Discovery Park

ENERGY CENTER
State Utility Forecasting Group (SUFG)

PURDUE UNIVERSITY

Energy Forecasting and Resource Integration

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Presented to:
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Outline

- Modeling techniques
- Uncertainty
- Projecting peak demand from energy forecasts
- Determining capacity needs from demand forecasts
- Incorporating load management and conservation measures
- Integrating intermittent resources

Using the Past to Predict the Future

- What is the next number in the following sequences?

  0, 2, 4, 6, 8, 10, 12, 14 ….

  0, 1, 4, 9, 16, 25, 36, 49, ...

  0, 1, 3, 6, 10, 15, 21, 28, ...

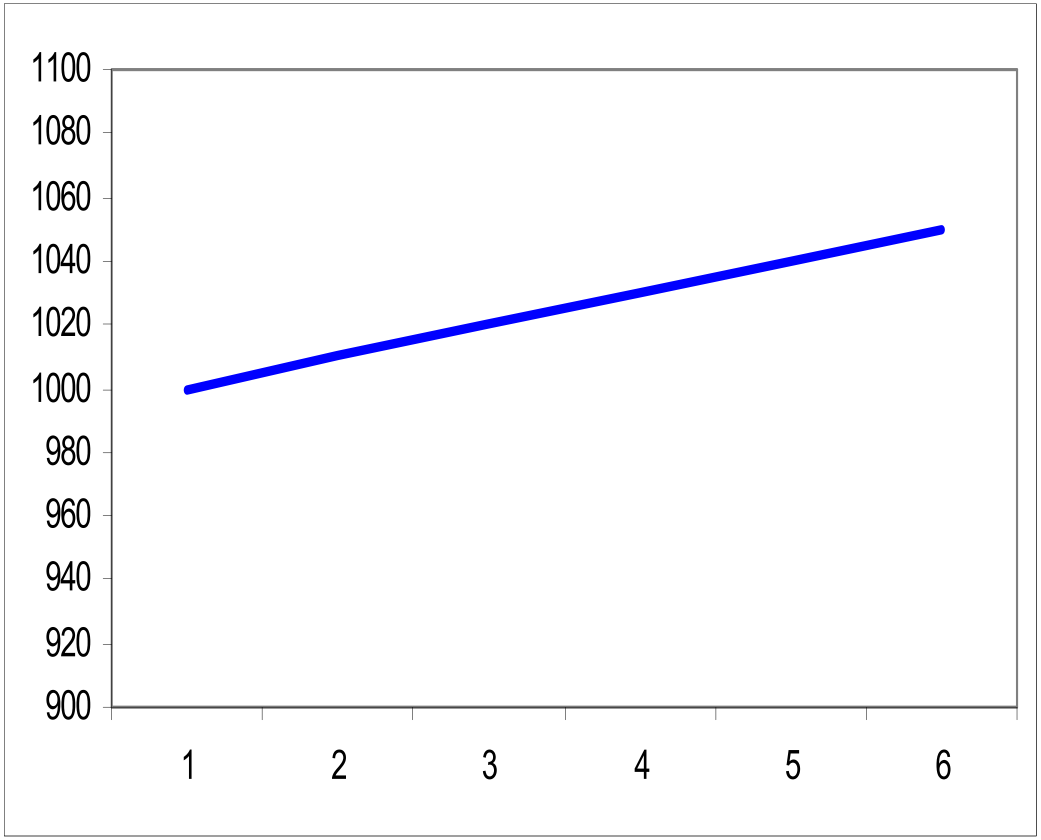
  0, 1, 2, 3, 5, 7, 11, 13, ...

  0, 1, 1, 2, 3, 5, 8, 13, ...

  8, 5, 4, 9, 1, 7, 6, ….

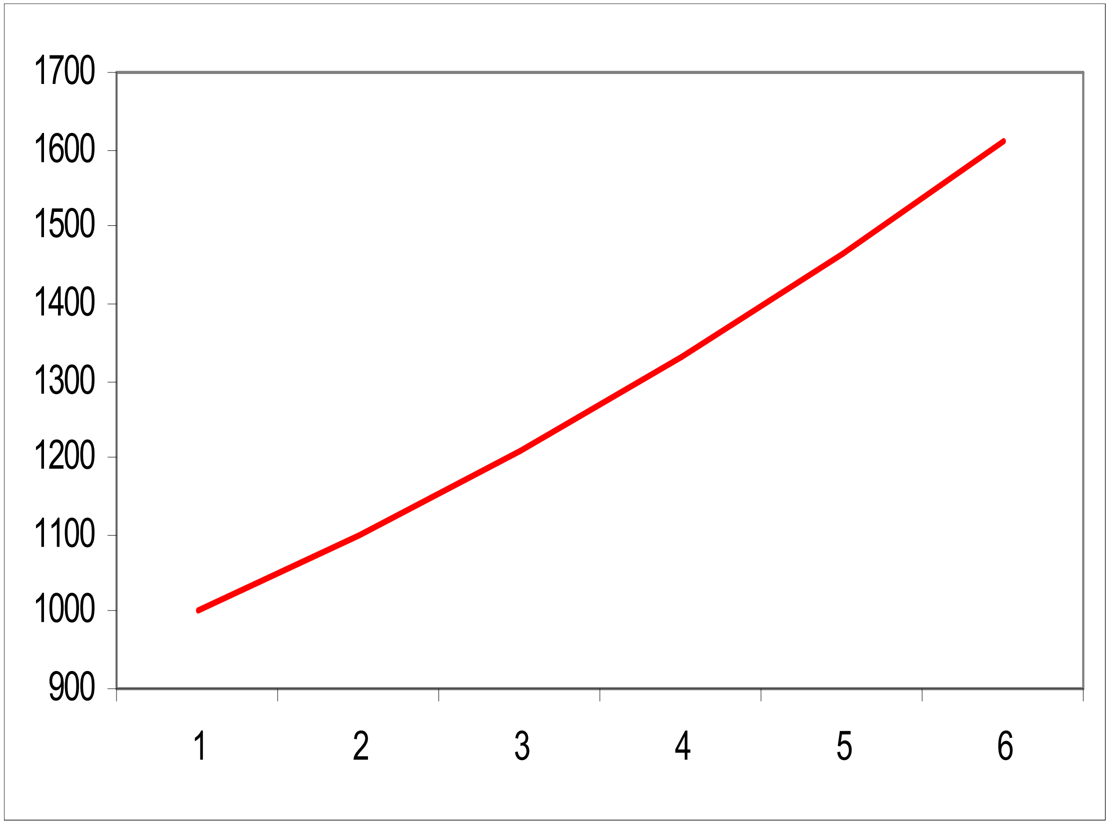
A Simple Example

1000
1010
1020
1030
1040
1050
?
?
?



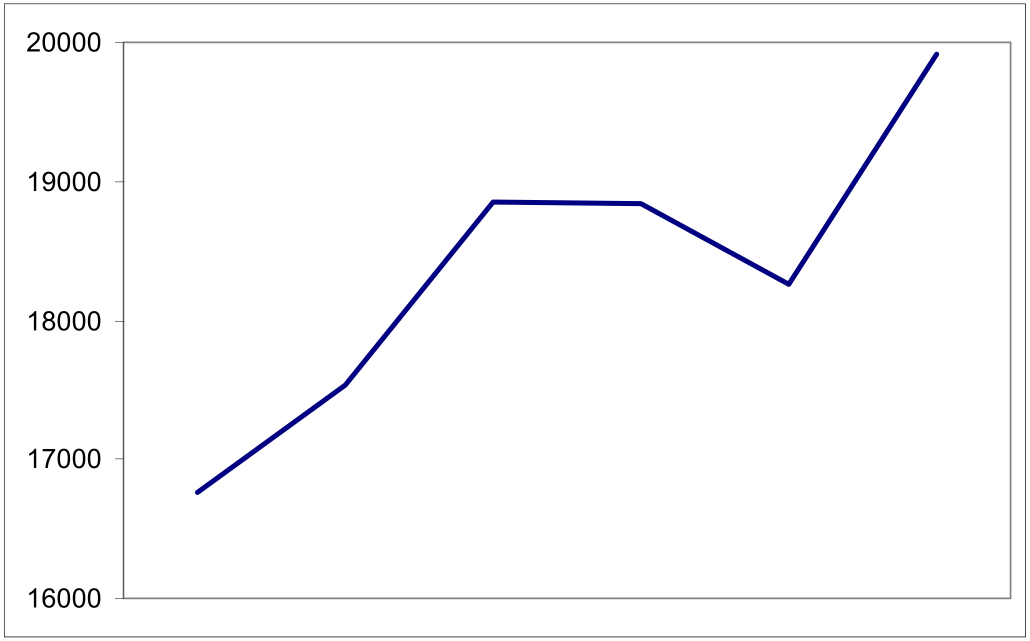
A Little More Difficult

1000
1100
1210
1331
1464
1610
?
?
?



Much More Difficult

16757
17531
18851
18843
18254
19920
?
?
?

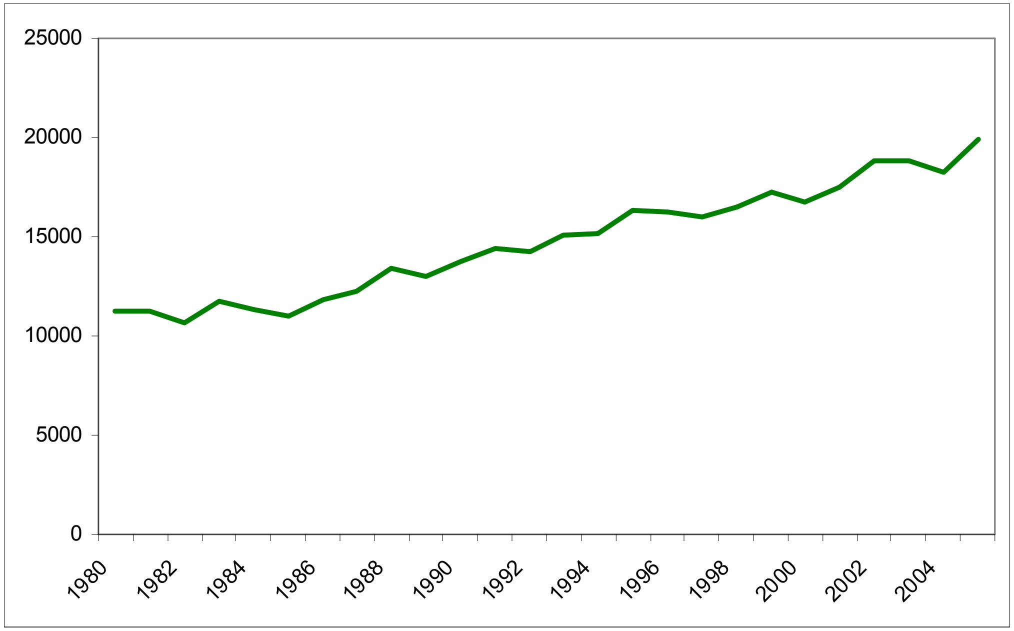


Much More Difficult

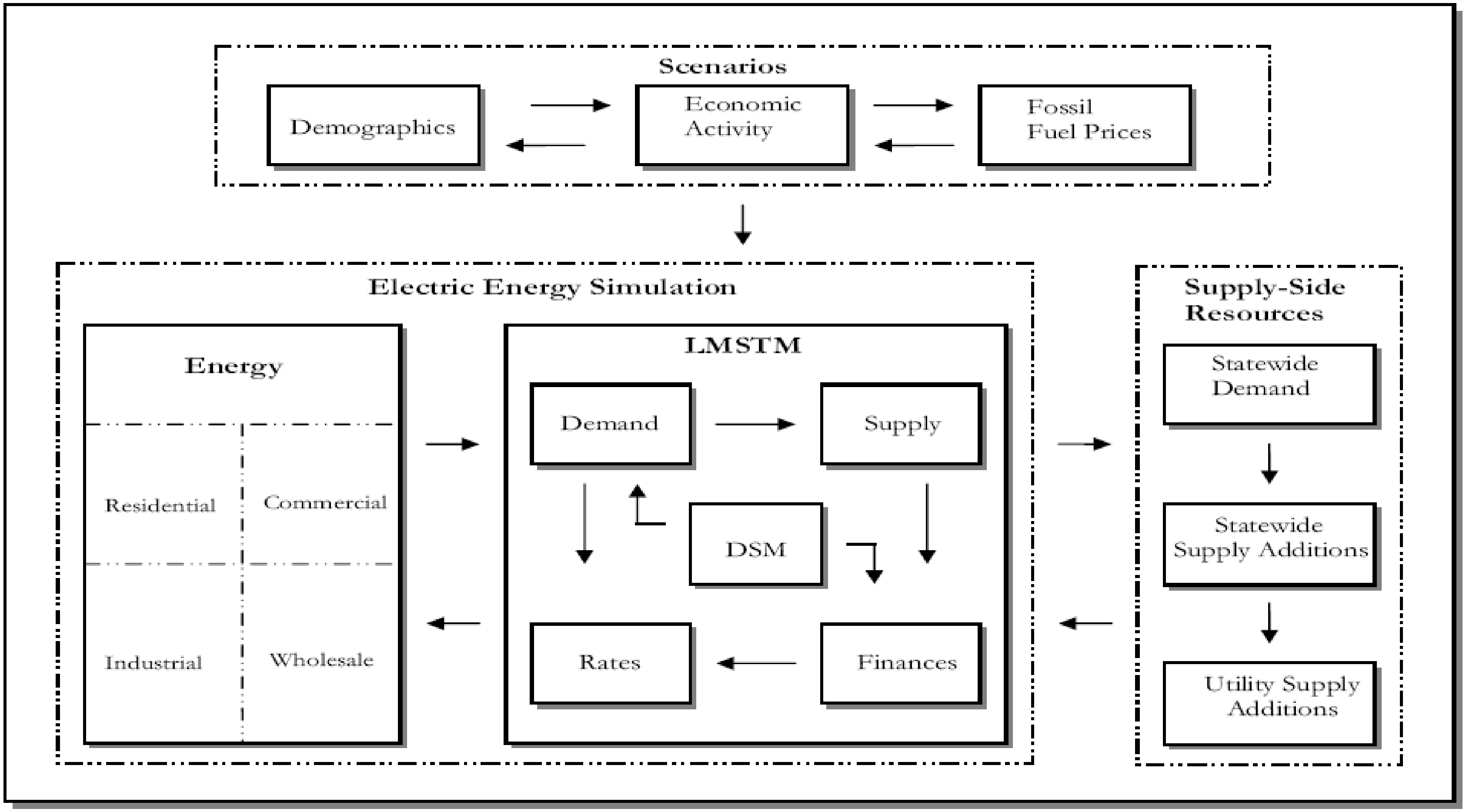
- The numbers on the previous slide were the summer peak demands for Indiana from 2000 to 2005.
- They are affected by a number of factors
  - Weather
  - Economic activity
  - Price
  - Interruptible customers called upon
  - Price of competing fuels

Question

- How do we find a pattern in these peak demand numbers to predict the future?



The Short Answer



Methods of Forecasting

- Palm reading
- Tea leaves
- Tarot cards
- Ouija board
- Crystal ball
- Astrology
- Dart board
- Hire a consultant
- Wishful thinking

Alternative Methods of Forecasting

- Time Series
  - trend analysis
- Econometric
  - structural analysis
- End Use
  - engineering analysis

Time Series Forecasting

- Linear Trend
  - fit the best straight line to the historical data and assume that the future will follow that line (works perfectly in the 1st example)
  - many methods exist for finding the best fitting line, the most common is the ordinary least squares method
    - Ordinary least squares: find the line that minimizes the sum of the squares of the differences between the historical observations and the line

Time Series Forecasting

- Polynomial Trend
  - Fit the polynomial curve to the historical data and assume that the future will follow that line
  - Can be done to any order of polynomial (square, cube, etc.) but higher orders are usually needlessly complex
- Logarithmic Trend
  - Fit an exponential curve to the historical data and assume that the future will follow that line (works perfectly for the 2^{nd} example)

Good News and Bad News

- The statistical functions in most commercial spreadsheet software packages will calculate many of these for you.
- These may not work well when there is a lot of variability in the historical data.
- If the time series curve does not perfectly fit the historical data, there is model error.
  - There is normally model error when trying to forecast a complex system.

Methods Used to Account for Variability

- Modeling seasonality/cyclicality
- Smoothing techniques
  - Moving averages
  - Weighted moving averages
  - Exponentially weighted moving averages
- Filtering techniques
- Box-Jenkins

Econometric Forecasting

- Econometric models attempt to quantify the relationship between the parameter of interest (output variable) and a number of factors that affect the output variable.
- Example
  - Output variable
  - Explanatory variable
    - Economic activity
    - Weather (HDD/CDD)
    - Electricity price
    - Natural gas price
    - Fuel oil price

Estimating Relationships

- Each explanatory variable affects the output variable in different ways. The relationships can be calculated via any of the methods used in time series forecasting.
  - Can be linear, polynomial, logarithmic…
- Relationships are determined simultaneously to find overall best fit.
- Relationships are commonly known as sensitivities.
- A number of techniques have been developed to find a good fit (ordinary least squares, generalized least squares, etc.).

Examples

- Project annual electricity requirements for Indiana and Mississippi using Excel spreadsheets

Example Sensitivities for State of Mississippi

A 10 percent increase in:	Results in this increase in electricity sales
Electricity price	-3.0 percent
Cooling degree days	+0.7 percent
Real personal income	+7.8 percent

End Use Forecasting

- End use forecasting looks at individual devices, aka end uses (e.g., refrigerators)
- How many refrigerators are out there?
- How much electricity does a refrigerator use?
- How will the number of refrigerators change in the future?
- How will the amount of use per refrigerator change in the future?
- Repeat for other end uses

The Good News

- Account for changes in efficiency levels (new refrigerators tend to be more efficient than older ones) both for new uses and for replacement of old equipment
- Allow for impact of competing fuels (natural gas vs. electricity for heating) or for competing technologies (electric resistance heating vs. heat pump)
- Incorporate and evaluate the impact of demand-side management/conservation programs

The Bad News

- Tremendously data intensive
- Primarily limited to forecasting energy usage, unlike other forecasting methods
  - Most long-term planning electricity forecasting models forecast energy and then derive peak demand from the energy forecast

Example

- State Utility Forecasting Group (SUFG) has electrical energy models for each of 8 utilities in Indiana
- Utility energy forecasts are built up from sectoral forecasting models
  - residential (econometric)
  - commercial (end use)
  - industrial (econometric)

Another Example

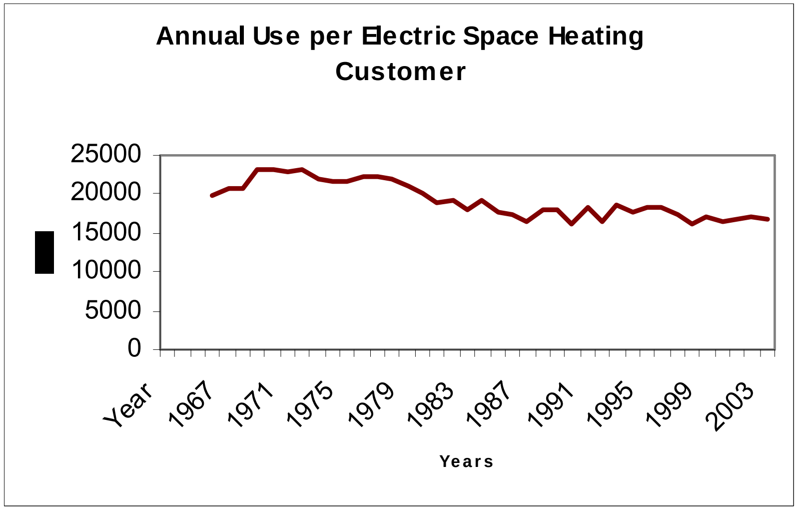
- The Energy Information Administration's National Energy Modeling System (NEMS) projects energy and fuel prices for 9 census regions
- Energy demand
  - residential
  - commercial
  - industrial
  - transportation

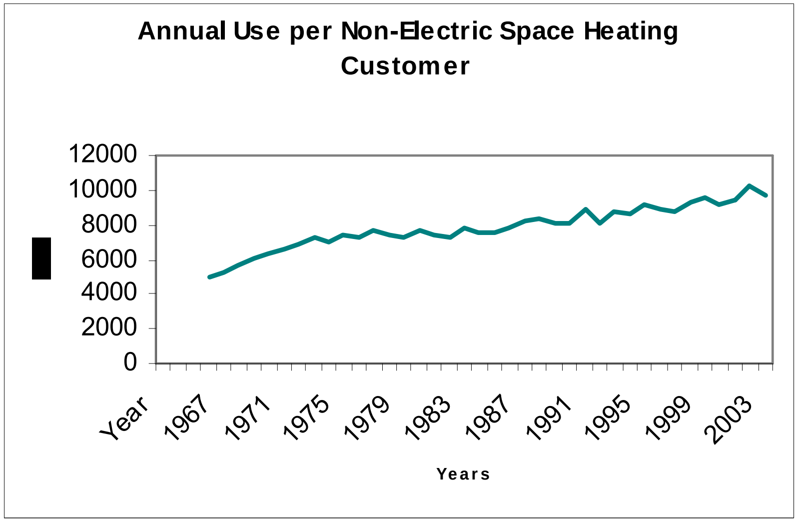
Residential Sector Model

Drivers?

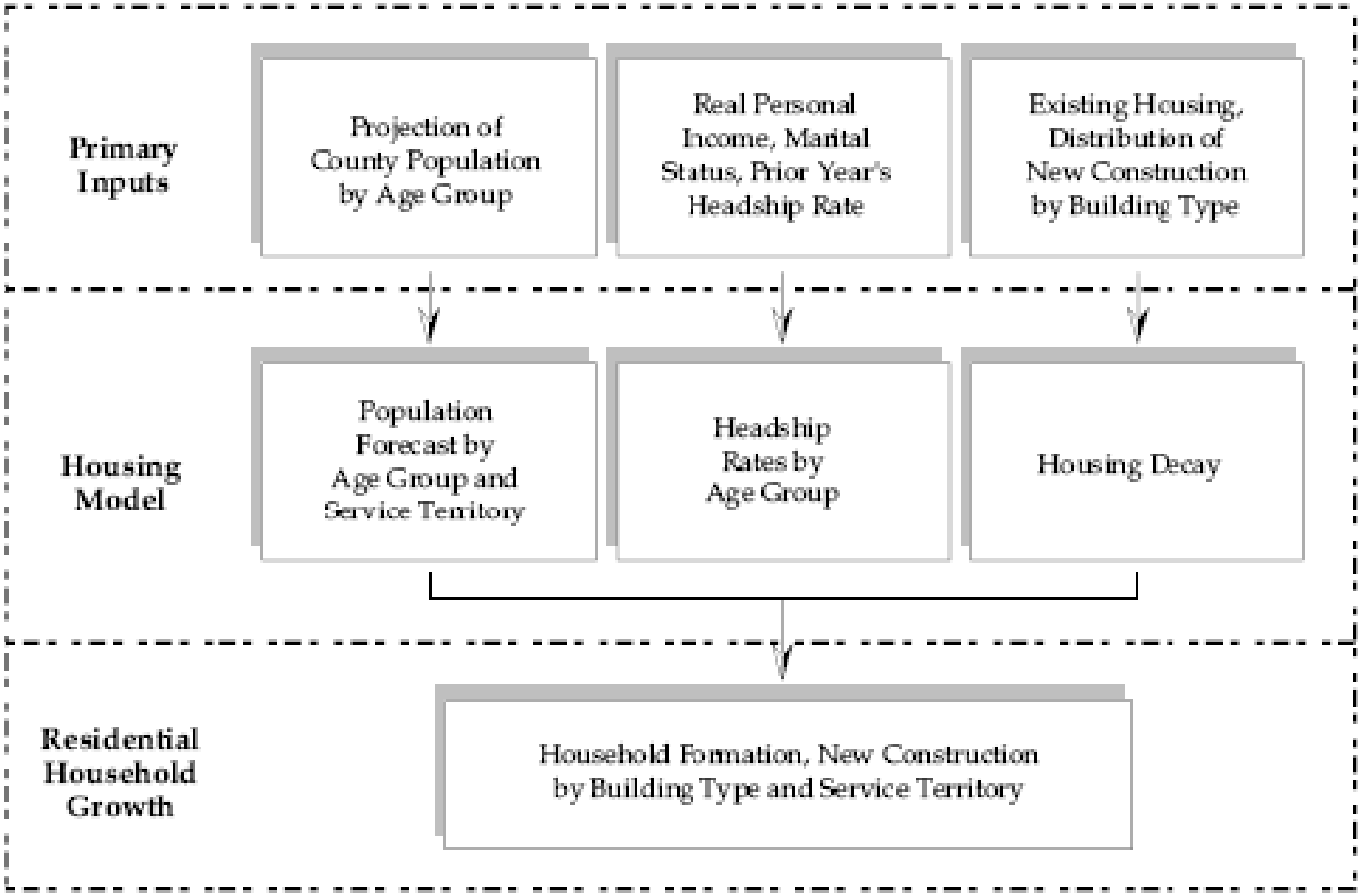
SUFG Residential Sector Model

- Residential sector split according to space heating source
  - electric
  - non-electric





Housing Formation Model

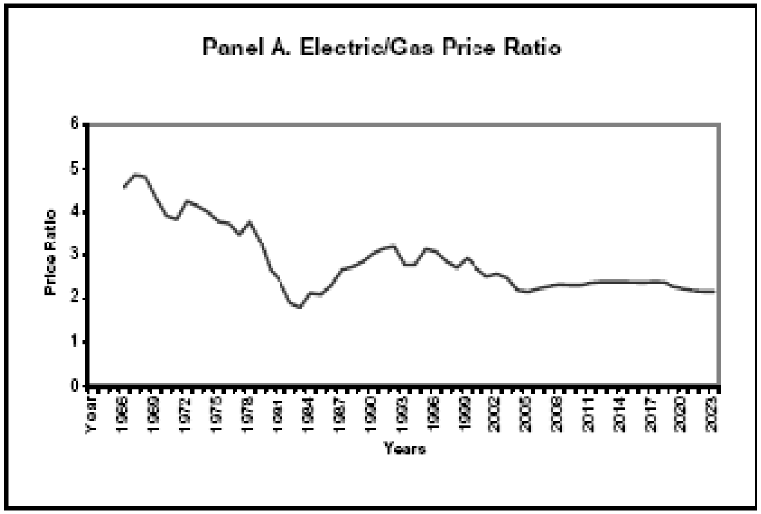


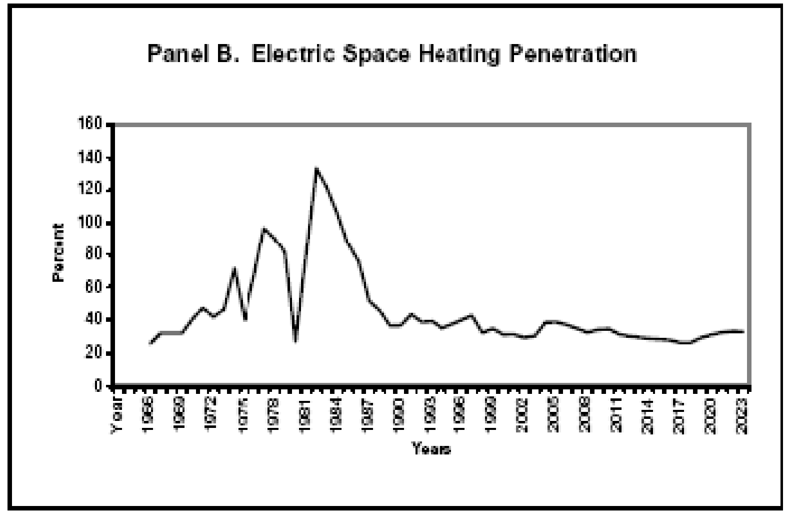
Expenditure Share Model

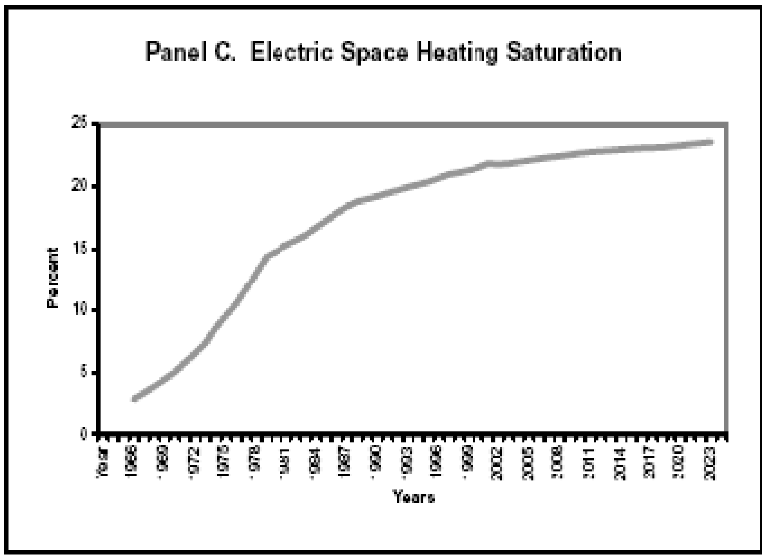
- SUFG uses the expenditure share model to project average electricity consumption by non-electric heating customers
- Relates the fraction of a household's total income that is spent on the commodity
- Log-log functional form
- Explanatory variables include: multi-period prices, real income per household, appliance price index, and heating/cooling degree days

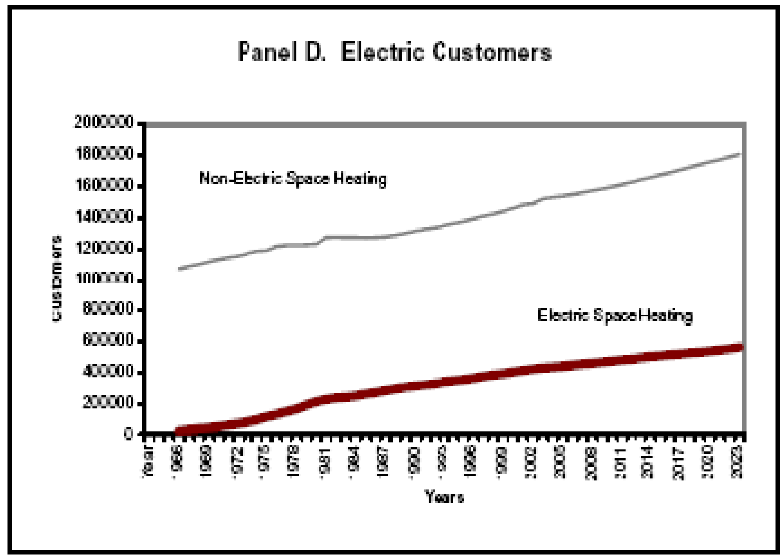
SUFG Residential Sector Model

- Major forecast drivers
  - demographics
  - households
  - household income
  - energy prices


Panel A. Electric/Gas Price Ratio
Price Ratio
Years


Panel B. Electric Space Heating Penetration
Percent
Years


Panel C. Electric Space Heating Saturation
Percent
Years


Panel D. Electric Customers
Customers
Non-Electric Space Heating
Electric Space Heating
Years

Residential Model Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	11.1
Electric Rates	-2.4
Natural Gas Price	1.0
Distillate Oil Prices	0.0
Appliance Price	-1.8
Household Income	2.0

Source: SUFG 2007 Forecast

NEMS Residential Module

- Sixteen end-use services
  - i.e., space heating
- Three housing types
  - single family, multi-family, mobile home
- 34 end-use technologies
  - i.e., electric air-source heat pump
- Nine census divisions

Commercial Sector Model

Drivers?

SUFG Commercial Sector Model

- 10 building types modeled
  - offices, restaurants, retail, groceries, warehouses, schools, colleges, health care, hotel/motel, miscellaneous
- 14 end uses per building type
  - space heating, air conditioning, ventilation, water heating, cooking, refrigeration, lighting, mainframe computers, mini-computers, personal computers, office equipment, outdoor lighting, elevators and escalators, other

SUFG Commercial Model

- For each end use/building type combination there is an initial stock of equipment
- Initial stock is separated by age (vintage) and efficiency
- Additional stock for next year is determined by economic drivers
- Some existing stock will be replaced due to failure or early replacement
- Older vintages are more likely to be replaced

Major Commercial Drivers

- Floor space inventory
- End use intensity
- Employment growth
- Population (schools and colleges)
- Energy prices

Commercial Model Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Electric Rates	-2.5
Natural Gas Price	0.2
Distillate Oil Prices	0.0
Coal Prices	0.0
Electric Energy-weighted Floor Space	12.0

Source: SUFG 2007 Forecast

NEMS Commercial Module

- Ten end-use services
  – i.e., cooking
- Eleven building types
  – i.e., food service
- 64 end-use technologies
  – i.e., natural gas range
- Ten distributed generation technologies
  – i.e., photovoltaic solar systems
- Nine census divisions

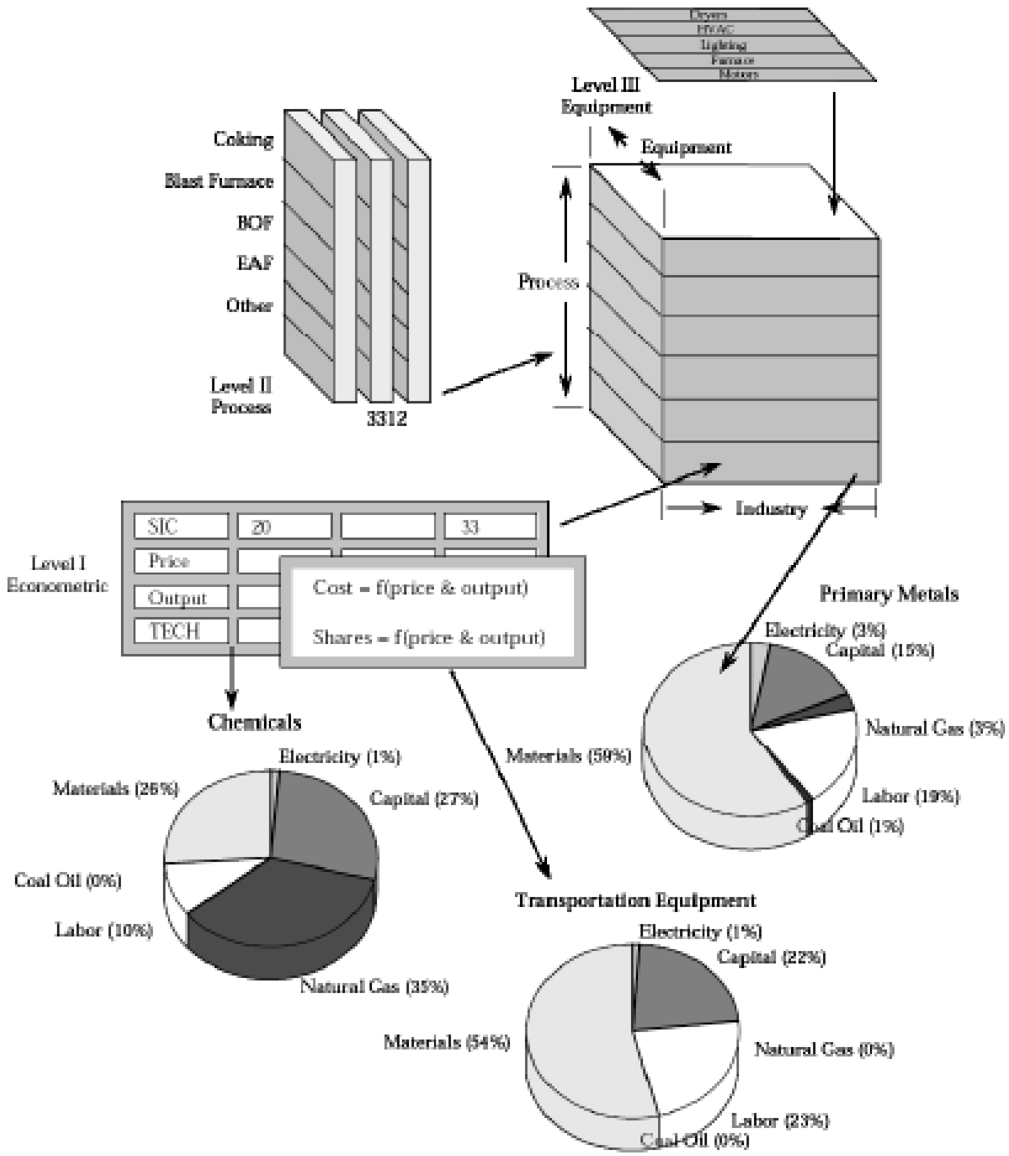
Industrial Sector Model

Drivers?

SUFG Industrial Sector Model

- Major forecast drivers
  - industrial activity
  - energy prices
- 15 industries modeled
  - classified by Standard Industrial Classification (SIC) system
  - some industries are very energy intensive while others are not

SUFG looks at industrial energy use from three perspectives:
- LEVEL I Econometric at 2-digit SIC level
- LEVEL II Process model of iron and steel industry
- LEVEL III Motor model to evaluate technologies and standards



Indiana's Industrial Sector

SIC	Name	Current Share of GSP	Current Share of Electricity Use	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity by Intensity by Sector	Forecast Growth in Electricity Use by Sector
20	Food & Kindred Products	3.51	5.61	0.96	-0.79	0.17
24	Lumber & Wood Products	1.95	0.70	0.96	-0.42	0.54
25	Furniture & Fixtures	1.60	0.46	0.62	-0.64	-0.02
26	Paper & Allied Products	1.36	2.96	0.96	-0.56	0.40
27	Printing & Publishing	2.55	1.30	0.96	-0.96	0.00
28	Chemicals & Allied Products	14.25	17.10	3.49	-0.80	2.70
30	Rubber & Misc. Plastic Products	4.77	6.25	4.52	-0.67	3.85
32	Stone, Clay, & Glass Products	1.76	5.30	0.96	-0.67	0.29
33	Primary Metal Products	8.55	31.34	1.02	1.76	2.77
34	Fabricated Metal Products	6.25	5.29	2.51	-0.76	1.75
35	Industrial Machinery & Equipment	6.73	4.44	1.05	-0.68	0.37
36	Electronic & Electric Equipment	16.19	5.54	5.33	-0.56	4.77
37	Transportation Equipment	22.89	9.38	3.87	-0.68	3.19
38	Instruments And Related Products	4.98	0.77	5.33	-0.86	4.47
39	Miscellaneous Manufacturing	1.63	1.06	4.19	-5.24	-1.05
Total	Manufacturing	100.00	100.00	3.48	-0.81	2.67

Source: SUFG 2007 Forecast

Industrial Model Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Real Manufacturing Product	10.0
Electric Rates	-4.8
Natural Gas Price	1.4
Oil Prices	0.9
Coal Prices	0.2

Source: SUFG 2007 Forecast

NEMS Industrial Module

- Seven energy-intensive industries
  - i.e., bulk chemicals
- Eight non-energy-intensive industries
  - i.e., construction
- Cogeneration
- Four census regions, shared to nine census divisions

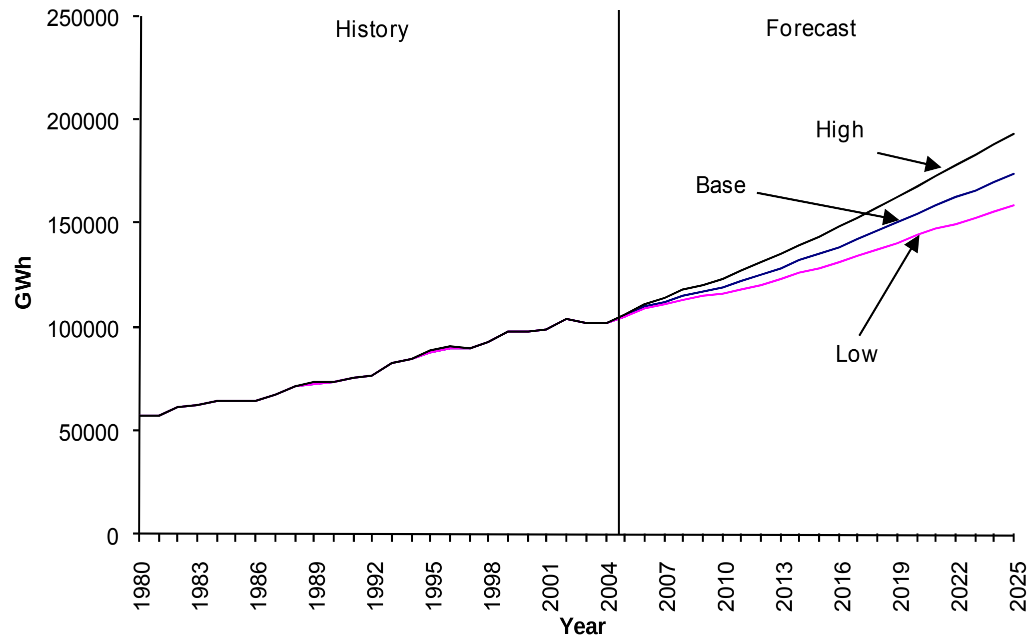
Sources of Uncertainty

- Exogenous assumptions
  - forecast is driven by a number of assumptions (e.g., economic activity) about the future
- Stochastic model error
  - it is usually impossible to perfectly estimate the relationship between all possible factors and the output
- Non-stochastic model error
  - bad input data (measurement/estimation error)

Alternate Scenarios

- Given the uncertainty surrounding long-term forecasts, it is inadvisable to follow one single forecast

- SUFG develops alternative scenarios by varying the input assumptions



Source: SUFG 2007 Forecast

Energy → Peak Demand

- Constant load factor / load shape
  - Peak demand and energy grow at same rate
- Constant load factor / load shape for each sector
  - Calculate sectoral contribution to peak demand and sum
  - If low load factor (residential) grows fastest, peak demand grows faster than energy
  - If high load factor (industrial) grows fastest, peak demand grows slower than energy

State/Regional Level Forecasting

- Underlying methodology is similar
  - same types of forecasting models
- Many states and RTOs build up a regional forecast from smaller forecasts (bottom-up approach)
- Others use a central approach

Problems with Bottom-Up Forecasts

- Inconsistent assumptions
  - two utilities both assume that the new manufacturing plant will be in their own territories (or neither do)
- One utility may include certain loads (requirement sales) while another may not
- Retail choice may influence a utility's projections
- All of these can lead to overcounting or undercounting

Problems with Central Approach

- Volume of data makes detailed modeling problematic
- Growth is not likely to be the same in different areas

Example - PJM

- PJM recently moved from a bottom-up to a central forecasting methodology
- Explanatory variables are gross product by metropolitan area and weather

Example - EIA

- National Energy Modeling System (NEMS) models nine census divisions
- Numerous sectors modeled, such as residential, commercial, industrial, transportation, oil supply, natural gas supply)

Energy → Peak Demand

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  - Peak demand and energy grow at same rate
- Constant load factor / load shape for each sector
  - Calculate sectoral contribution to peak demand and sum
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Energy → Peak Demand

- Day types
  - Break overall load shapes into typical day types
    - low, medium, high
    - weekday, weekend, peak day
  - Adjust day type for load management and conservation programs
  - Can be done on a total system level or a sectoral level

SUFG Example

- Forecast growth rates

– residential energy	2.21%
– commercial energy	2.46%
– industrial energy	2.67%
– total energy	2.46%
– peak demand	2.46%

- Note: Growth rates for total energy and peak demand have not always been this similar in previous forecasts

Load Diversity

- Each utility does not see its peak demand at the same time as the others
- 2007 peak demands occurred at:
  - Hoosier Energy – 8/8, 6PM
  - Indiana Michigan – 8/7, 4PM
  - Indiana Municipal Power Agency – 8/8, 4PM
  - Indianapolis Power & Light – 8/8, 5PM
  - NIPSCO – 8/7, 5PM
  - PSI Energy – 8/8, 5PM
  - SIGECO – 8/9, 4PM
  - Wabash Valley – 8/7, 7PM
- Statewide peak – 8/8, 5 PM

Example

- Three utility, single day example on Excel spreadsheet
- This is normally done for each of the 8,760 hours in a year

Load Diversity

- Thus, the statewide peak demand is less than the sum of the individual peaks
- Actual statewide peak demand can be calculated by summing up the load levels of all utilities for each hour of the year
- Diversity factor is an indication of the level of load diversity
- Historically, Indiana's diversity factor has been about 96 – 97 percent
  - that is, statewide peak demand is usually about 96 percent of the sum of the individual utility peak demands

Peak Demand → Capacity Needs

- Target reserve margin
- Loss of load probability (LOLP)
- Expected unserved energy (EUE)
- Assigning capacity needs to type
  - peaking
  - baseload
  - intermediate
- Optimization

Reserve Margin vs. Capacity Margin

$$RM = \frac{capacity - demand}{demand} x100\% \qquad CM = \frac{capacity - demand}{capacity} x100\%$$

- Both reserve margin (RM) and capacity margin (CM) are the same when expressed in megawatts
  - difference between available capacity and demand
- Normally expressed as percentages

Reserve Margins

- Reserve/capacity margins are relatively easy to use and understand, but the numbers are easy to manipulate
  - Contractual off-system sale can be treated as a reduction in capacity or increase in demand
    - does not change the MW margin, but will change the percentage
  - Similarly, interruptible loads and direct load control is sometimes shown as an increase in capacity

Example

- Say a utility has 800 MW of native load on peak, 1100 MW of generation, and a 200 MW contractual sale off-system
  - What is the reserve margin if it subtracts the sale from its capacity?
  - What if it adds the sale to its peak demand?
- What if it had 1200 MW of generation?

Loss of Load Probability

- Probabilistic method that accounts for the reliability of the various sources of supply
- Given an expected demand for electricity and a given set of supply resources with assumed outage rates, what is the likelihood that the supply will not be able to meet the demand?

Expected Unserved Energy

- Similar calculation to LOLP, used to find the expected amount of energy that would go unmet

- Both are used in resource planning to ensure that sufficient capacity is available for LOLP and/or EUE to be less than a minimum allowable level

Capacity Types

- Once the amount of capacity needed in a given year is determined, the next step is to determine what type of capacity is needed
  - peaking (high operating cost, low capital cost)
  - baseload (low operating cost, high capital cost)
  - intermediate or cycling (operating and capital costs between peaking and baseload)
    - some planners only use peaking and baseload

Assigning Demand to Type

- SUFG uses historical load shape analysis for each of the utilities to assign a percentage of their peak demand to each load type
- Percentages vary from utility to utility according to the characteristics of their customers
  - utilities with a large industrial base tend to have a higher percentage of baseload demand
  - those with a large residential base tend to have a higher percentage of peaking demand
- Rough breakdown:
  - baseload 65%, intermediate 15%, peaking 20%

Assigning Existing Resources

- SUFG then assigns existing generation to the three types according to age, size, fuel type, and historical usage patterns
- Purchased power contracts are assigned to type according to time period (annual or summer only) and capacity factor
- Power sales contracts are also assigned to type

Assigning Capacity Needs to Type

- Future resource needs by type are determined by comparing existing capacity to projected demand, while accounting for interruptible and buy through loads, as well as firm purchases and sales and retirement of existing units
- Breakdown of demand by type is not projected to change across the forecast horizon

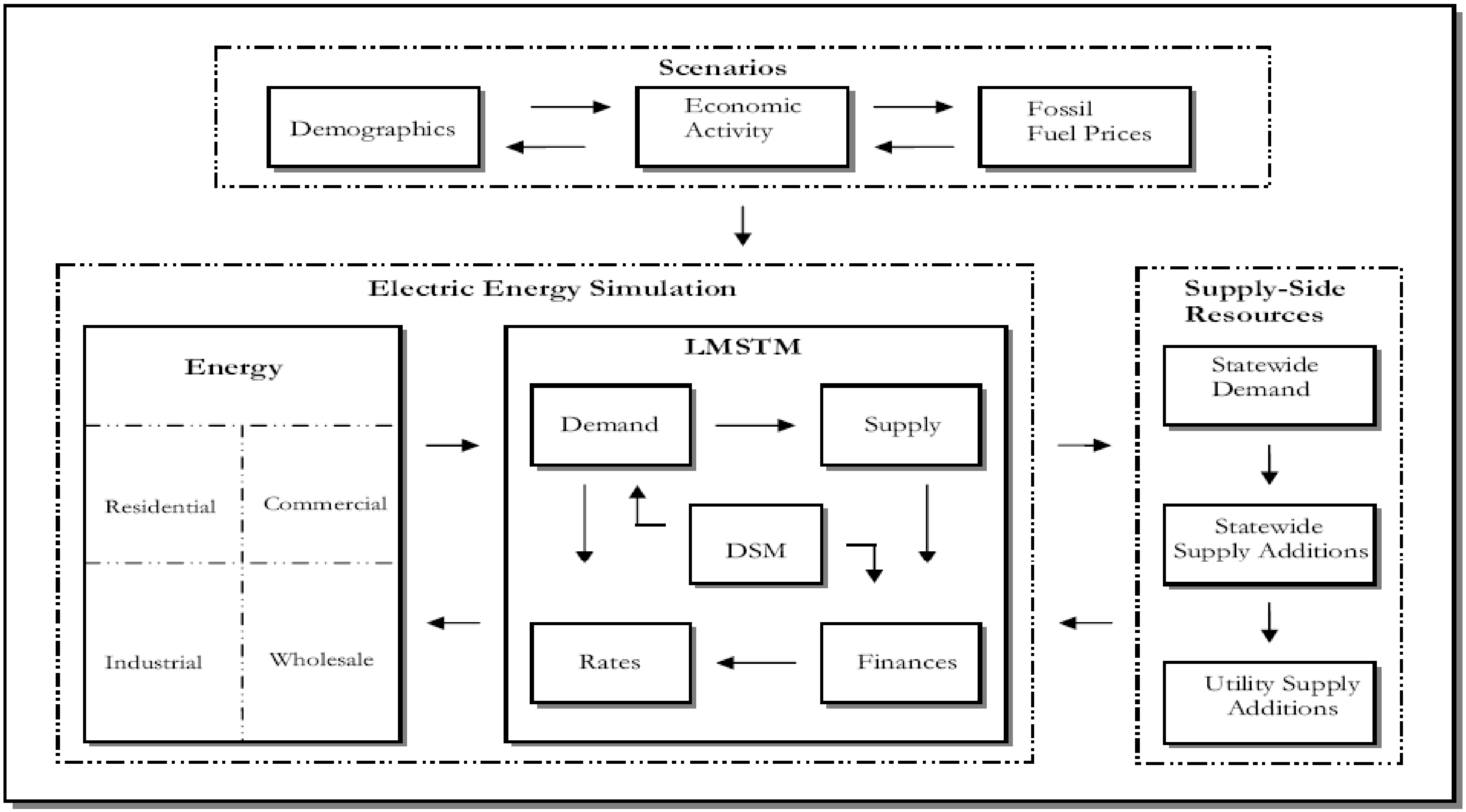
NEMS Electricity Market Module

- Eleven fossil generation technologies
  - i.e., advanced clean coal with sequestration
- Two distributed generation technologies
  - baseload and peak
- Seven renewable generation technologies
  - i.e., geothermal
- Conventional and advanced nuclear
- Fifteen supply regions based on NERC regions and sub-regions

Load Management and Conservation Measures

- Direct load control and interruptible loads generally affect peak demand but not energy forecasts
  – delay consumption from peak time to off-peak time
  – usually subtract from peak demand projections
- Efficiency and conservation programs generally affect both peak demand and energy forecasts
  – consumption is reduced instead of delayed
  – usually subtract from energy forecast before peak demand calculations

Back to the Short Answer



Intermittent Resources

- All resources have some degree of uncertainty as to availability
  - unplanned outages
- Some resources have additional uncertainty due to the intermittent nature of the source of energy
  - wind, solar, hydro

Operational Issues

- Dispatch
  - sudden changes in output can force operators to take normally uneconomic actions
- Commitment
  - may need to carry additional reserve generation to account for variations in output

Planning Issues

- Capacity value
  - What fraction of full power is likely to be available when demand is highest?
- Impact on needs for other types of resources
  - “Wind needs a dance partner”

Capacity Value Methods

- Rule of thumb
- Capacity factor
- Peak period experience
- Effective load carrying capability
  - amount of additional load that can be served with addition of new resource
- Results vary widely (5-40%)

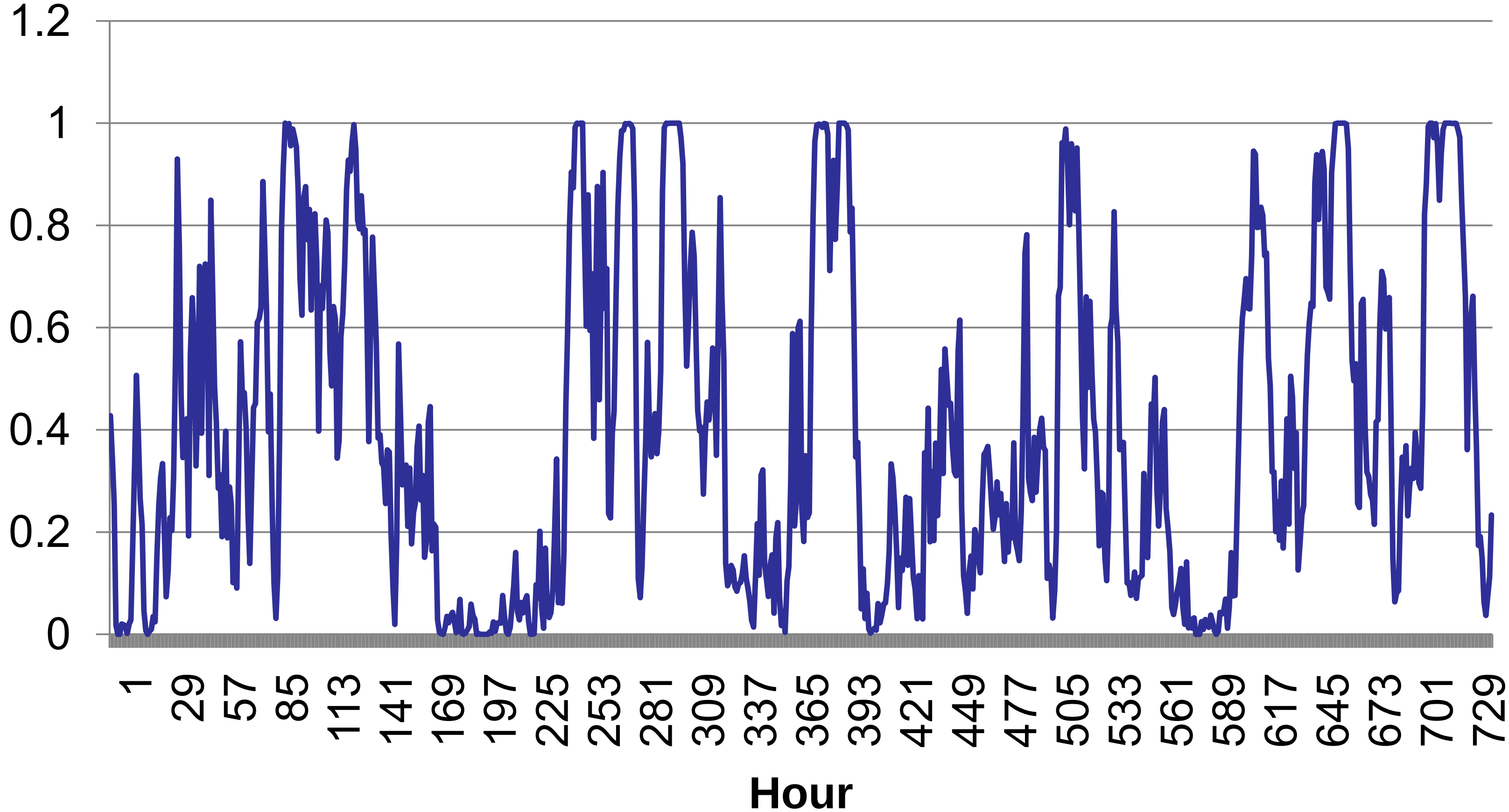
Example

- Using actual Indiana hourly load data and wind speed data collected by an Indiana utility, estimate the capacity value of a new wind installation

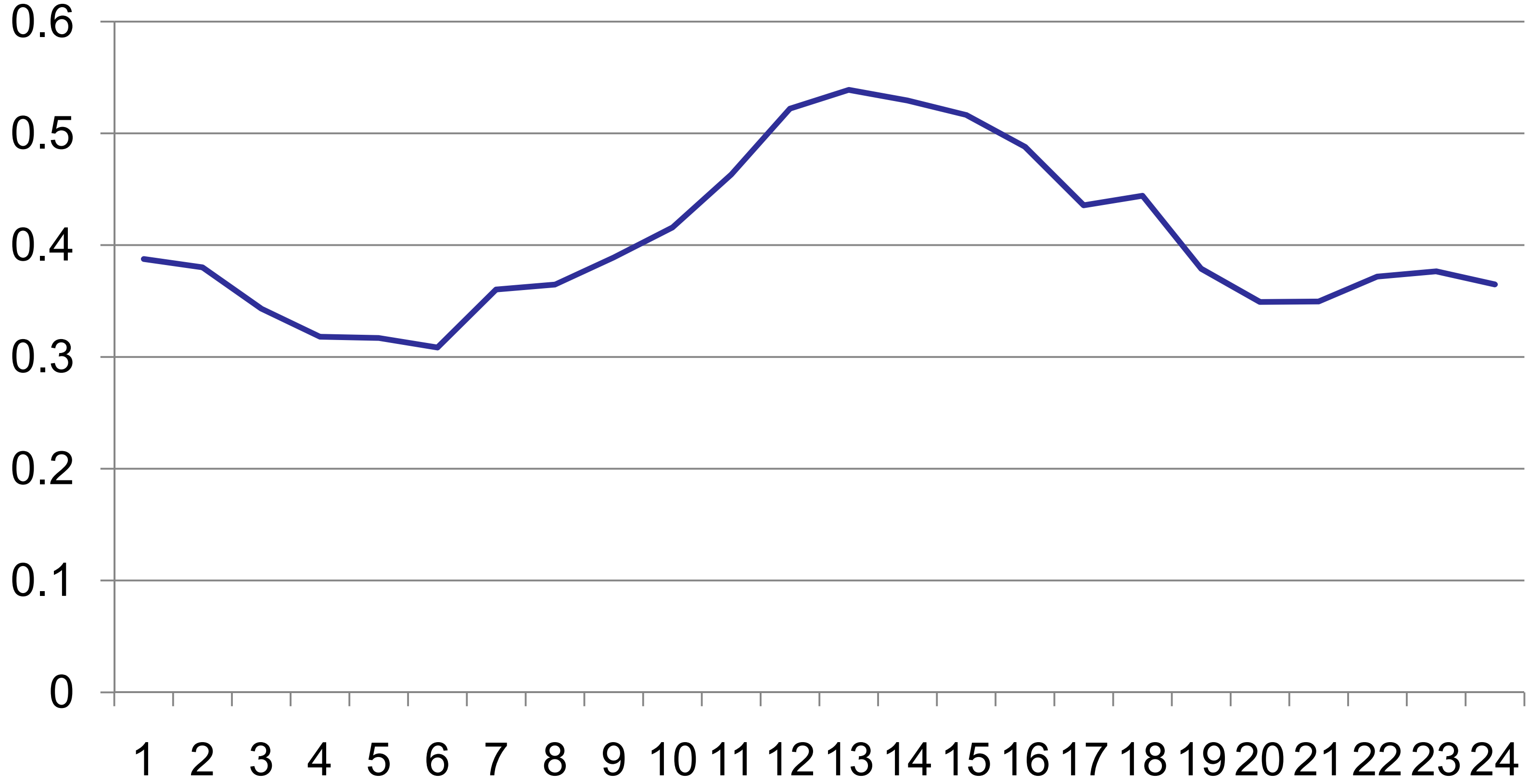
Wind Data

- Data collected from 4 sites between September 2006 and October 2007 on a 5-minute basis
- Wind speed converted to power output using wind vs. power data for a 1.5 MW wind turbine
- Power output averaged across hour to produce hourly power output for one year

Fraction of Max Output – October 2006



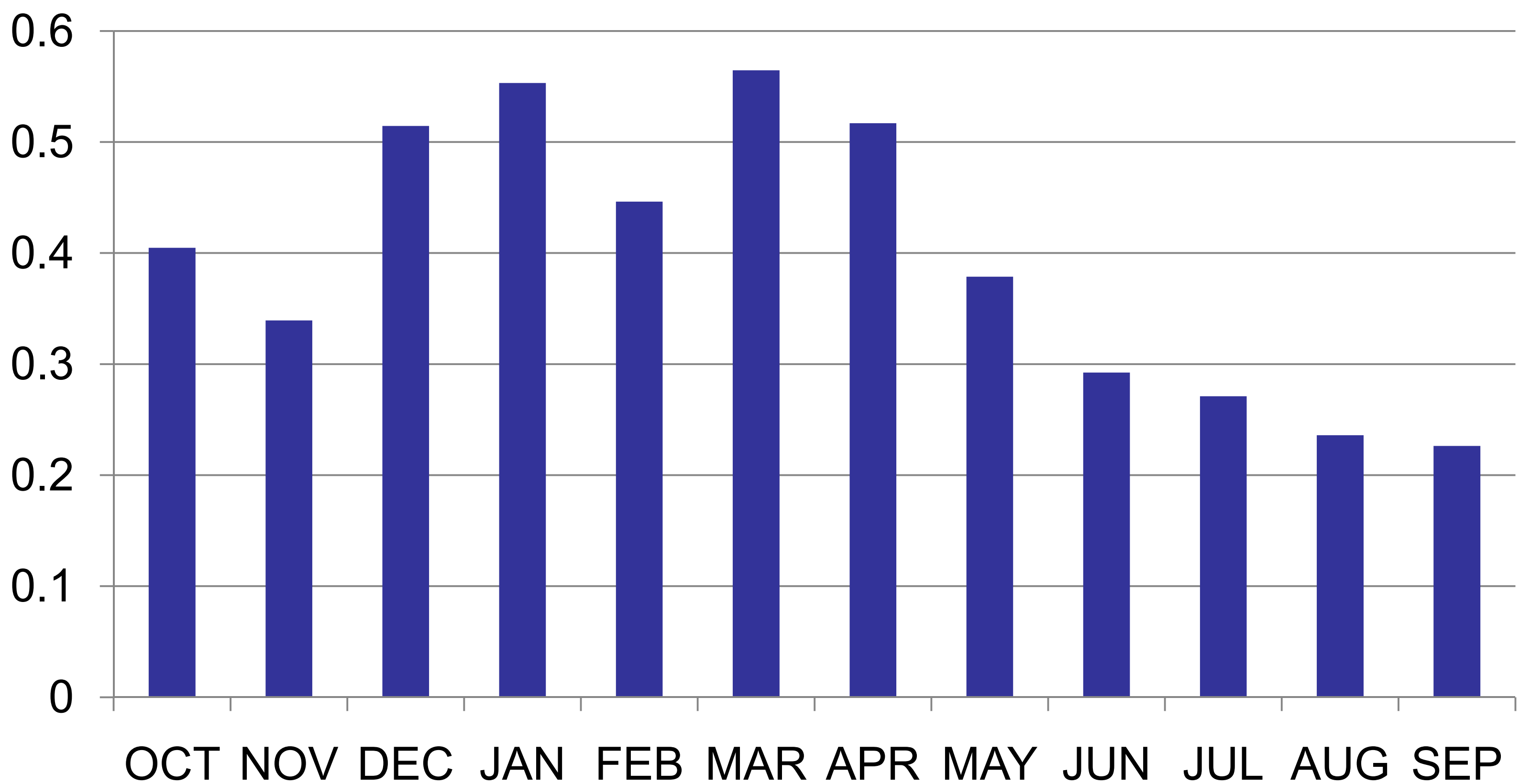
Average Daily Loadshape October 2006



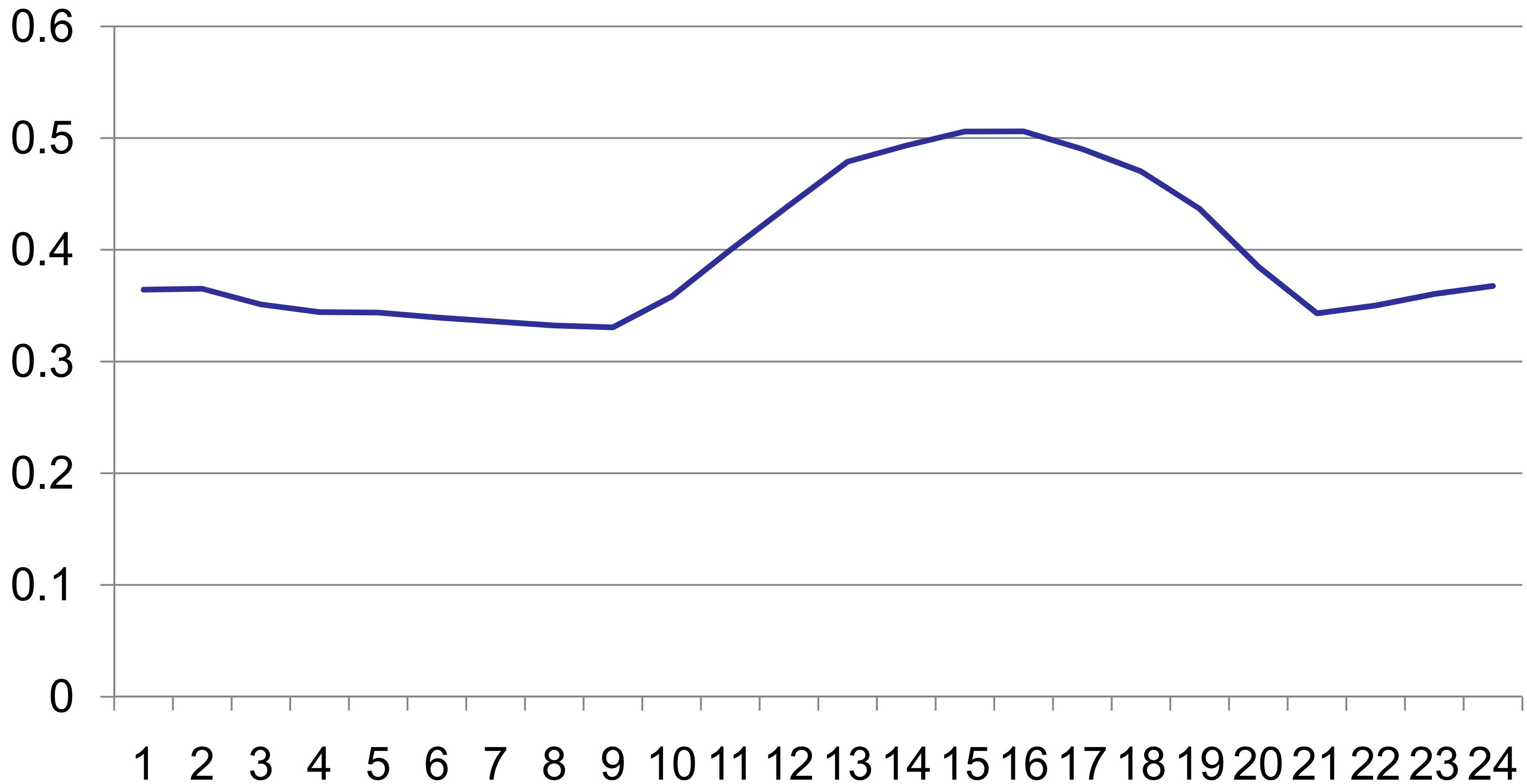
Other Months

- Similar loadshapes
  - average wind power is highest between 1 PM and 6 PM
- Highest capacity factor occurs in March (56.4 percent)
- Lowest capacity factor occurs in September (22.6 percent)

Monthly Capacity Factors



Annual Average Daily Loadshape



Load Data

- Statewide hourly load data for the same 12-month period
- Peak occurs on August 8 at 5PM
- Monthly capacity factor for wind in August is 23.6 percent
- Wind power output at August 8 at 5 PM is 15.2 percent

What is the Capacity Value?

- Using capacity factor
  - 39.5 percent using annual
  - 23.6 percent using month of peak demand
- Using rule of thumb
  - SUFG is using 15 percent for its forecast
- Using peak period availability
  - 15.2 percent
- What type of capacity is it (baseload, intermediate, peaking)?

What is the Impact on Resource Needs?

- Determine resource needs by type without wind
- Subtract the output of the wind turbines
- Determine new resource needs
- Repeat for various levels of wind penetration

Assumptions

- Baseload resources are used to meet the lowest 60th percentile of the annual load
- Peaking resources are used to meet any load above the 90th percentile
- Intermediate resources are used to meet the remainder

Resource Needs – No Wind

- Baseload 12,291 MW
- Intermediate 3,616 MW
- Peaking 4,910 MW
- Total 20,818 MW

- System load factor - 62.7 percent

Resource Needs – 100 MW Wind

- Baseload 12,238 MW (change -53)
- Intermediate 3,637 MW (change +21)
- Peaking 4,927 MW (change +17)
- Total 20,802 MW (change -16)

- System load factor 62.5 percent

Resource Needs – 500 MW Wind

- Baseload 12,046 MW (change -245)
- Intermediate 3,688 MW (change +72)
- Peaking 5,007 MW (change +97)
- Total 20,742 MW (change -76)

- System load factor – 61.8 percent

Resource Needs – 1000 MW Wind

- Baseload 11,798 MW (change -493)
- Intermediate 3,754 MW (change +138)
- Peaking 5,114 MW (change +204)
- Total 20,666 MW (change -152)

- System load factor – 60.9 percent

Resource Needs – 5000 MW Wind

- Baseload 10,103 MW (change -2,108)
- Intermediate 4,521 MW (change +905)
- Peaking 5,802 MW (change +892)
- Total 20,425 MW (change -393)

- System load factor – 53.6 percent

Diminishing Capacity Value

- With 5,000 MW of wind, we only reduce resource needs by 7.9 percent, instead of the 15.2 percent we saw for lower penetration levels
- Peak demand shifted to an hour when wind output was only 4 percent of capacity

Implications

- Beyond its capacity value, wind causes a shift between types of resources needed to meet the remaining load
- Baseload resources decrease
- Peaking and cycling resources increase
- Total resources needed decrease

Further Information

- State Utility Forecasting Group
  – http://www.purdue.edu/dp/energy/SUFG/
- Energy Information Administration
  – http://www.eia.doe.gov/index.html