Emissions Benefits of Distributed Generation in Texas: Phase I Analysis

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Gas Technology Institute question

- How much could Distributed Generation reduce emissions in Texas?
- Phase I was quick estimate for 2012 with expected ERCOT system profile and small DG added
- Paper considered NO_X, SO_2, and carbon
- Transmission and locational issues not addressed
- Phase II may look at additional topics

Methodology

- Establish 1999 mix of demand and supplies and extend to 2012
- Modify demands to reflect some DG additions
- Dispatch systems using Oak Ridge model
- Compare emissions reductions to amounts added from DG
- Calculate additional reductions from CHP

Four Key Results

- Marginal emissions in Texas come from gas-fired plants, largely steam-fired
  - Moderate NO_X and carbon, no SO_2
- DG emissions are lower than displaced central plants so reduce total emissions
- CHP improves emissions results even more
- Further study warranted on:
  - Capacity addition delays versus retirements
  - Locational impacts

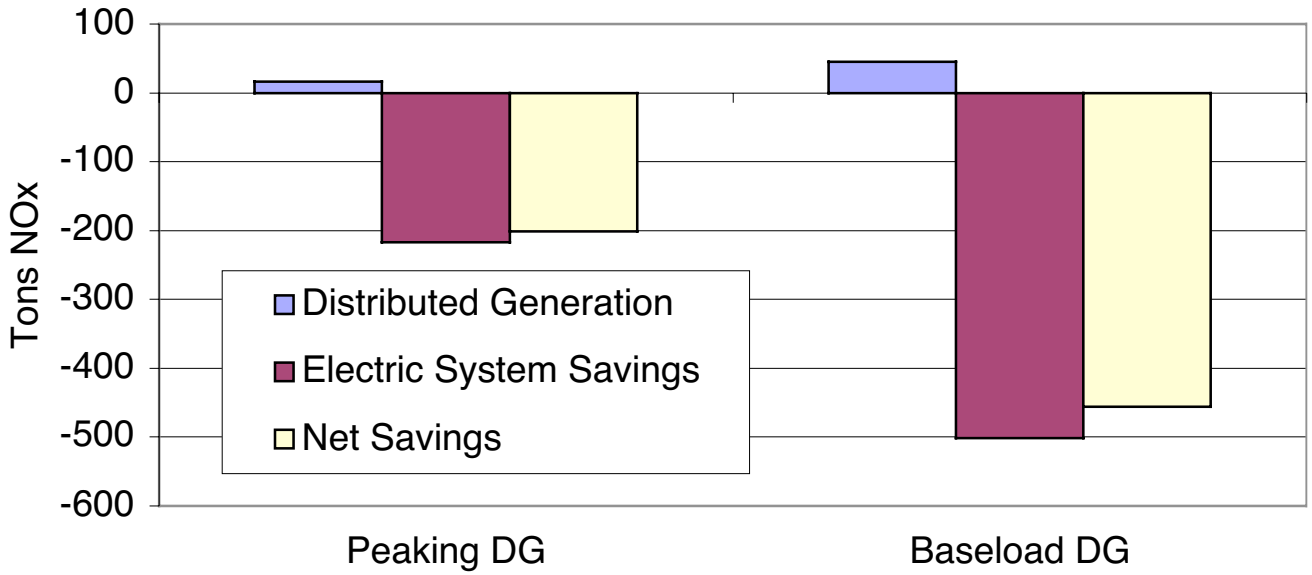
Marginal production from gas-fired plants

- **Peaking DG (8-8 weekdays) displaces less-efficient, dirtier sources**
- **Baseload DG (100% of time) displaces broad array of gas-fired plants**
- **Coal, nuclear, hydro and other technologies infra-marginal**

	Peaking DG	Baseload DG
Displaced Energy, GWh	313	876
Displaced Source		
Gas ST	59%	36%
Gas CT	26%	21%
Gas CC	15%	43%
Avg Efficiency	33%	37%
NO_x, lb/MWh	1.39	1.14
NO_X, lb/mmbtu	0.134	0.124
SO_2, lb/MWh	0.00	0.00
CO_2, lb/MWh	1,210	1,078

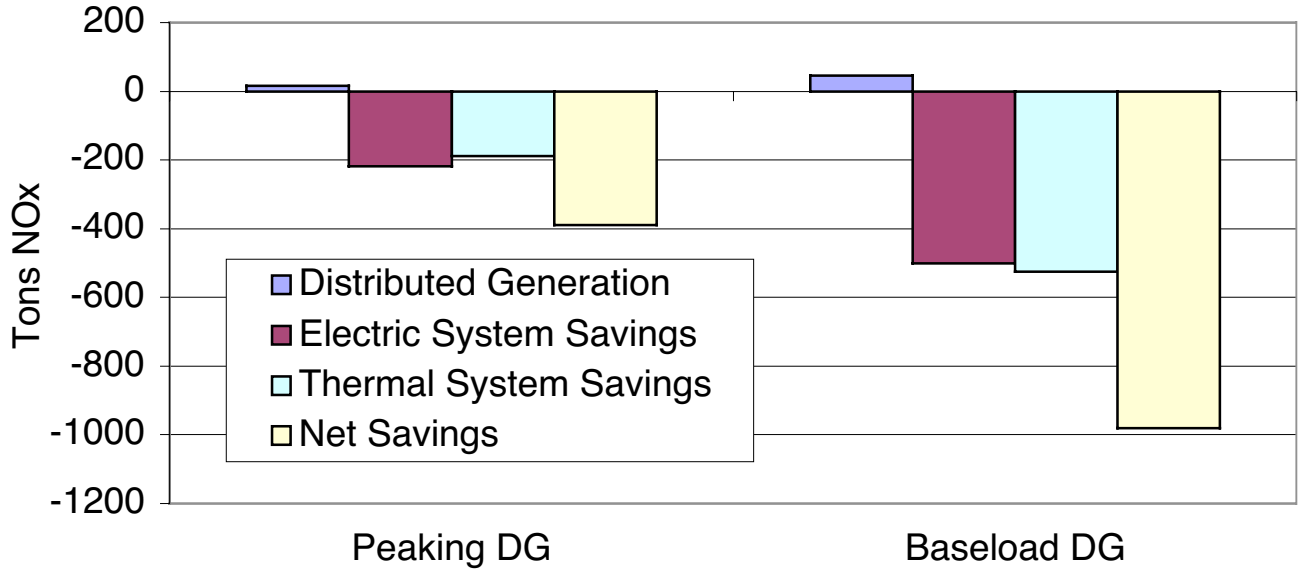
DG results in net savings

- **100 MW of Gas Combustion Turbine-8J with emissions of 0.104 lb/MWh**

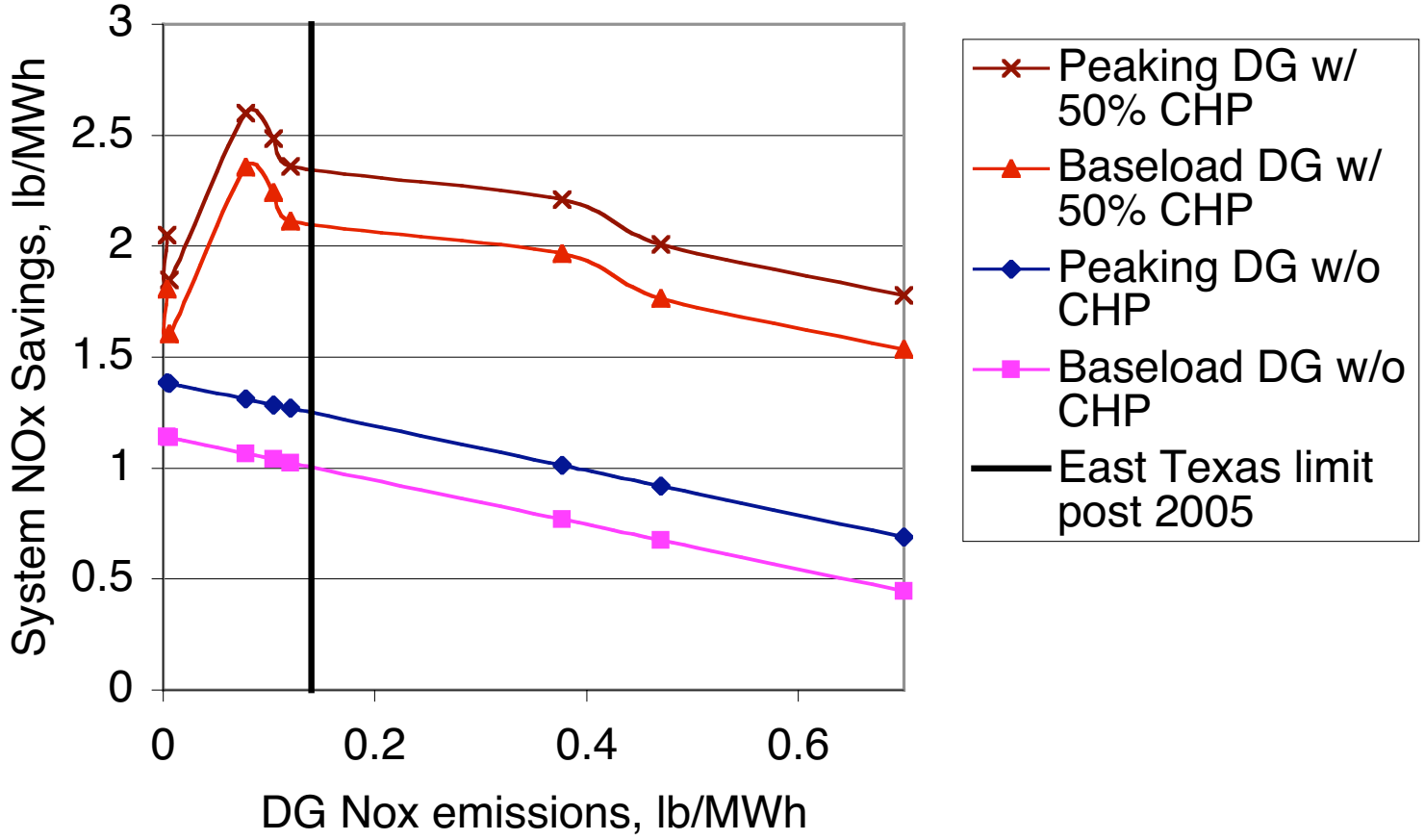


DG with CHP has additional savings

- Gas turbine-8J has emissions of 0.011 lb/mmbtu
- 50% of DG heat displaces boiler operation at 0.23 lb/mmbtu



Level of NO_x savings depends on DG



Potential Further Analysis

- Update plants list to match recent additions, cancellations, and retirements
- Conduct sensitivities on:
  - Emission rates of central plants
  - Capacity displaced by DG instead of just energy (new plants delayed or old plants retired)
- Include locational impacts (non-attainment areas)

Backup slides

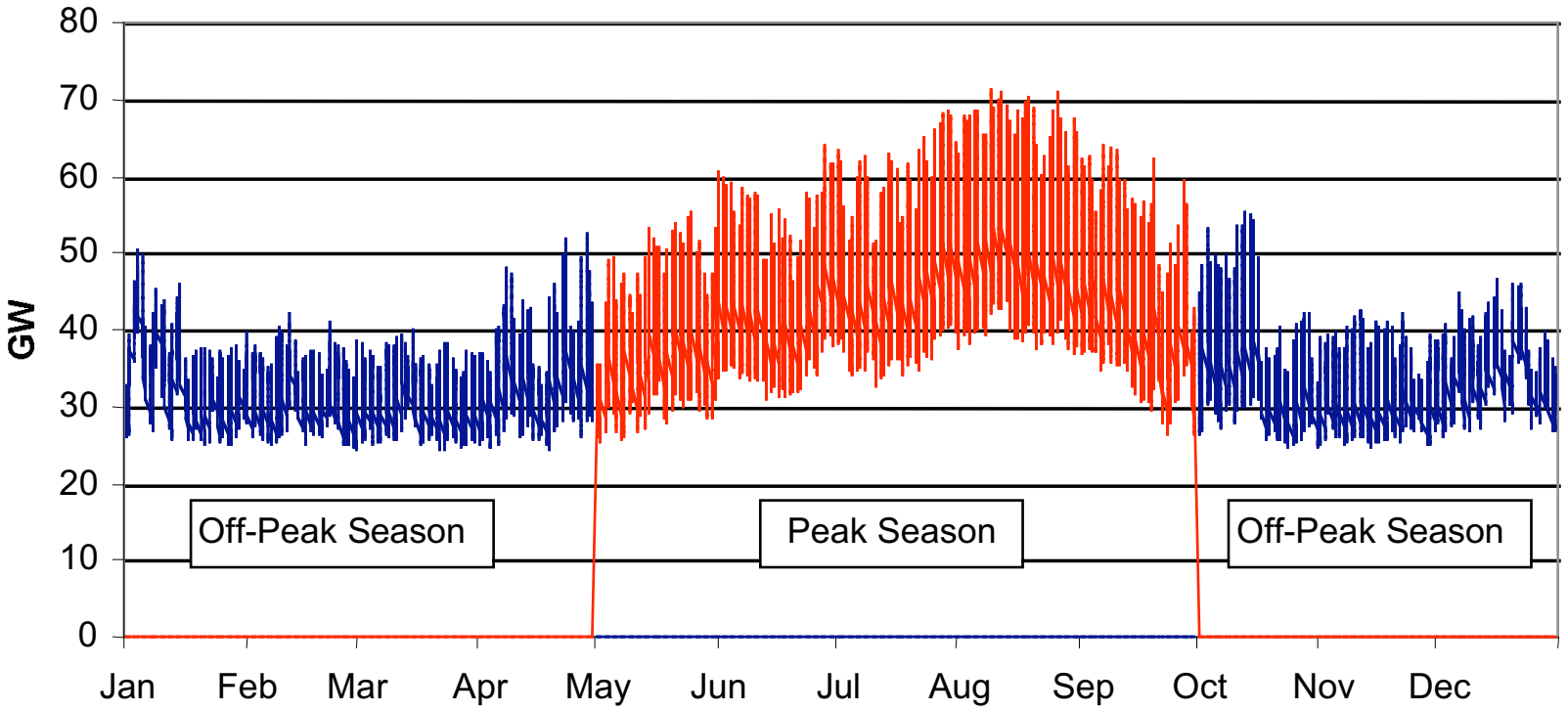
Methodology Details

- Define customer demands
- Define DG scenarios
- Define power plant supplies
- Dispatch power plants to meet demand
- Calculate DG emissions
- Include CHP emissions savings
- Compare to base with no DG

Define electric power demand

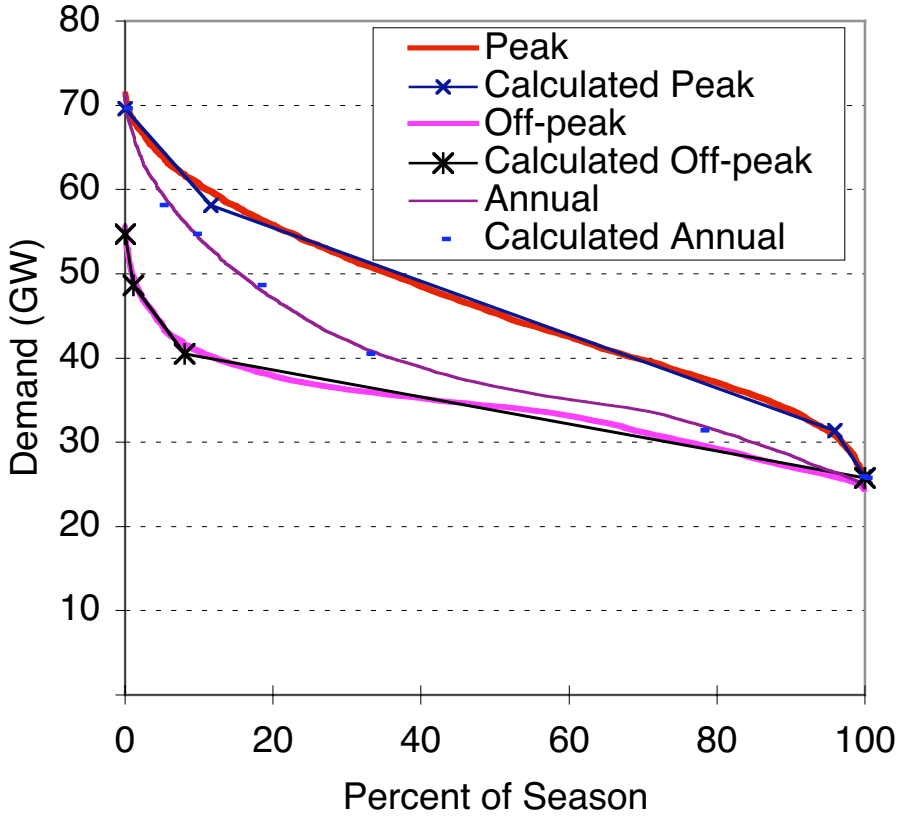
- Find Hourly System Demand
- Escalate to 2012
- Convert to Load Duration Curve (LDC)
- Create new demand curves with DG production removed

Texas Hourly Demands for 2012 (1999 values x 1.294)



Load Duration Curve reorders demands by increasing amounts

- Percent of time demand equals or exceeds a power level
- Separate curves for peak and off-peak seasons
- Convert to 4-line segments for model



Define DG Scenarios

- 100 MW DG
  - Large enough to see change in plant operations
  - Small enough to not affect reserve margins
- Two DG scenarios
  - Baseload operates all year
  - Peaking operates 8am to 8pm weekdays
- Load curves recalculated with DG supply removed

Model 2012 DG technologies

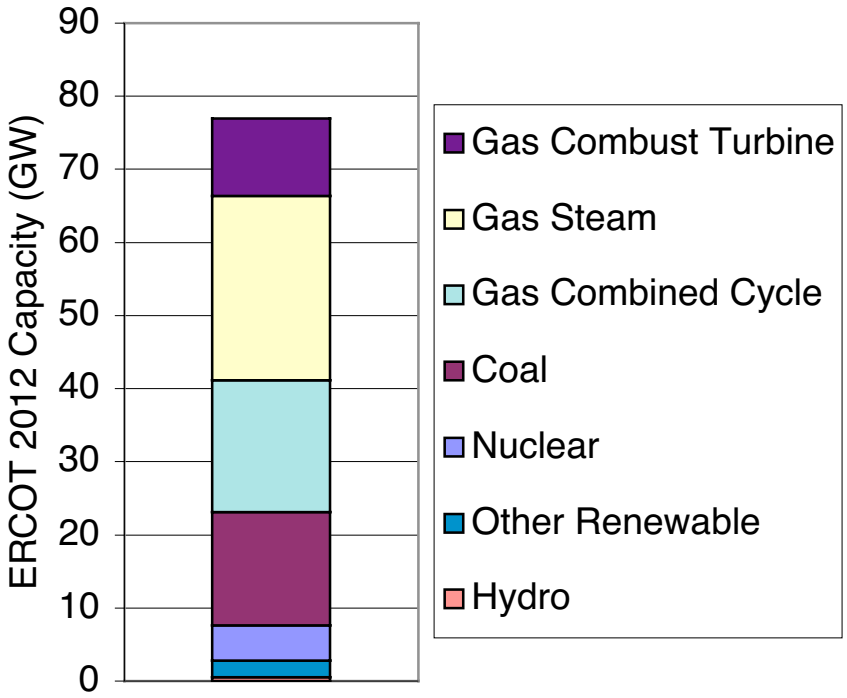
Technology	Model/Type and NO_X reduction method	Electrical Efficiency	NO_X lb/MWh
Fuel Cell-12	**ONSI PC-25 / Phosphoric Acid**	**45%**	**0.0033**
Fuel Cell-16	**Siemens / SOFC**	**54%**	**0.0055**
Microturbine-6D	**Capstone 60, DOE research target**	**36%**	**0.078**
Combustion Turbine-6J	**Solar Mercury 50 Dry Low-emissions combustion: 9 ppm NOx**	**36%**	**0.377**
Combustion Turbine-8J	**Solar Mercury 50 Dry Low-NOx combustion; SCR: 2.5 ppm NOx**	**36%**	**0.104**
Natural Gas Engine-9D	**Cummins QSK/QSV 98% closed-loop SCR + oxidation catalyst**	**34%**	**0.120**
Natural Gas Engine-Med NOx	**Cummins QSK/QSV with NO_X set to current Texas standard**	**34%**	**0.470**
Natural Gas Engine-High NOx	**Cummins QSK/QSV with NO_X set to higher NOx value**	**34%**	**0.700**

Define power plant supply

- Inventory of plants found from EIA, EPA and RDI databases show 660 units in ERCOT
- Data sets include information on:
  - Capacity
  - Fuel Cost
  - Outage Rates
  - Operations & Maintenance
  - Fuel types
  - Efficiency
  - Age
  - Construction Cost
  - Emissions

Inventory of plants from EIA and RDI includes additions and retirements

- Most power from gas-fired plants
- List does not include most recent retirements, additions, cancellations



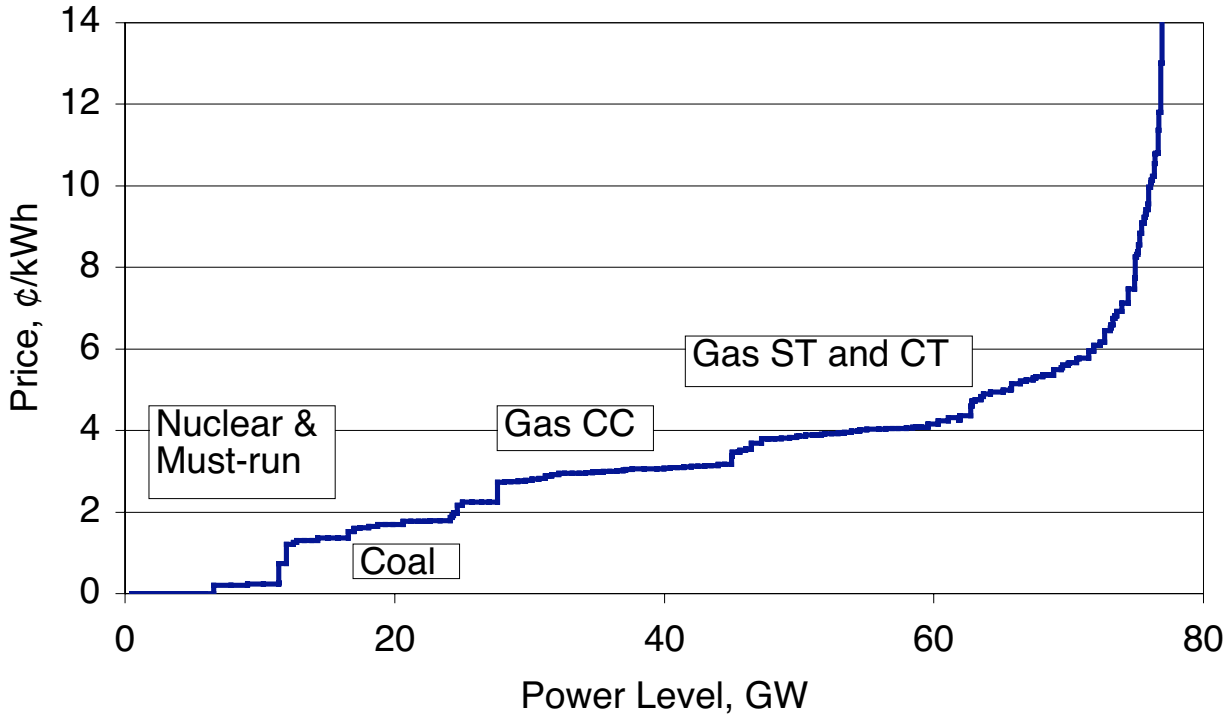
Base operation for ERCOT in 2012 by plant types

	Capacity MW	Generation TWh	Avg Capacity Factor	NO_X Tons	NO_X Lb/ MWh
Nuclear	4,817	37.5	89%	0	0
Coal	15,436	113.2	84%	205	3.62
Gas Combined Cycle	18,035	115.2	73%	15	0.26
Gas Steam	25,222	41.9	19%	55	2.64
Gas Combustion Turbine	10,595	27.8	30%	5	0.32
Hydro	522	95	18%	0	0
Other	2,278	848	37%	0	0
Total	76,906	343.8	51%	279	1.62

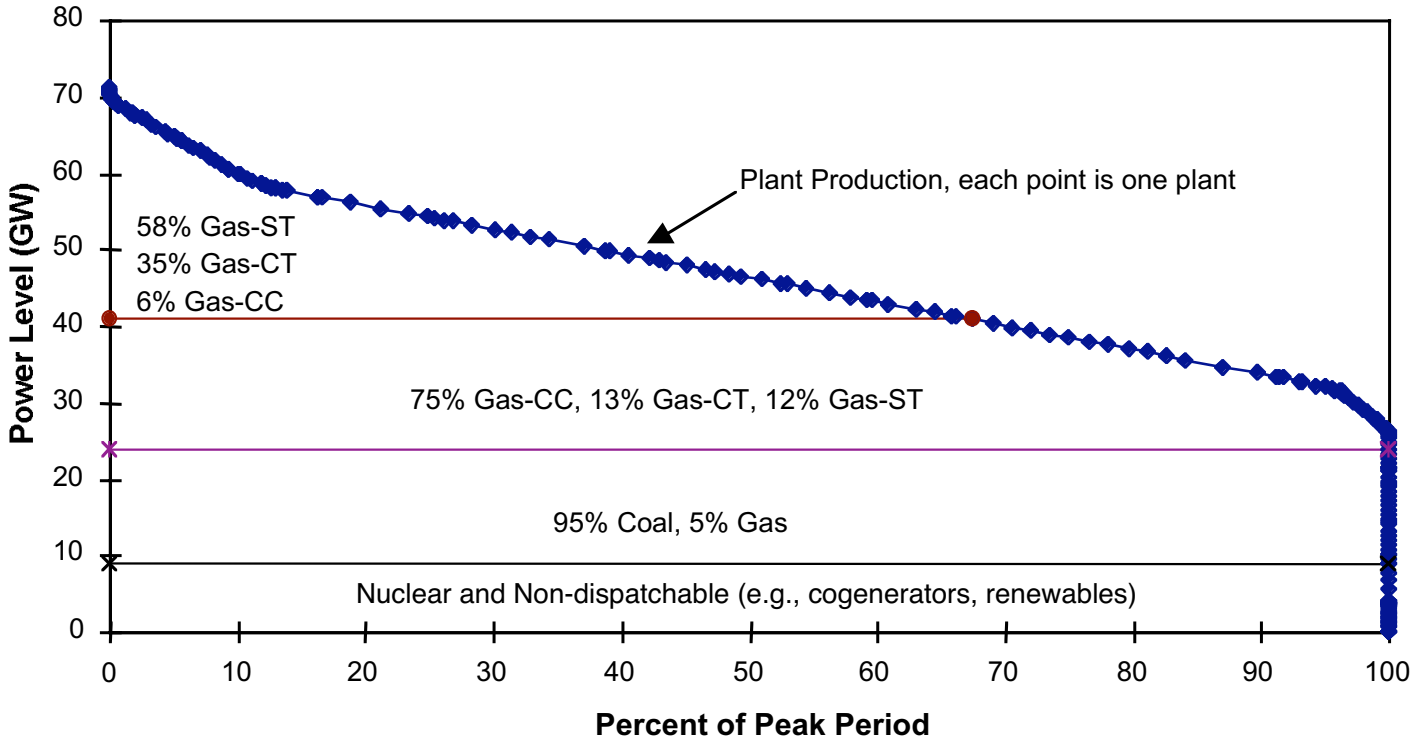
Oak Ridge Competitive Electricity Dispatch (ORCED) model

- MS Excel model of bulk power market with marginal cost and average cost pricing
  - Up to 202 power plants
  - Covers single year
  - Based on earlier single utility model ORFIN
- Used in multiple carbon emission and restructuring studies, e.g.:
  - Generation adequacy under restructuring
  - Power prices in CA and Pacific NW
  - Carbon emissions in Midwest with carbon tax
  - National carbon emissions with clean energy programs
  - Multiple emission control strategies

Order plants by marginal cost



Plants on margin change as demand increases



Exhaust heat displaces other gas for thermal needs

- **Amount of usable heat depends on DG technology used**

Technology	Heat Exchanger Efficiency	Electrical Efficiency	Total Efficiency
Fuel Cell	**50%**	**45%-54%**	**73%-70%**
Microturbine	**67%**	**36%**	**79%**
Combustion Turbine	**62%**	**36%**	**76%**
Natural Gas Engine	**52%**	**34%**	**68%**
Non-CHP Boiler	**72%**	**-**	**-**

Assume displaced boilers have emissions similar to gas-fired steam plants (0.23 lb/mmbtu)
Assume only 50% of DG includes CHP