Rate Design Subcommittee

On Standby or Ready for Prime Time? - CHP Rates & Regulations for a Modern Grid

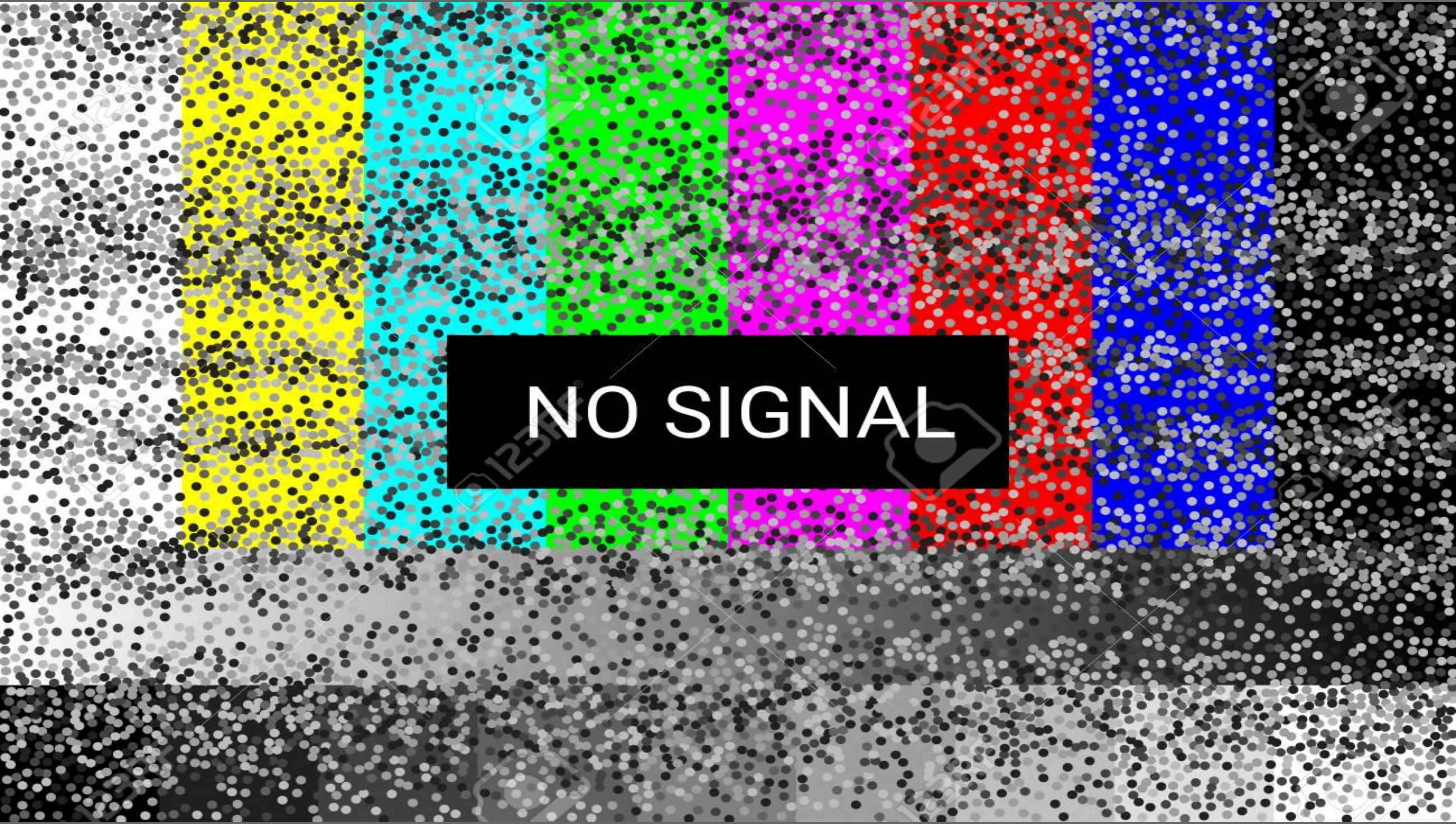
NARUC Summer Policy Summit

ON **STANDBY** OR
READY FOR **PRIMETIME**?

A UTILITY PERSPECTIVE

July 2018

OTTER TAIL POWER COMPANY



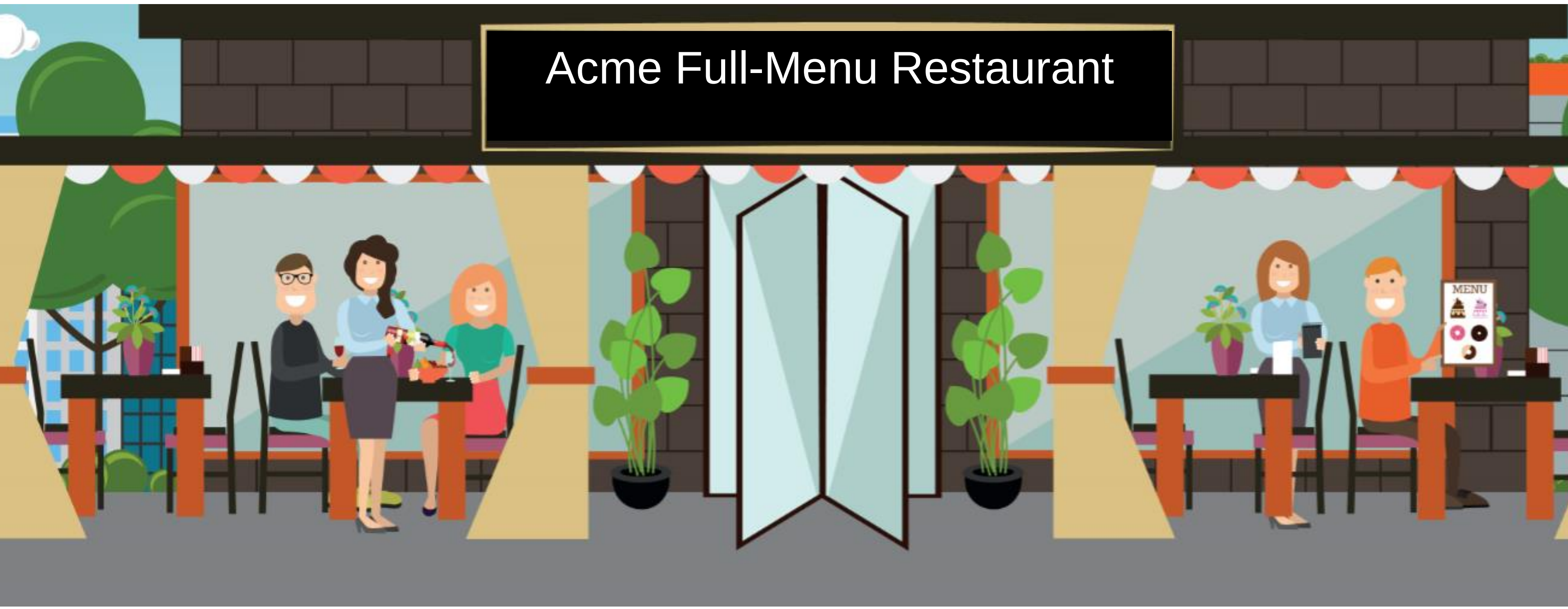
OTTER TAIL POWER COMPANY


PLEASE STAND BY

ABOUT US

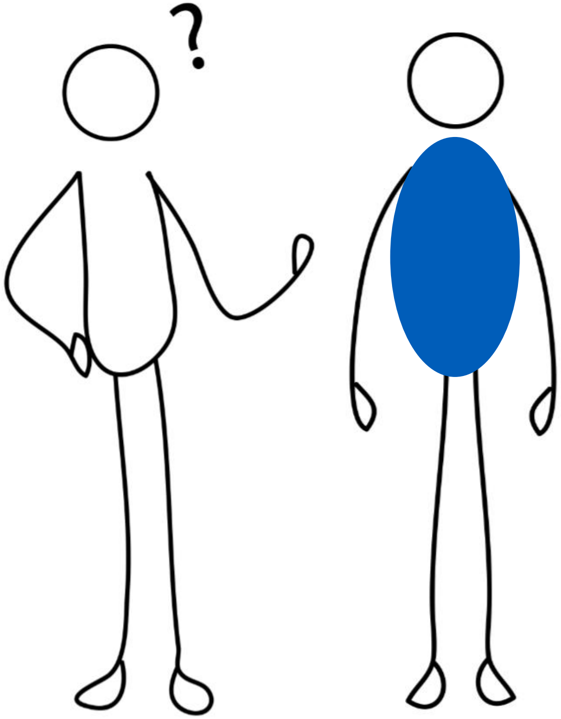
We’re small.

HERE’S WHERE WE START


Acme Full-Menu Restaurant
MENU


COFFEE

SERVICE CONCEPTS

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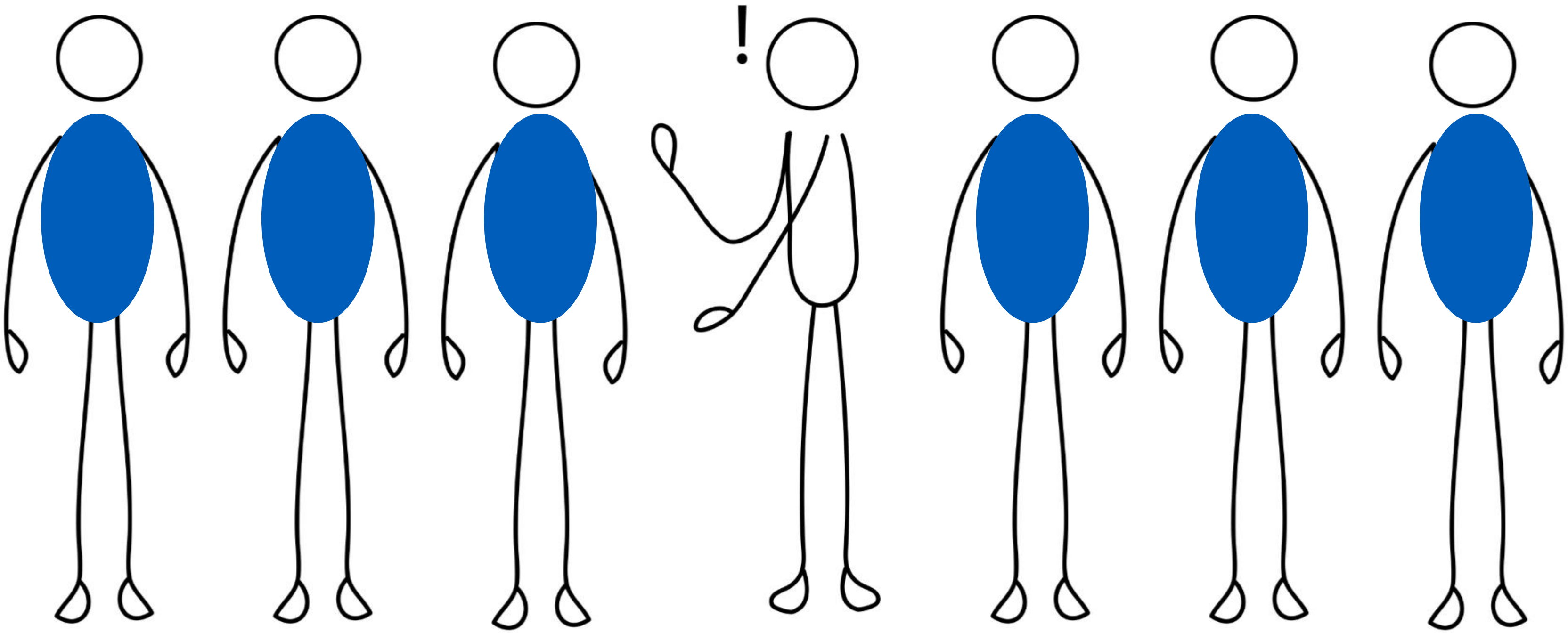
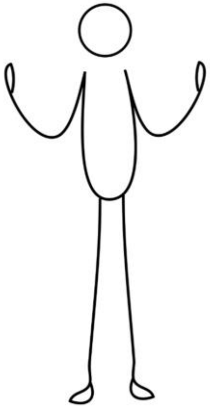




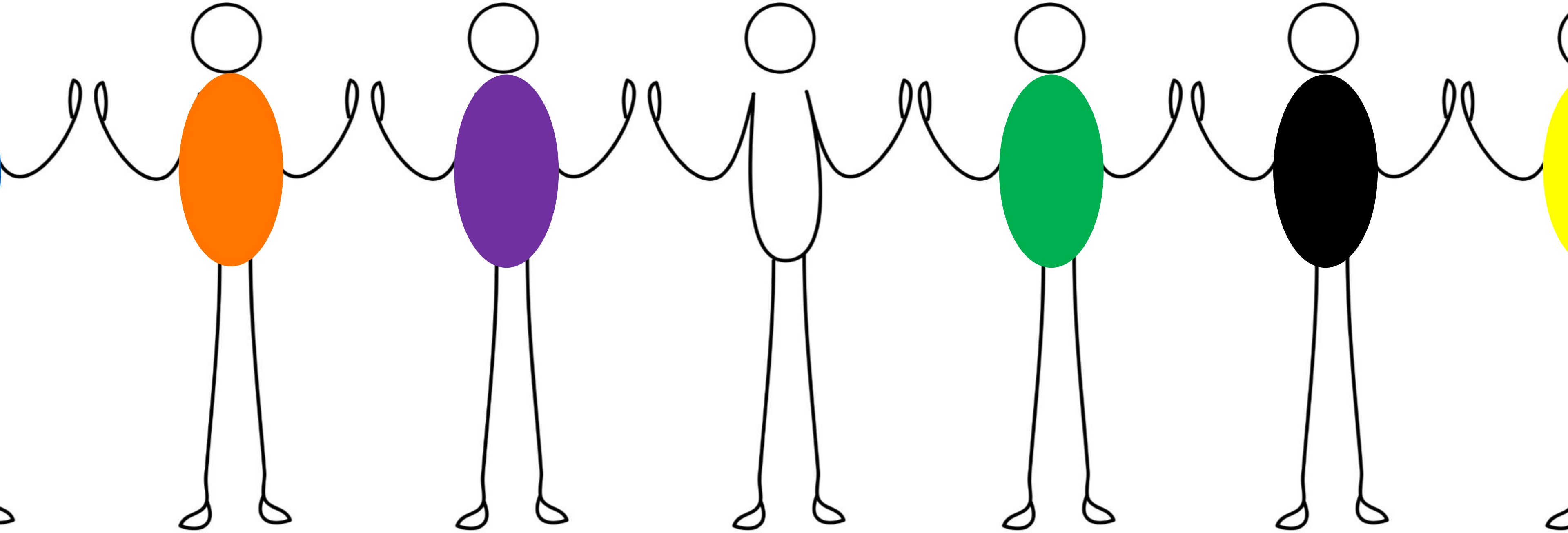
BEST PRACTICES

1. Identify costs and benefits
2. Provide clear price signals
3. Offer flexible service options
4. Balance simplicity and complexity…
5. Customer-Friendly Items

READY FOR PRIMETIME?

“If we wait until we’re ready, we’ll be waiting for the rest of our lives.”

"The Series Of Unfortunate Events Book 6: The Ersatz Elevator" by Lemony Snicket



SUPPORTING CAST

REGULATORS
REGULATORY AFFAIRS DEPARTMENT
ENGINEERS/ACCOUNTANTS EVERYWHERE

LEAD CAST

PRICING & TARIFF ADMINISTRATORS
CUSTOMERS

SPECIAL THANKS

MOMS EVERYWHERE
INDEPENDENT SPIRITS
OUR PREDESESSORS

NARUC
EEI
NRRI
DOE…..
The Sun

Rate Design Subcommittee

On Standby or Ready for Prime Time? - CHP Rates & Regulations for a Modern Grid

NARUC Summer Policy Summit

Apples to Apples: Comparing Monthly Customer Standby Charges Across Utilities

presentation to
2018 NARUC Summer Policy Summit
July 15, 2018

5lakes energy
www.5lakesenergy.com

Comparing Standby Rates

- Some differences are expected
  - Revenue requirements
  - Market structures
- Comparison still valuable for flagging outliers and raising questions for follow-up
- Cost of service analysis

Difficult to Compare

- Lack of uniformity
- Lack of transparency
- Utilities provided simulated calculations, but <u>system sizes and other assumptions differed</u>
- A need to highlight customer experience through estimated standby bills

Customer Characteristics

- 3,000 kW in supplemental service
- 2,000 kW in reserved standby service
- General service, primary distribution level
- One month of standby charges

Outage Scenario Comparison

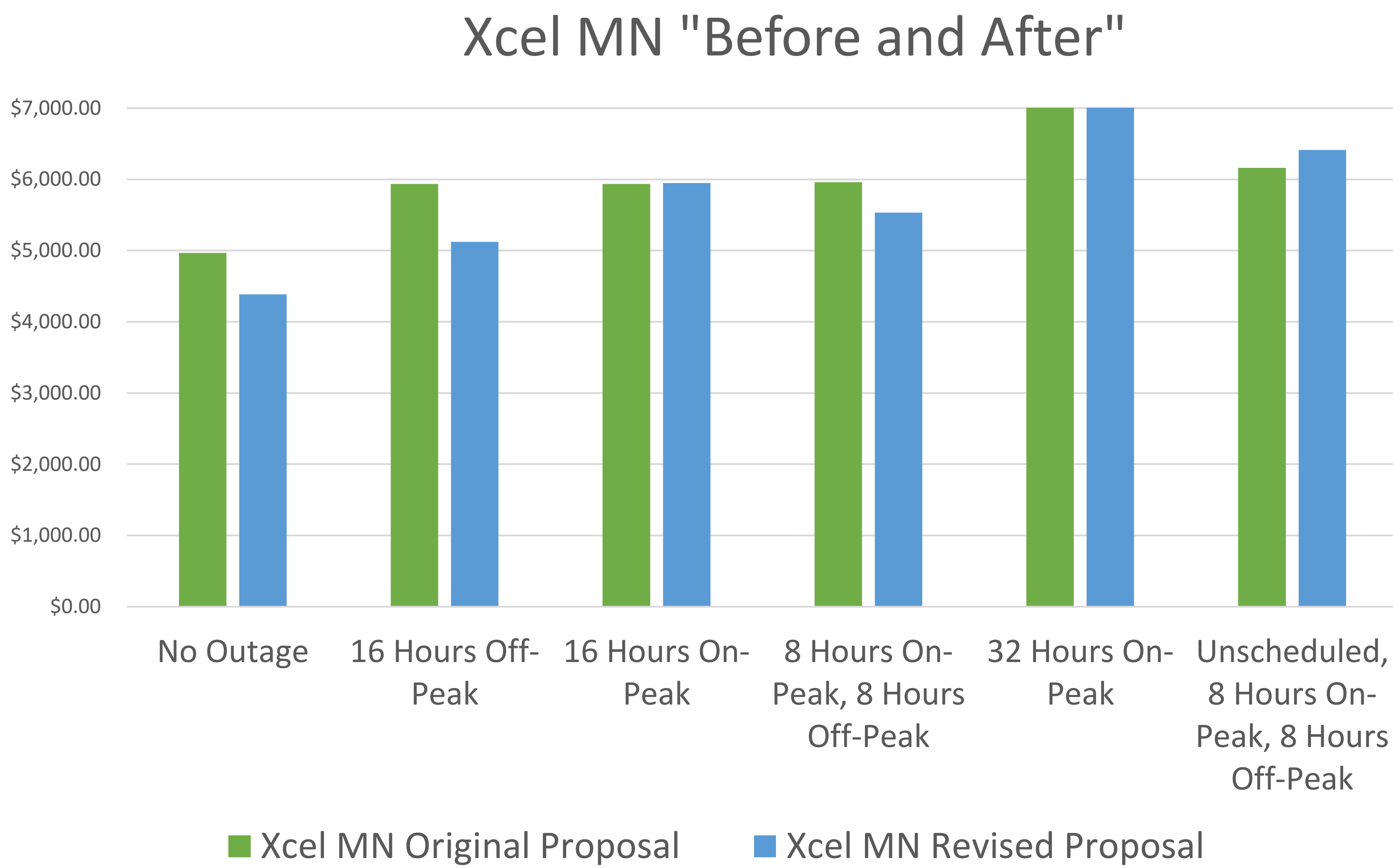
- No outage
- Scheduled, 16-hour off-peak outage
- Scheduled, 16-hour ON-peak outage
- Scheduled, 8-hour ON-peak, 8 hour off-peak outage
- Scheduled, 32-hour ON-peak
- Unscheduled, 8-hour ON-peak, 8-hour off-peak outage

Minnesota Utilities

2 MW Cogeneration – Outage Scenarios
Cost of Standby Service ($) – monthly*

Scenario Description	Minnesota Power	Xcel	Otter Tail Power	Dakota Electric
No Outage	1,007	4,965	1,632	6,594
Scheduled Outage 16 Hrs Off-Peak	2,699	5,934	3,166	20,127
Scheduled Outage 16 Hrs On-Peak	2,699	5,934	4,113	20,127
Scheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	2,699	5,934	3,639	20,127
Scheduled Outage 32 Hrs On-Peak	4,391	7,958	6,593	22,560
Unscheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	20,180	6,160	4,407	20,127

**analysis from August 2016*



Xcel MN "Before and After"
$7,000.00
$6,000.00
$5,000.00
$4,000.00
$3,000.00
$2,000.00
$1,000.00
$0.00
No Outage
16 Hours Off-Peak
16 Hours On-Peak
8 Hours On-Peak, 8 Hours Off-Peak
32 Hours On-Peak
Unscheduled, 8 Hours On-Peak, 8 Hours Off-Peak
Xcel MN Original Proposal
Xcel MN Revised Proposal

Michigan Utilities

2 MW Cogeneration - Outage Scenarios
Cost of Standby Service ($) – monthly*

Scenario Description	Consumers	DTE	UMERC	UPPCO
No Outage	8,300	10,535	0	0
Scheduled Outage 16 Hrs Off-Peak	9,246	11,657	2,218	2,911
Scheduled Outage 16 Hrs On-Peak	11,645	18,653	3,098	3,883
Scheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	11,191	13,405	2,658	3,397
Scheduled Outage 32 Hrs On-Peak	14,833	30,272	6,196	7,766
Unscheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	11,191	17,545	30,536	31,631

**analysis from February 2017*

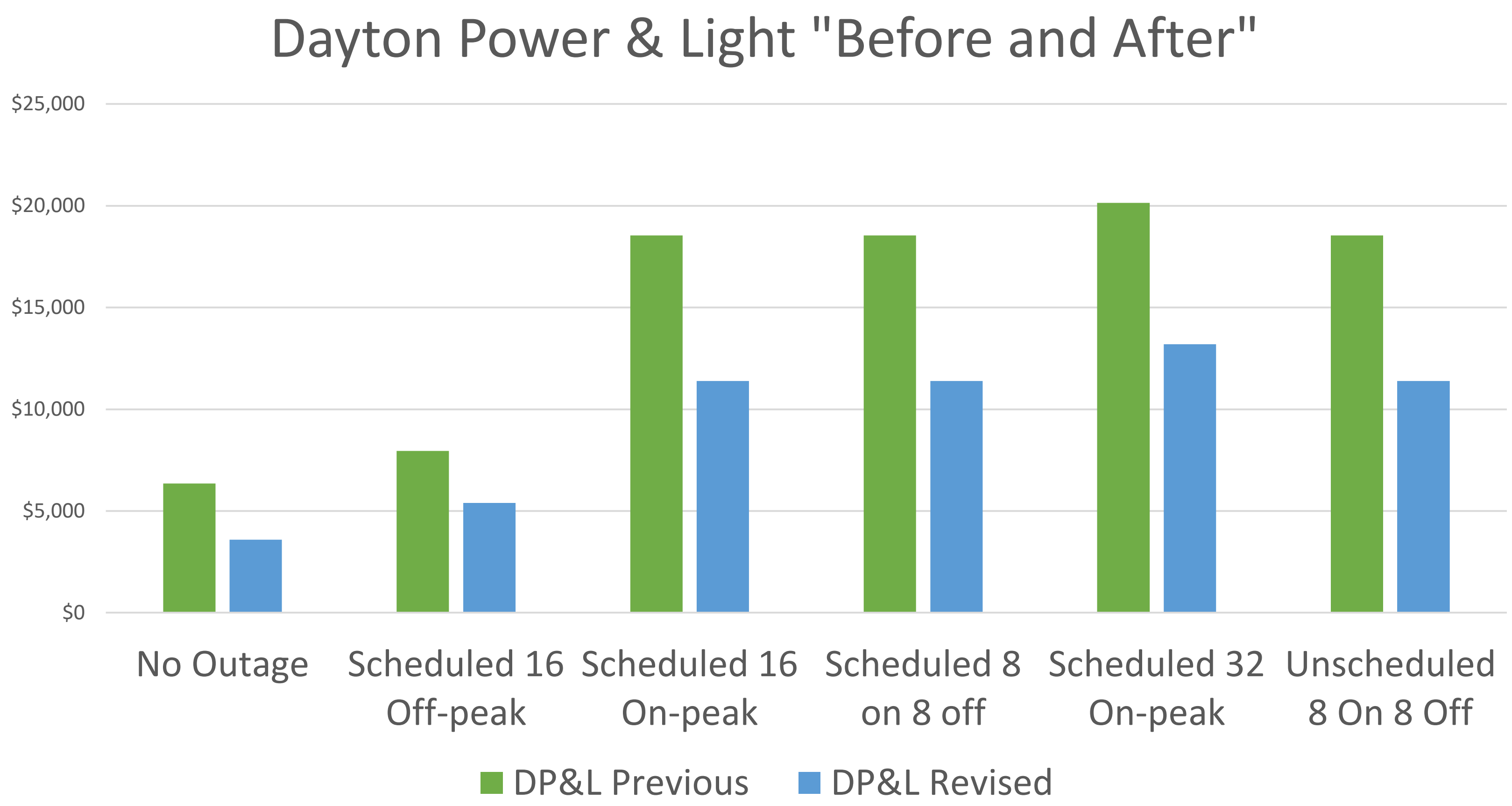
Ohio Utilities

2 MW Cogeneration – Outage Scenarios

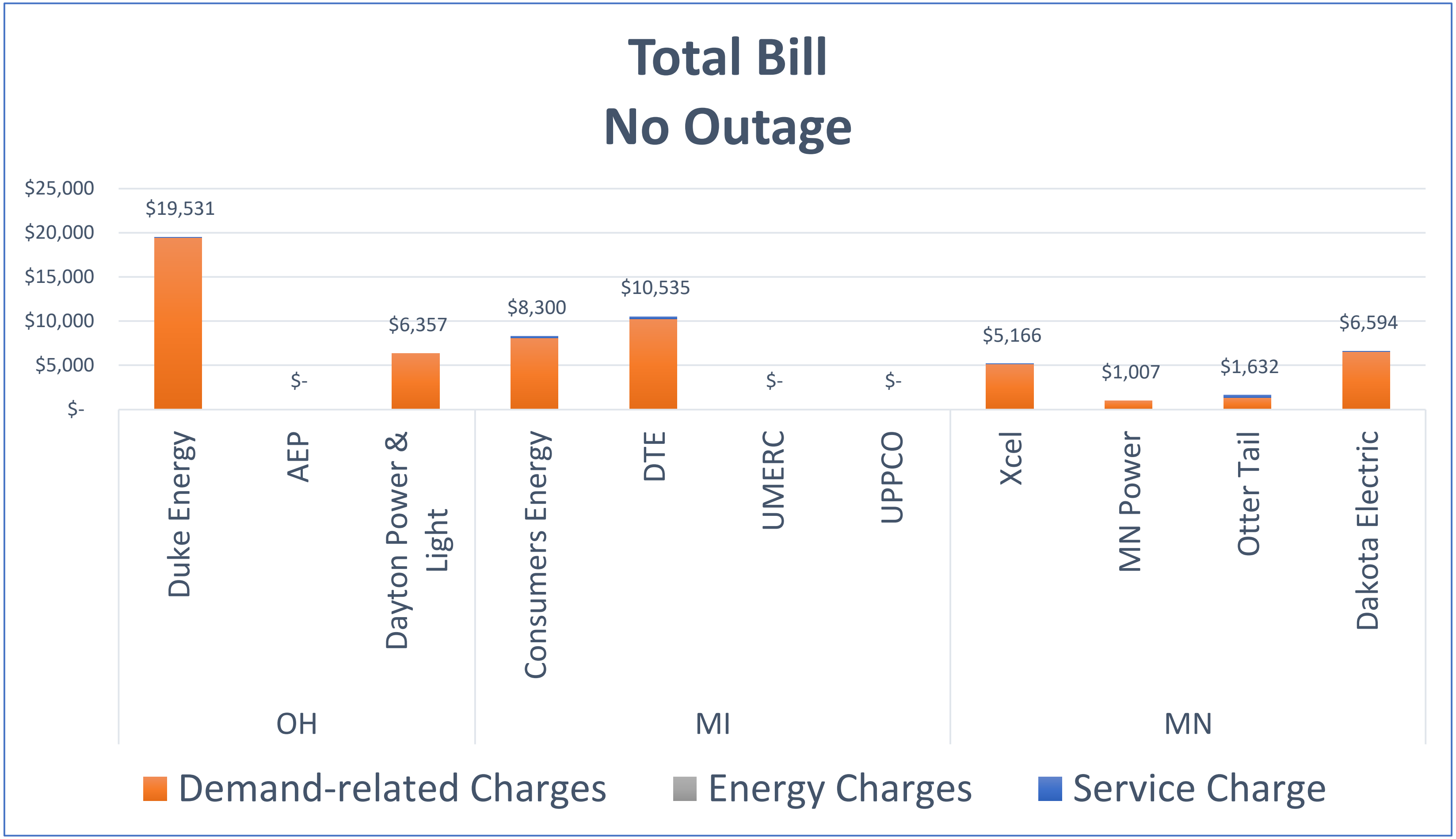
Cost of Standby Service ($) – monthly*

Scenario Description	Duke	AEP Ohio	Dayton Power & Light
No Outage	19,531	0	6357
Scheduled Outage 16 Hrs Off-Peak	21,063	13,120	7952
Scheduled Outage 16 Hrs On-Peak	21,063	22,360	18,547
Scheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	21,063	22,360	18,547
Scheduled Outage 32 Hrs On-Peak	22,661	24,436	20,143
Unscheduled Outage 8 Hrs On-Peak, 8 Hrs Off-Peak	22,011	22,360	18,547

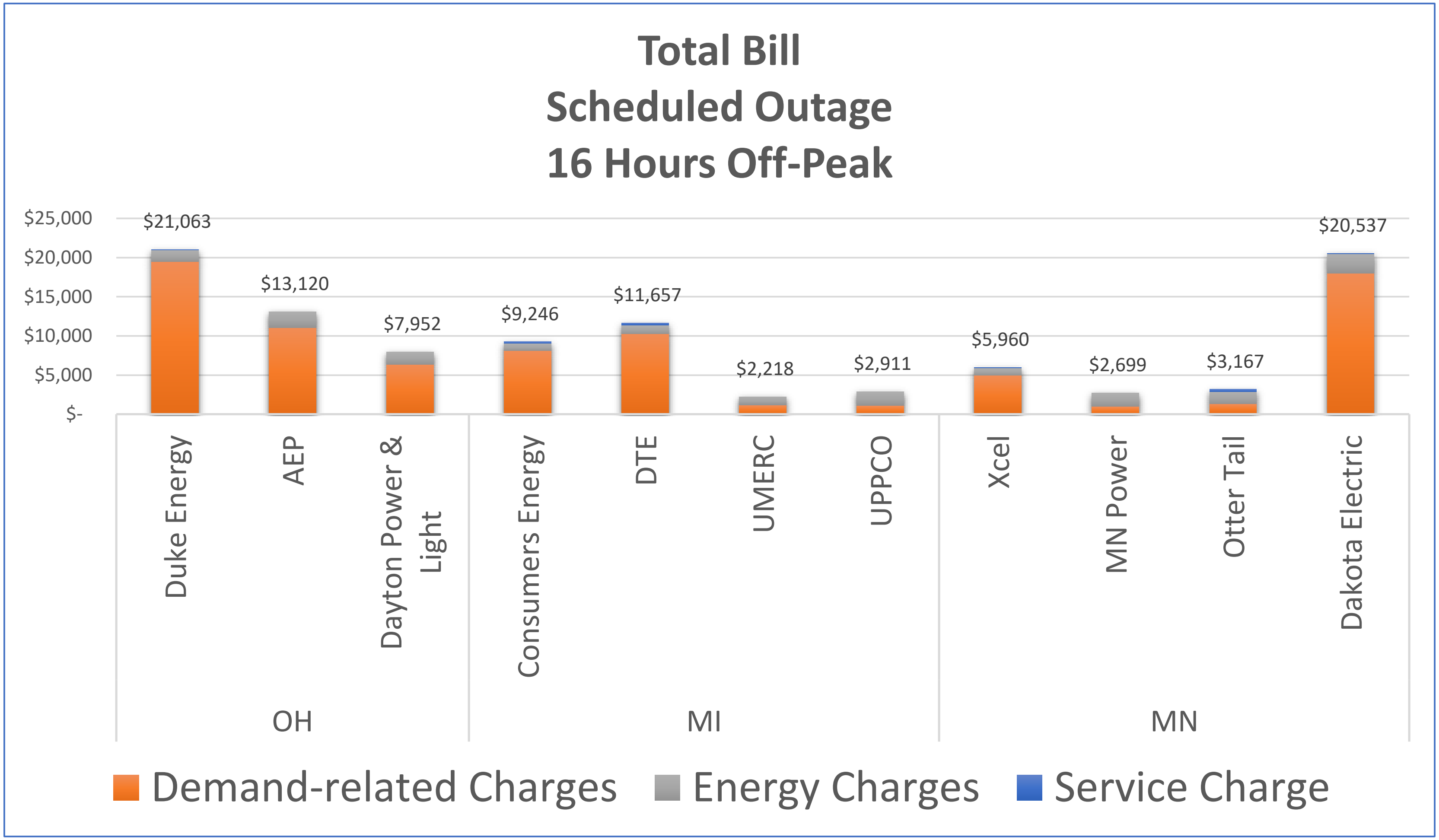
**analysis from August 2017*



Dayton Power & Light "Before and After"
$25,000
$20,000
$15,000
$10,000
$5,000
$0
No Outage
Scheduled 16 Off-peak
Scheduled 16 On-peak
Scheduled 8 on 8 off
Scheduled 32 On-peak
Unscheduled 8 On 8 Off
DP&L Previous
DP&L Revised



Total Bill
No Outage
$25,000
$20,000
$15,000
$10,000
$5,000
$-
$19,531
$-
$6,357
$8,300
$10,535
$-
$-
$5,166
$1,007
$1,632
$6,594
Duke Energy
AEP
Dayton Power & Light
Consumers Energy
DTE
UMERC
UPPCO
Xcel
MN Power
Otter Tail
Dakota Electric
OH
MI
MN
Demand-related Charges
Energy Charges
Service Charge


Total Bill
Scheduled Outage
16 Hours Off-Peak
$25,000
$20,000
$15,000
$10,000
$5,000
$-
$21,063
$13,120
$7,952
$9,246
$11,657
$2,218
$2,911
$5,960
$2,699
$3,167
$20,537
Duke Energy
AEP
Dayton Power & Light
Consumers Energy
DTE
UMERC
UPPCO
Xcel
MN Power
Otter Tail
Dakota Electric
OH
MI
MN
Demand-related Charges
Energy Charges
Service Charge

Benefits of Comparison

- Evaluate transparency, clarity
- Evaluate utility's level of openness and cooperation
- Illustrates incentives in current SBR design
- Outliers jump out and suggest areas for further discussion and investigation regarding <u>fairness</u> and <u>cost justification</u>

“Apples-to-Apples” Applications

- Regulators very interested in “apples to apples” standby rate comparisons
- Economic development interest
- Can be used in general rate case intervention or other proceedings, in conjunction with cost of service analysis
- Customers interested in cogeneration can estimate monthly standby bills and better understand how to interpret the published tariff

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5lakes energy
www.5lakesenergy.com

Rate Design Subcommittee

On Standby or Ready for Prime Time? - CHP Rates & Regulations for a Modern Grid

NARUC Summer Policy Summit

July 15, 2018

Getting Standby Rates Right for a Modern Grid

NARUC Summer Policy Summit, 2018

Scottsdale, Arizona

David Littell
Principal
The Regulatory Assistance Project (RAP)®

Portland, Maine
United States

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raponline.org

Overview

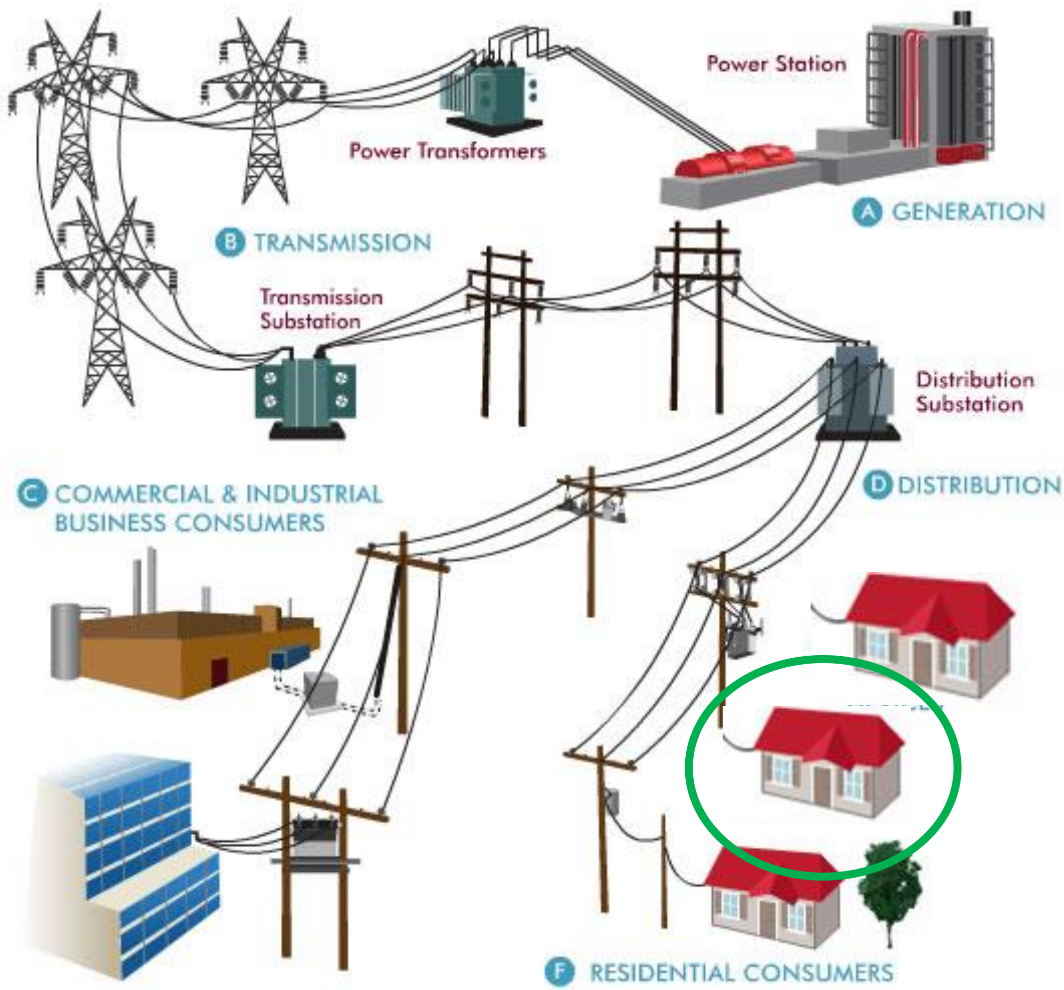
- What is Standby Service?
- Design Considerations and Principles:
  - Fair Compensation
  - Dynamic Efficiency
- Designing Standby Rates Well
- Implications for Microgrid Rate Design

1 What Is Standby Service?

What Is Standby Service?

- Set of electric utility products for customers with on-site, non-emergency generation
- Provides for a utility backstop service
- Standby service terms determine relative economics of:
  - self-provision
  - utility full requirements service &
  - purchasing competitively

Local Distribution Costs

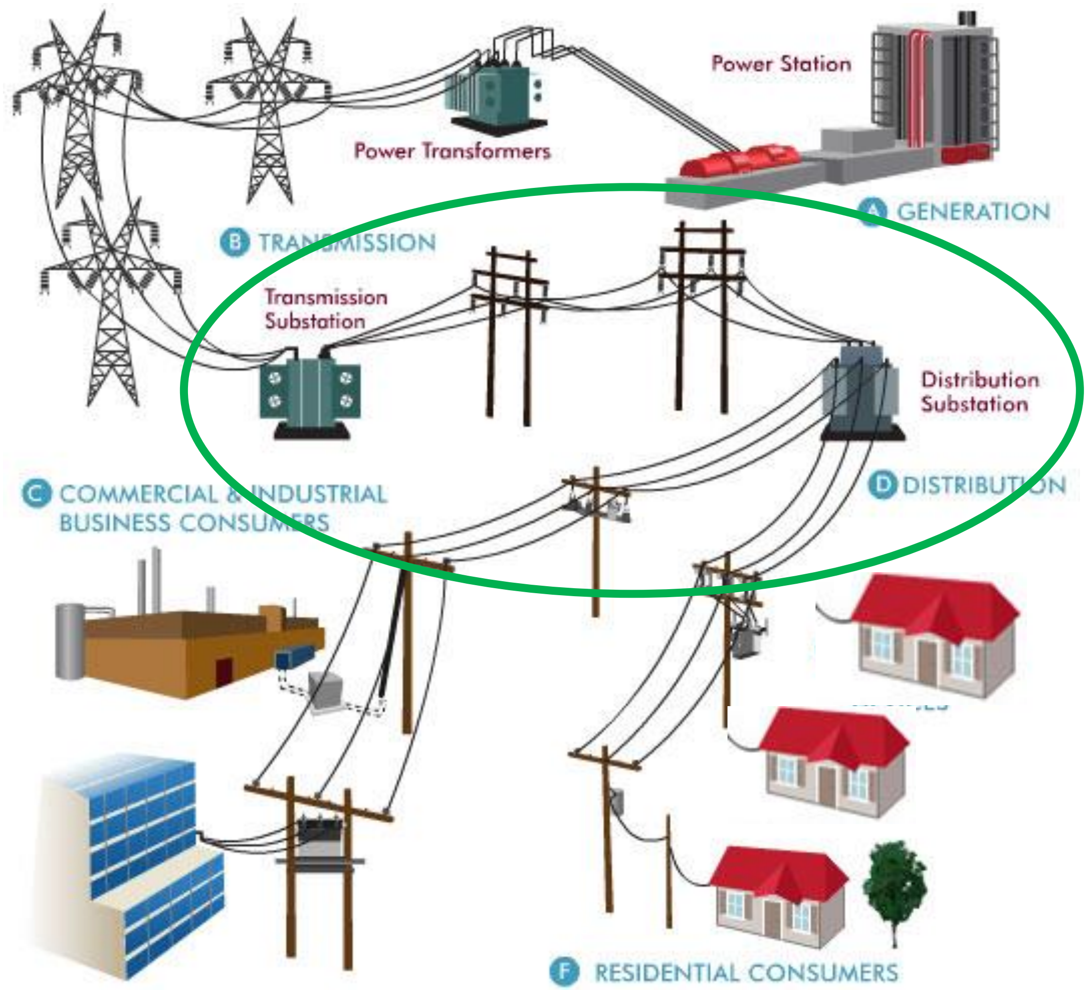


The only distribution costs that are attributable to any particular customer are the meter and service drop, and billing costs.

The transformer must be sized to the combined load of a few customers.

The rest is sized to the combined load of many customers.

Distribution Poles and Wires



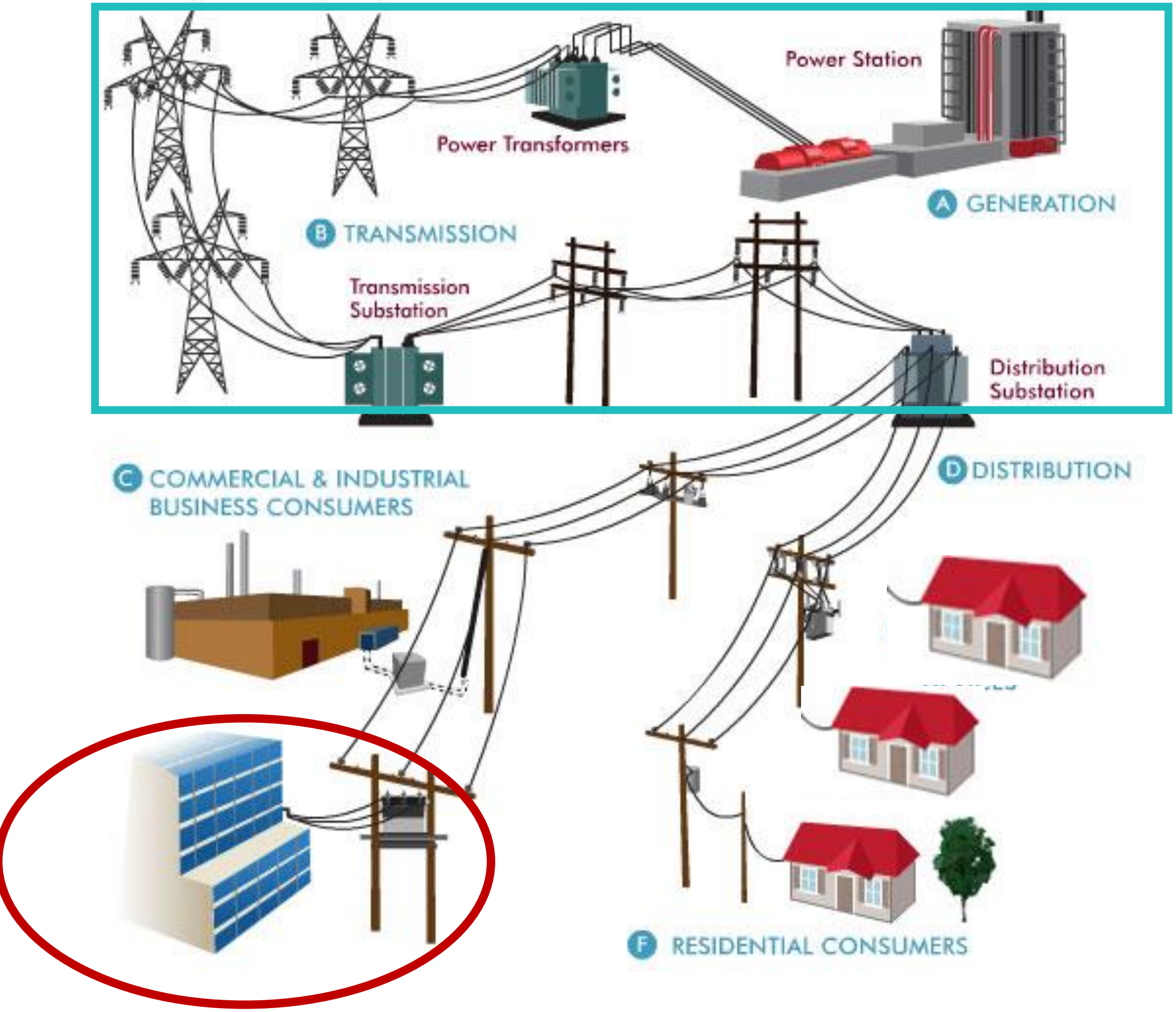
The distribution infrastructure is sized to the combined loads of all customers.

Adding (or losing) a customer does not change these costs.

They are built to deliver electricity (kWh). All customers using them should share in the cost.

If combined peak demand changes, the system design would change.

Recovery of Bulk Power Costs?



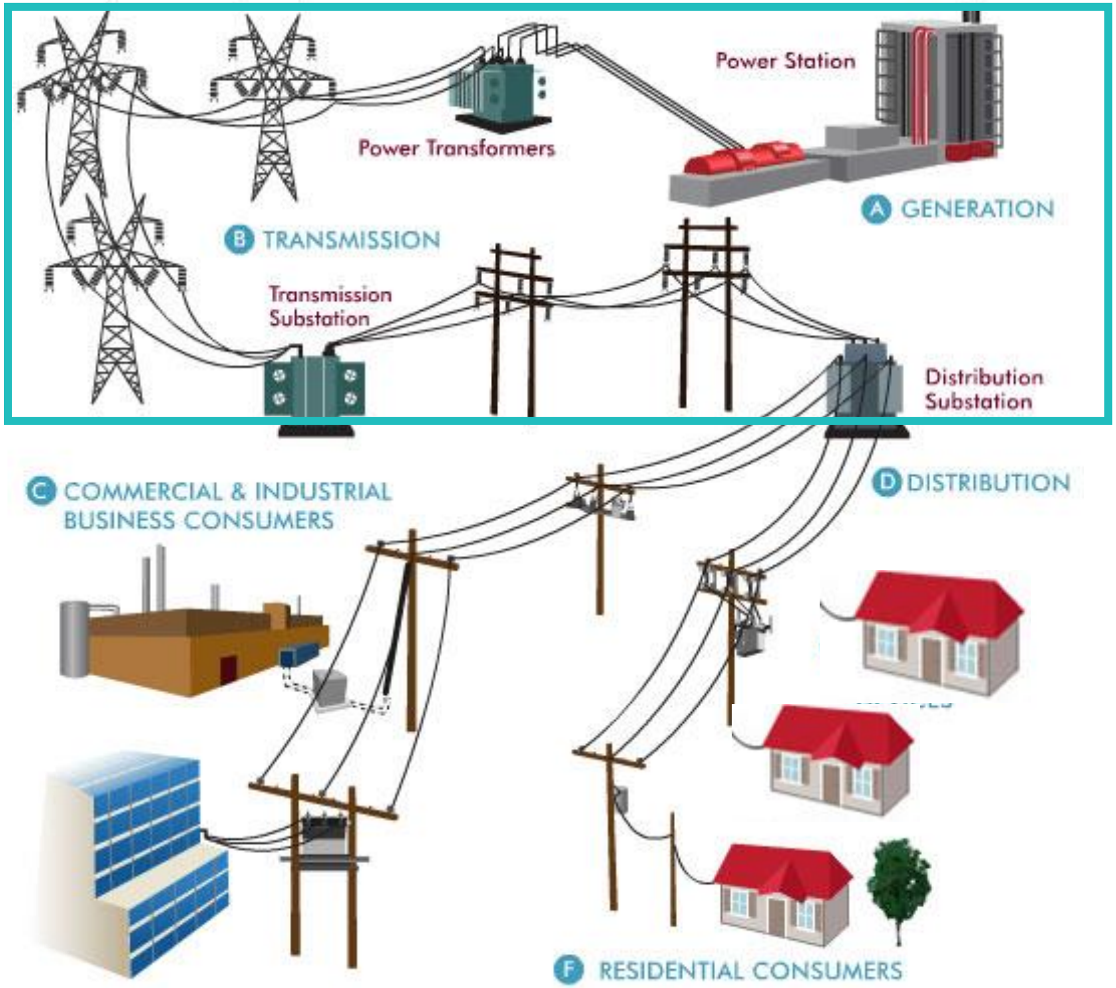
Capacity requirements are driven by peak demand.

Baseload resources are built for energy.

Transmission is mostly associated with remote (baseload and renewable) generating plant.

The size of the bulk system is driven by the combined needs of all customers.

Recovery of Bulk Power Costs?



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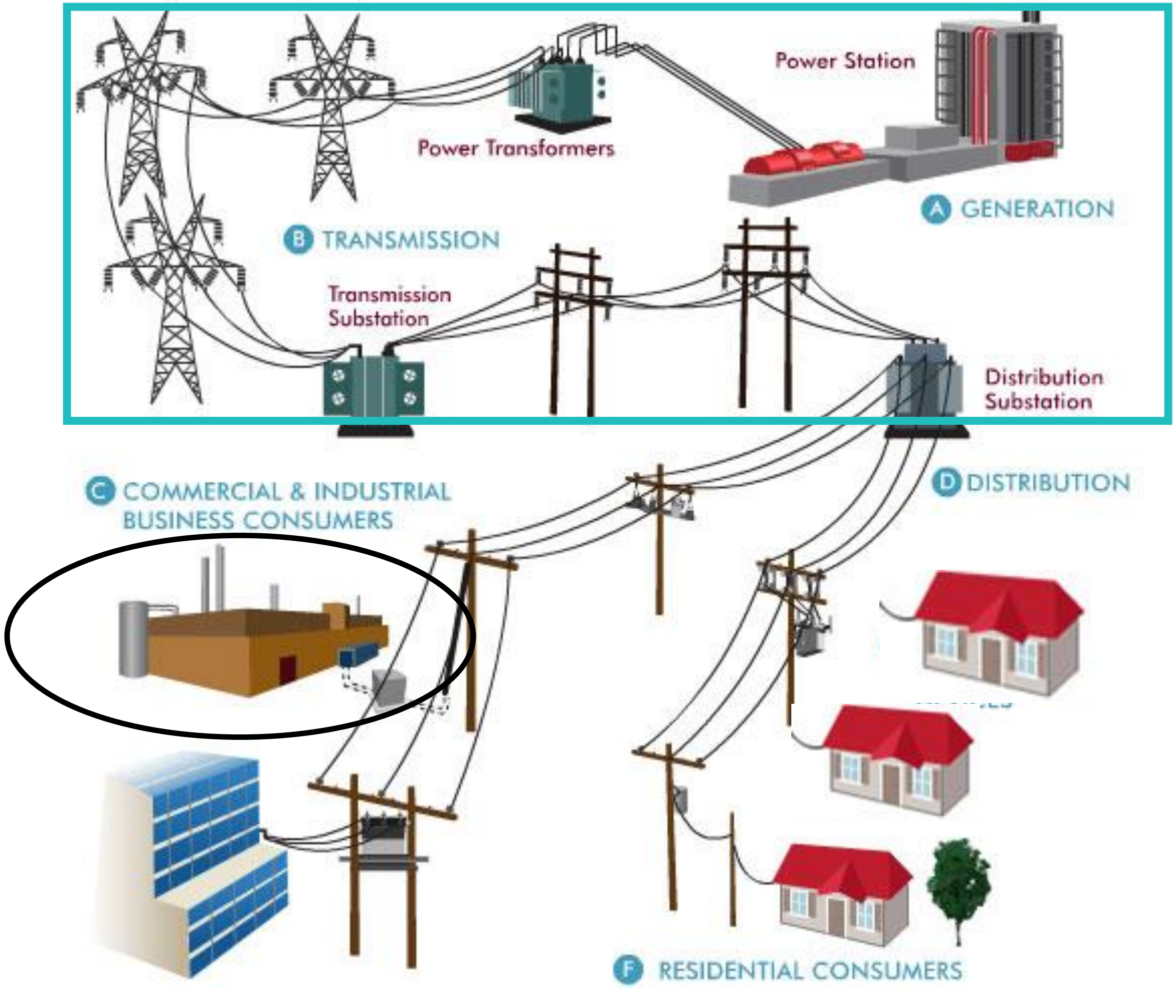
Recovery of Bulk Power Costs?



Capacity requirements are driven by peak demand.

Baseload resources are built for energy.

Transmission is mostly associated with remote (baseload and renewable) generating plant.

The size of the bulk system is driven by the combined needs of all customers.

Individual Customers and the Cost of Service

Standby service considers the components of full requirements service:

- Local distribution service
- Poles and wires
- Bulk power

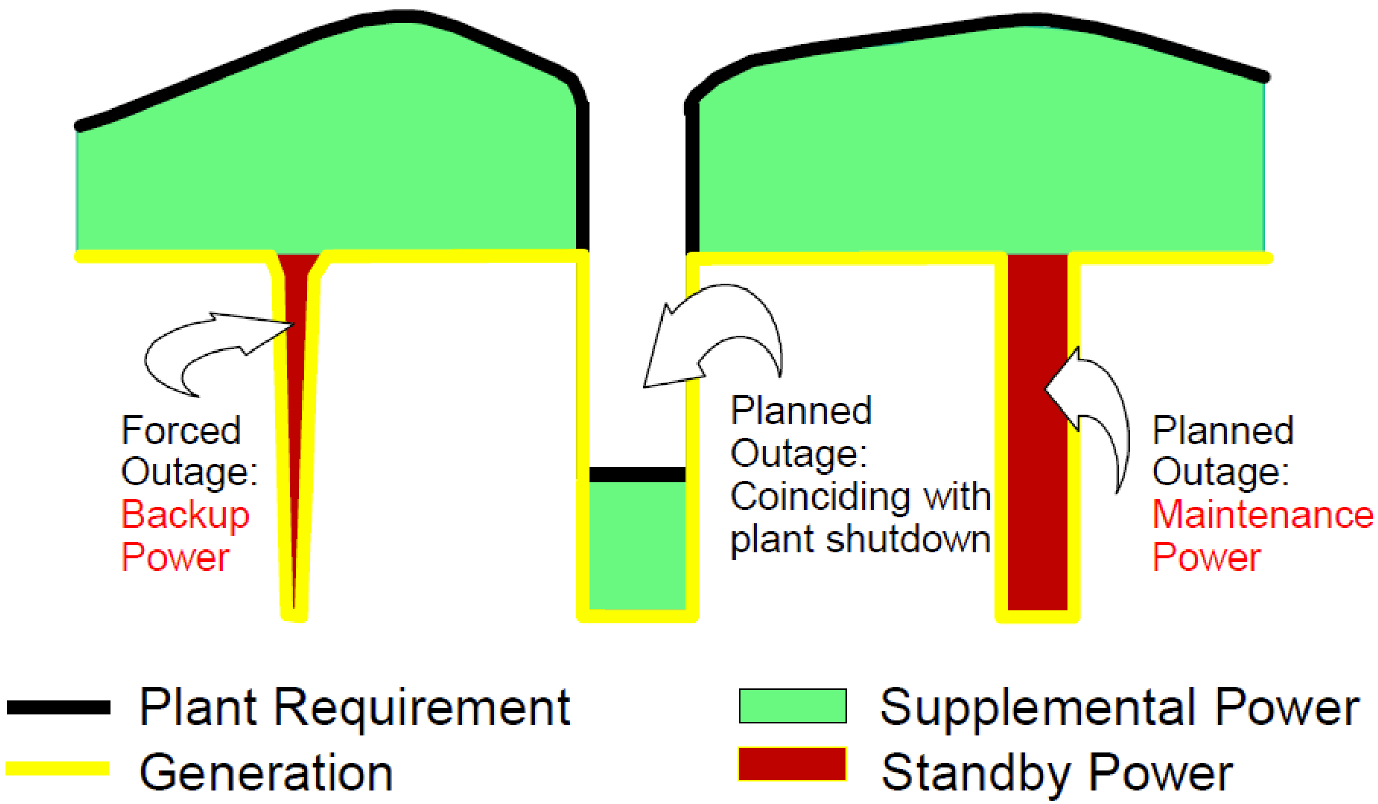
How does the individual customer affect each?

Components of Standby Service (partial requirements service)

- **Backup power** during an unplanned generator outage
- **Maintenance power** during scheduled generator service
- **Economic replacement power** when it costs less than on-site generation
- **Supplemental power** when on-site generation does not meet all of customers' needs
- **Delivery service**

15 MW gas turbine generator set at Michigan State Univ., Solar Turbines Inc.

Example of a Self-Generator's Purchase Requirements



2 Design Considerations and Principles

Traditional Utility Perspective

- Obligation to serve means standing ready to provide backup power when generator is not producing
- Utility maintains generation reserves and T&D facilities to do that, at a cost
- Failure to recover these costs from customer-generators results in a subsidy by other customers (or loss to utility)
- Looks at costs from utility perspective and does not recognize benefits to grid system

“Cost Causer Pays” for Standby Service cuts in different directions

- Coincident outages are likely drivers of standby costs, not sum of individual customers’ generators
- Use of standby service may not coincide with peak demand of utility facility providing service
- Individual lines and feeders may have substantial excess capacity during coincident outages (so no incremental cost), or may be fully utilized and facing upgrades in near future (and this changes over time)

Unlike Traditional Service, There Are Grid Benefits

- Where delivery system is facing upgrades:
  - Distributed generation may allow deferrals, in which case benefits may offset costs
  - In some cases, these benefits may exceed costs
- Real net costs may be negligible, negative or unknown
- In some states, public policy preference for more efficient or less polluting energy sources is recognized as a benefit
- Customers with standby service may provide demand reductions and even demand response

Design Considerations for Standby Rates

- Customer's savings per kWh produced on-site compared to buying from grid
- Reasonable balance between variable charges vs. contract demand or reservation charges
- Encouraging customer-generators to use electric service most efficiently and minimize costs imposed on electric system
- Providing opportunities for customer-generators to avoid charges when not taking service

14 MW biomass system, courtesy of MAN Diesel & Turbo North America, Inc.

More Design Considerations

- Load diversity - Generators won't all fail at same time or during system peak
  - Shared T&D facilities are designed to meet demand by a pool of customers, not a single customer's needs
  - Includes assessing CHP and PV production and failure profiles in aggregate
- Demand charges
  - Daily as-used demand charges for backup power
  - On-peak vs. off-peak demand
- Opportunities for customer-generators to buy backup power at market prices and avoid utility reservation charge for generation service
- Option for customer demand response or storage to mitigate all or a portion of backup charges

Goals in Standby Rate Design

- How can standby rates be designed that:
  - Incentivize low forced outage rates?
  - Encourage scheduled outages during off-peak periods?
  - Encourage shared capacity?

4 Best Practices

Standby Rates Best Practices: Allocation of Utility Costs

- Generation, transmission, and distribution charges can be unbundled
- Generation reservation demand charges based on utility's cost and forced outage rate of customers' generators on utility's system
- Higher-voltage delivery charges should recognize load diversity

Elements Appearing in Some Tariffs

- capacity levels and demand ratchets
- scheduled versus unscheduled use of power
- time-varying rates
- metering and billing
- minimum monthly charges
- DG compensation for generation & ancillary services to grid
- generator types or size provisions
- liability and insurance requirements
- dispute resolution
- provisions specific to wires-only companies

Interesting Tariff Elements

- Shared distribution facilities charge (e.g., substations and transmission facilities)
  - based on 15 minute demand on-peak, no annual ratchet
- Local distribution charge (e.g., transformers and local lines)
  - based on average of 2 highest non-peak demands in 12 months
  - Minimum charge is baseline but can be reduced with load curtailment plan for outages or with EE plans

More Elements

- Supplemental reserves
  - Tariff provides self-supply options including an option for an approved load reduction plan
- Unscheduled outages
  - based on real time prices
- Scheduled maintenance, economic replacement and unscheduled. outage service
  - Based on daily demand

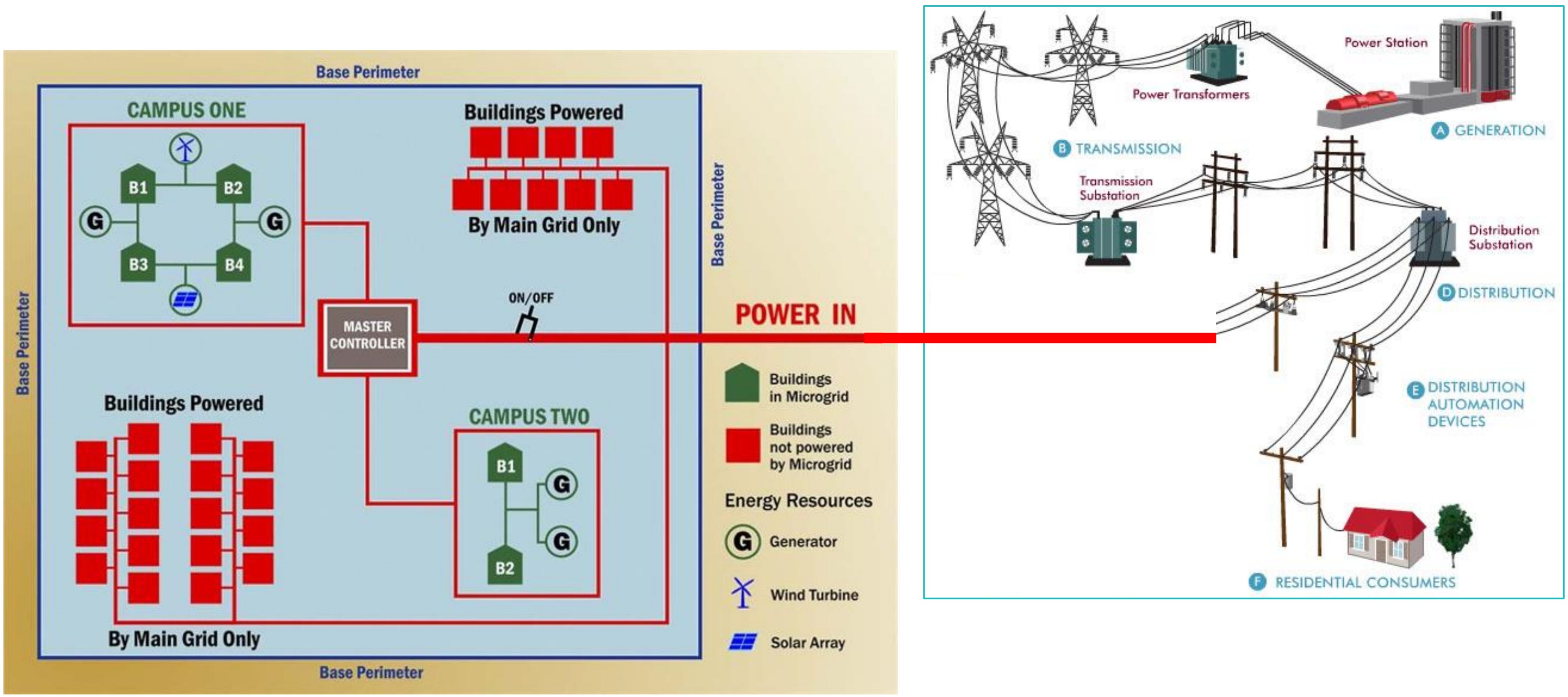
Standby Rates: Best Practices

- Appropriate incentives
  - Pro-rated daily demand charges
  - Schedule maintenance with discounted daily maintenance demand charges
- Customer options
  - Interruptible standby service option
  - Customers should be able to procure standby service from the open market

5 Implications for Microgrid Rate Design

Are standby rates appropriate for microgrids - or for distributed generation plus storage users?

Is a Microgrid Different?



Utility's Costs for Microgrid

- Engineering studies
- Distribution system upgrades
  - Switching gear
  - Operational controls
  - Communications/IT (if any)
- DERs owned by utility (if any)

Customer or Third-party Microgrids

In 2017

46%

of new microgrid projects were third-party owned

New Microgrid Rate Design Considerations

All the same considerations as above, plus:

- If a microgrid provides community benefits, should non-connected customers who may benefit bear a portion of costs?
- Should macrogrid (D) operator pay microgrid owner for services on an as-procured basis, and then recover those costs from ratepayers?

About RAP

The Regulatory Assistance Project (RAP)® is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future.

Learn more about our work at raponline.org

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The Power of Collaboration on CHP

How Utility Ownership of CHP at Customer Sites Unlocks Significant Untapped Value for All Customers

Lowest Levelized Costs, Reduced Grid Losses, Deferral of T&D Investment, Greater Electric & Thermal Resiliency, Foundation for Microgrid Development, Lower Emissions & Water Use, Economic & Community Development, Enhanced Industrial Competitiveness & Jobs Growth

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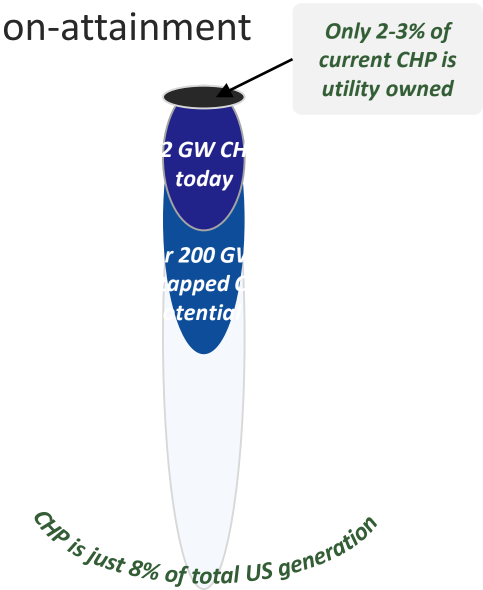
NARUC Summer Policy Summit

Introduction / Basis for Today’s Discussion

CHP is an invaluable natural efficiency resource – but is <u>vastly underutilized</u> in US

- Well applied CHP is the **most efficient method of generating power**; **<u>doubling</u> current grid efficiency** – unloading grid, reducing T&D losses & investment
- CHP is based on established technology with **lower investment risk** – faster planning & development in smaller MW sizes – and can be developed in any air quality district – even non-attainment
- CHP significantly **reduces emissions and water use**
- CHP supplies energy at point of use **enhancing resiliency** and establishing foundation for **microgrid developments**
- CHP provides **many other uniquely valuable local benefits**, providing for economic/industrial development, jobs and expansion of local tax base.



* Source: DOE/ICF CHP Deployment Study March 2016

Why is CHP so underutilized?

- Are there ways to increase the deployment of this national efficiency resource to benefit our 21st century Grid and all parties?

Why is CHP So Much More Efficient than Combined Cycle?

- Both use Gas Turbine Engines around 38% efficient & HRSG for steam production
- With CHP most waste heat can be beneficially used locally where 70% of energy in steam lost in CC condensing cycle
- CHP serves Load at point of use avoiding T&D losses avg 6-8%. Grid losses (I^2R) can double in peak periods
- Can operate at 94-96% capacity factor whereas US Fleet of NGCC averages ~ 56% CF in 2016-17
- ~ 90% of Power Outages are on Distribution system (last mile)– CHP generates locally providing enhanced resiliency

Note: Water vapor from the 1160 MW combined cycle power plant in Minooka, Illinois – plant is *≈50% HHV efficient, meaning half of fuel input is lost as waste heat to atmosphere –water vapor produced from waste heat from cooling towers & stacks is highly visible on cold days*

Now a Quick Look at *Traditional View* of CHP in Utility Industry

- Many Utilities generally view CHP as a **competitive, customer-owned resource . . .**
- Support it intellectually, but prefer *not in my back yard*
- Few evaluate CHP in IRPs along with other resources
- Thus, **typically customers install it 'behind the meter'** having to overcome **well documented hurdles – thousands of excellent sites are never developed**
- When CHP is installed behind the meter . . .
- **Utility loses load & revenue** - recovers standby charges but not enough to recover all base revenue
- Eventually **lost fixed costs are spread** to customers

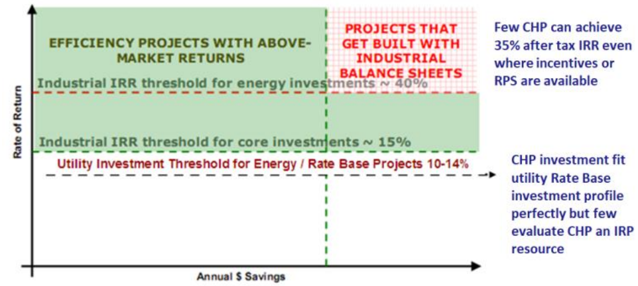
(note: generic example provided in appendix to slides)

Hurdles to Increased Use of CHP

- Financial uncertainty
- CHP cost and performance uncertainty
- Regulatory uncertainty
- Electric utility uncertainty
  - Utility goal is affordable and reliable power
  - Generally neutral to negative on CHP
  - CHP represents a loss of revenue to the utility and can result in the deferral of investment
  - This often results in unfavorable tariffs, drawn out interconnect and other roadblocks to CHP

Institute for Industrial Productivity

Customers require premium IRR for non-core investment



Notes: Hurdles to customer owned CHP are well documented. Examples by Institute for Industrial Productivity, 2014. Investment /payback chart source: Recycled Energy

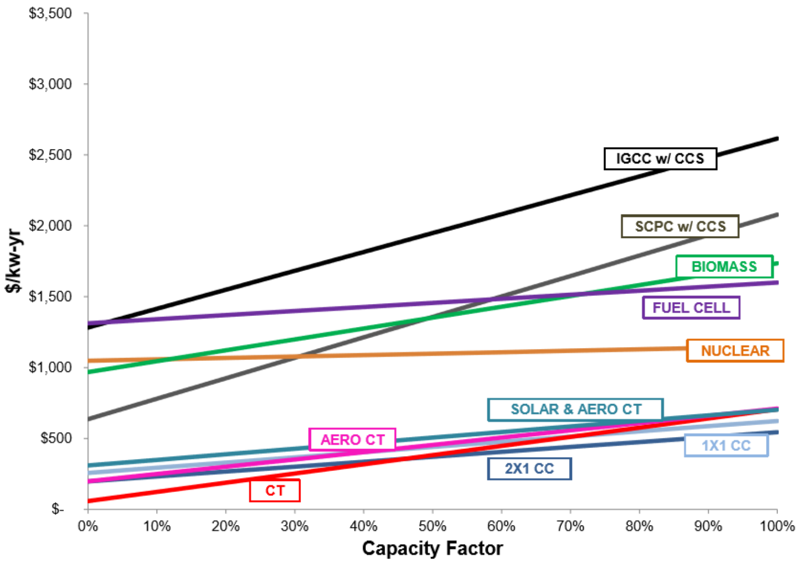
What Happens when CHP is Evaluated as a Supply Resource in IRPs?
In front of the meter (IFOM) . . . Instead of behind the meter (BTM)

"Hold on, where's the forest again?"

Levelized Busbar Costs from IRPs

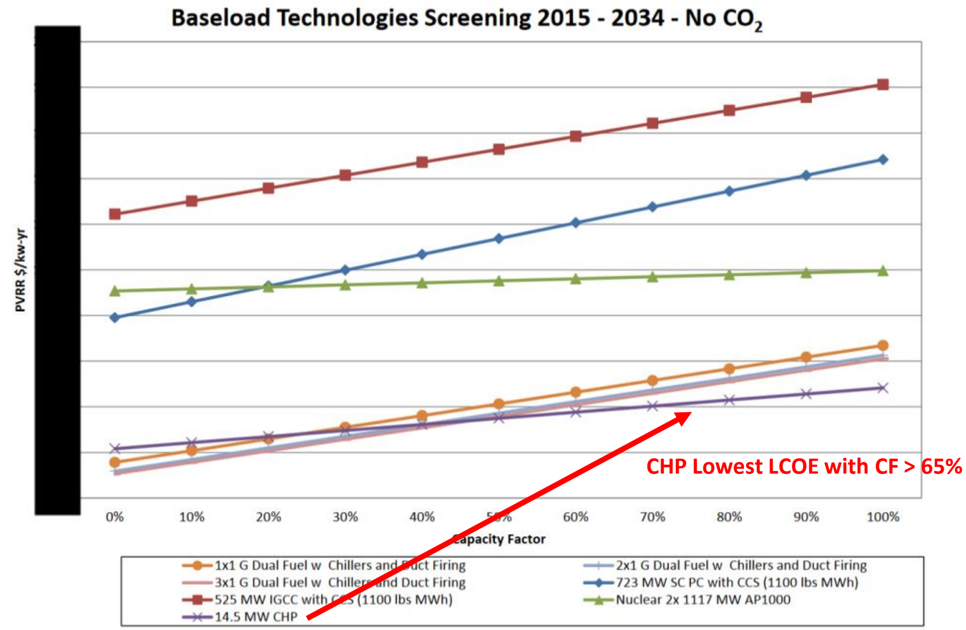
Dominion Energy 2016 IRP public version

Figure 5.2.1 - Dispatchable Levelized Busbar Costs (2023 COD)



CHP Not Evaluated - NGCC lowest LCOE

Duke Energy Indiana 2015 IRP public version

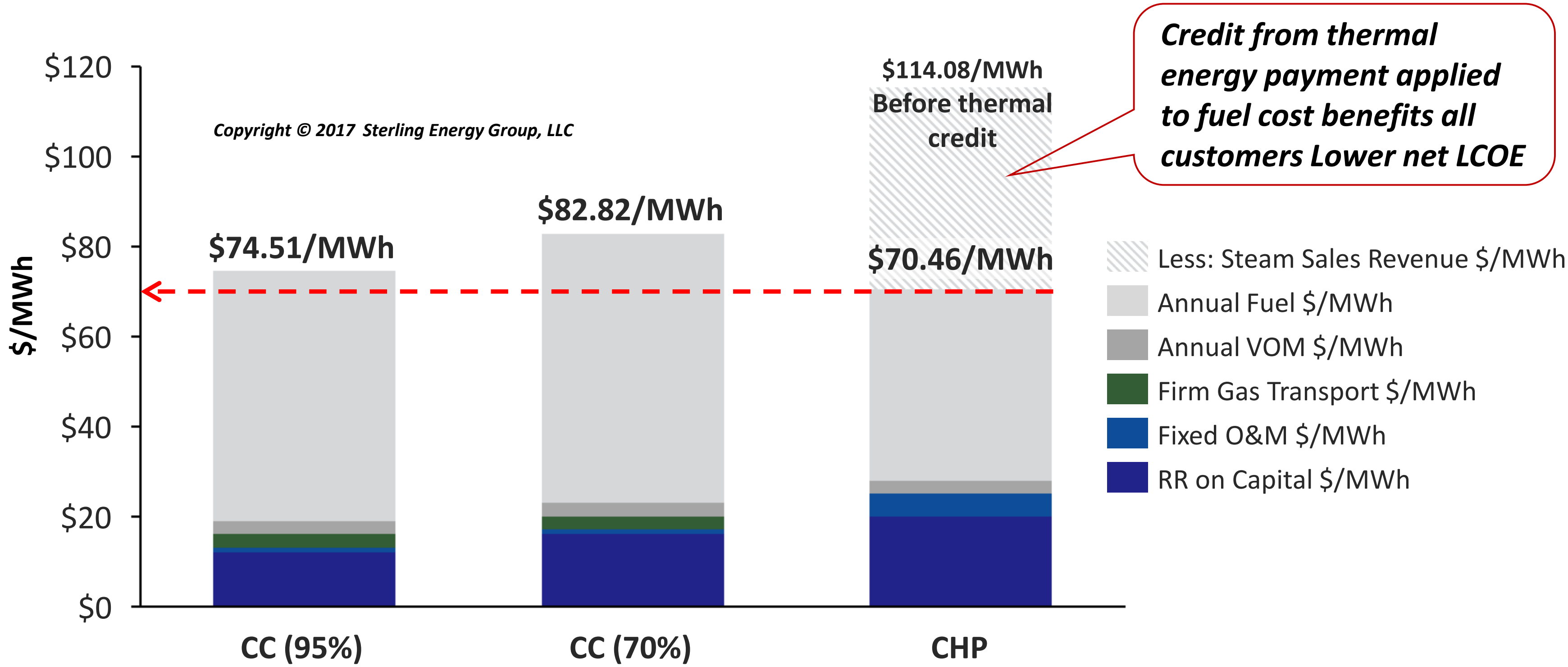


CHP Evaluated - with thermal credit applied to fuel

Source: Public published versions of IRPs for Dominion Energy and Duke Energy Indiana

A Closer Look: Levelized Cost of Energy Comparison (life cycle)

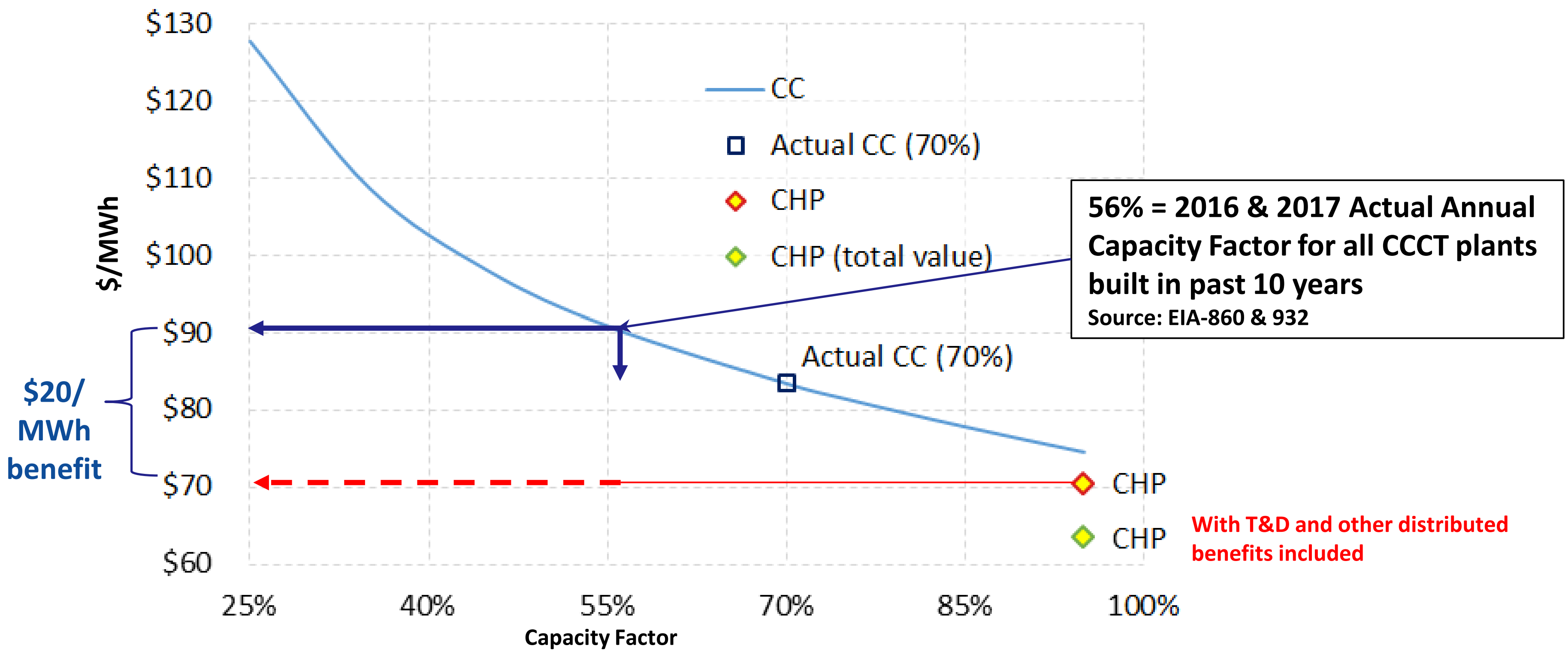
800 MW Advanced CCCT vs 21 MW CHP - with thermal credit to fuel



Notes: LCOE calculations are based upon standard IRP life cycle methodology, for cost of capital, depreciation F & V O&M taken from several published Utility IRP data and cost to construct CCCT and actual CHP plants costs. Capacity factors for CC are 95% and 70% with CHP 95%

A Closer Look - Levelized Cost of Energy Comparison

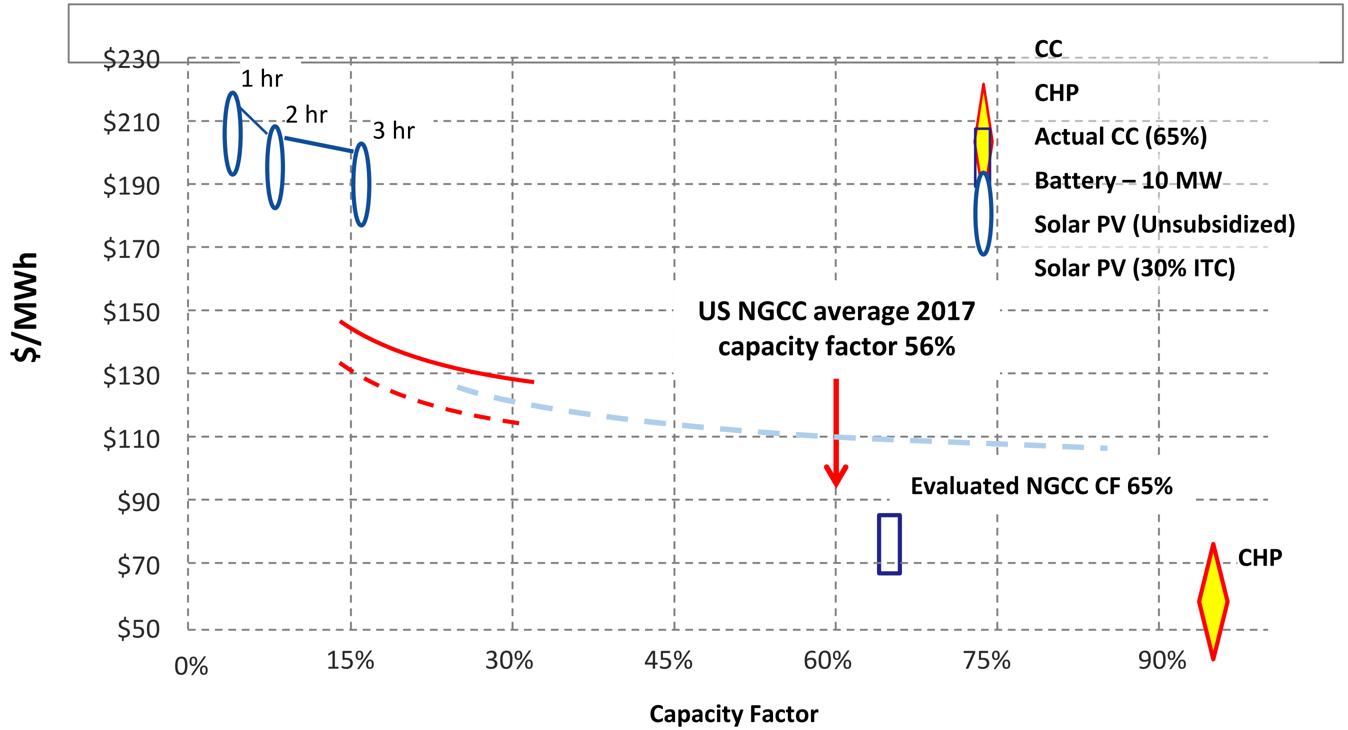
800 MW Advanced CCCT vs 21 MW CHP - with thermal credit to fuel



Notes: LCOE calculations are based upon standard IRP life cycle methodology, for cost of capital, depreciation F & V O&M taken from actual Utility IRP data and cost to construct CCCT and CHP plants. Capacity factors for CC are 95% and 70% with CHP 95% Actual CCCT capacity factor of 56.3% from EIA-860 for 2015

LCOE of Today's Key Resources by Capacity Factor

Busbar costs: Does not value T&D, Resilience and Local Benefits of the DERs shown

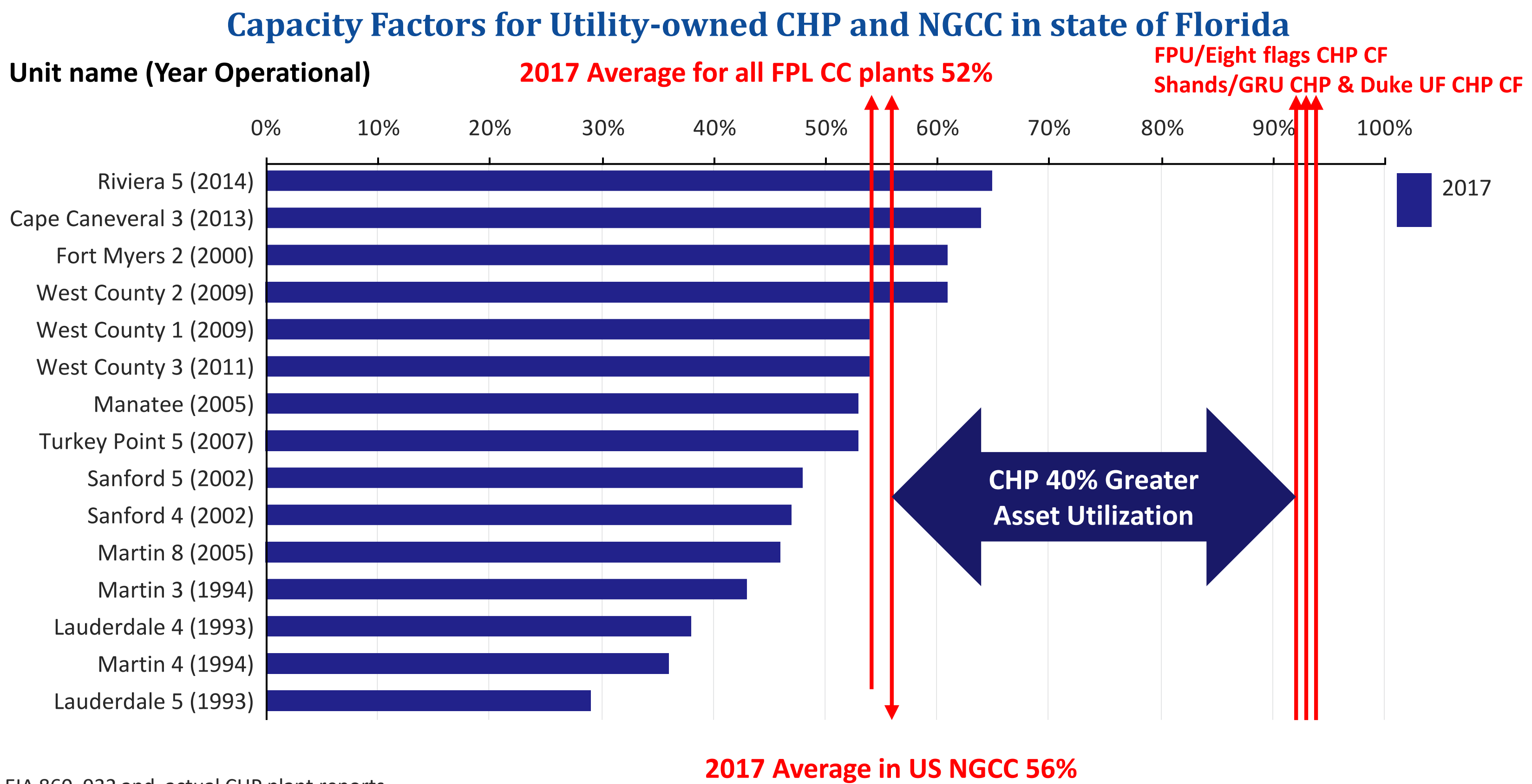


All resources shown are routinely evaluated in current IRP & Planning Studies, Except CHP

Source: PV and Storage based on Lazard LCOE and LCOS, Fall 2017 report & forecasts. NGCC and CHP developed by SEG using actual utility IRP cases and fuel forecast

Importance of Capacity Factor - Utilization of rate based investment

3 Utility owned CHP's operated 40% higher Capacity factor than NGCC in Florida



Source: EIA 860, 932 and actual CHP plant reports

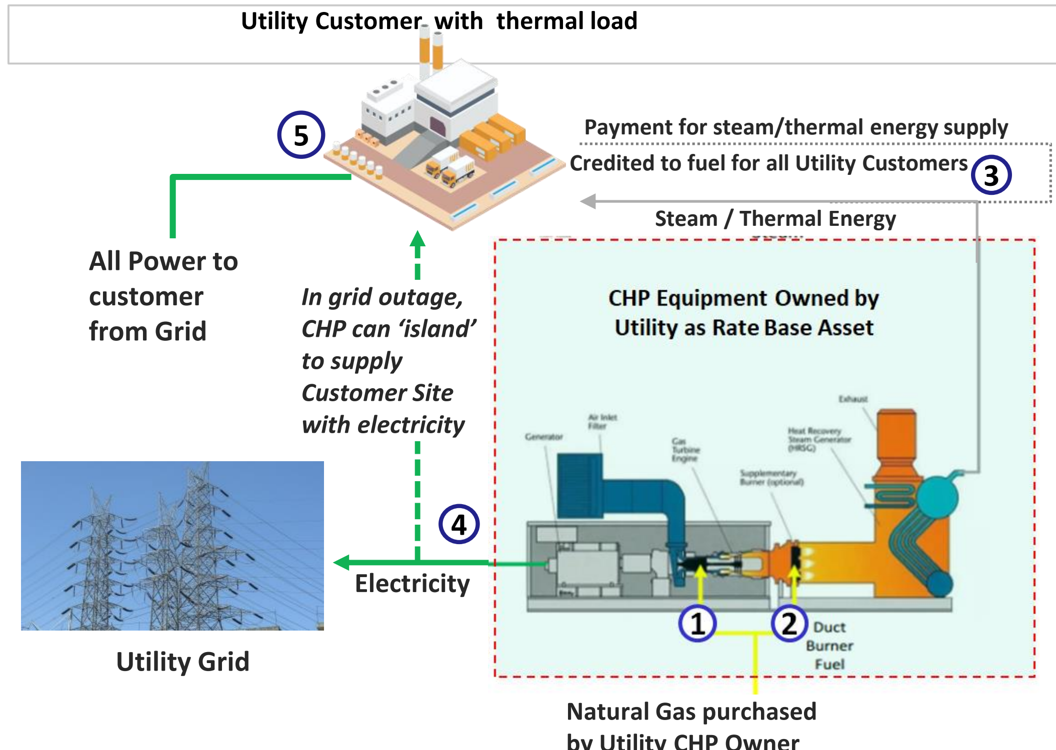
Structure for Utility-Owned CHP is Straightforward

Meter Points for Utility-owned CHP

1. Fuel to Gas Turbine – by utility
2. Fuel to Duct Burner – by customer
3. Steam/Thermal to host - under long term agreement
4. Electricity produced by CHP to Grid
5. Electricity to Customer from Grid

   Utility continues to serve
   Customer Electric Load at meter

Utility-owned CHP Structure – in front of meter

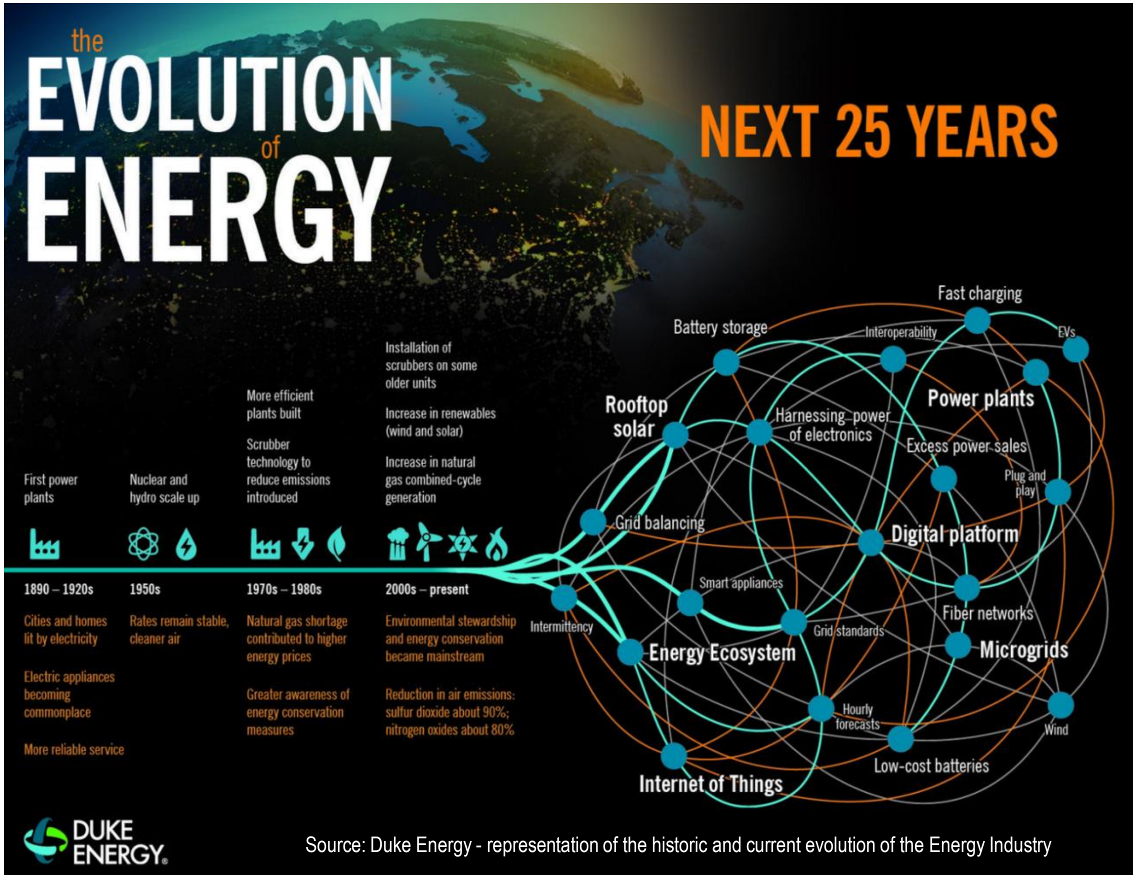


In Case You Haven't Noticed, Our Industry is Changing . . .

Rapid growth of Variable RE will accelerate, but **still dependent upon natural gas beyond mid century for half of Total MWh**

#1 Industry issue on latest survey . . . **Increasing System Resiliency**

Faster, smarter, cleaner, more resilient, & closer to customer requires ***Rethinking how we plan and value distributed resources***



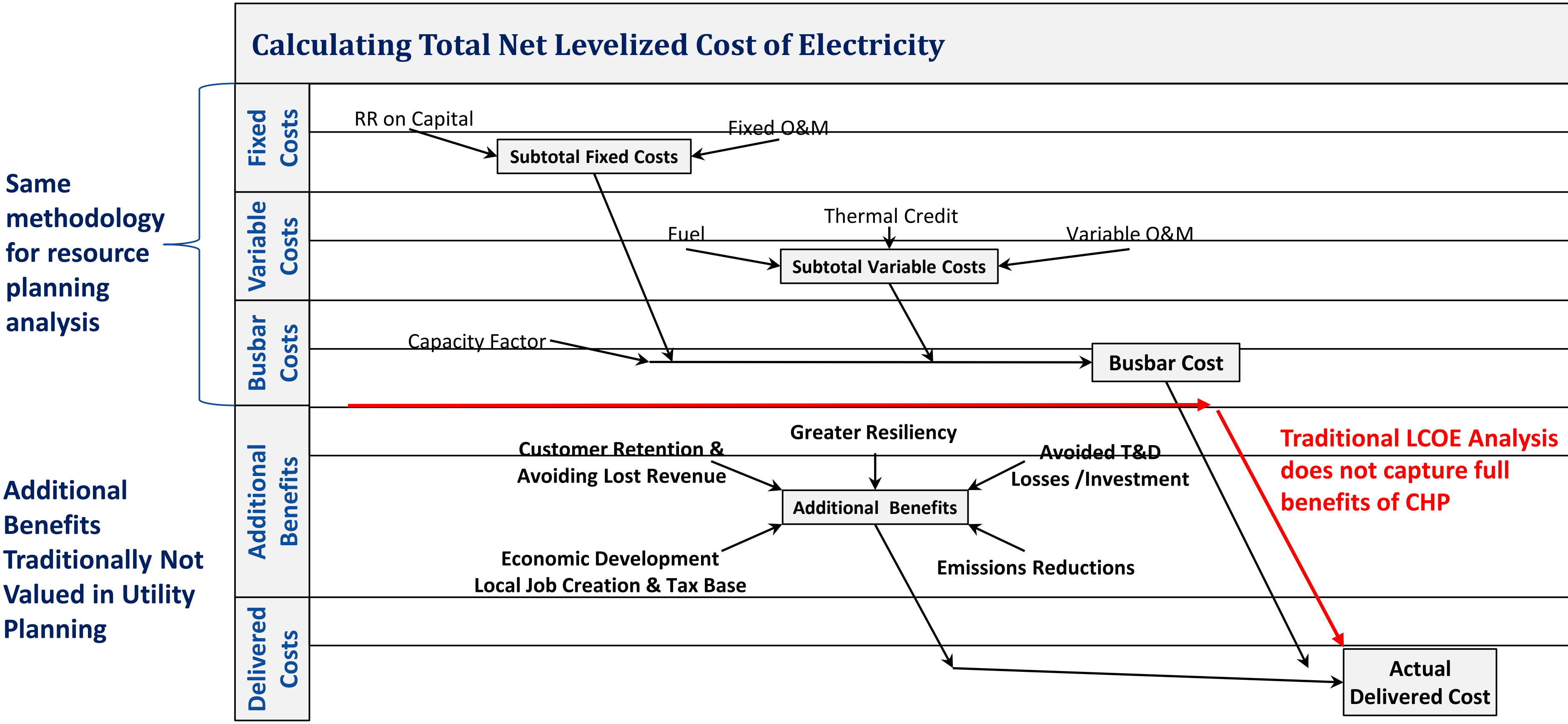
Distributed Benefits and how Should they be Valued?

Rapid growth of distributed generation and grid edge solutions make it is essential for Utilities to <u>rethink & value the (non-traditional) benefits from CHP and other DER</u> that are available on both sides of the meter – not evaluated in busbar analysis

From a societal perspective, <u>as many benefits and costs as possible should be monetized so the net benefits derived are all-inclusive to reflect the utility's and its customers' interests as well as those of all economic sectors and all citizens</u>.

Source: EPRI, the Integrated Grid, a Benefit – Cost Framework, Final Report

Comparing Traditional Busbar costs vs Total Benefits of CHP



Bottom line: Traditional Hurdles to CHP Evaporate with Collaboration

Investment

Utility makes investment at 10-12% ROE vs 30+% after tax IRR required by industrials for non-core asset

CHP/microgrid is a core asset for utility to own/operate

Risk

Utility has no fuel / spark spread risk

Utility is familiar with technology, O&M of turbines

Builds capacity in smaller, cleaner increments

Interconnections

Utility handles both sides of electric, fuel connections

No 'policy' conflict

Can provide microgrid / islanding for critical customers

Tariffs

No standby or backup tariffs required

No recovery mechanism or incentives required

Greater CHP Development

leads to . . .

Utility

- Makes Low risk rate-based investment
- Gets least-cost, base load capacity
- No lost revenue
- Reduced T&D losses / improved grid reliability
- Supports microgrid development

Host

- Gets modernized, super-efficient thermal capacity
- Lower energy costs
- No investment or O&M risks
- Greater resiliency in thermal & electric supply

Community

- Jobs and local tax base growth
- Economic development
- 50% greater efficiency means less emissions and related benefits locally and nationally

Case Reviews – Recent Utility Owned CHP Projects

- Florida Public Utilities / Chesapeake Utilities 22 MW CHP at Rayonier Advanced Materials Amelia, Island Florida (operating since June 2016)
- Duke Energy / Clemson University 15 MW CHP at Clemson, South Carolina (under construction)
- DTE Energy / Ford 34 MW CHP at Dearborn, Michigan (under construction)

Picture shows the FPU/Chesapeake Eight Flags Energy 21 MW CHP at Rayonier Advanced Materials (RYAM) property. RYAM serves as thermal host, located on Amelia Island, Florida
Project at 8’ above sea level was elevated 10’ and designed / hardened to withstand CAT 4 storm. No damage from Hurricane’s Matthew and Irma both of which glanced island as CAT 1
$38 MM project supplies approximately half of FPU island customer electric load plus critical steam and hot water to RYAM, operating since June 2016 at ~ 95% capacity factor

CHP Benefits to FPU, Rayonier and the Amelia Island Community

For Florida Public Utilities & Customers

- Lower electric cost to all customers than every other alternative evaluated
- Increased resiliency by local generation supporting microgrid dev for 20k on Amelia Island (previously served only by 30 mi radial line)
- Increased local tax base and employment
- 77% efficiency = 80% lower NO_X & 38% less CO_2
- 2 BCF /yr new NG load
- Additional 5 MW electric 2-3 BCF/yr NG from expansion

For Rayonier & Community

- Increased steam capacity and electric resiliency, less down time/year
- 4-6 more production days & revenue /year
- Ability to expand mill -- $125 MM expansion approved (could not happened without CHP)
- Expansion adds $27MM /yr to & 50 permanent jobs for Amelia Island economy

Eight Flags Energy CHP

Duke Energy / Clemson University 15 MW CHP – under Construction

For Duke Energy Carolinas

- 15 MWe to Duke Energy grid and steam to campus @ 94-95% capacity factor
- Clemson steam payment credited back to fuel for all Duke Energy customers making CHP least cost resource
- Reduced T&D load & losses in high growth region

For Clemson University

- Increased energy security & resiliency of campus power supply with 15 MW CHP on campus - permits islanding in Grid outage
- Eliminates need and significant cost of building 2nd utility feeder for campus growth
- Allows allow aging steam plant to be closed in future with site repurposed for student center and other high value University needs

DTE / Ford Dearborn Campus 34 MW CHP -- under construction

For DTE Energy

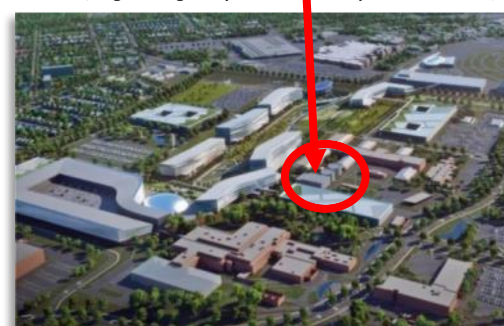
- 34 MW regulated grid asset owned & operated as DTE
- Avoids loss of load & revenue if Ford or 3rd party built and owned CHP
- Generating in highly congested area reduces Grid losses, helps avoid future T&D investment & provides energy resiliency

For Ford

- Supplies total energy for $2B Campus redevelopment of Ford's Research / Eng & HQ campuses for 30k employees
- Assures energy resiliency from on-site steam & power designed to island if grid out
- Avoids use of Ford capital for non core business assets
- Allows decommissioning of 60 yr old boiler house plus substantial efficiency and environmental improvements

Rendering DTE Owned 34 MW CHP at Ford

Ford Research/Engineering Campus under development Dearborn, MI



Suggested Take Away for Regulators

- Help assure in-front-of-meter (IFOM) CHP is evaluated in IRPs as supply and/or distribution system asset
- Help assure full range of benefits are considered - on both sides of meter
  - Explore CHP as cornerstone of microgrid developments for enhanced resiliency
  - Consider LCOE, T&D impacts, Microgrid /Resiliency, Industrial Development, Customer & Community Benefits
- *Review recent state of Virginia regulation to include evaluation and development of up to 200 MW of CHP in state utility IRP's – can be developed either as supply or demand side resource (copy included in appendix to slides)*

Take Away for Utilities & Utility Customers - with thermal loads

TAKEAWAY

For Utilities

- Identify key customers with continuous thermal loads and evaluate benefits of collaboration on CHP – calculate value of 'key customer retention'
- Document T&D, resiliency, & industrial development benefits in addition to LCOE
- Explore how collaboration with key industrial, institutional and governmental customers can be win/win for all

For Institutional / Industrial Customers

- Where 'inside the fence' CHP does not meet financial criteria for development, discuss collaboration with your utility to explore joint development of CHP/microgrid
- Evaluate value of enhanced resiliency, operating days, and modernization provides

Thanks for your Time . . .

NARUC Summer Policy Summit

Questions?

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Presentation Addendum / Examples

- The following slides provide additional supporting information and details

Recent Virginia Regulation to incorporate 200 MW CHP into IRPs provides a Guide

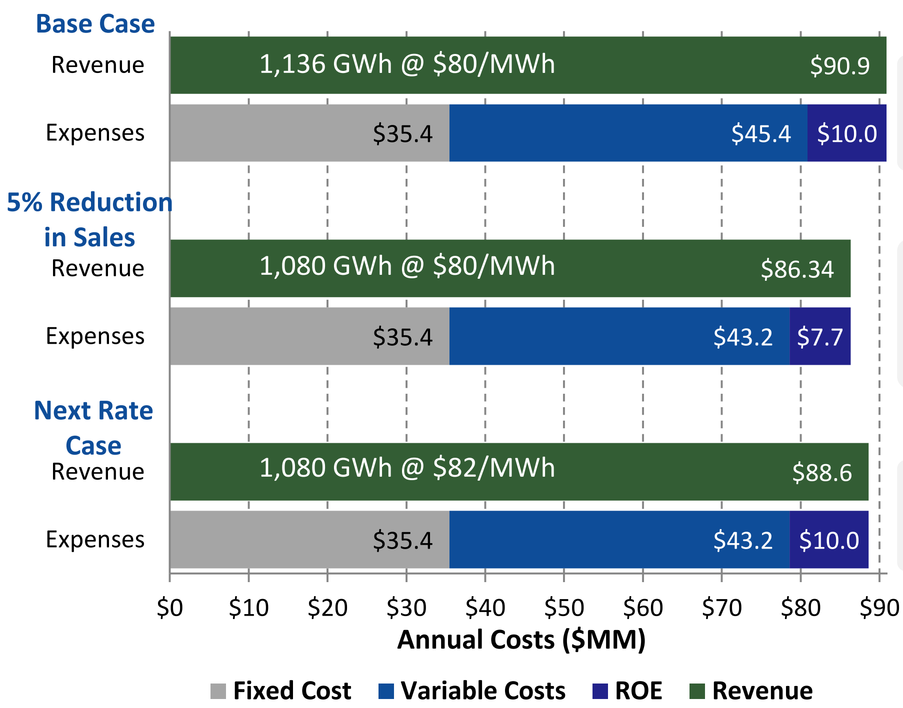
- In 2018 Virginia establishes specific goals for evaluation of CHP in all IRP's for development of 200 MW of CHP, with established efficiency targets
- Innovative language permits CHP to be evaluated & developed either as supply side, utility-owned or demand side (via incentives) measures
- Actual language follows:

- **Regulation Language . . .**
- 12. That any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, **shall consider in its integrated resource plan next filed after the effective date of this act, either as a demand-side energy efficiency measure or a supply-side generation alternative, whether the construction or purchase of one or more generation facilities with at least one megawatt of generating capacity, having a measurable aggregate rated capacity of 200 megawatts by 2024, that use combined heat and power or waste heat to power and are located in the Commonwealth, are in the customer interest**.

- For purposes of this analysis, the total efficiency, including the use of thermal energy, for eligible combined heat and power facilities must meet or exceed 65 percent (Lower Heating Value). The assumed efficiency of waste heat to power systems, which do not burn any supplemental fuel and use only waste heat as a fuel source, is 100 percent. The term 'waste heat to power' means a system which generates electricity through the recovery of a qualified waste heat resource. The term 'qualified waste heat resource' means (i) exhaust heat or flared gas from an industrial process that does not have, as its primary purpose, the production of electricity, and (ii) a pressure drop in any gas for an industrial or commercial process.

Example: Financial Impact when a Customer installs CHP – behind meter

What Happens when Utility Customer installs /owns CHP?



For a utility earning $10MM/yr on $182MM rate base at 11% ROE – or $8.80/MWh spread over 1,136 GWh/yr sales. . .

If the utility loses 5% of sales to CHP, fixed costs remain and ROE is reduced by >20%. Standby charges don't cover lost baseload revenue. Utility shareholders lose in the short term.

Eventually, unrecovered costs are typically spread back to other customers, who lose in the long term.

CHP Technical Potential by Size

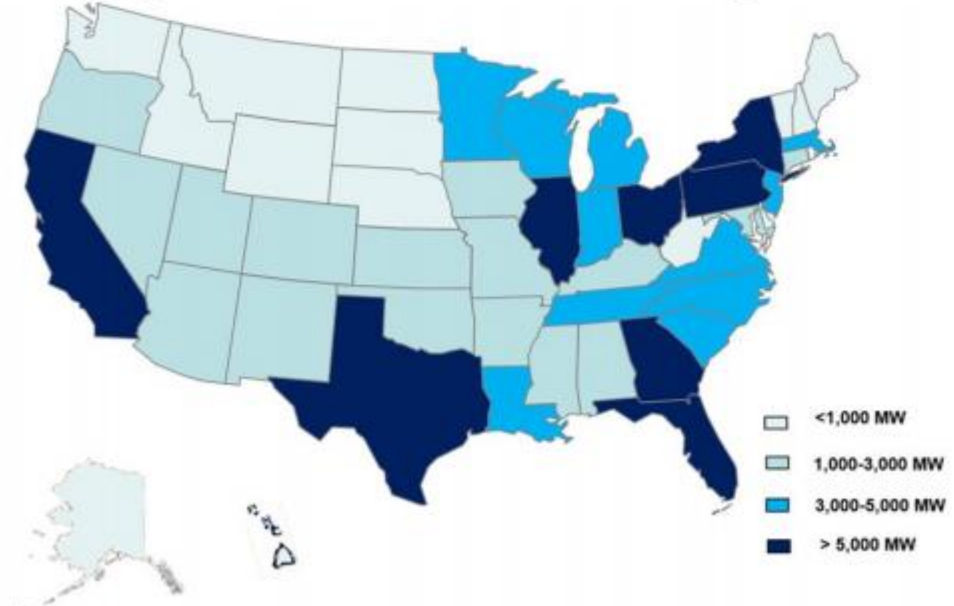
Table III-1: Total CHP Technical Potential across All Facility Types

Business Type	50-500kW		0.5 - 1 MW		1-5 MW		5-20 MW		>20 MW		Total Sites	Total Capacity (MW)
	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)		
On-site Industrial CHP	34,502	6,281	6,069	4,341	7,424	15,5[illegible]	1,901	17,036	479	22,157	50,375	65,381
On-site Commercial CHP	185,625	20,068	37,939	18,100	15,535	20,284	1,084	9,452	174	8,026	240,358	75,930
On-site WHP CHP	332	73	132	95	341	868	204	2,003	96	4,585	1,105	7,624
Export Industrial CHP	na	0	na	7	na	3,929	na	11,535	na	65,578	na	81,048
Export District Energy CHP	0	0	0	0	5	18	8	75	51	10,567	64	10,660
Total	**220,459**	**26,422**	**44,140**	**22,543**	**23,305**	**40,666**	**3,197**	**40,101**	**800**	**110,913**	**291,902**	**240,644**

U.S. DOE CHP Deployment Program, 2016.

CHP Technical Potential by State

Figure III-1: On-site Technical Potential by State



U.S. DOE CHP Deployment Program, 2016.

Comments on FPU/Rayonier Eight Flags CHP on Amelia Island, Florida by Industrial Host and Florida Regulator

Paul Boynton, Chairman, President and CEO of Rayonier Advanced Materials, September 2016

- By partnering with FPU on this CHP facility, we have a stable cost source of steam coming into our facility that as we have operational changes, whether by design or not by design, even by unfortunate circumstances, it allows us to take on additional steam or power, as we may need to and stabilize our operation. So it should help us produce more product year round for the customers in a very reliable way for us. It helps us stabilize our operations and reduce the cost of our products.

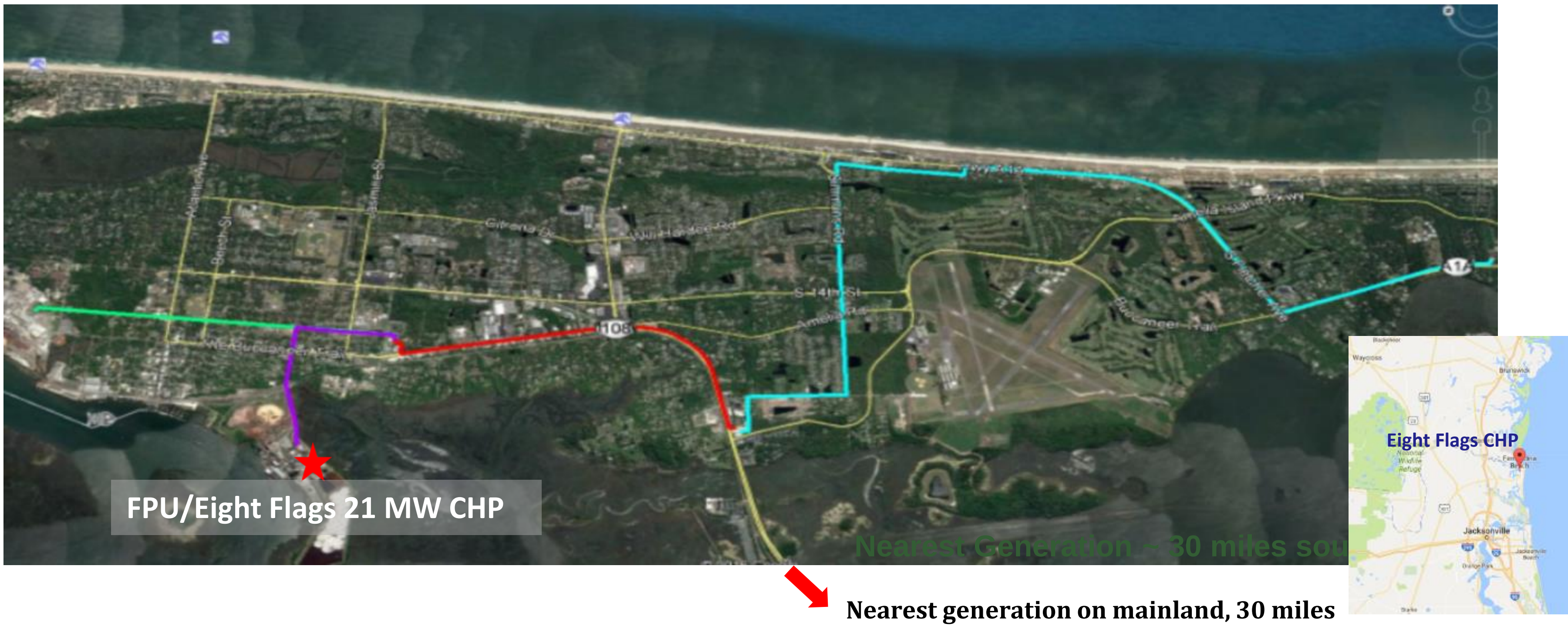
- Our expansion will create over 50 high-paying jobs and contribute more than $27 million annually to Northeast Florida's economy (note: mill expansion would not have occurred without CHP)

Art Graham – Chairman, Florida Public Service Commission at Eight Flags CHP Groundbreaking March 2015

- *"To see the two economic drivers in this area decide to come together and form this synergy, I think is a fantastic idea and is something that is great to do. I know there are a lot more opportunities to do this in the Southeast. I would encourage you guys to move forward and drive hard ahead. I'd be more than happy to go to other regulators to let them know what this means for their states."*

Eight Flags CHP provides basis for establishment of FPU Microgrid serving 20,000 on Amelia Island – previously supplied only by generation over 30 mile radial 138 kV line from Jacksonville area

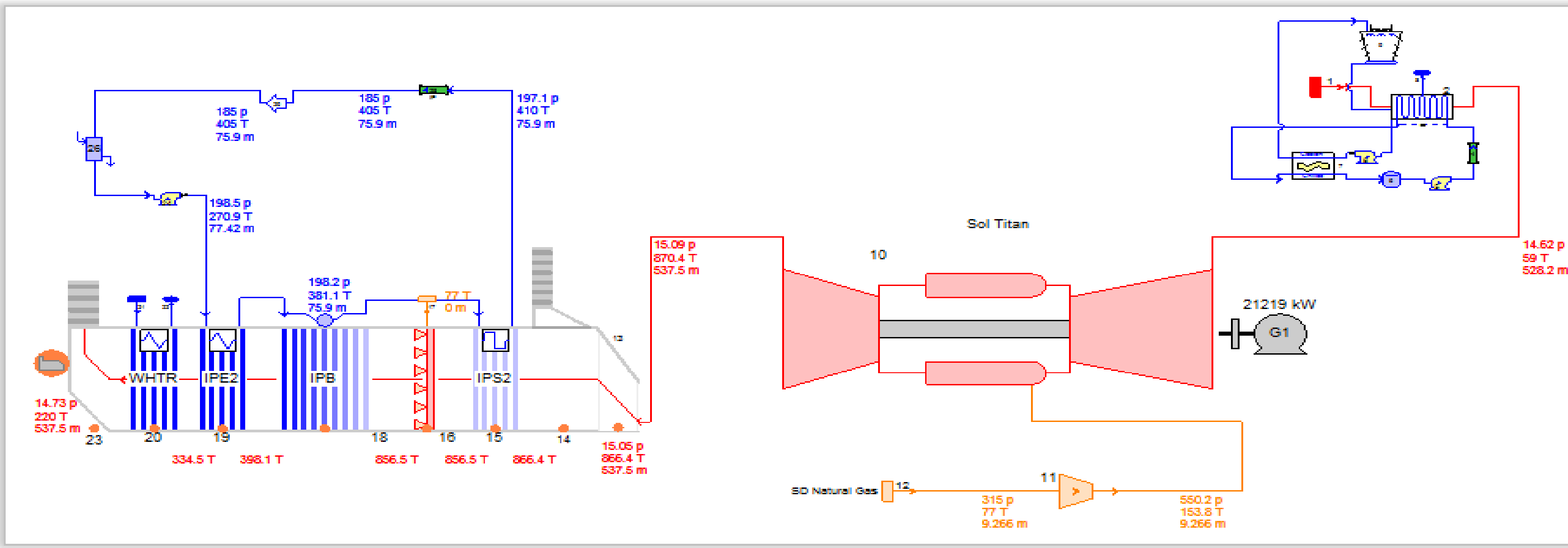
FPU 69 kV and 138 kV lines on Amelia Island shown below – Island served previously by generation from 30 miles away



Heat Balance: FPU – Eight Flags CHP

21 MW / 200kpph 160 psig 420F steam & 550 gpm heated water

Project Efficiency:	**77.6% (HHV) / 83.8% (LHV)**	**Fuel input:**	62 MW 211.6 MMBtu/hr
(Net) Power output:	20.7 MW 70.5 MMBtu/hr	**Total Thermal output:**	26.2 MW 89.6 MMBtu/hr
Steam:	21.7 MW 74.1 MMBtu/hr	**Heated Demin Water:**	4.5 MW 15.4 MMBtu/hr



Setting the Solar Turbines Titan 250 21 MW Gas Turbine next to Generator on Elevated Platform

Elevation & Storm Hardened Designed to Survive CAT 4 Hurricane Storm Surge

FPU / Chesapeake Eight Flags CHP Videos

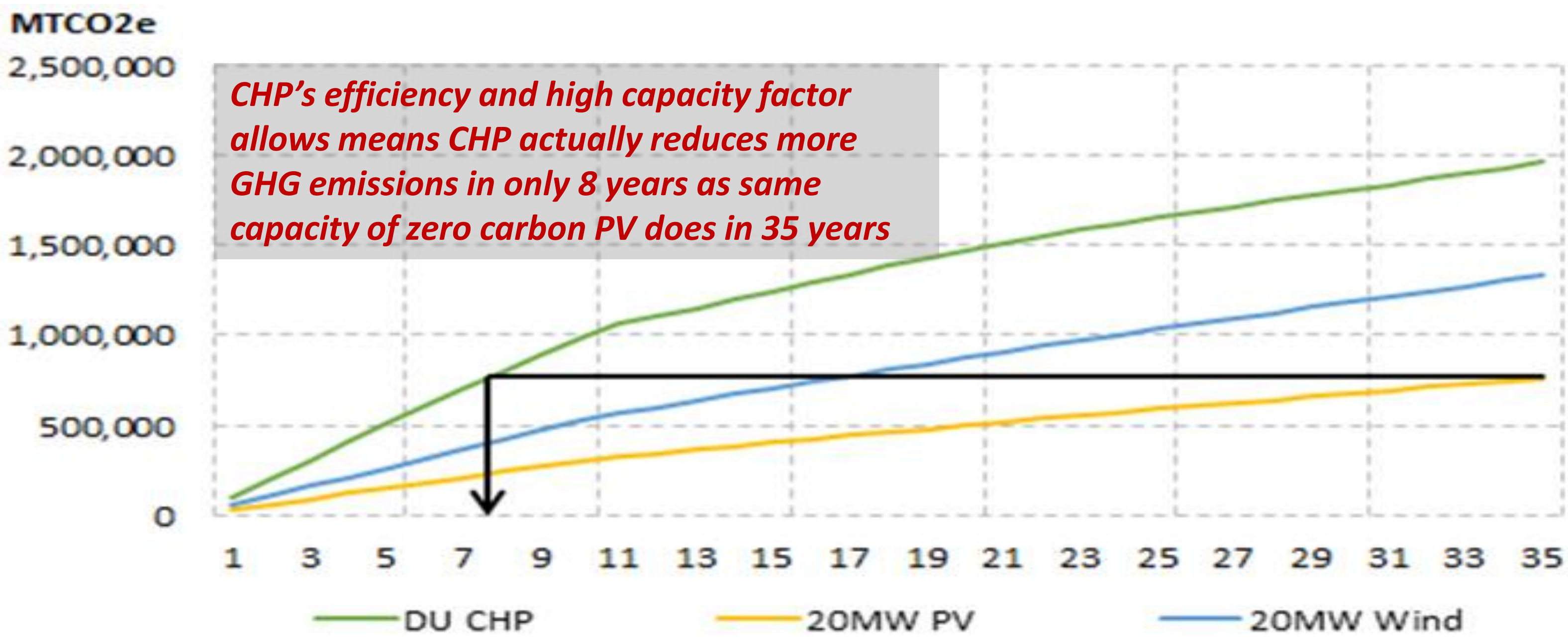
Can copy & Paste Video Link to view Eight Flags CHP Construction video
Top link – non narrated Bottom link - narrated

https://youtu.be/mMuaJfLiAJo

https://youtu.be/1UaNWrRBMpo

Life Cycle Emission Benefits of 20 MW Capacity

comparing natural gas fired CHP topping cycle, PV and Wind per MW of installed capacity

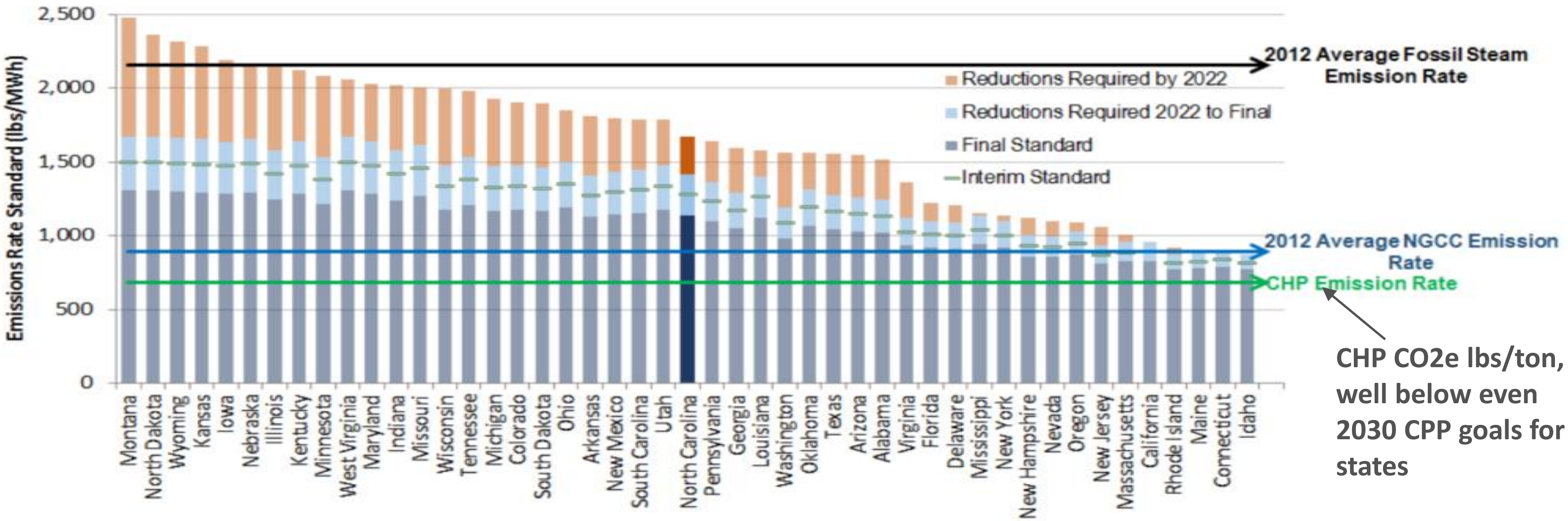


Calculated using actual dispatch model results beginning 2020 for DEC North Carolina, demonstrating specific unit emissions displaced by year
Capacity Factors: 95% for CHP, 22% for PV, and 34% for Wind

Snapshot on CHP Emission Benefits Nationally vs Coal and NGCC

CHP Reduces Grid Emissions Even as RE Penetration increases

Dispatch studies demonstrate, CHP is a base load resource that sites on top of Nuclear & RE in dispatch order, always displacing highest fossil unit



Adapted from "The Clean Power Plan; Focus on Implementation and Compliance", January 2016, by The Brattle Group

Rethinking CHP -- Benefits Summary

- ✓ Well applied CHP is Most Efficient Method of Power Generation – Doubles Grid Efficiency
- ✓ Can have Lowest Levelized Costs of Any Resource
- ✓ Reduced Grid Losses – serves load a point of use – May Avoid Future T&D Investment
- ✓ Enhances Electric & Thermal System Resiliency for Host – supports Microgrid
- ✓ Faster Planning & Implementation – Lowers Investment Risk from uncertain growth
- ✓ Significantly Lowers Emissions & Water Use
- ✓ Provides Substantial "Across the Meter Benefits"
  - Enhances Economic & Community Development
  - Improves Industrial Competiveness & Jobs Growth
- ✓ All well applied CHP is beneficial whether behind meter or in front of meter
  - Utility collaboration with customer & ownership eliminates all barriers and opens door to more CHP development with no lost revenue and need for incentives

Rate Design Subcommittee

On Standby or Ready for Prime Time? - CHP Rates & Regulations for a Modern Grid

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