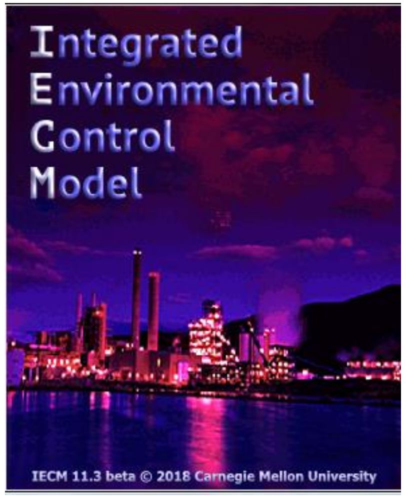
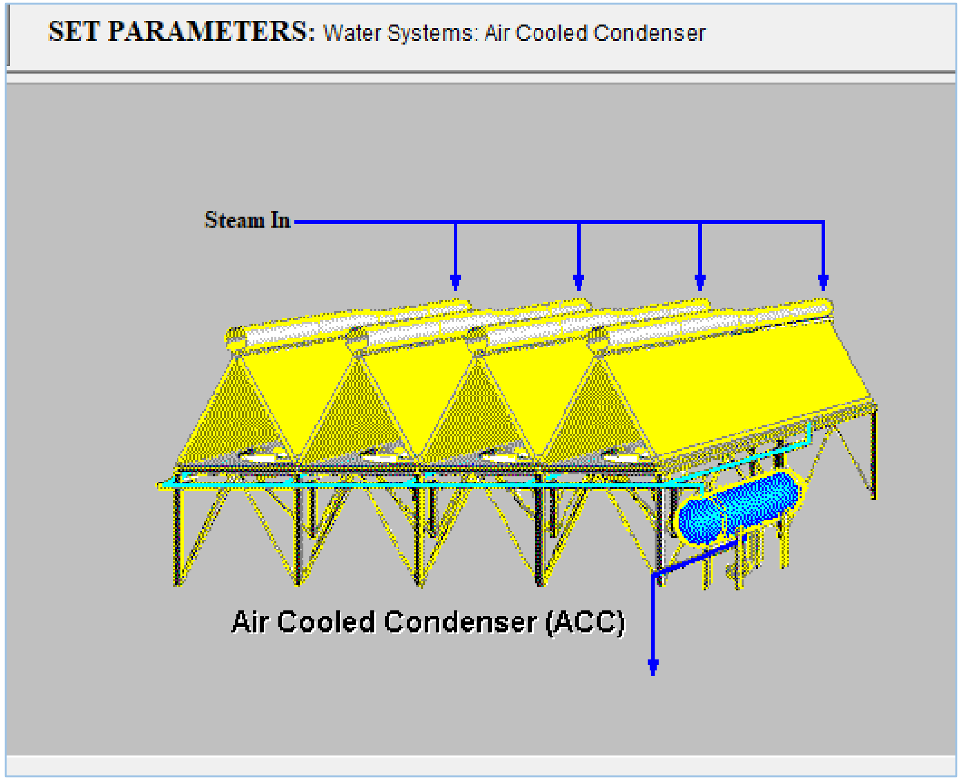
Regional Analysis of Dry Cooling Retrofits Using IECM

Haibo Zhai* and Ed Rubin, Carnegie Mellon University





Source: CMU

*Now at University of Wyoming

Disclaimer and Acknowledgments

- This presentation was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof

- The authors would like to thank Eric Grol (NETL), and Marc Turner (KeyLogic) for their input and assistance in performing this work. Team KeyLogic's contributions to this work were funded by the National Energy Technology Laboratory under the Mission Execution and Strategic Analysis contract (DE-FE0025912) for support services.

Motivation

- Thermoelectric power plants are a major source of freshwater withdrawals and consumption in the U.S.
- Increasing water stress in arid regions or during dry seasons has driven some states to restrict freshwater use by power plants
- Future capacity expansion in these regions can be constrained by water availability (and exacerbated by climate change)
- Evaporative emissions from wet cooling towers are typically the largest source of water consumption at electric power plants

Project Objectives

- Estimate the potential savings in water consumption that would result from retrofitting dry cooling systems at <u>existing coal-fired power plants with wet cooling systems</u> in a specified region
- Estimate the associated costs of these retrofits
- Identify the potential for a shortfall in net generating capacity due to the increased energy requirements of dry cooling

All impacts to be evaluated at each electrical generating unit (EGU) on a monthly and annual average basis, with results aggregated to the regional level

Project Scope

- The study region includes two states: Arizona and New Mexico. Existing coal-fired units with wet cooling tower systems are:
- Plants in Arizona:
  - Cholla (2 units)
  - Apache Station (1 unit)
  - Coronado (2 units)
  - Springerville (4 units)
- Plants in New Mexico:
  - Escalante (1 unit)
  - San Juan (2 units)

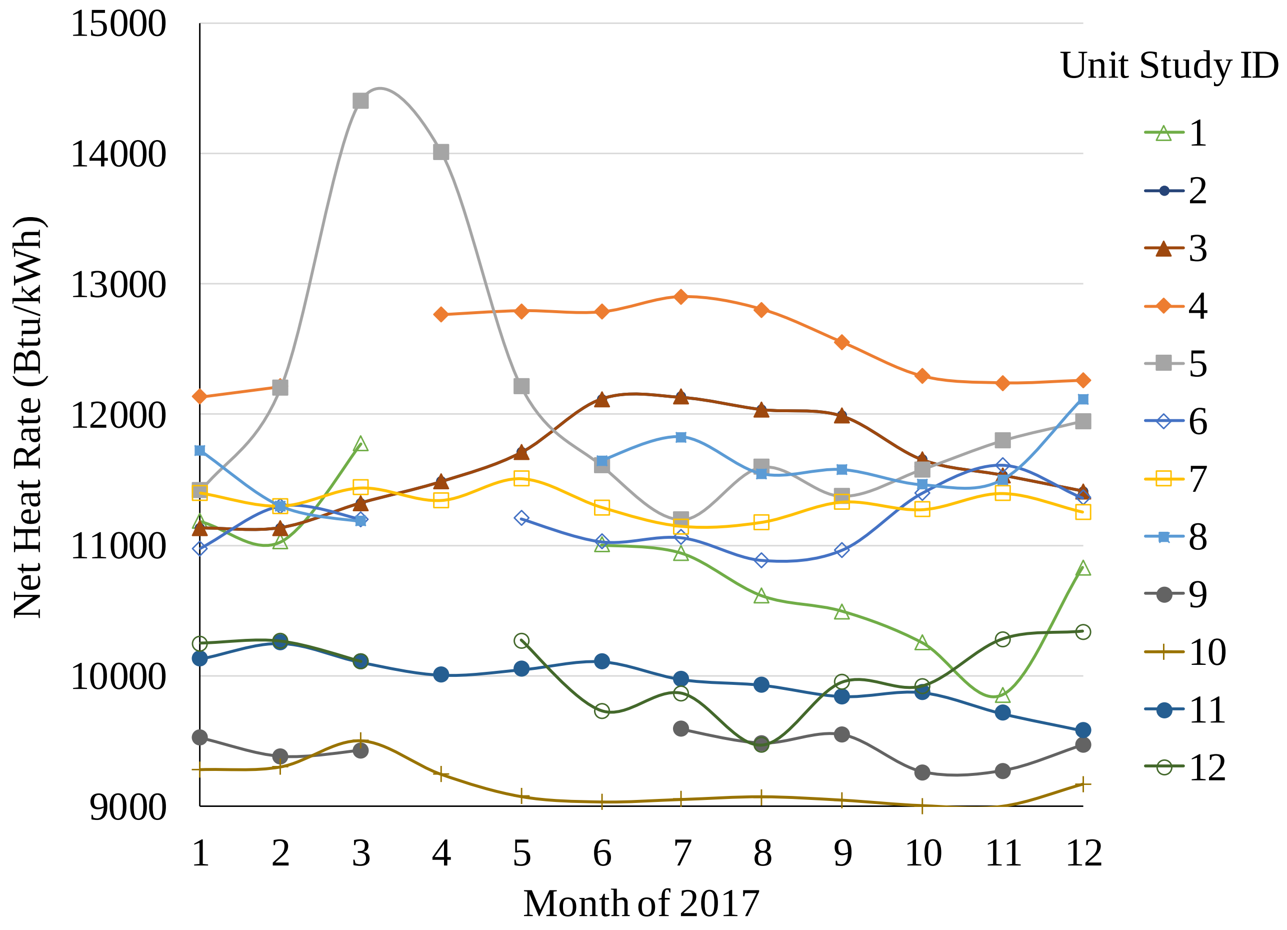
Total = 6 locations and 12 units analyzed

Existing Coal-Fired EGUs with Wet Towers in Arizona and New Mexico*

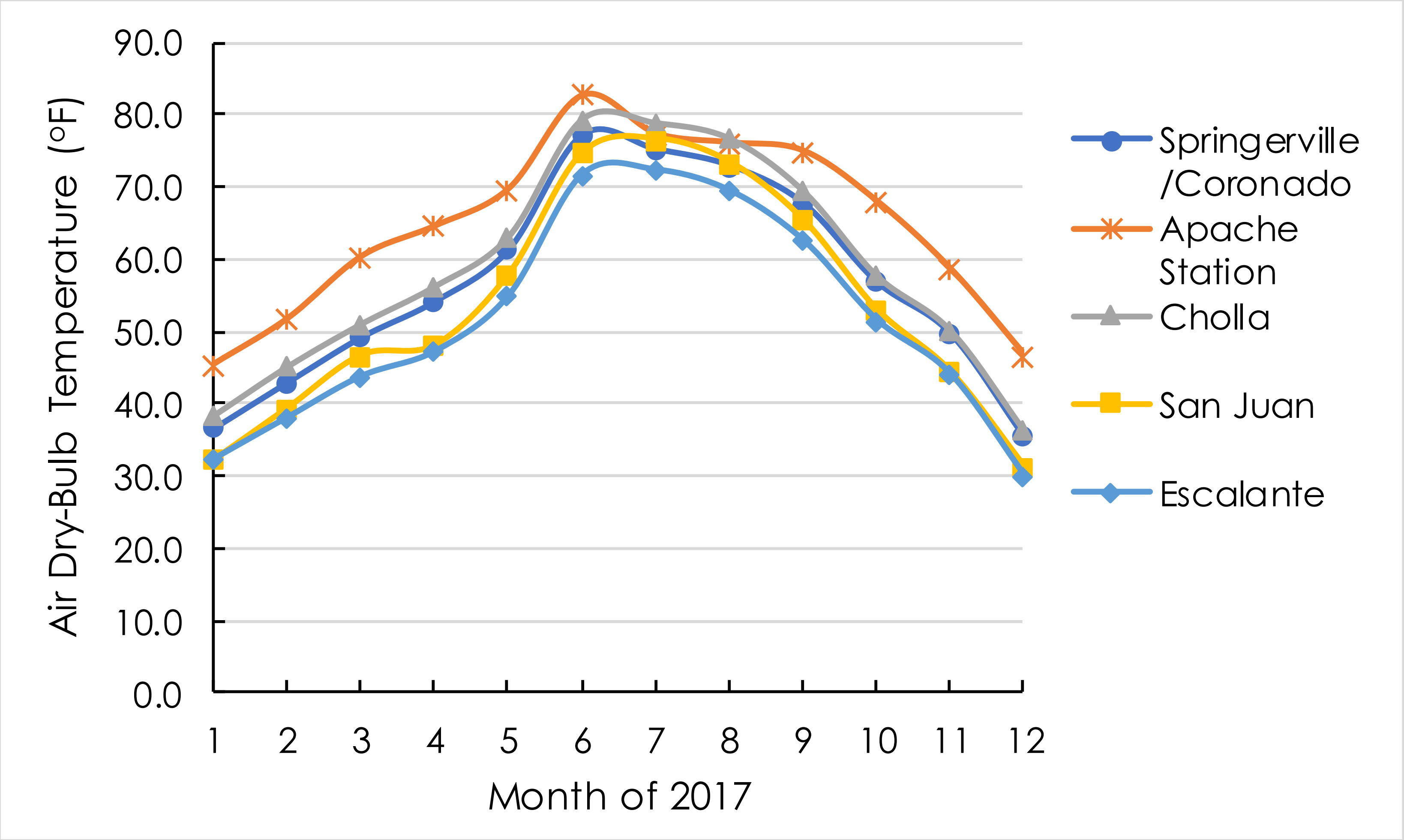
State	New Mexico			Arizona								
Plant name	Escalante	San Juan		Cholla		Apache	Coronado		Springerville			
Unit ID	87_B_1	2451_B_1	2451_B_4	113_B_3	113_B_4	160_B_3	6177_B_U1B	6177_B_U2B	8223_B_1	8223_B_2	8223_B_3	8223_B_4
Study ID	1	2	3	4	5	6	7	8	9	10	11	12
Unit type	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Online year	1984	1982	1982	1980	1981	1979	1979	1980	1985	1990	2006	2009
Nameplate capacity (MW)	257	369.0	555.0	312.3	414.0	204	410.9	410.9	424.8	424.8	458.1	458.1
Annual net heat rate (Btu/kWh)	10,740	11,232	11,649	12,526	11,799	11,163	11,313	11,608	9,430	9,151	9,956	9,991
Parasitic load (% of MWg)	7.1	7.8	5.8	7.8	5.8	7.1	5.8	5.8	5.8	5.8	5.8	5.8
Air Pollution Controls												
NOx (in-furnace)	√	√	√	√	√	√	√	√	√	√	√	√
NOx (post-combustion)	none	√	√	none	none	√	√	√	none	none	√	√
Mercury	√	√	√	√	√	√	√	√	none	none	√	√
Particulates	√	√	√	√	√	√	√	√	none	none	√	√
SO_2	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Dry FGD	Dry FGD	Dry FGD	Dry FGD

*As of 2017

Monthly Net Heat Rate of Existing Coal-Fired Units with Wet Towers



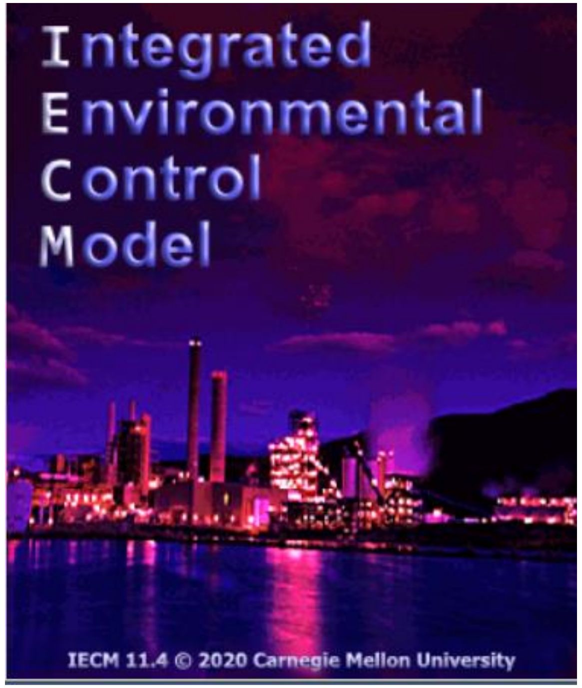
Monthly Temperature Trend at Climate Monitoring Stations Nearest Each Plant



Research Approach

- **Use the IECM to model each unit with a wet cooling system; estimate its current monthly and annual water consumption, and the levelized cost of electricity generation over its remaining life**
- **Repeat the unit-level analysis assuming retrofit of a new dry cooling system (air cooled condensers, ACC)**
  - Update the IECM thermodynamic and cost models for ACC based on a recent NETL study of dry cooling system performance, capital cost, and operating & maintenance costs
- **Use these results to calculate the dry cooling system water savings, cost per gallon of water saved, and net MW capacity reduction at each plant; aggregate these results to regional totals and averages**

Modeling Coal-Fired Units in IECM



CONFIGURE SESSION: Plant Design

Configuration: <User Defined>

Combustion Controls

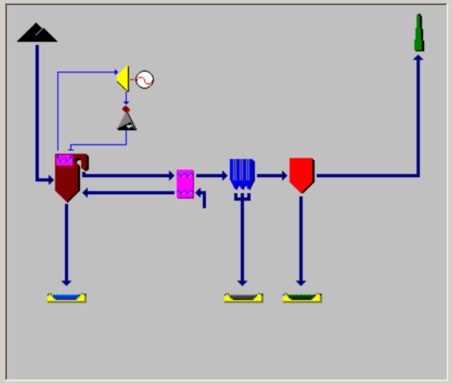
Fuel Type:	Coal
NO_x Control:	In-Furnace Controls

Post-Combustion Controls

NO_x Control:	None
Mercury:	None
Particulates:	Fabric Filter
SO_2 Control:	Wet FGD
CO_2 Capture:	None

Water and Solids Management

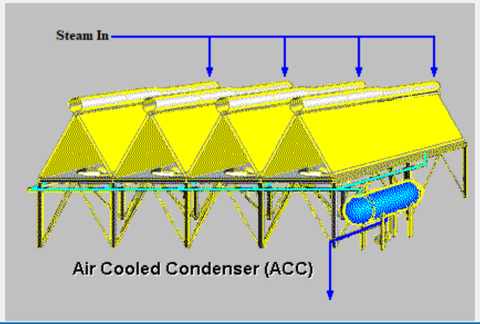
Cooling	Air Cooled Condenser
Wastewater:	Ash Pond
Flyash	No Mixing



Note: Options in gray are accessible only after other required options are selected.

SET PARAMETERS: Water Systems: Config

Title	Unc	Value	Calc
Configuration Menus			
Condenser Type		NETL ACC	
Configuration		A-Frame (60 deg)	



SET PARAMETERS: Overall Plant Performance

Title	Unc	Value	Calc	Min	Max	Default
Gross Electrical Output (MWg)		312.3		100	2500	Calc
(See **Base Plant** to set this value.)						
Capacity Factor (%)		51.8		1e-15	100	75
Plant Location		US Southwest Regioi		Menu	Menu	US Midwe...
(**US Southwest States**: AZ, CA, CO, NM, NV, UT)						
(See **Plant Location** in **CONFIGURE SESSION** to set this value.)						
Ambient Air Temperature (Dry Bulb Average) (deg. F)		58.6	☐	15	100	Calc
Ambient Air Pressure (Average) (psia)		12.4	☐	12	15	Calc
Relative Humidity (Average) (%)		39.3	☐	0	100	Calc
Ambient Air Humidity (Average) (lb H2O/lb dry air)		0.004844	☑	0	0.03	Calc
Average Annual Rainfall (inches/yr)		15.31	☑	0	200	Calc
Water Life Cycle Assessment Enabled?		Yes		Menu	Menu	Yes

GET RESULTS: Water Systems: 2. Air Cooled Condenser: Capital Cost

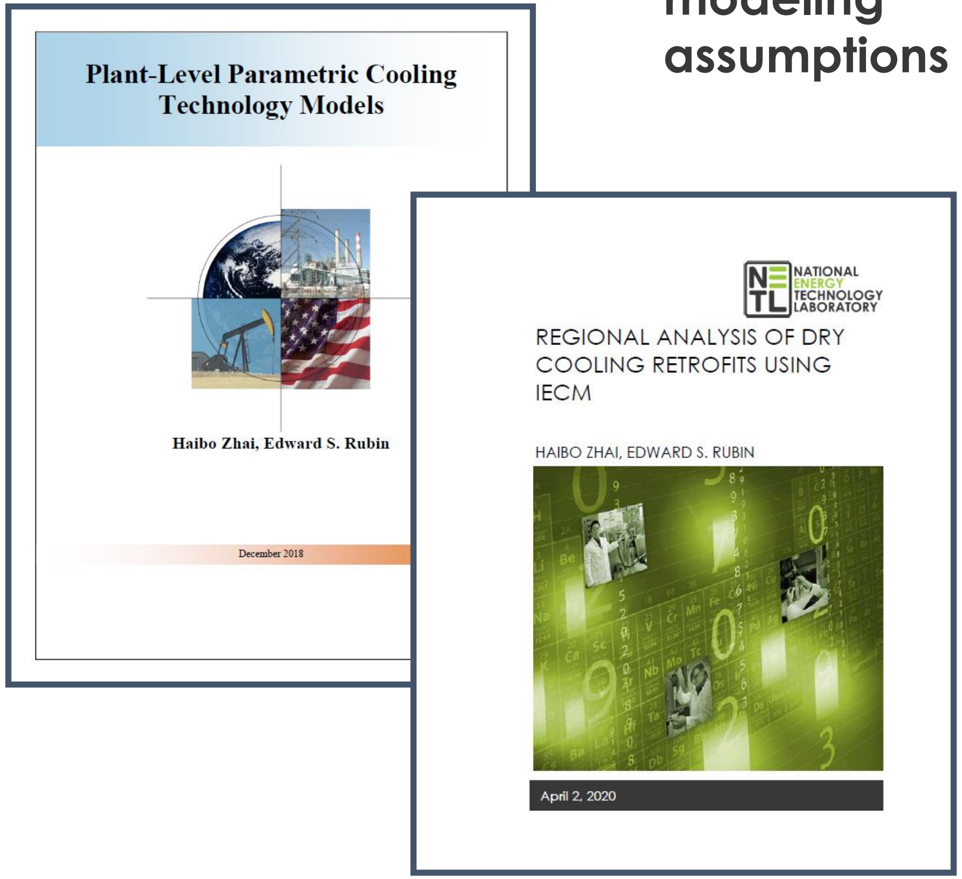
	A	B
1	Air Cooled Condenser Process Area Costs	Capital Cost ($/kW-net)
2	Condenser Structure	65.97
3	Steam Duct Support	0.8922
4	Electrical & Control Equipment	3.879
5	Auxiliary Cooling	7.602
6	Cleaning System	1.348
7		
8		
9	Process Facilities Capital	79.68
10		
11		
12		
13		
14		
15		
16		

	A	B
1	Air Cooled Condenser Plant Costs	Capital Cost ($/kW-net)
2	Process Facilities Capital	79.68
3	General Facilities Capital	7.968
4	Engineering & Home Office Fees	7.968
5	Process Contingency Cost	3.984
6	Project Contingency Cost	13.75
7	Interest Charges (AFUDC)	8.227
8	Royalty Fees	0.3984
9	Preproduction (Startup) Cost	2.731
10	Inventory (Working) Capital	0.5667
11	Financing Cost	0
12	Other Owner's Costs	0
13	Total Capital Requirement (TCR)	125.3
14		
15		
16	Effective TCR	125.3

Free IECM download at: www.iecm-online.com

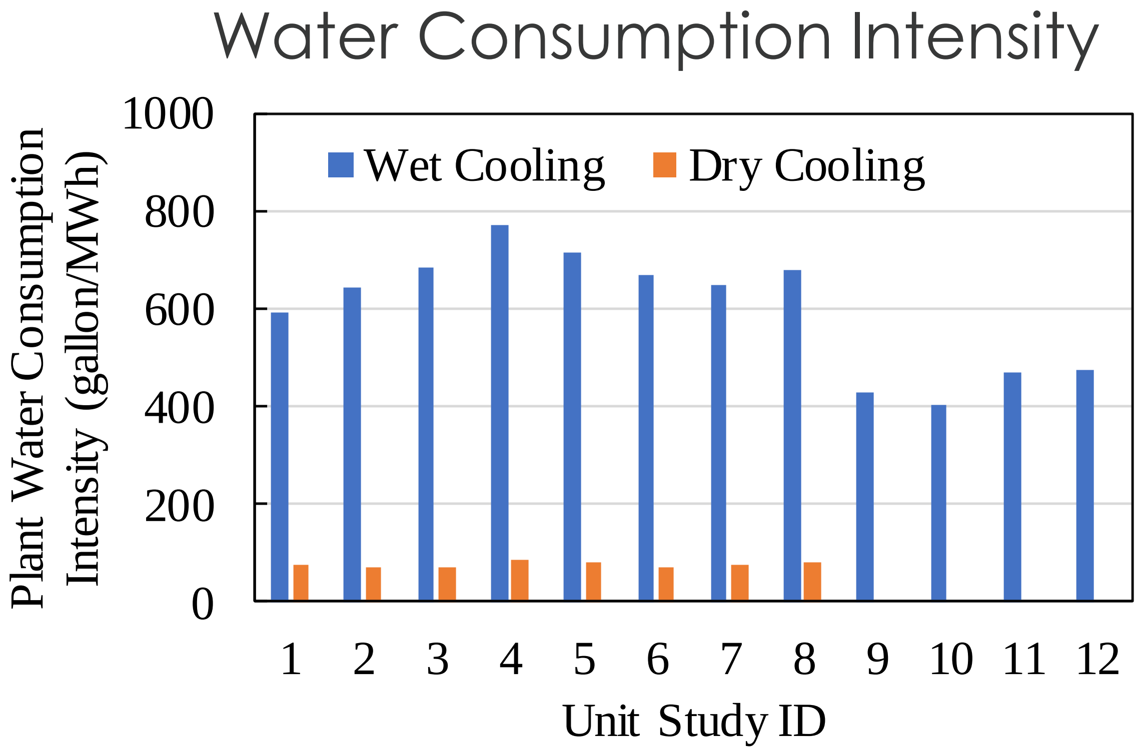
Key Assumptions for Unit-Level Analysis

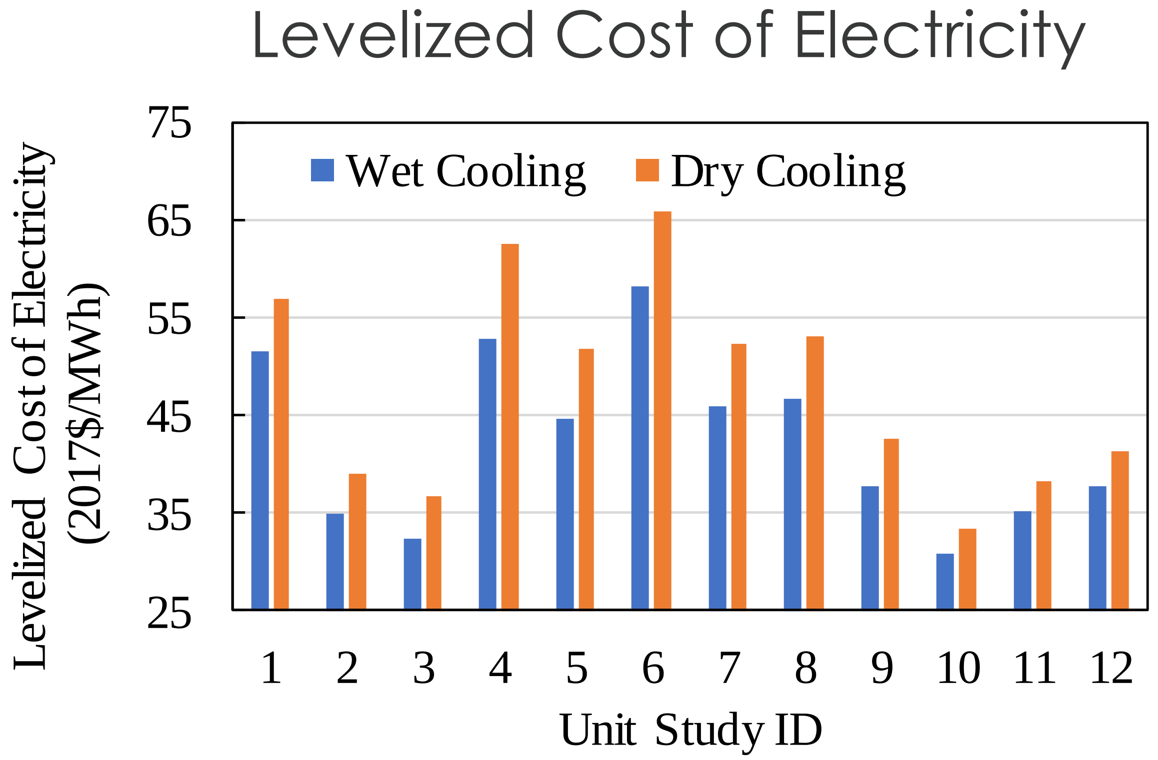
See two NETL reports for details of all modeling assumptions



- Dry cooling system size is based on annual average ambient conditions
- Monthly plant heat rate and parasitic load with dry cooling are adjusted based on monthly average dry bulb air temperature
- Dry cooling capital cost is amortized over 30 years or remaining EGU life (based on a 50 year life)
- Base case assumes IECM water price and no capital cost premium for retrofits
- Monthly fuel use and operating hours are same for pre- and post-retrofit cases

Key Results for Existing Coal-Fired EGUs with Wet and Dry Cooling Systems



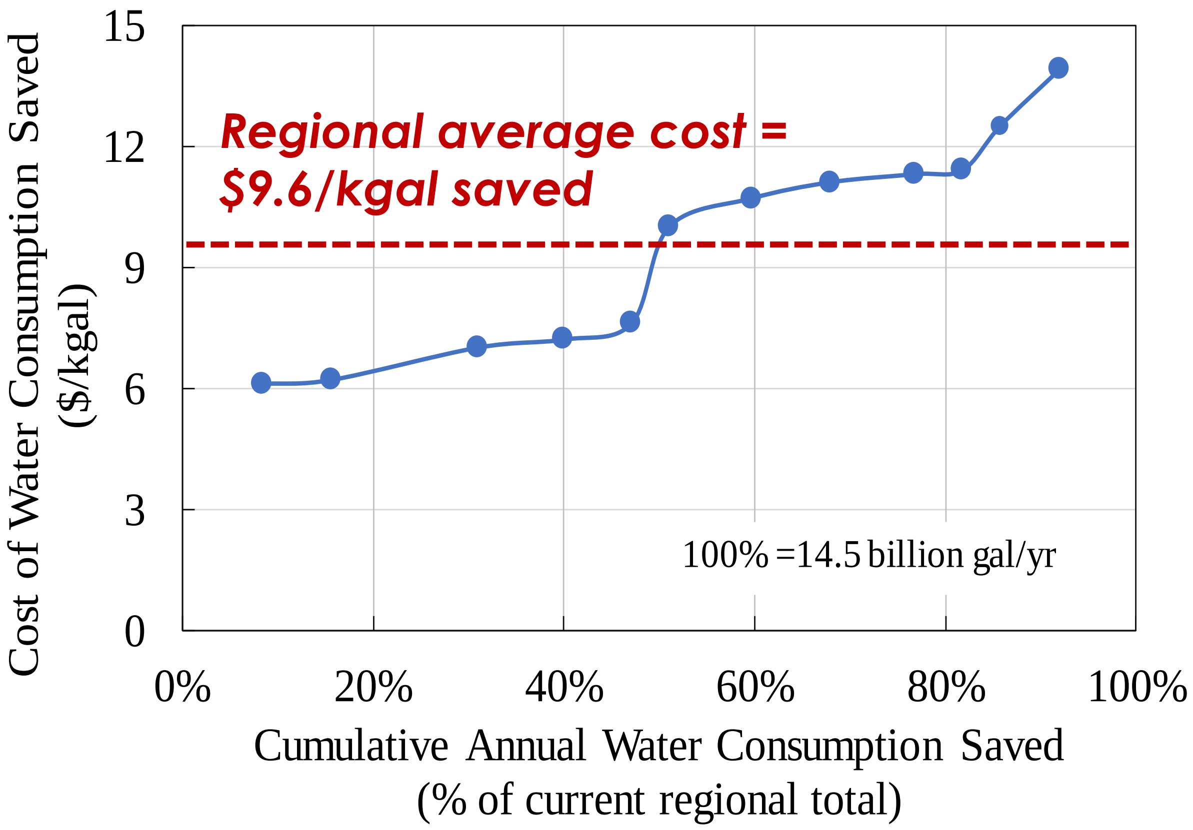


Regional average water consumption falls by 92.5%

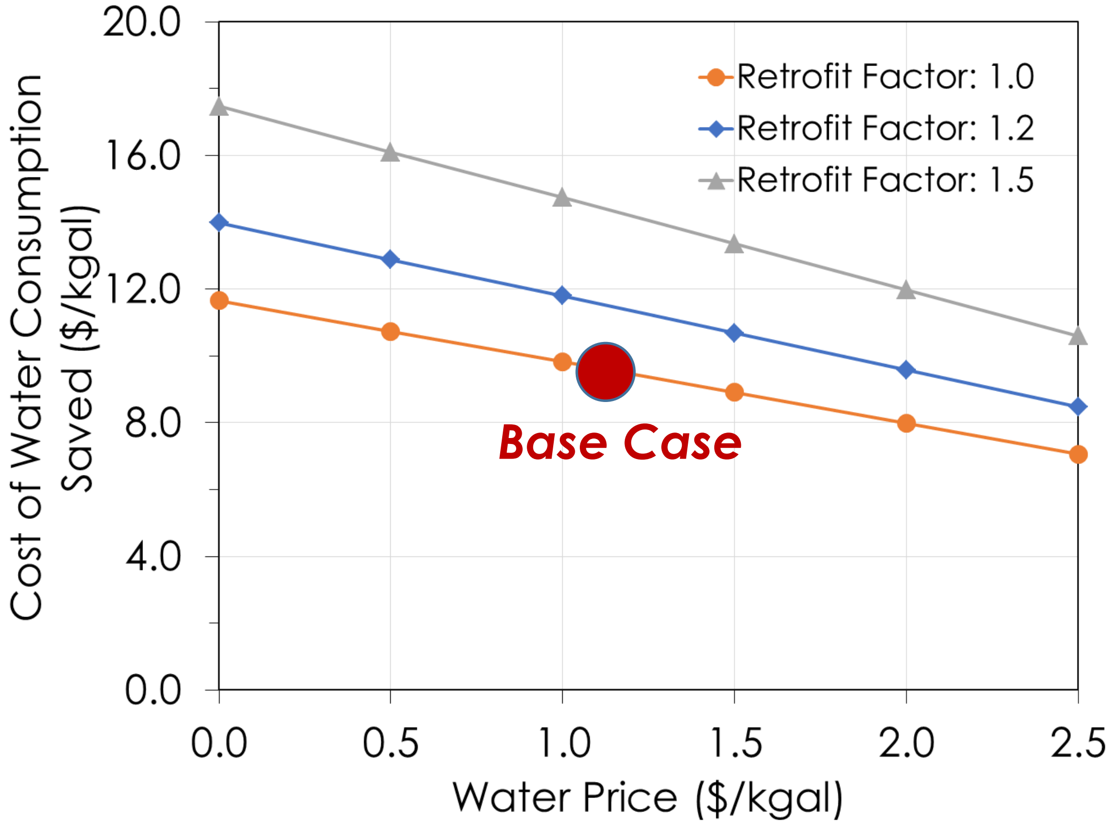
Regional average cost of electricity increases by 12.4%

Cost per Gallon of Water Saved

Cost of Reduced Water Consumption vs. Annual Water Savings



Regional Cost Sensitivity to Water Price and Retrofit Factor



Changes in Net Regional Capacity after Dry Cooling Retrofits

- <u>On an annual basis</u>, the estimated reduction in net regional capacity is 32 MW, or 0.8% of total net capacity
- <u>On a monthly basis</u> the change in net regional capacity varies from:
  - +8 MW to -79 MW, or
  - +0.2% to -2.0% of net capacity
  - The largest decreases in capacity (and water consumption) occur in the month of July

These decreases in net regional capacity can be offset by increases in unit-level capacity factors

Conclusions

- Replacing wet cooling tower systems with dry cooling systems can substantially reduce power plant water consumption in dry, arid regions
- There are tradeoffs in terms of increased cost and reductions in net generating capacity, especially during summer months
- This study estimated the magnitude of these water reduction benefits and associated costs for coal-fired power plants in a two-state region of the western U.S.
- Additional plant-level data and analysis are needed to refine the estimates presented here, or to extend them to shorter time periods

Thank you

rubin@cmu.edu
hzhai@uwyo.edu