



***Tariff impacts on system sizing and trends  
in system design & multiple properties  
bifurcated by public right of way***

**Bruce Hedman  
ICF International  
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# Agenda

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- Tariff Issues
- Bifurcation

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# CHP Economics 101

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- + Savings in Purchased Electricity
    - Increased Fuel Costs
    - Incremental O&M Costs
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+ Operating Savings

*Electric rate design has a significant impact on CHP economics*



# Principles of Rate Design



- *Revenue-Related Objectives:*
  - Rates should yield the total revenue requirement;
  - Rates should provide predictable and stable revenues; and
  - Rates themselves should be stable and predictable.
- *Cost-Related Objectives:*
  - Rates should be set so as to promote economically-efficient consumption (static efficiency);
  - Rates should reflect the present and future private and social costs and benefits of providing service (*i.e.*, all internalities and externalities);
  - Rates should be apportioned fairly among customers and customer classes;
  - Undue discrimination should be avoided; and,
  - Rates should promote innovation in supply and demand (dynamic efficiency).
- *Practical Considerations:*
  - Rates should be **simple, certain, payable conveniently, understandable**, acceptable to the public, and easily administered.
  - Rates should be, to the extent possible, free from controversies as to proper interpretation.



# Electricity Tariffs 101

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- Different users do not pay the same price per kilowatt-hour.
- Tariffs are divided into service classes depending on what the power is being used for and the amount of power delivered to the user.
- Service classes are further divided based on the voltage at which the user receives service.



# Electricity Tariffs 101

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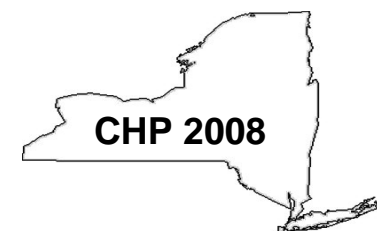


- Tariff structures are not standardized among utilities.
- Each has different features that benefit different classes of users to a greater or lesser degree.
- Each has its own complexities and idiosyncrasies.
- This having been said, they do have certain features in common.



# Electric Rate Components

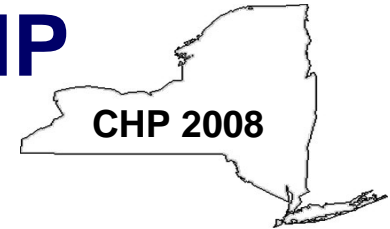
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- *Customer Charges* – Fixed monthly charge for each type of customer
- *Energy Charges* – Volumetric commodity or infrastructure charges based on kWh consumed
- *Demand Charges* – Assessed against peak demand (kW) per a given period (usually a monthly period); may be ratcheted
  - Distribution, transmission and generation components
  - Bundled and unbundled



# Effect of Rate Structure on CHP



Unfavorable for CHP

Favorable for CHP

Entirely Demand Based Rates

Decreasing/no ratchets, Increasing energy charges

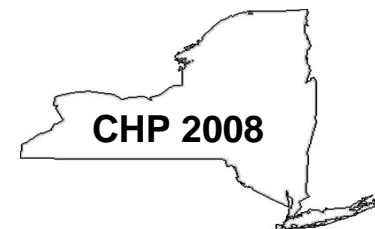
Increasing demand charges, Increasing ratchets

Entirely Energy Based Rates

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# Impact of Electricity Tariffs



- Efficient, cost-effective CHP is usually sized to match thermal loads and run long hours
- Tariffs influence prime mover configuration
- Tariffs impact system sizing
- Tariffs impact operating strategy
- Not all impacts result in highest efficiency or most energy savings and emissions benefits



# Electricity Rates for CHP Customers



- Users with on-site generation are often referred to as “partial requirements customers”
- Services are often provided under different rate schedules than for non-DG customers
  - *Standby or Back-up* – serves a customer’s load during an unscheduled outage of the CHP system
  - *Supplemental service* – serves demand in excess of CHP generation, often supplied at the applicable full-requirements tariff
  - *Scheduled maintenance* – serves a customer’s load, without penalty or reservation charge, while the CHP system is being serviced



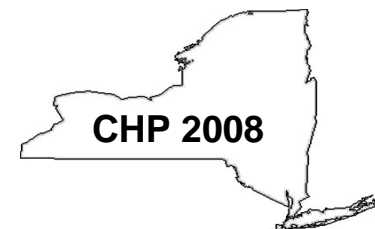
# Typical Elements of Standby Rates



- Customer Charges
- Reservation or contract demand charges
  - Demand charge related to amount of back-up needed, to recover costs of facilities dedicated solely to the customer, ratcheted
    - √ Wires, transformers, possibly reserves in cases of vertically integrated utilities
- As-Used Demand Charges
  - Monthly or daily demand charges to recover costs of shared facilities, e.g., substations, feeders, transmission
- Energy charges
  - For remaining delivery costs
  - Commodity



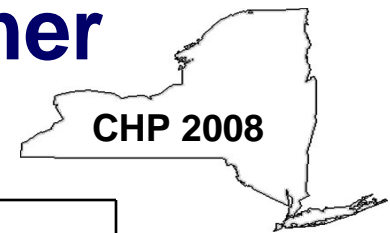
# Impact of Standby Tariffs



- Customer requirements
  - Peak annual demand of 13,000 kW
  - Energy consumption of 92,800 MWh
- CHP system
  - 5,000 kW
  - Six outages during peak hours in two months
- Compared the total annual costs of grid-supplied electricity under partial requirements tariffs to costs under otherwise applicable full requirements tariffs.



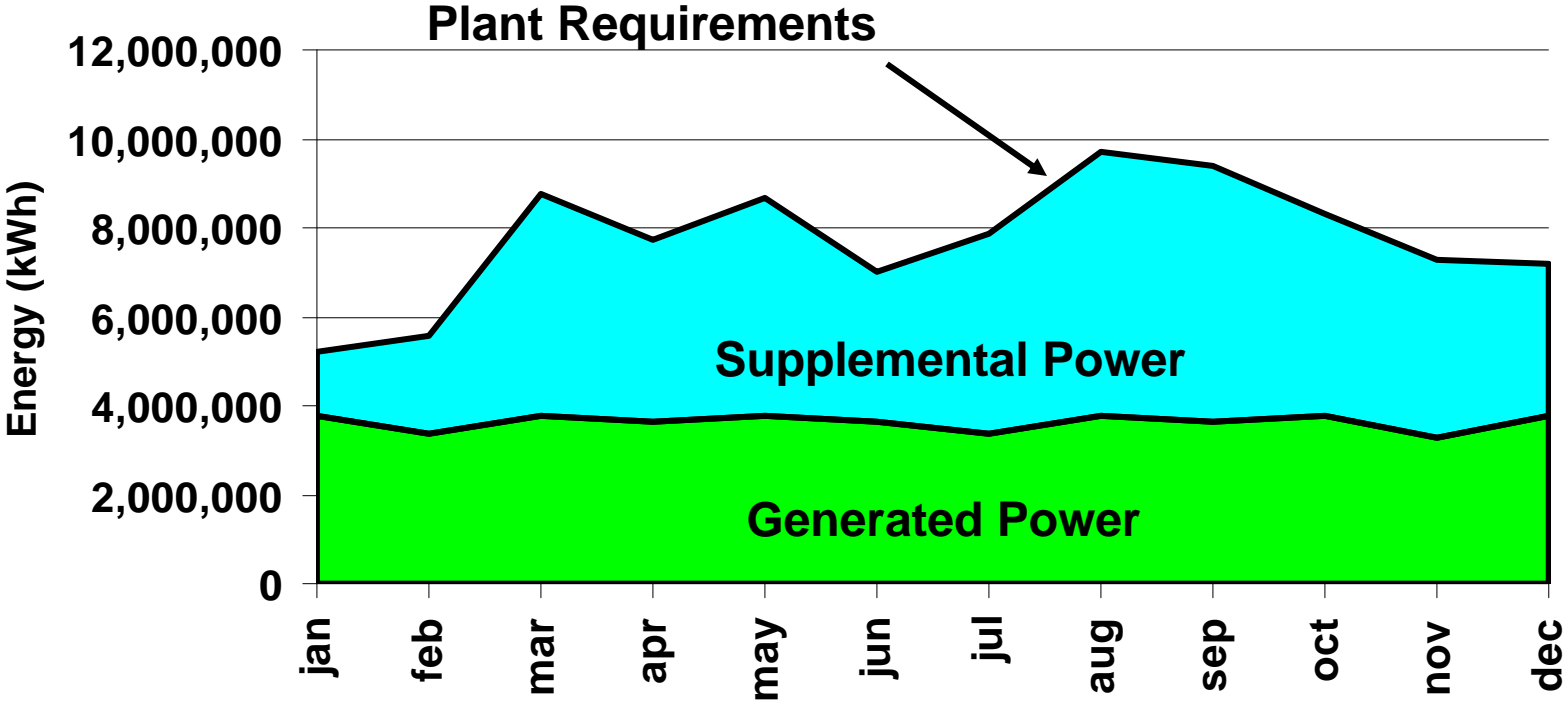
# Characteristics of CHP Customer



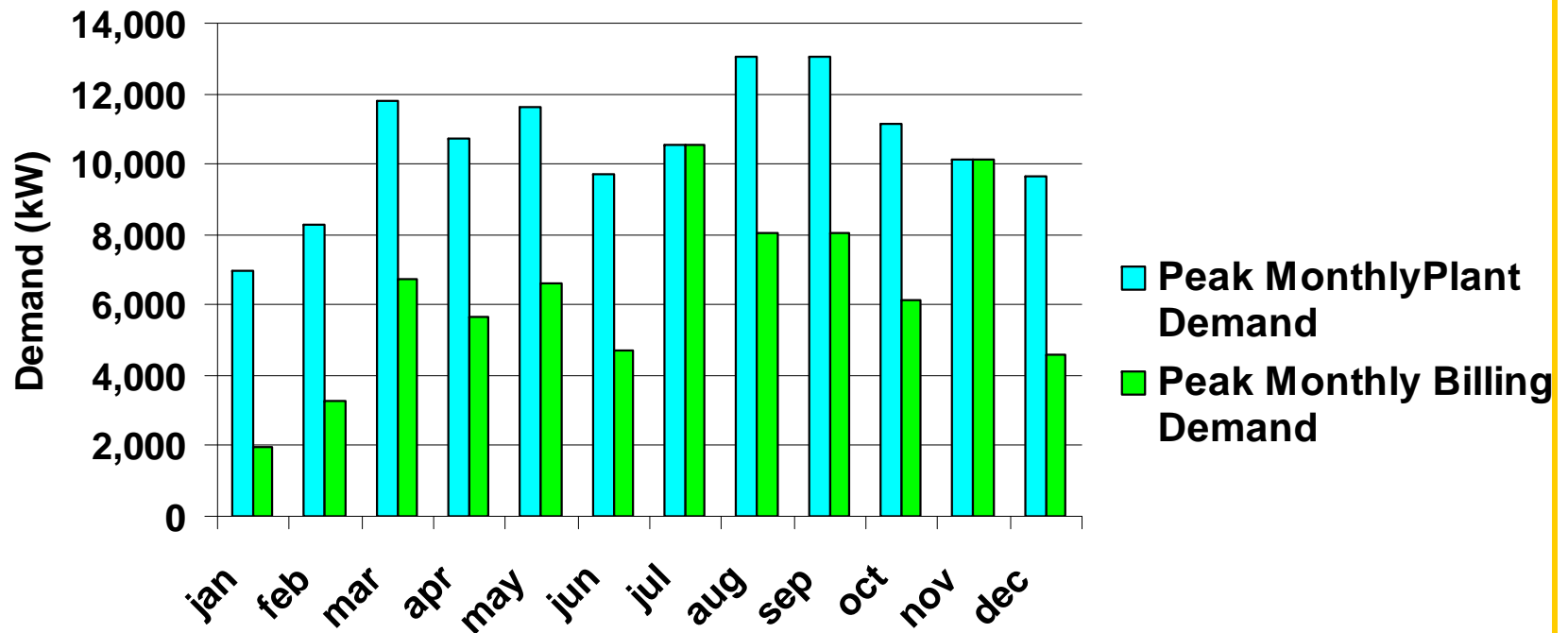
<b>Plant Consumption Details</b>		
Peak Demand, kW		13,077
Operating Hours		8,760
Annual Power Consumption, kWh		92,762,451
<b>CHP System</b>		
Prime Mover		Gas Turbine
Electric Capacity, kW		5,048
System Availability, %		98%
System Hours of Operation		8,616
<b>Energy Summary</b>		
	Base System	Gas Turbine
Purchased Power, kWh	92,762,451	49,273,191
Generated Power, kWh		43,489,260



# Annual Power Requirements



# Peak Billing Demands



# Metrics



- Calculate average cost per kWh for grid-supplied electricity under full requirements tariff and under partial requirements tariff
  - That is, the annual electric bill divided by *purchased* kWh
  - Typically the partial requirements average is higher than the full requirements average
- Calculate value of avoided purchased electricity by on-site generation
  - Bill savings divided by kWh *generated*



# Metrics



- Lastly, compare value of avoided purchases to value of grid-supplied electricity under full requirements tariff
  - Avg. value of avoided kWh / Avg. cost of full requirements kWh
  - The higher the ratio of avoided cost to the full retail average price, the higher the savings realized by the user
- Considers electric savings only, no consideration of fuel costs or thermal savings



# Examples Outside New York

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- Portland General Electric and Hawaiian Electric Company
- Both apply full requirements tariffs to partial requirements customers
- Both include reservation demand charges for standby
- HECO includes additional energy charge for standby



# Portland General Electric



Unbundled Service for Partial and Full Requirements Customers, > 1 MW, With Monthly As-Used Demand Charges Portland General Electric		
	Partial Requirements	Full Requirements
	Secondary Voltage	Secondary Voltage
Part 1: Customer Charge		
Customer Charge	\$130.00/month	\$130.00/month
Part 2: Transmission Charges		
On-Peak Demand	\$0.66/kW-month	\$0.66/kW-month
Part 3: Distribution Charges		
Sum of A + B		
A. Facility Capacity		
First 1,000 MW	\$1.86/kW-month	\$1.86/kW-month
Over 1,000 MW	\$0.37/kW-month	\$0.37/kW-month
B. On-Peak Demand		
	\$2.27/kW-month	\$2.27/kW-month
Part 4: Generation Charges		
Generation Contingency Reserves		
Sum of A + B		
A. Spinning, > 2,000 kW		
	\$0.2340/kW-month	NA
B. Supplemental, > 2,000 kW		
	\$0.2340/kW-month	NA
System Usage Charge		
	\$0.00430/kWh	\$0.00430/kWh
Energy Charge		
On-Peak (6a-10p, M-S)		
	\$0.06071/kWh	\$0.06071/kWh
Off-Peak (all other times)		
	\$0.05021/kWh	\$0.05021/kWh



# Portland General Electric

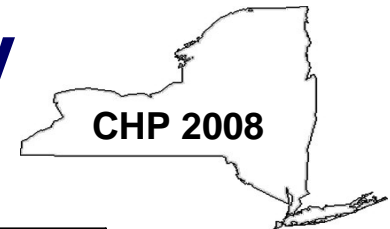


Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased Electricity, kWh	92,762,451	49,273,191
Facilities Charges	\$1,560	\$1,560
Distribution Demand Charges	\$352,879	\$219,625
Transmission Demand Charges	\$83,750	\$50,436
Generation Demand Charges	\$0	\$24,554
Energy Charges	\$5,601,087	\$2,975,163
Total Electric Charges	\$6,039,276	\$3,271,339
Average Rate for Purchased Power	\$0.0651	\$0.0664
Average Avoided Rate	n/a	\$0.0636

Average Avoided Rate as a % of Average Retail Service Rate **97.76%**



# Hawaiian Electric Company



Unbundled Service for Full and Partial Requirements Customers, > 1 MW With Daily As-Used Demand Charges Hawaiian Electric Company		
	Partial Requirements	Full Requirements
<b>Part 1: Customer Charge</b>		
Customer Charge	\$230.00/month	\$230.00/month
<b>Part 2: Delivery Charges, Demand</b>		
First 500 kW of billing demand	\$10.00/kW-month	\$10.00/kW-month
Next 1000 of billing demand	\$9.50/kW-month	\$9.50/kW-month
Over 1500 kW of billing demand	\$8.50/kW-month	\$8.50/kW-month
Sum of A + B		
A. Reservation Demand Charge	\$7.26/kW-month	NA
B. As-Used Demand Charge	\$0.66/kW-day	NA
<b>Part 3: Delivery Charges, Energy</b>		
First 200 kWh/month/kW of billing demand	\$0.072087	\$0.072087
Next 200 kWh/month/kW of billing demand	\$0.064104	\$0.064104
Over 400 kWh/month/kW of billing demand	\$0.061010	\$0.061010
Standby kWhs (in addition to ECAC)	\$0.124/kWh	
<b>Part 4: Energy, Commodity (ECAC)</b>		
	\$0.15/kWh	



# Hawaiian Electric Company



Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased Electricity, kWh	92,762,451	49,273,191
Facilities Charges	\$2,760	\$2,760
Delivery Demand Charges	\$1,099,596	\$584,751
Reservation Demand Charges	\$0	\$444,973
Daily Back up Demand Charges	\$0	\$19,988
Distribution Energy Charges	\$6,019,079	\$3,194,132
Standby Energy Charges	\$0	\$90,128
Commodity Energy Charges	\$13,914,368	\$7,390,979
Total Electric Charges	\$21,035,802	\$11,727,710
Average Rate for Purchased Power	\$0.2268	\$0.2380
Average Avoided Rate	n/a	\$0.2140

Average Avoided Rate as a % of Average Retail Service Rate **94.38%**



# New York Partial Requirements Rates



- “Standby Rates” revised in 2003 – 2004 timeframe
- Designed to reflect a “more cost-based rate design”
- Based on costs reflecting “the size of the facilities needed to meet a customer’s maximum demand”
- Included a phased-in approach and exemptions for systems < 1 MW and with a minimum efficiency of 60 percent



# New York Partial Requirements Rates



- Standby rates do not mirror full requirements rates
- Includes “contract” demand charge based not on generator size, but on maximum facility demand
- Includes daily “as-used”, on-peak demand charges
  - Based on demand in peak hours, and
  - Monday through Friday
- Severe penalties for exceeding contract demand



# Orange and Rockland



Unbundled Service for Full and Partial Requirements Customers, > 1 MW With Daily As-Used Demand Charges Orange and Rockland		
	Partial Requirements	Full Requirements
	SC-25	SC 9
Part 1: Customer Charge		
Customer Charge	\$278.47/month	\$328.56
Part 2: Distribution Charges, Demand		
Period A, all kW (8a-11p, summer)		\$9.20/kW-month
Period B, all kW (8a-11p, other)		\$4.32/kW-month
Period C, all kW (all other times)		\$0.00/kW-month
Contract Demand Charge		
	\$2.88/kW-month	
As-Used Demand Charge		
Summer (June-Sept)	\$0.3918/kW-day	
Non-Summer (Oct-May)	\$0.2577/kW-day	
Part 3: Distribution Charges, Energy		
Period A, all kWh	0.00	\$0.01031
Period B, all kWh	0.00	\$0.01031
Period C, all kWh	0.00	\$0.00384
Part 4: Energy, Commodity		
	Energy, ancillary service, capacity at wholesale market prices (assume \$0.09/kWh)	



# Orange and Rockland



Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased Electricity, kWh	92,762,451	49,273,191
Facilities Charges	\$3,948	\$3,336
Distribution Demand Charges	\$774,945	\$0
Contract Demand Charges	\$0	\$451,927
As-Used Daily Demand Charges	\$0	\$455,983
Distribution Energy Charges	\$624,143	\$0
Generation Energy Charges	\$7,606,521	\$4,040,402
Total Electric Charges	\$9,009,557	\$4,951,648
Average Rate for Purchased Power	\$0.0971	\$0.1005
Average Avoided Rate	n/a	\$0.0933

Average Avoided Rate as a % of Average Retail Service Rate

**96.07%**



# Consolidated Edison



<b>Unbundled Service for Full and Partial Requirements Customers, &gt; 1 MW With Daily As-Used Demand Charges Con Ed</b>		
	<b>Partial Requirements</b>	<b>Full Requirements</b>
	<b>SC No 14-RA</b>	<b>SC No 9 II</b>
Part 1: Customer Charge		
Customer Charge	\$908/month	\$908
Part 2: Distribution Charges, Demand		
Period A, Mon – Fri, 8am-6pm, (Jun-Sept)		\$5.86/kW-month
Period B, Mon – Fri, 8am-10pm, (Jun-Sept)		\$11.09/kW-month
Period C, all kW (Jun - Sept)		\$10.94/kW-month
Period A, Mon – Fri, 8am-6pm, (Other)		\$8.14/kW-month
Period C, all kW (Other)		\$3.54/kW-month
Contract Demand Charge	\$5.41/kW-month	
As-Used Demand Charge		
Mon – Fri, 8am-6pm, (Jun-Sept)	\$0.3423/kW-day	
Mon – Fri, 8am-10pm, (Jun-Sept)	\$0.6910/kW-day	
Mon – Fri, 8am-10pm, (other)	\$0.5200/kW-day	
Part 3: Distribution Charges, Energy		
All kWh	0.00	\$0.0058/kWh
SBC	\$0.0018/kWh	\$0.0018/kWh
Period C, all kWh	0.00	\$0.00384
Part 4: Energy, Commodity		
Energy, ancillary service, capacity at wholesale market prices (assume \$0.12/kWh)		

# Consolidated Edison



Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased Electricity, kWh	92,762,451	49,273,191
Facilities Charges	\$0	\$10,896
Delivery Demand Charges - Jun-Sep	\$1,295,995	\$0
Delivery Demand Charges - all other	\$939,370	\$0
Contract Demand Charge	\$0	\$848,933
As-Used Daily Demand Charges	\$0	\$1,060,399
Systems Benefits Charge	\$166,972	\$88,692
Energy Delivery Charges	\$538,022	\$0
Commodity Charges	\$11,131,494	\$5,912,783
Total Electric Charges	\$14,071,854	\$7,921,702
Average Rate for Purchased Power	\$0.1517	\$0.1608
Average Avoided Rate	n/a	\$0.1414

Average Avoided Rate as a % of Average Retail Service Rate **93.22%**



# National Grid



Unbundled Service for Full and Partial Requirements Customers, > 1 MW With Daily As-Used Demand Charges National Grid		
	Partial Requirements	Full Requirements
	SC 7	SC 3A
Part 1: Customer Charge		
Customer Charge	\$1,426/month	\$902
Part 2: Distribution Charges, Demand		
Delivery - All months		\$7.63/kW-month
CTC- all months		\$3.72/kW-month
Contract Demand		
Delivery	\$3.54/kW-month	
CTC	\$2.05/kW-month	
As-Used Demand Charge		
Delivery	\$0.1887/kW-day	
CTC	\$0.1095/kW-day	
Part 3: Distribution Charges, Energy		
SBC	\$0.00164/kWh	\$0.00164/kWh
Part 4: Energy, Commodity		
	Energy, ancillary service, capacity at wholesale market prices (assume \$0.09/kWh)	



# National Grid



Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased Electricity, kWh	92,762,451	49,273,191
Facilities Charges	\$10,824	\$17,112
Distribution Demand Charges	\$968,198	\$0
Competitive Transition Demand Charges	\$472,044	\$0
Contract Demand - Delivery	\$0	\$555,494
Contract Demand - CTC	\$0	\$321,684
Daily as used demand charges - Delivery	\$0	\$277,132
Daily as used demand charges - CTC	\$0	\$160,816
Systems Benefits Charge	\$152,130	\$80,808
Energy Charges	\$8,348,621	\$4,434,587
Total Electric Charges	\$9,951,827	\$5,847,634
Average Rate for Purchased Power	\$0.1073	\$0.1187
Average Avoided Rate	n/a	\$0.0944

Average Avoided Rate as a % of Average Retail Service Rate

**87.97%**



# Comparisons



Utility	Avoided Rate with Commodity Charge	Avoided Rate without Commodity Charge	Delivery Revenues Retained with CHP
PGE	97.8%	83.8%	61.0%
HECO	94.4%	83.4%	61.0%
O&R	96.1%	74.8%	65.0%
Con Ed	93.2%	67.6%	68.0%
Nat Grid	88.0%	25.3%	88.0%



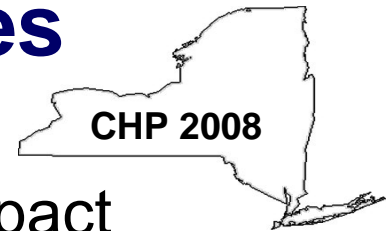
# Observations on New York Rates



- “Avoided rate” metric only tells part of the story – impacted by tariff structure, absolute values of the rate components, relative value of commodity rate compared to delivery rates, and possibly by load factor of customer
- Revised “Standby Rates” are a compromise
  - Monthly demand rates lower, but placed on highest full facility load for past 12 months
  - As-used daily demand only applied to peak periods
- As-used daily demand promotes high reliability and use of off-peak periods for scheduled maintenance



# Observations on New York Rates



- Shift to hourly commodity pricing likely to impact operating strategies – run during peak periods, purchase power during low price off-peak periods
- Rate structures do not protect against inconsistent or inappropriate application
- *What are your experiences?*



# Bifurcation



- Inability to wheel power across a public right of way without becoming a “public utility”
- Inability to sell power to non-related entities on adjacent properties
- Both of the above
- Constrains “optimal” design – may limit both efficiency and emissions benefits
- Historically difficult to do in New York for both commercial/industrial and agricultural DG



# Illustration – CHP in Ethanol



- Energy is the second largest cost of production for dry mill ethanol plants
- Electric and steam demands are large and coincident
  - Typical power demand is 4 to 15 MW
  - Typical steam use is 40,000 to 250,000 lb/hr
- Electric and steam profiles are relatively flat
- Operating hours are continuous
- *Energy costs are rising*



# Typical CHP Options for Ethanol Plants



- Gas Turbine CHP
  - *If sized to electricity load, additional steam needed*
  - *If sized to thermal load, excess power produced*
- Gas Turbine/Supplemental Fired CHP
  - *Can be sized to meet both steam and electric loads*

# Dry Mill Energy Consumption



Energy Consumption	Natural Gas
Plant Capacity, MMgal/yr	60
Operating Hours	8600
Annual Electric Use, MWh	83,220
Average Electric Demand, MW	9.5
Steam Use, lbs/hr	158,000
Annual Steam Use, MMlbs	1,384
Annual Boiler Fuel Use, MMBtu	1,730,000
Annual Drier Fuel Use, MMBtu	525,000



# CHP Options Evaluated

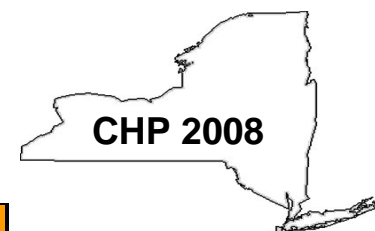
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- Case 1: Gas Turbine/Supplemental Fired
  - *Electric output sized to plant demand*
  - *Large amounts of supplemental firing*
- Case 2: Gas Turbine with Power Sales
  - *Sell 11 MW of power to adjacent plant*
  - *Thermal output better sized to plant steam demand (supplemental firing reduced)*



# CHP Option Descriptions



CHP System Fuel Use	Case 1	Case 2
CHP Capacity, MW	<b>10.1</b>	<b>20.2</b>
CHP Sales, MW	<b>0</b>	<b>11</b>
CHP Fuel, MMBtu	1,071,688	2,143,377
Duct Burner Fuel, MMBtu	1,034,899	526,751
Generation, MWh	<b>86,979</b>	<b>173,957</b>
<b>SHP System Fuel Use</b>		
Boiler, no CHP, MMBtu	1,730,100	1,730,100
Boiler, w/CHP, MMBtu	28,440	28,440
Boiler Savings, MMBtu	1,701,660	1,701,660
T&D Losses, %	7.50%	7.50%
Displaced Central Generation, MWh	<b>94,031</b>	<b>188,062</b>



# CHP Benefits Increase with Larger Thermally Matched System



	Case 1	Case 2
Electric Region	NECC	NECC
Generation	All Fossil	All Fossil
<b>Energy Savings</b>		
Central Station Heat Rate, Btu/kWh	11,123	11,123
SHP Energy, MMBtu	2,697,567	3,665,024
CHP Energy, MMBtu	2,106,587	2,670,128
Energy Savings, MMBtu	<b>590,980</b>	<b>994,896</b>
Energy Savings, % SHP	<b>21.9%</b>	<b>27.1%</b>
<b>CO2 Savings</b>		
Central Station CO2, lb/MWh	1573	1573
SHP CO2, Tons	173,503	247,458
CHP CO2, Tons	123,235	156,202
CO2 Savings, Tons	<b>50,267</b>	<b>91,255</b>
CO2 Savings, % SHP	<b>29.0%</b>	<b>36.9%</b>



# Progress in New York



- In August 2007 NYPSC approved a request by a CHP facility for exemption to regulation under the Public Service Law to enable it to wheel power to a non-related entity over a public road
- St. Luke's Hospital and Utica College
  - 3.6 MW (4 engines) sited "at" hospital providing steam/hot water/absorption cooling
  - The system will run parallel to National Grid and have separate electric distribution systems leading to the Hospital, and associated Nursing Home, and the College
  - Burrstone Energy is builder, owner and operator of the system

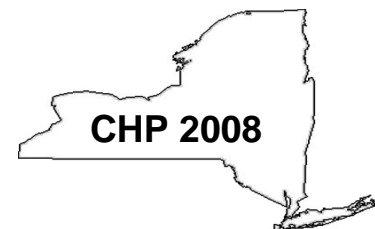
# Progress in New York



- The NYPSC cited PSL S2(20-d), a cogeneration facility includes besides the electric and steam cogeneration facility itself, “such transmission or distribution facilities as may be necessary to conduct electricity...or useful thermal energy to users located at or near a project site”
- In December 2007, the NYPSC ruled that all three facilities are eligible for standby service, and all qualify for the CTC exemption provided for in Special Provision L
- Ensures a properly sized, and efficiently designed system will proceed

# Wrap Up

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- Questions?
- Experiences?
- Recommendations?

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