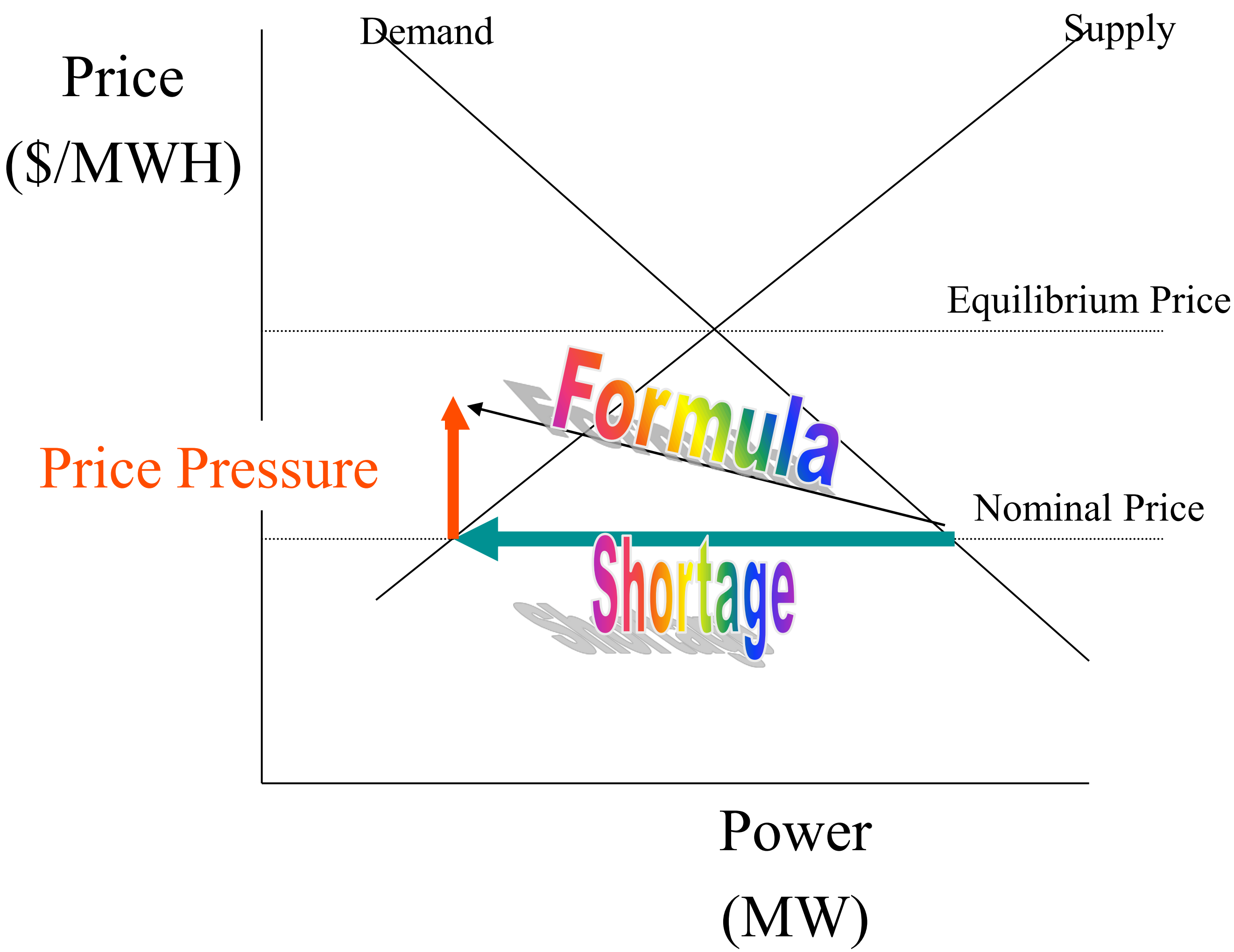
- NERC once had a policy that control areas, like today's ISOs and most investor owned utilities, were to control their supply and demand relative to each other that the difference (ACE or Area Control Error) crossed zero within ten minutes of the time that the ACE last crossed zero. This lessened the likelihood that control areas were unduly leaning on other control areas, that they were thus managing their shortages and surpluses.

# ACE

- Unscheduled imbalance with the rest of the system as biased for system frequency error
- Calculated every 3 seconds on many systems
- Shows the ISO is physically out of balance
- If supply is not equal to demand, should the spot settlement price be something different from the dispatch price?

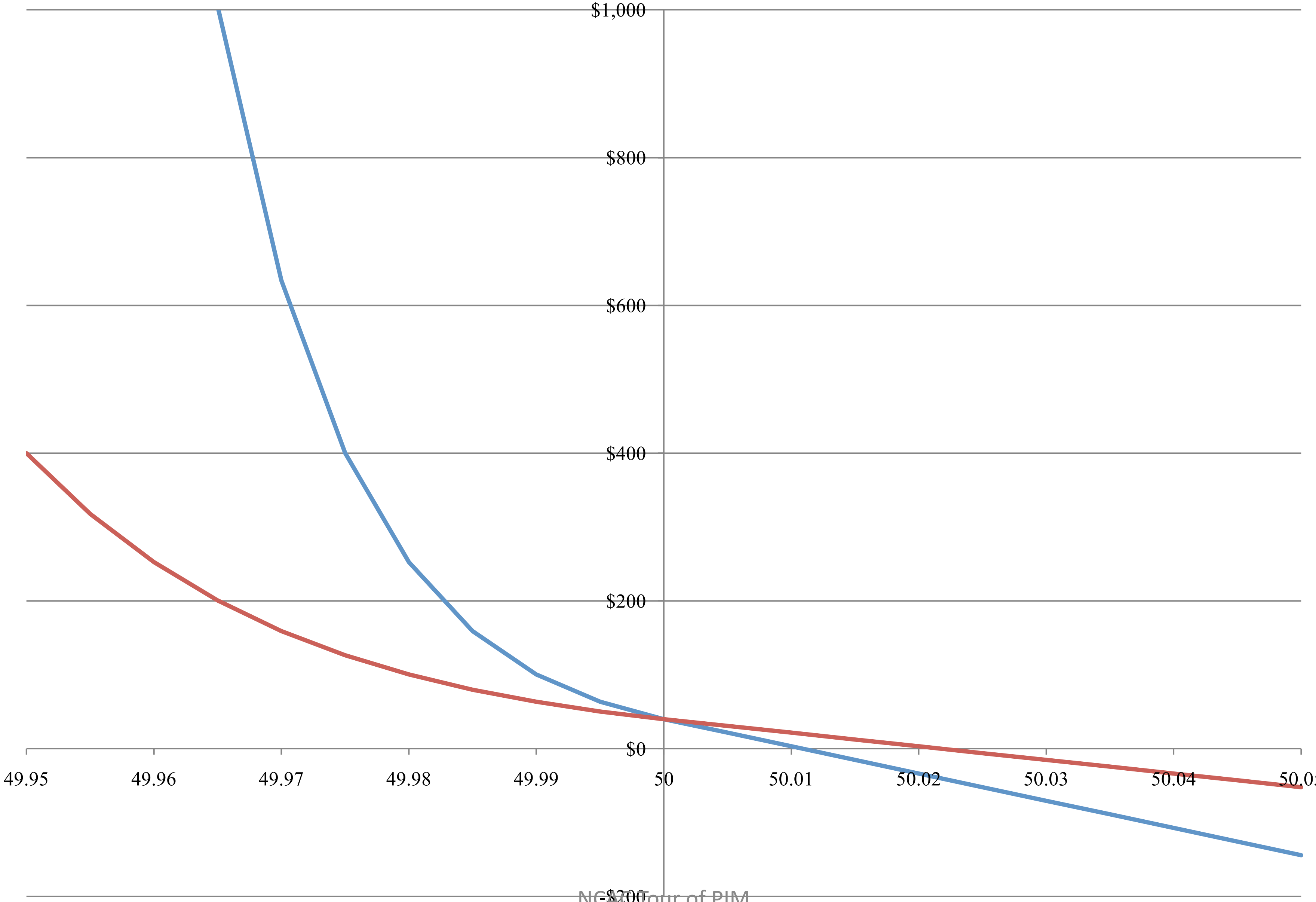
# Wide Open Load Following

# Dynamic Economic Theory



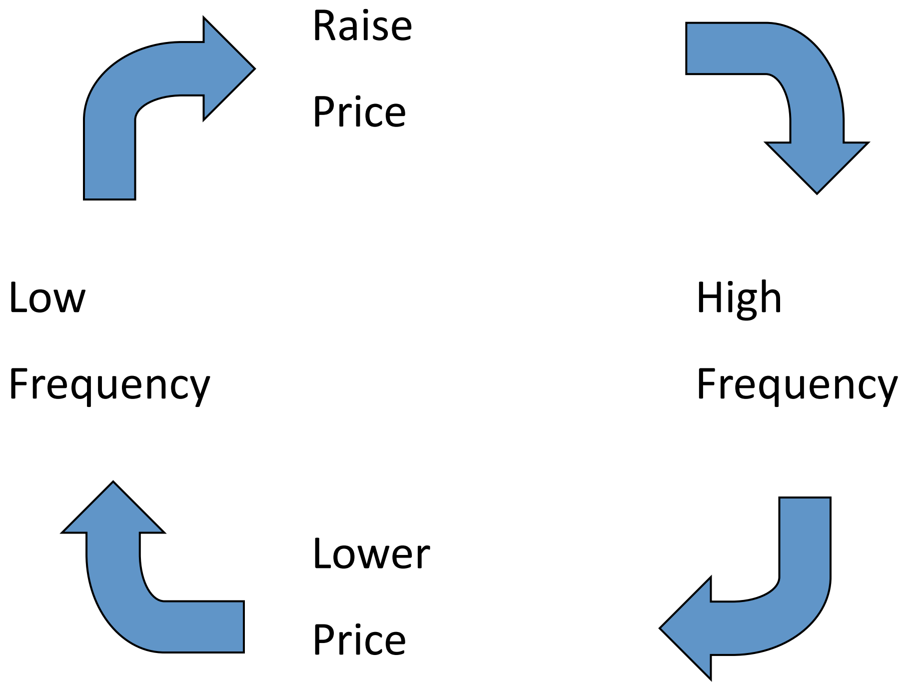
- For unscheduled flows of electricity, WOLF uses the concurrent shortage to set the price for the unscheduled flow. For active power, the shortage (or surplus) is measured by frequency error, unscheduled interchange, time error, and cumulative time error. For reactive power, the shortage (or surplus) is measured by voltage excursions.

# WOLF


$1,000
$800
$600
$400
$200
$0
-$200
49.95
49.96
49.97
49.98
49.99
50
50.01
50.02
50.03
50.04
50.05

- For an isolated electric system such as Tasmania or ERCOT (the Electricity Reliability Council of Texas), there can be no unscheduled flows with neighbors. In such situations, ACE simplifies to frequency error. This graph is for a system that operates at 50 Hertz. Notice that the price goes negative when the frequency gets too high.

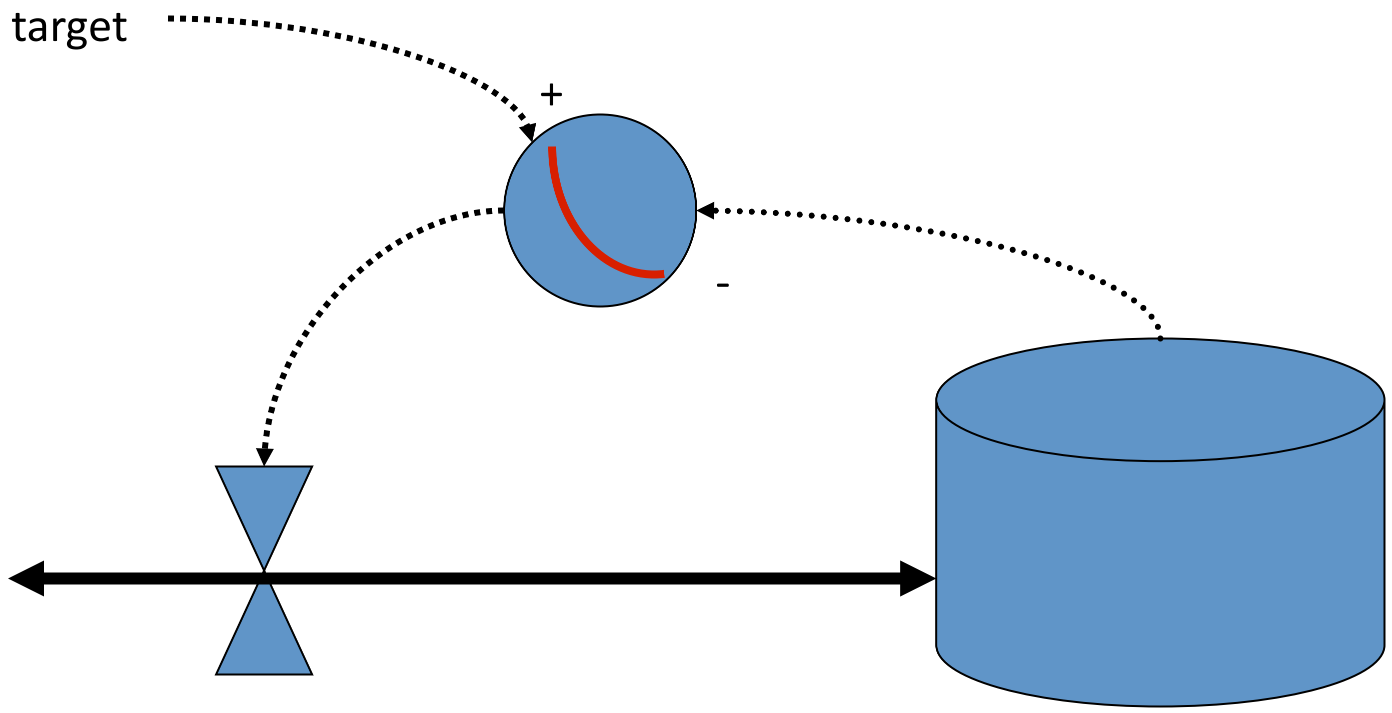
# WOLF Pricing
# Control Theory



# WOLF pricing is a dynamic dance

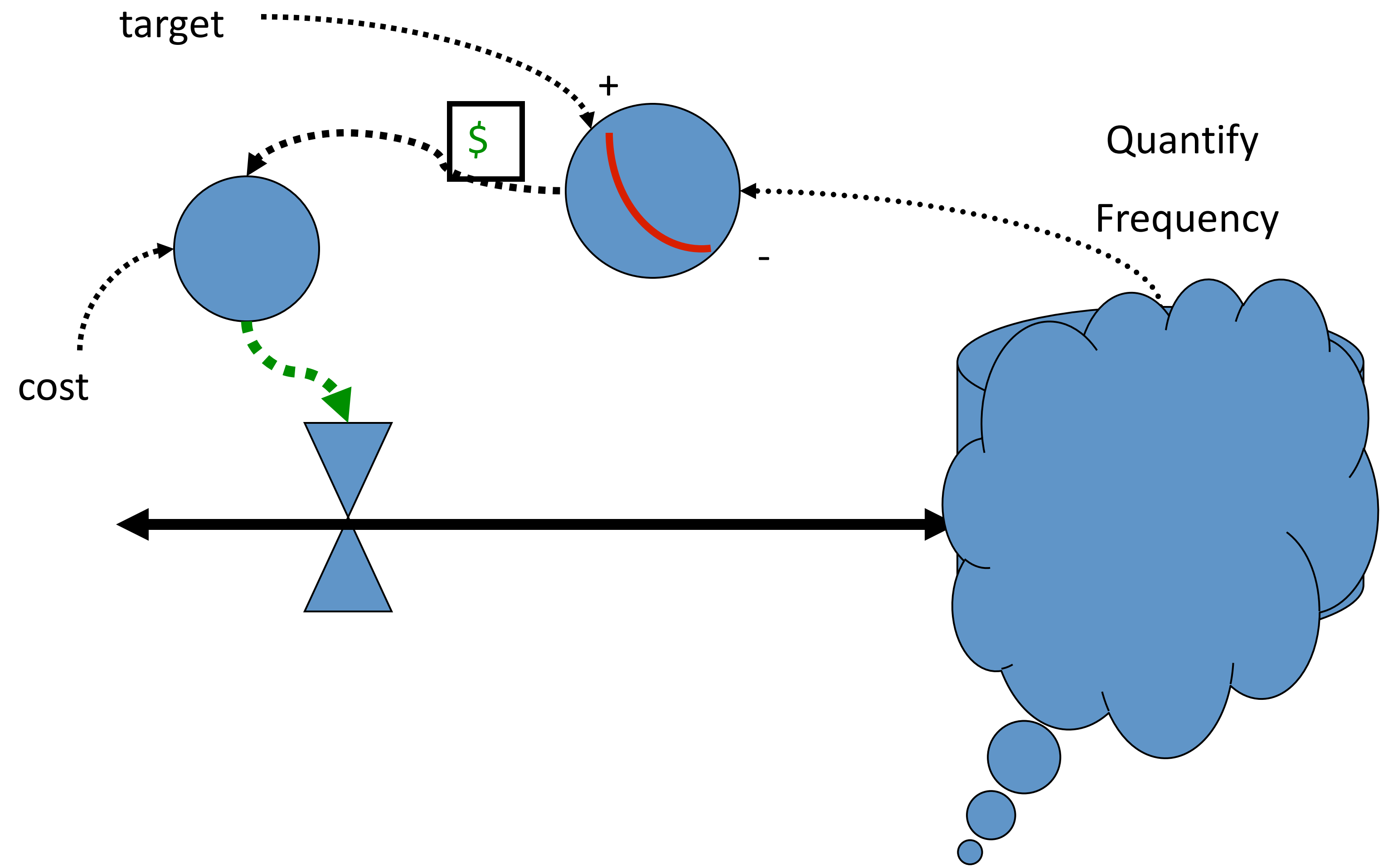
What we do in response to the anticipated price changes the price on us

# Wide Open Load Following Control Theory



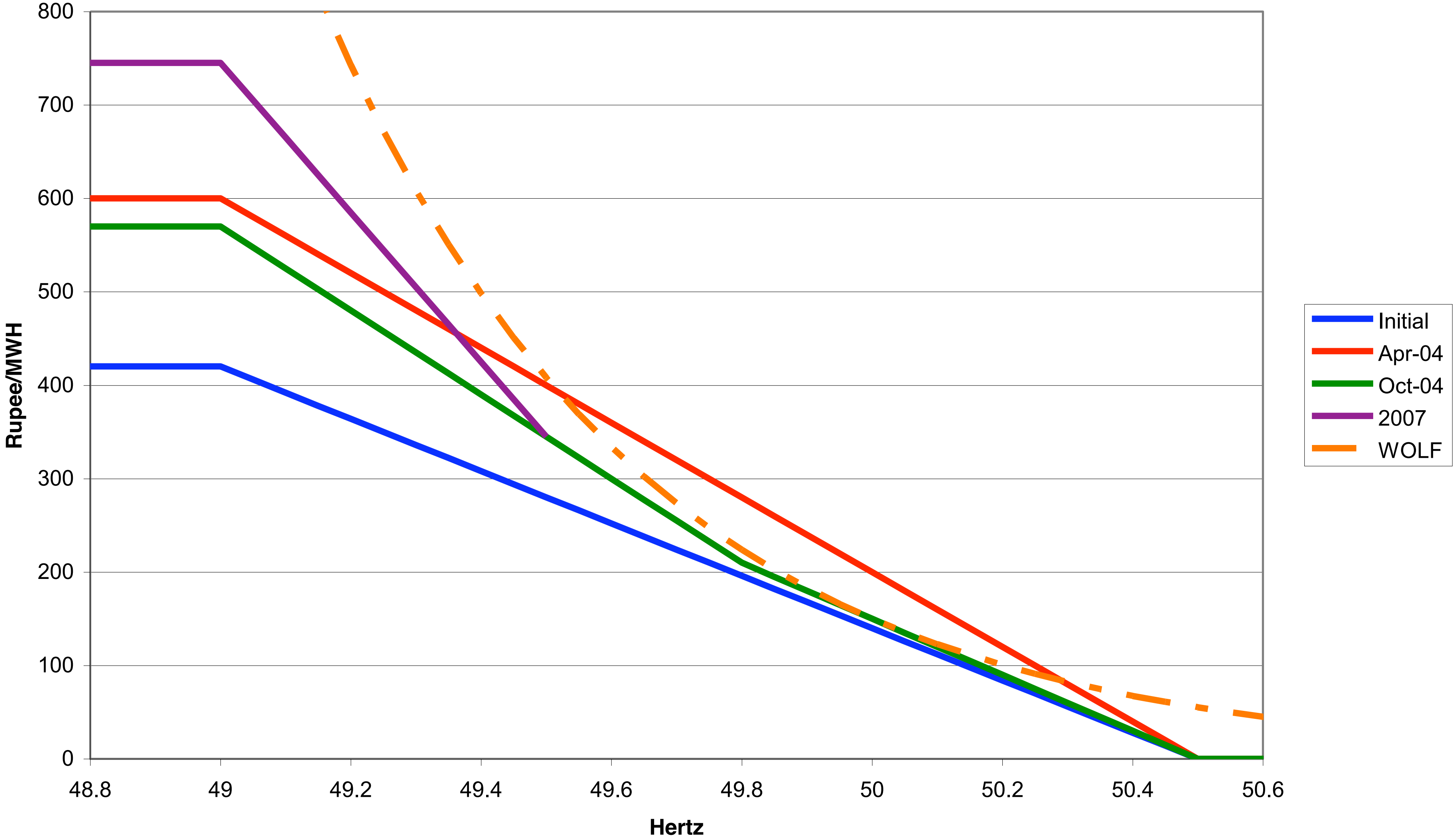
- Dynamic pricing can be compared to operating a water storage tank. There is a meter to determine the current level of water in the tank. There is a target for the amount of water that is desired to be in the tank. The supply valve/pump is operated to put water into the tank or to take water out of the tank based on whether the metered volume in the tank is above or below the target.

# Wide Open Load Following Control Theory

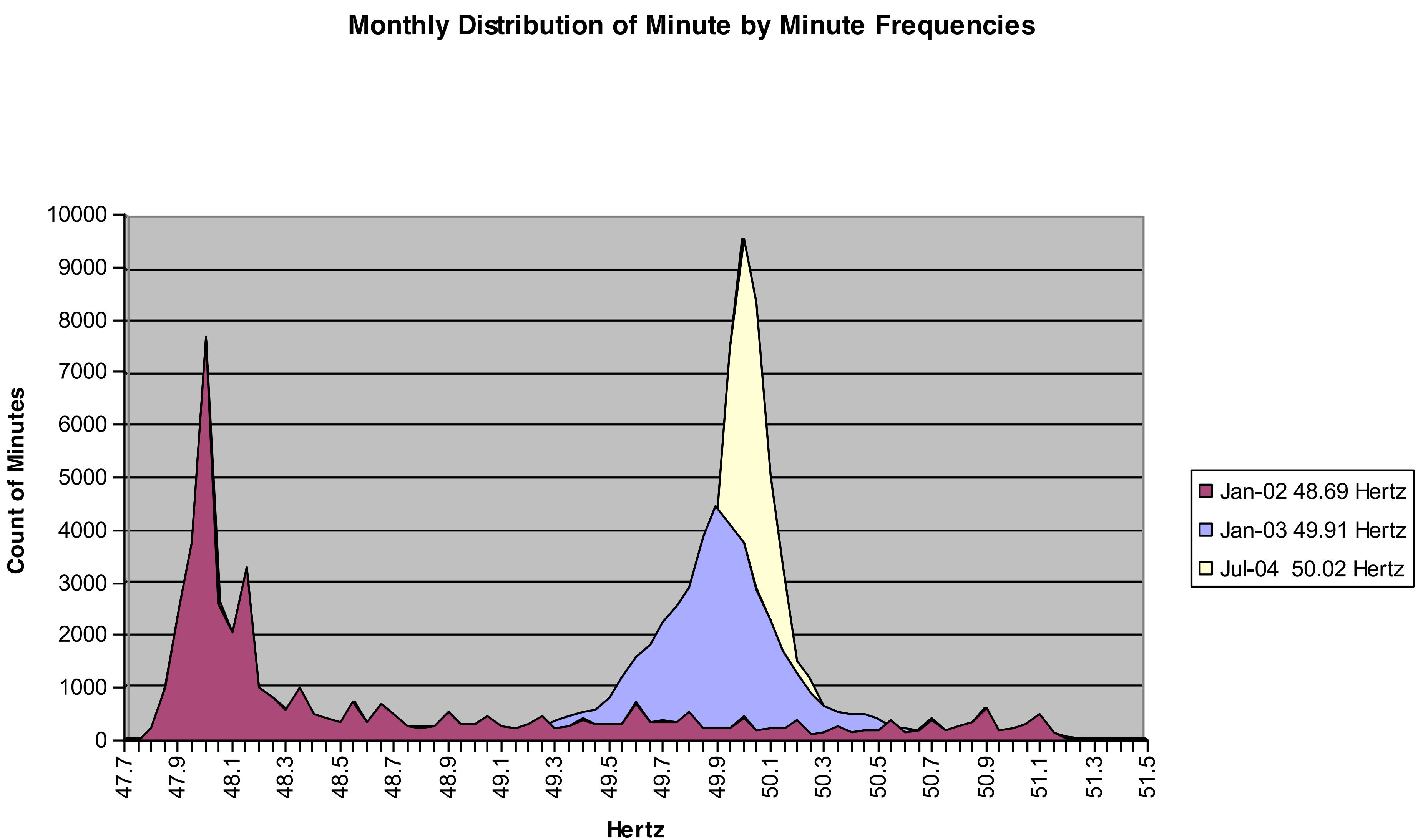


- For pricing purposes, the water tank level can be considered to be ACE, or system frequency for an isolated system. Any variation from the nominal frequency will be compared to a target and run through a pricing curve. Operators will compare that price to their costs and decide how to dispatch their generators, which will then change the system frequency.

## ABT UI Pricing Chart
## Figure 7



- India put into place Availability Based Pricing of Unscheduled Interchange in 2002/2003. This is to price the variation between dispatched amounts and actual generation or the variation between the a utility’s load and its supply.  India has modified the pricing curve since its initial implementation.


Monthly Distribution of Minute by Minute Frequencies
Count of Minutes
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
47.7
47.9
48.1
48.3
48.5
48.7
48.9
49.1
49.3
49.5
49.7
49.9
50.1
50.3
50.5
50.7
50.9
51.1
51.3
51.5
Hertz
Jan-02 48.69 Hertz
Jan-03 49.91 Hertz
Jul-04 50.02 Hertz

Comments on Previous Slide

- Before the implementation of ABT pricing of UI (google InPowerG to find a discussion of the concept), India had very poor frequency discipline. UI was implemented in the Southern region as of 1/1/2003. That month frequency discipline was much better, and improved over the next 18 months.

# Transmission

- Differentiate prices due to line losses
- Differentiate prices due to line congestion
- Loop flow among ISOs and Utilities
  - May have contributed to 2003 blackout
  - Causes price discrepancies at borders
- What were loop flows on PJM during blackout?

# Reactive Power

- Part of power flow that returns to the source within each cycle
- Moderates local voltage conditions
- WOLF
  - When local voltage is high
    - Pay lagging
    - Charge leading
  - When local voltage is low
    - Pay leading
    - Charge lagging