The Clean Power Plan

Implications for the Western Interconnect

PRESENTED TO

Optimizing Carbon Market Mechanisms in the Western Interconnect

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THE Brattle GROUP

Agenda

- CPP Standards in WECC
- Implementation Decisions
- Outlook for Post-2020 AB 32
- Potential Implications for WECC

Final Clean Power Plan

Who: Existing Generation Units (EGUs) considered affected units under the 111(d) applicability criteria are grouped into two categories:

- *Fossil Steam*: Coal and oil/gas-fired steam turbine units
- *NGCC*: Natural gas-fired combined cycle units
- Not Included: Combustion turbine units

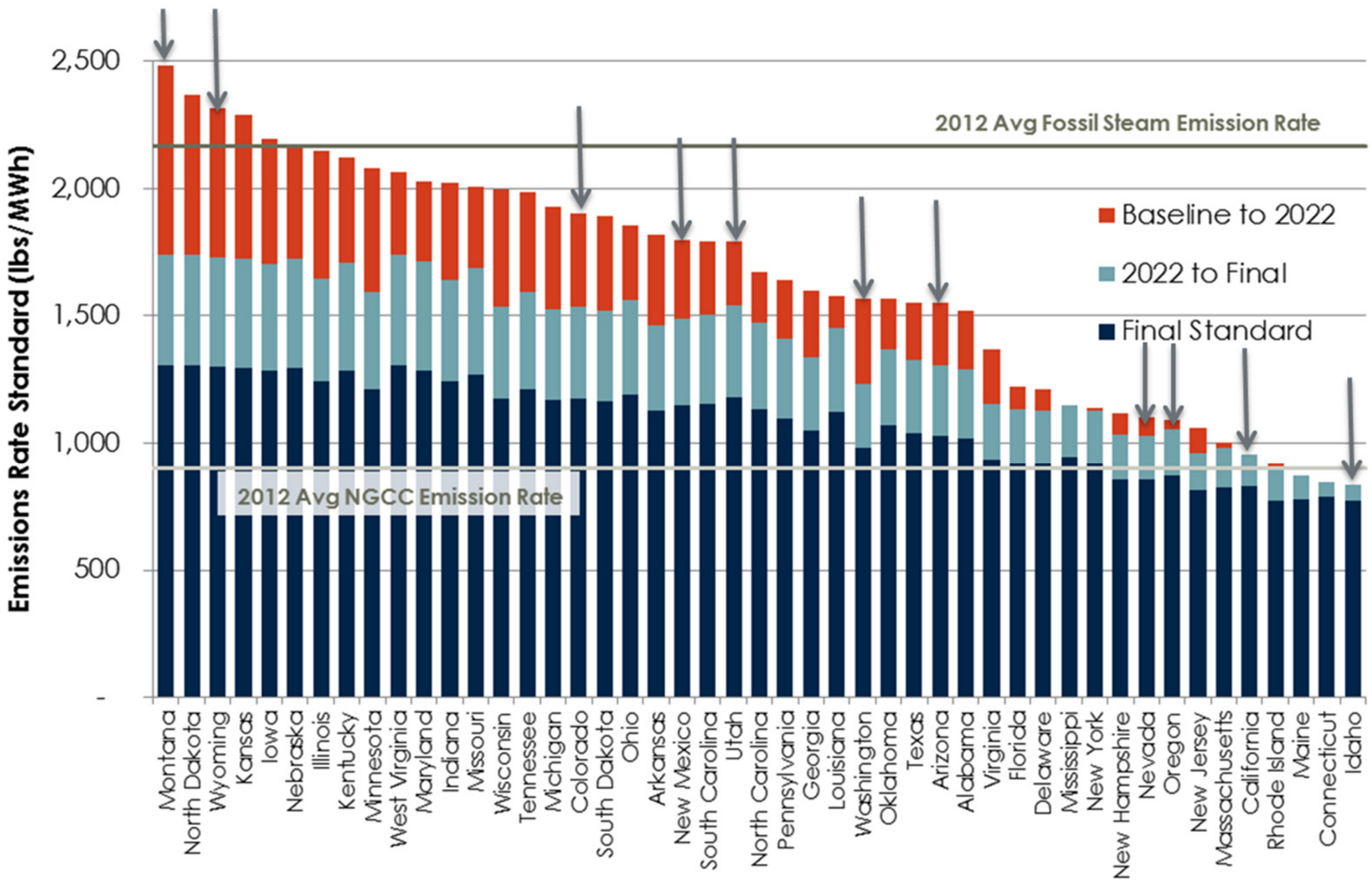
When:

- *Thursday! January 21, 2016*: End of comment period on federal plan, model rules, and Clean Energy Incentive Program
- *September 6, 2016*: Initial submission of state plans, may request extension
- *September 6, 2018*: Final submission of state plan
- *2022 – 2029*: Annual EGU standards, with three interim compliance periods
- *2030 and beyond*: Final EGU standard

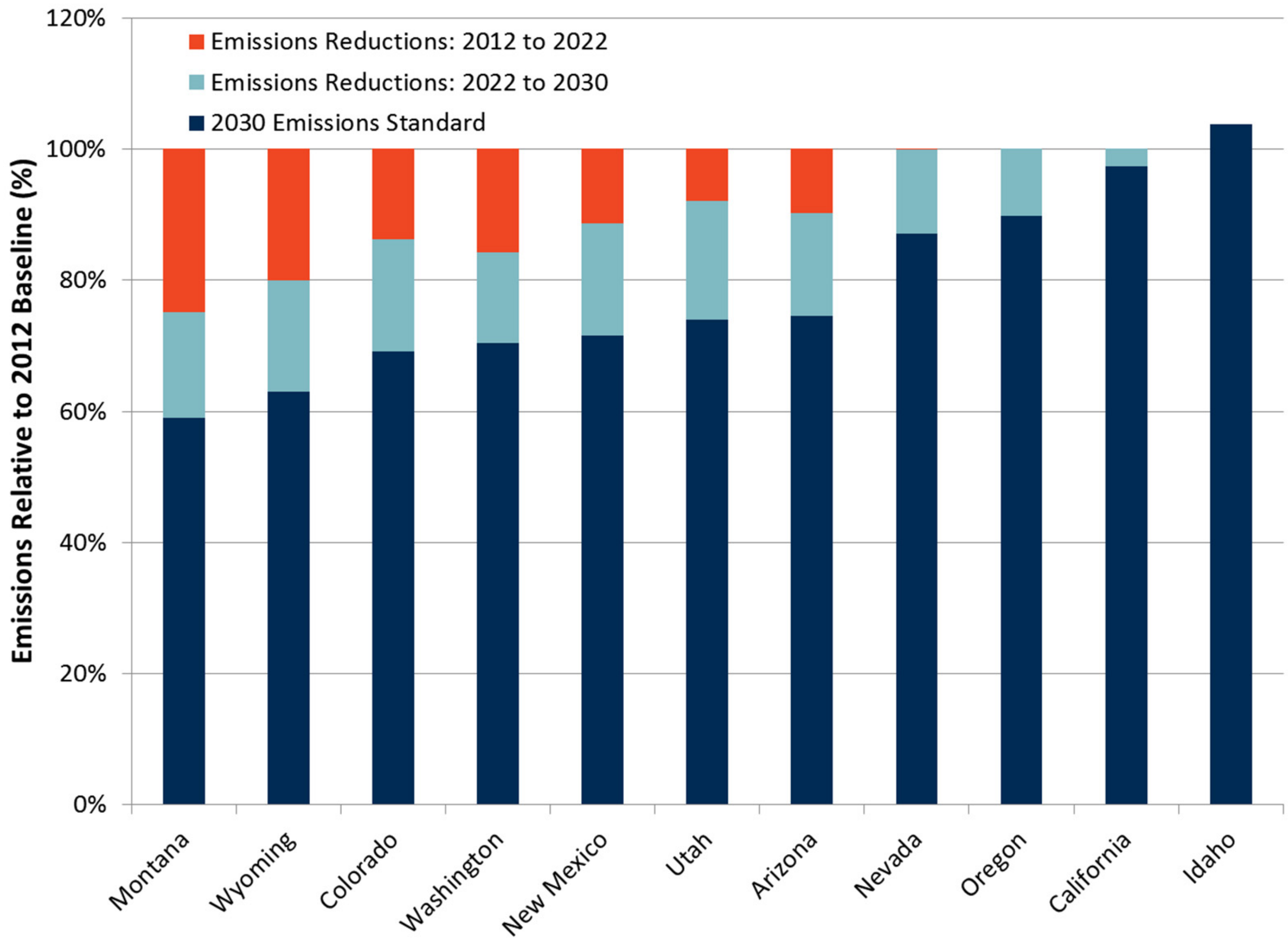
Wide Range of Reductions Required Amongst Western States

Rate reductions are phased-in from 2012 Baseline to 2030 goals

- Largest reductions in Western Interconnection are in MT, WY and CO
- 5 states need to achieve over 40% of reductions by 2022 to remain on track



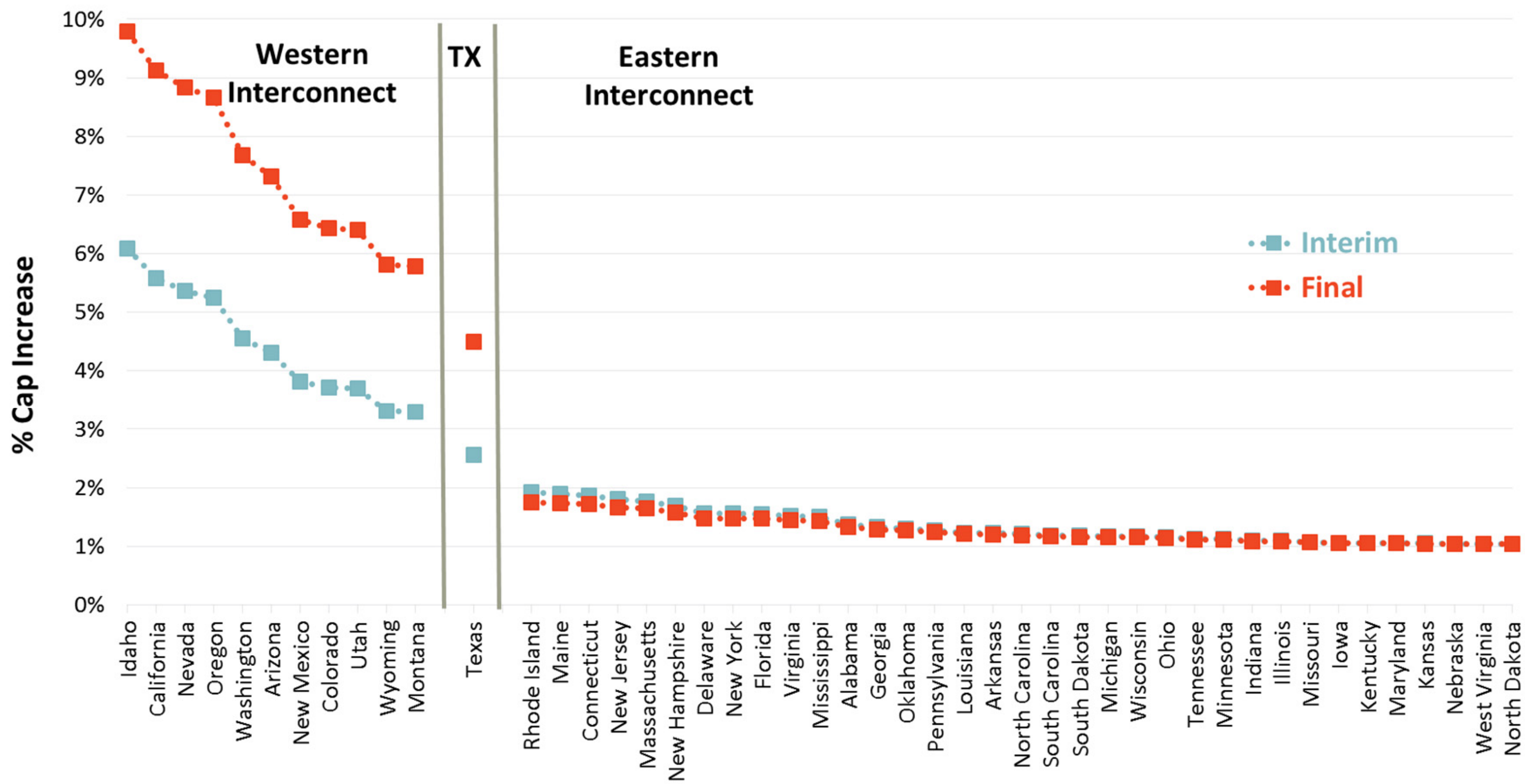
Similar pattern to reductions required under Mass-Based Standards



New Source Complement has a Larger Impact in Western Interconnect

Additional emissions attributed to new sources are significantly higher in WECC than the rest of the U.S.

- Cap increase higher due to higher load growth and less incremental output from EGUs, new RE, and under construction units in WECC



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States will need to make several decisions beyond implementing Rate or Mass Standards

Design Element	Primary Options
Compliance Standard	• **Mass-Based** (FIP, Trade-Ready) – CO_2 allowances required for all emissions • **Subcategory Rate-Based** (FIP, Trade-Ready) – NGCCs and fossil steam required to meet different rates • **State Average or Multi-State Average Rate-Based** – All covered units meet the same rate
Covering New CCs and Existing CTs	• Rate-based approaches will not cover these units by default • Mass-based can cover new units emissions through New Source Complement and states can propose to cover CTs
Mass-based CO_2 Allowance Allocation	• To existing generators (e.g. based on historical CO_2 output or projected allowable output) • To load serving entities • Set-aside and allocation for policy objectives (e.g. renewables, avoid coal retirement) • Auction-based
Trading and Addressing Seams	• Adopt a trade-ready compliance option for trading to other states with similar plan • Create a new multi-state coordination group (e.g. average rate approach or mass-based) • Join an existing CO_2 market (California or RGGI) • Apply a "CO_2 price adder" on imported power (similar to California) if at a leakage risk (e.g. from mass-based to rate-based state)
Renewables Standards (similar for EE)	• **Rate-based:** new units eligible under CPP can earn Emission Rate Credits (ERCs) • **Mass-based:** all renewables earn additional revenue through power prices • **Expanded RPS**: additional revenue stream for meeting state RPS requirement can be available either just for new renewables or all

Thoughts on Rate vs. Mass Standards

	Mass-Based (FIP)	Subcategory Rate-Based (FIP)	State-Specific Rate-Based
Potential Pros	• Trade ready • Simplest trading with significant experience (no need for EE/RE M&V) • Use CO_2 allocation and/or auctions to achieve policy goals (e.g., fund EE/RE, or offset customer rates) • Coal retirements help compliance relative to subcategory rate • *Possibly* fewest seams issues if identical plants treated the same	• Trade ready • Possibly less leakage than mass (i.e. power prices do not change as much under rate-based) • Allows CO_2 emissions to adjust to changes in load levels • Easier to respond to load growth or nuke/hydro retirements under rate-based	• Mostly same as subcategory • If state-specific rate is high or state is uniquely positioned, state-specific rate could be less stringent • Coal retirements help compliance relative to subcategory rate
Potential Cons	• *Possibly* more concerns regarding leakage to neighboring states that use rate-based, to new units & CTs • Allowances allocation to plant owners can introduce investment inefficiencies (e.g., old units stay online to receive future allowances) • Some states will worry about windfall to existing RE, nukes, and hydro from higher power prices	• Much more M&V required for trading, more complicated to participate (e.g. EE M&V, gas-shift ERCs) • Inconsistent treatment between existing and new NGCCs result in inefficient dispatch • Coal retirements have minimal benefit for compliance	• Mostly same as subcategory • Not trade-ready (unless multi-state averages are agreed upon, which may be challenging)

Complementary Policy Measures

Most states will pursue complementary policies even if they choose a mass or rate based trading option

- Existing or likely policies will affect the analysis of rate vs. mass
- Political preferences for policy measures could affect choice as well
  - RE/EE policy measures create ERCs
  - ERCs provide direct monetary support mechanism for RE/EE
  - Value of RE/EE policy measures less direct, unless awarded allowances
- States that prefer to “keep their hands on the tiller” with RE/EE support may prefer rate-based systems

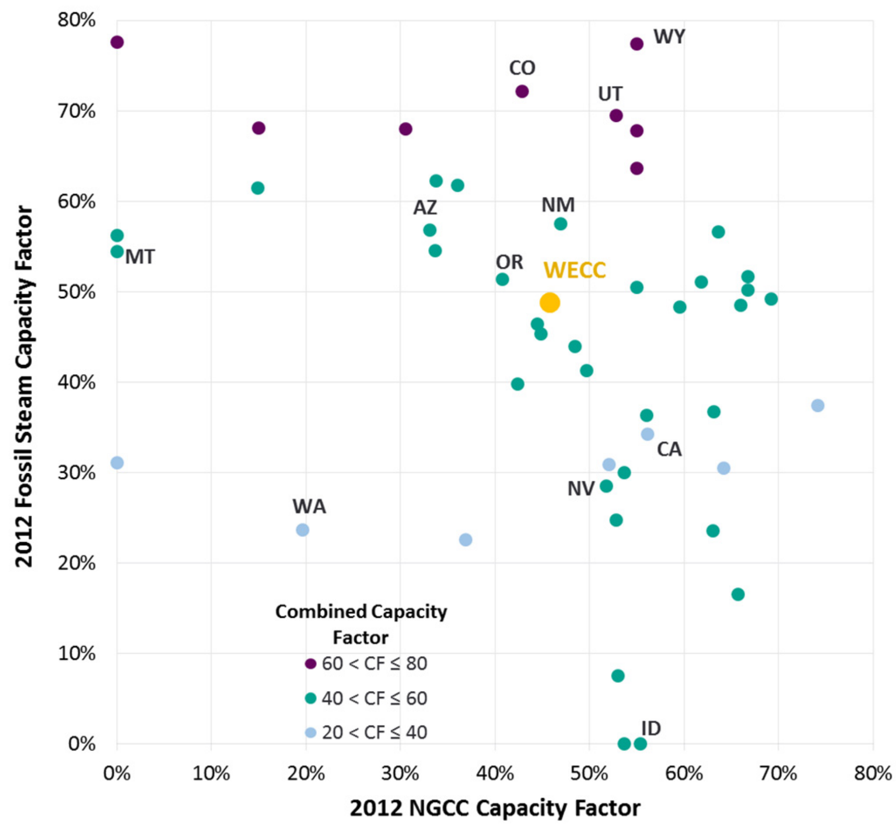
States that prefer to design their own policies and forego the model trading systems can elect either mass or rate based plans

- Mass based target needs to be as strict, backstop provisions (e.g., AB-32)
- States can set their own individual EGU rates, but have to demonstrate attainment of state average goal, no interstate ERC trading allowed

Projected output from EGUs is important factor to consider for CPP implementation approach

CPP standards do not account for affected sources increasing their output to meet increasing load growth

- If EGUs projected to increase output, rate-based standards likely easier
- If EGUs projected to decrease output, mass-based may be preferred



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Future of the CA Cap and Trade Program

California cap and trade program is in its 4th year of operation

- Auction prices remaining just above the floor ($13/ton)
- Limited GHG emission reductions seen so far; import emissions down 20%

What we know about the post-2020 cap and trade program

- 2030 Cap: Likely to codify 40% reductions from 1990 levels by 2030
- Complementary policies continue to be a significant component of the approach (50% RPS by 2030, expanded EE, proposed petroleum reductions)
- CPP states will likely have limited ability to trade with CA without linking programs; likely near term addition of Ontario and Manitoba

Significant uncertainties in program design remain unresolved

- Whether the floor price escalation continue at 5% + inflation
- How significant bank of allowances will be handled
- How imports under the CPP in 2020 will be charged for CO2 emissions

Linkage between CA and Mass-Based States

CPP regulations makes it unlikely that AB32 and CPP allowances will be interchangeable

- Regulations appear to restrict allowances from economy-wide programs being used for compliance in mass-based states
- Also not likely that CA will be interested in using CPP allowances for compliance

California cap and trade program is currently linked with Quebec and potentially will be joined by Ontario and Manitoba

- QC and CA share a similar economy-wide approach including more than 80% of GHG emissions under the cap
- Ontario and Manitoba stated intent to join
- Interest from NY to link RGGI to CA/QC, but unclear whether jurisdictions with caps on solely electric power sector due to CPP will be added

How does CA Handle Import Emissions with CPP?

Implementation of CPP in western states may result in GHG emissions of California imports being covered under both CPP and AB 32

The ARB will have three options for deciding whether to continue to include GHG emissions from neighboring states depending on the extent to which they find CPP achieves similar goals

1. No credit: No changes to import obligations; simple, but potential for double counting
2. Full credit: Remove import obligation and adjust GHG cap; simple, but will need BAU forecast of import emissions to adjust cap
3. Partial credit: Reduce import obligation to account for CPP reductions, potentially based on measure of relative stringency and adjust GHG cap; much more complex

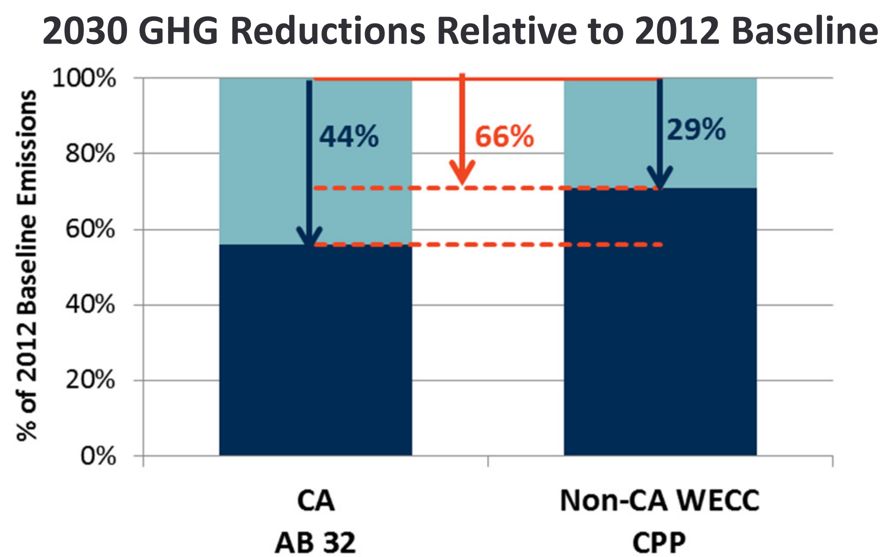
How Stringent is CPP Compared to AB 32?

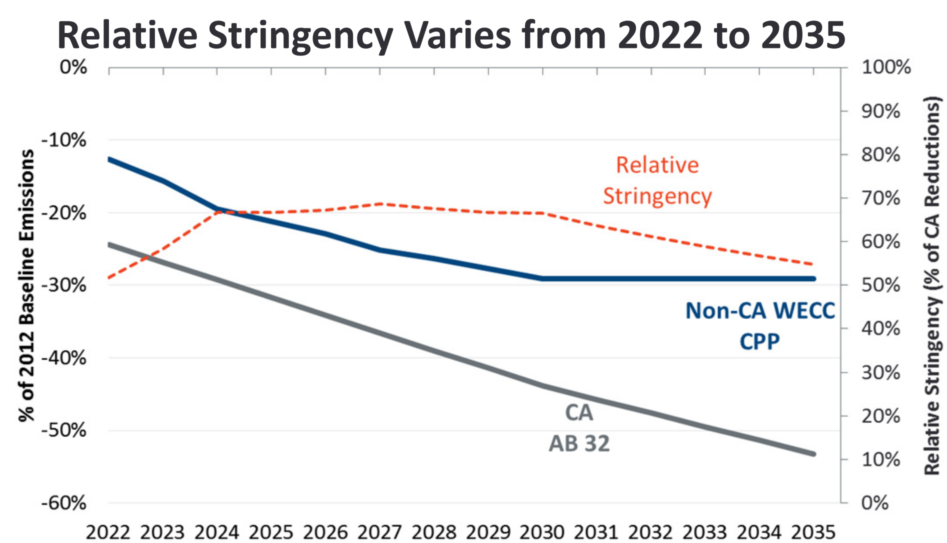
ARB will need to consider whether CPP is as stringent as AB 32

- Linked with Quebec due to similar coverage of sources and GHG reductions
- Consider existing WECC GHG policies (such as EE, RPS) as not equivalent
- Where do CPP reductions fit?

Relative to 2012 baseline emissions, CPP standards on average achieve 60% GHG reductions relative to AB 32

- Cumulatively, CPP 40% less stringent
- Relative stringency increases from 50% to 70%, but decreases beyond 2030





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Implications for the Western Interconnection

Potential development of three (or more) carbon markets could lead to distortions in dispatch costs between similar technologies

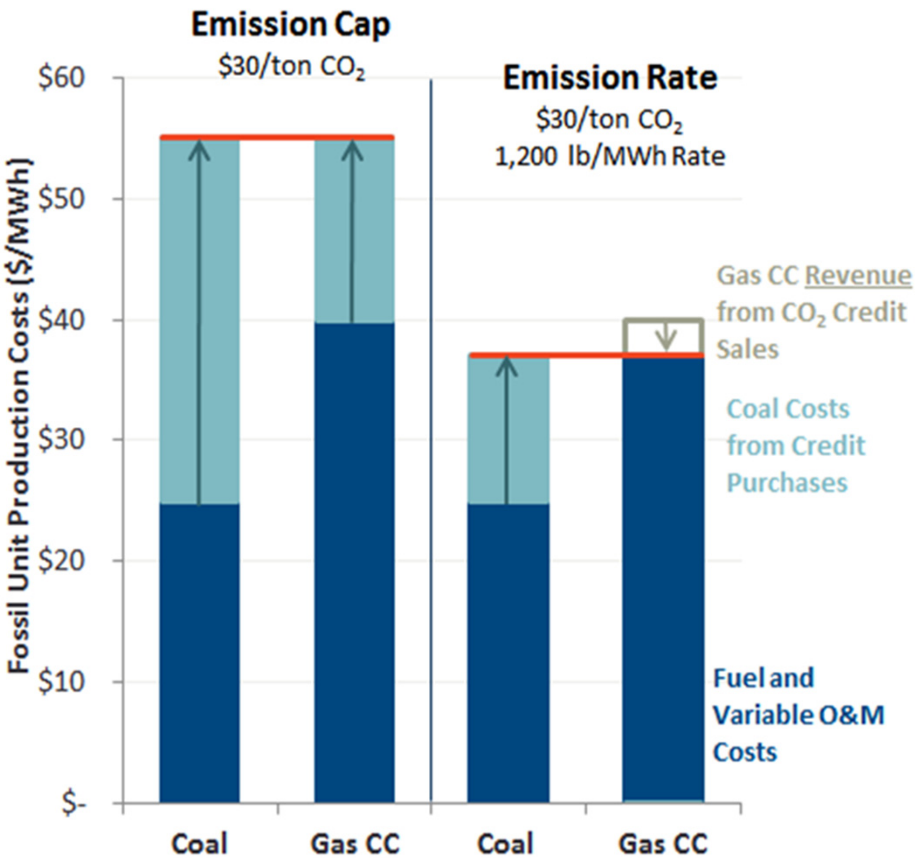
- CA allowances, CPP allowances, ERCs (*plus* any non-trade ready plans)

De-carbonization will likely alter generation capacity

- Coal retirements limited in WECC compared to eastern states
- WECC has great renewable resource potential

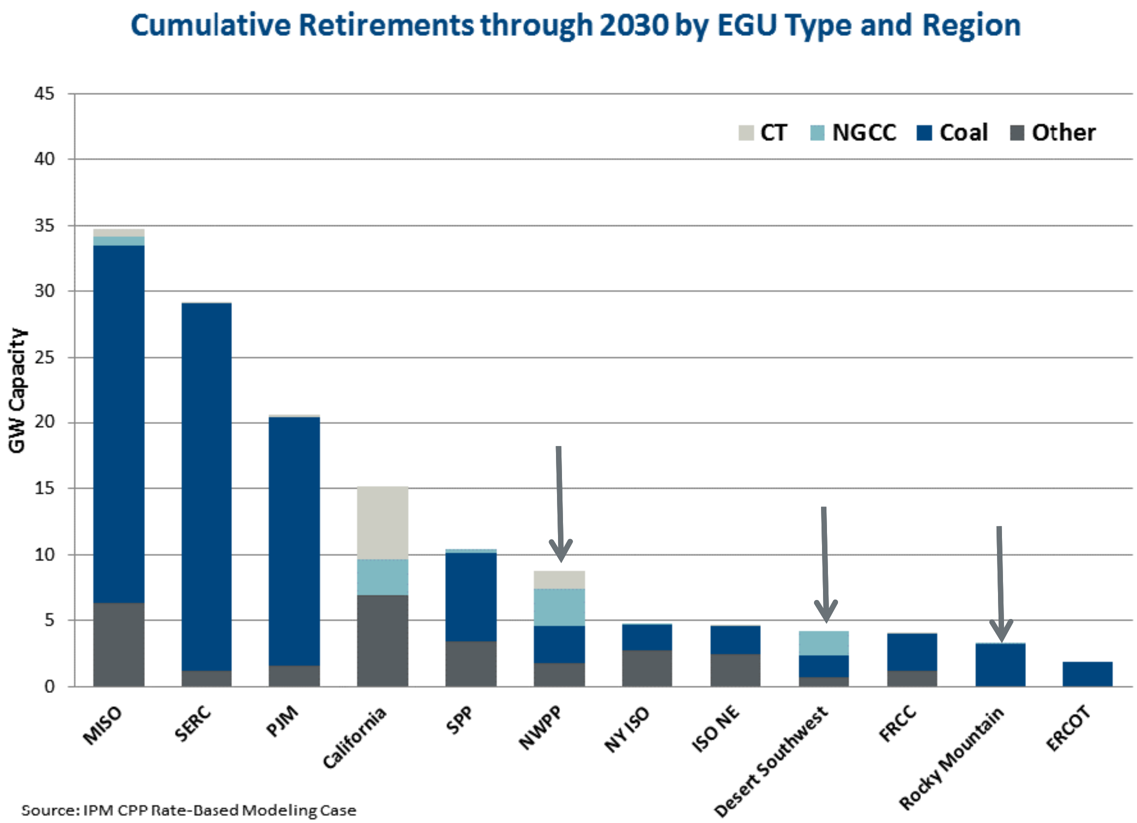
Planning the transmission system to accommodate changes will need to consider a wide range of future scenarios and benefits

Wholesale Price Differs Rate vs. Mass Programs



- Red bar is wholesale price
- Illustrative example assumes state average rate program
- Mass-based program (cap) adds to coal and NGCC bids
- Rate-based program has blend of adders on coal (ERC demand) and credits for NGCC generation ("fossil ERC" supply)
- Price impact depends on emission rates and capacity mix

EPA Projection of CPP Impacts



- Compared to the Eastern Interconnection, EPA's estimated generation retirements for the West is limited
- 5 – 10 GW of coal retirements in West
- But many states are likely to need additional renewable energy resources to comply, particularly CA

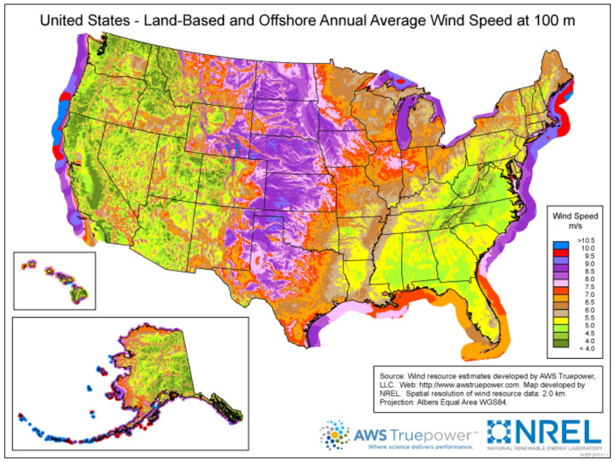
		Base Year	Base Year Source	Base Capacity RE (excluding hydro) (GW)	Incremental RE to Base (including new hydro) (GW)	Total 2030 RE Capacity (including new hydro) (GW)	Incremental Energy Efficiency (2030) (GW)	Cumulative Coal Retirements in 2030 (GW)
CPP (Rate)	[1]	2012	CPP	98	84	182	132	97
CPP (Mass)	[2]	2012	CPP	98	81	179	132	108

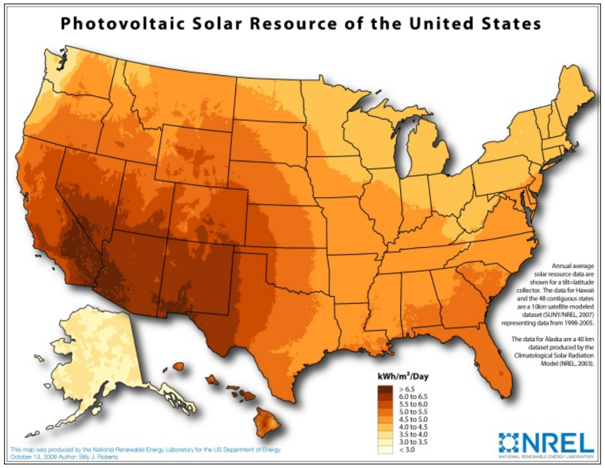
Renewable Resource Potential

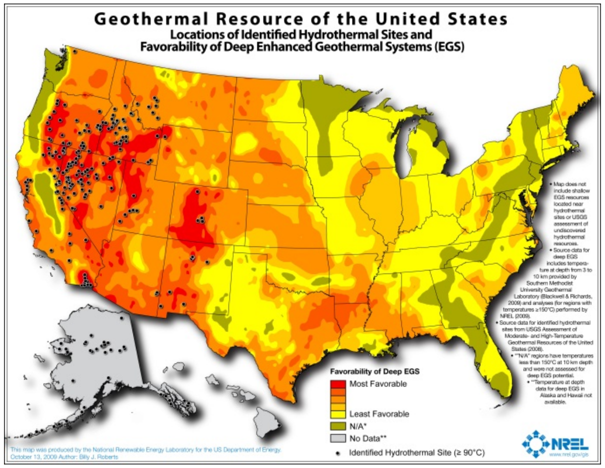
Potential for and quality of renewable resources vary by region

- Lowest-cost onshore wind resources are on the edge with Eastern Interconnection and Texas. These resources have a 10-15% capacity factor advantage, which translates to more than $20/MWh reduction in cost of wind
- Southwest has a tremendous amount of solar resources.
- Some western states have the highest potential for geothermal.

There is also significant opportunity to increase import from Canadian hydropower







How will CPP Drive Transmission Development

Coal retirements or coal-to-gas switching likely only a modest driver for regional transmission needs; even less so for interregional need

Most significant (though uncertain) driver will be the <u>extent to which low-cost renewable resources are relied upon</u> for emission reduction

- National (vs. regional/local) compliance approach, higher gas prices, carbon prices, and PTC/ITC will have significant impact on the economics of renewables

Transmission continues to face the "chicken-or-egg" challenge

- Facilitating low-cost renewable development will require new transmission
- But without the renewable development occurring, existing transmission planning processes will not identify transmission needs

CPP-Related Renewables Needs Re to Meet CPP

- We estimate $25-40 billion of transmission is still needed nationwide to accommodate ramp-up of existing state RPS requirements
- EPA estimates about 85 GW of new wind/renewables to meet CPP needs, implying almost $50 billion of likely additional transmission needs
- With alternative assumptions, 110 GW of new wind generation and $60 billion of transmission could be needed to achieve the CPP's emission rate reductions

Estimated U.S. Transmission Investment Driven by Renewables and CPP

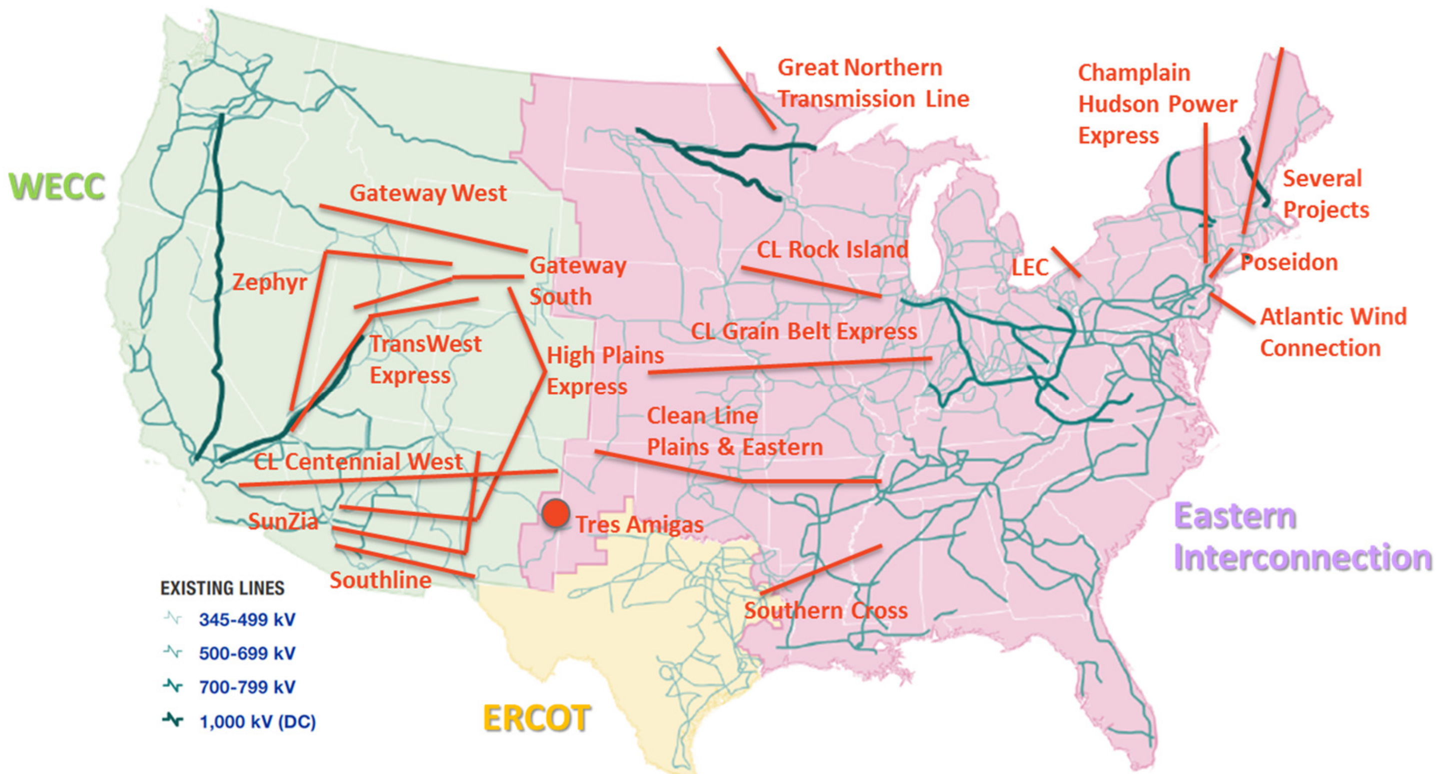
		Ramp up of Existing State RPS	EPA Estimate w/ CPP	Brattle Estimate w/ CPP
Estimated Wind Capacity	GW	**50-70**	**85**	**110**
Regional Transmission	**$billion**	**20-33**	**40**	**50**
Interconnection related	$billion	5-7	9	11
Total Transmission	**$billion**	**25-40**	**50**	**60**

Sources and Notes:
Brattle Estimate with the CPP assumes 50% of required emission rate reduction achieved through added wind generation.

Already-Proposed Interregional Projects

Numerous developers have proposed participant-funded or merchant lines

- Most of which are driven by plans to deliver low-cost wind, solar, or hydro resources to regions with high RPS needs
- Many of these projects' value proposition is too narrowly focused on single drivers (mostly renewables).



Key Barriers to More Effective Grid Planning

Three key barriers to identifying and developing the most valuable transmission infrastructure investments:

- Planners and policy makers **do not consider the full range of benefits** that transmission investments can provide and thus understate the expected value of such projects
- Planners and policy makers **do not account for the high costs and risks** of an insufficiently robust and insufficiently flexible transmission infrastructure on electricity consumers and the risk-mitigation value of transmission investments to reduce costs under potential future stresses
- **Interregional planning processes are ineffective** and are generally unable to identify valuable transmission investments that would benefit two or more regions
- Additional challenges related to regional cost recovery and state-by-state permitting processes

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- Experience with transmission planning and development, climate and renewable policy analysis, and wholesale electricity market design
- Recent transmission-related projects include analysis of the benefits of new transmission, review of transmission permitting processes and costs, and long term scenario analysis for the ERCOT transmission system
- Renewable and climate policy analysis completed for New England RPS market, California AB32 programs, and federal Renewable Fuel Standard
- Assisted utilities, RTOs, and cooperatives in identifying future scenarios to consider in strategic planning efforts
- Brings project management and operations experience from previous work commissioning and operating oil refinery process units while working for Honeywell
- M.S. in Technology and Policy from the Massachusetts Institute of Technology; B.S. in Chemical Engineering from the University of Notre Dame

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Marc Chupka provides expertise on the market impacts of both domestic and international energy and environmental policy. He assists energy market clients and counsel in a broad span of management analysis, regulatory proceedings, and litigation support. Mr. Chupka has focused on integrated resource planning, electricity and fuel procurement policies, renewable energy policy design, and climate change policies.

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Note:

The views expressed in this presentation are strictly those of the presenter and do not necessarily state or reflect the views of *The Brattle Group, Inc*.

Ms. Judy Chang is an energy economist and policy expert with a background in electrical engineering and 20 years of experience in advising energy companies and project developers with regulatory and financial issues. Ms. Chang has submitted expert testimonies to the U.S. Federal Energy Regulatory Commission, U.S. state and Canadian provincial regulatory authorities on topics related to transmission access, power market designs and associated contract issues. She also has authored numerous reports and articles detailing the economic issues associated with system planning, including comparing the costs and benefits of transmission. In addition, she assists clients in comprehensive organizational strategic planning, asset valuation, finance, and regulatory policies.

Ms. Chang has presented at a variety of industry conferences and has advised international and multilateral agencies on the valuation of renewable energy investments. She holds a BSc. In Electrical Engineering from University of California, Davis, and Masters in Public Policy from Harvard Kennedy School, is a member of the Board of Directors of The Brattle Group, and the founding Director of New England Women in Energy and the Environment.

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"Checklist" of Transmission Benefits

Benefit Category	**Transmission Benefit** (see 2013 WIRES paper)
Traditional Production Cost Savings	Production cost savings as currently estimated in most planning processes
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
	j. More realistic "Day 1" market representation
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future transmission needs, wheeling revenues, HVDC operational benefits

Considering All Transmission Benefits is Important

Estimated Annual Base-Case Benefits and Costs of CA Palo Verde-Devers 2 Line

Example: ERCOT Long-Term System Assessment

Table 3.1: 2014 LTSA Key Drivers Developed by ERCOT Stakeholders

Key Drivers	Description
Economic Conditions	U.S. and Texas economy; regional and state-wide population, oil & gas, and industrial growth; Liquefied Natural Gas (LNG) export terminals; urban/suburban shifts; financial market conditions; and business environment
Environmental Regulations and Energy Policy	Environmental regulations, including air emissions standards (e.g., ozone, MATS, CSAPR), GHG regulations, water regulations (e.g., 316(b)), and nuclear safety standards; energy policies including renewable standards mandated fuel mix, sol
Alternative Generation Resources	Capital cost trends for improvements affectin capacity additions, st (DG) costs, and financi
Natural Gas and Oil Prices	Gas prices are a functi LNG exports, industria prices are dependent spread of horizontal d affect drilling locations
Transmission Regulation and Policies	New policies around t neighboring regions, a
Generation Resource Adequacy Standards	Economically determin flexible resource requir
End-Use/New Markets	End-use technologies demand-response; ch increase interest in mic
Weather and Water Conditions	May affect load growt technology mix, aver extreme weather event

http://www.brattle.com/news-and-knowledge/news/brattle-consultants-assist-ercot-in-scenario-planning-and-improving-its-long-term-transmission-planning-process

Table 3.2: 2014 LTSA Scenarios Developed by Stakeholders

Candidate Scenarios	Description
Current Trends	Trajectory of what we know today (e.g., LNG export terminals and West Texas growth, prolonged high oil prices)
Global Recession	Significant reduction in economic activities in the U.S. and abroad
High Economic Growth	Significant population and economic growth from all sectors of the economy (affecting residential, commercial, and industrial load)
High Efficiency/High DG/Changing Load Shape	Reduced *net* demand growth due to increase in distributed solar, cogeneration and higher building and efficiency standards
High Natural Gas Prices	High domestic gas prices
Stringent Environmental Regulation/Solar Mandate	On top of current regulations, the Environmental Protection Agency (EPA) also regulates GHG emissions. Federal or higher Texas renewable standards. More stringent water regulations. Texas legislative mandate on utility-scale and distributed solar development.
High LNG Exports	Significant additional construction of liquefied natural gas (LNG) terminals (beyond Current Trends)
High System Resiliency	Severe climate and system events leading to more stringent reliability and system planning standards
Water Stress	Low water availability
Low Global Oil Prices	Sustained low oil prices

Interpretation and Uses of the Scenario-Based Transmission Planning

- Future scenarios are used to **evaluate the potential future transmission** needs (including location, size and timing).
- A scenario **does not represent a deterministic future** that *will* occur. Instead, together the **scenarios cover the range of plausible futures**.
- Some planners are inclined to assign "probabilities" to each future scenario, inevitably assigning "Current Trends" the highest probability because it is developed **with "known and knowable facts" today**.
- Best to not assign probabilities, instead, **carry all scenarios to market simulations** and evaluate the transmission projects needed under all scenarios
- Assess if certain projects
  (1) Are needed in multiple/most scenarios;
  (2) Mitigate the risk of very high cost outcomes;
  (3) Are better long-term solutions than smaller-scale projects that only address the most immediate needs.
- Scenario-based transmission planning can also help **evaluate the types of public policies** that transmission planners may want to support.