Introduction to Integrated Resource Planning

Devi Glick and Shelley Kwok– Synapse Energy Economics
Juan Pablo “JP” Carvallo – Berkeley Lab

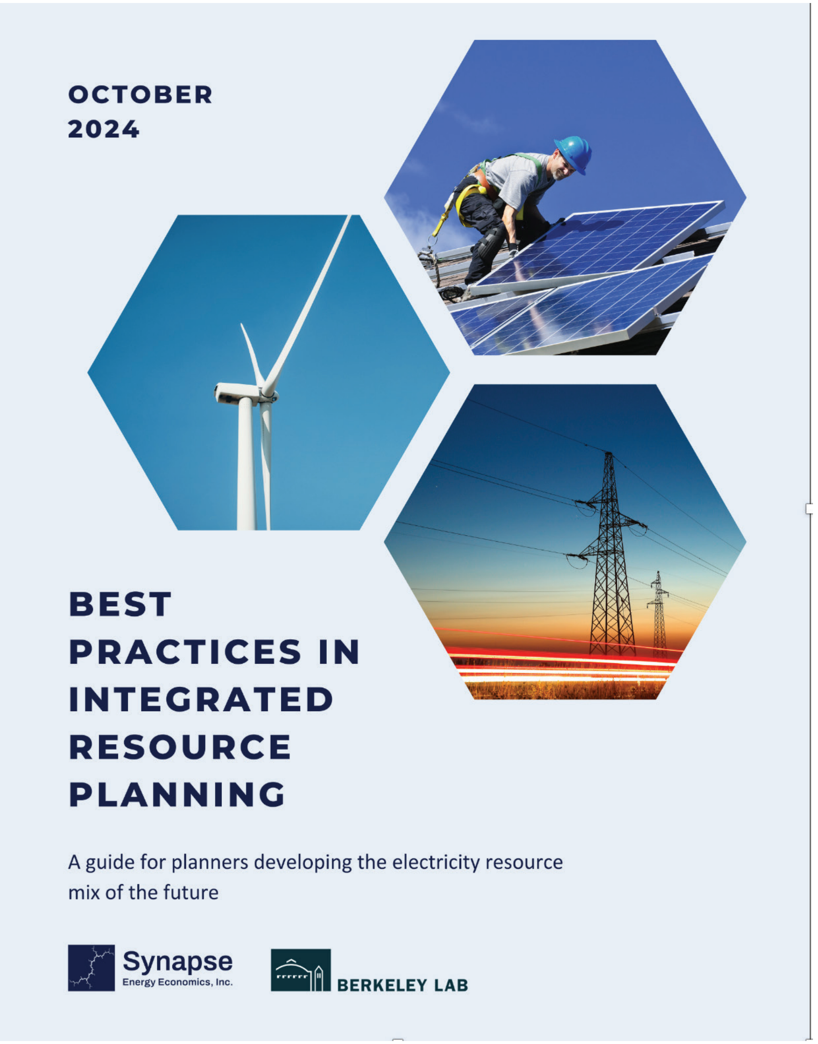
Clean Energy Innovation Fellows Training - October 31, 2024

Synapse
Energy Economics, Inc.

Energy Markets & Policy
BERKELEY LAB

Forthcoming report

Today's training is based on a forthcoming report by Synapse Energy Economics and Berkeley Lab, available here soon



Introduction to IRP

Synapse Energy Economics, Inc.

Energy Markets & Policy
BERKELEY LAB

What is IRP?

- Integrated Resource Plan – The process, the plan, the document
- **An IRP is a plan that seeks to find an optimal combination of resources, from among supply and demand-side options, to satisfy future energy service demands in an economic and reliable manner**
  - Used primarily in vertically integrated states, where utilities are responsible for meeting their customers' energy and capacity needs
- IRPs provide an opportunity to engage stakeholders and regulators in long-term planning decisions
- A properly executed IRP results in a transparent report and a clear short-term action plan

IRPs generally seek to find the least-cost resource plan subject to:

- **Reliability requirements**
- **Regulatory requirements**
- **Operational constraints**
- **Market factors**

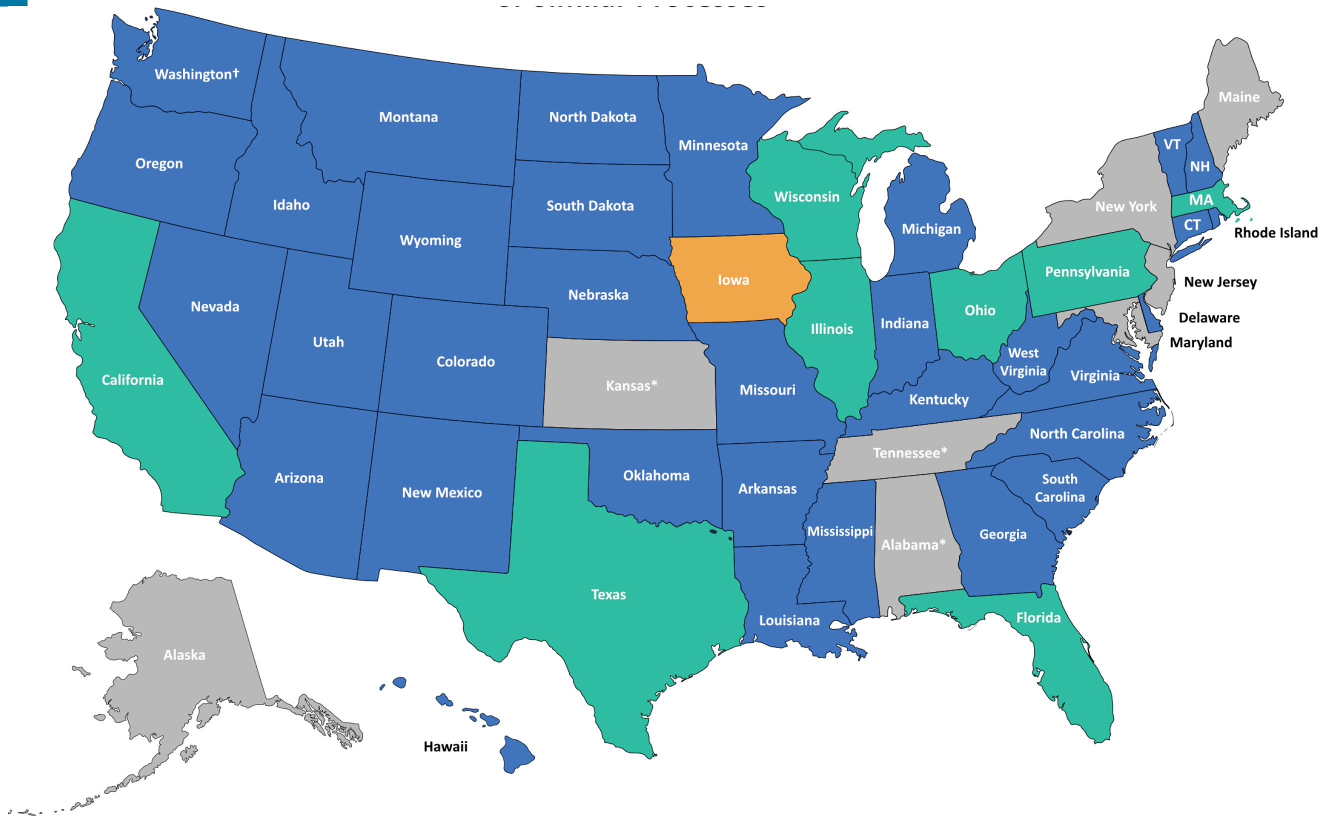
Where are IRPs used?

Resource plan types in the US

- Full IRP
- Long-term resource plan
- No filing requirement

Regulatory scrutiny varies

- Litigated docket
- Formal acknowledgement
- No formal approval process



*In Kansas, Evergy is required to file an IRP. In Alabama, Alabama Power voluntarily files an IRP. In Tennessee, Tennessee Valley Authority files an IRP.
†In Washington, dual-fuel utility Puget Sound Energy is required to file an Integrated System Plan.

State has an IRP and filing requirement

State is developing or revising an IRP rule and filing requirement

State has a filing requirement for long-term plans

State does not have a filing requirement for long-term plans

Elements of an IRP: Inputs

- Load forecast
- Demand-side resources
- Commodity prices
- Supply-side resources
- Market integration assumptions
- Transmission & topology
- Regulatory factors
- Other system constraints

Elements of an IRP: Tools and analysis structure

Tools

- Production cost and capacity expansion modeling
- Resource adequacy (RA) modeling

Analysis structure

- Scenarios, sensitivities, and portfolios
- Preferred portfolio & short-term action plan

Outputs

- Preferred portfolio
- Short-term action plan
- System costs & emissions

Regulatory context

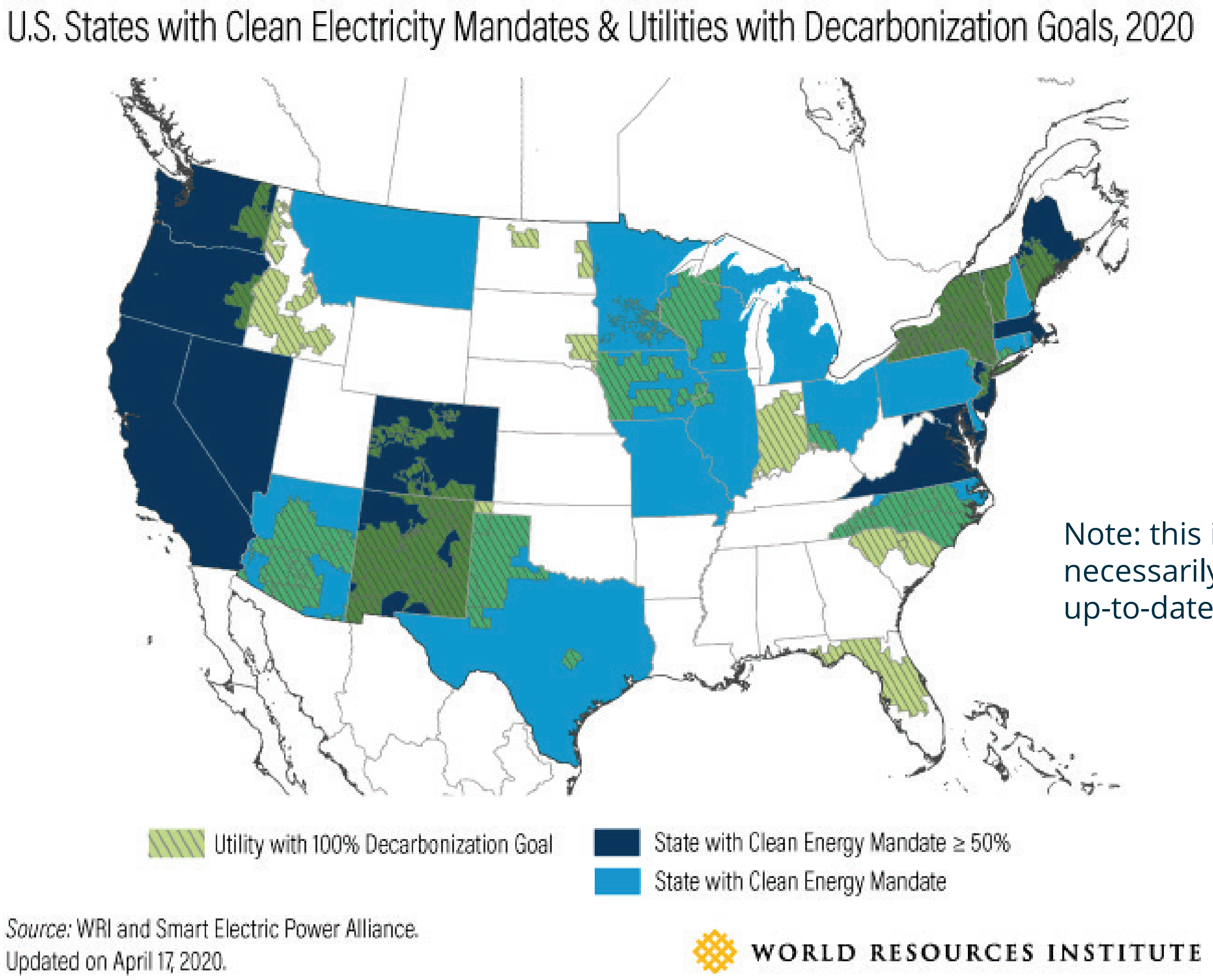
Regulatory compliance

- IRP is about selecting a least-cost, least-risk plan ***subject to compliance with reliability and regulatory constraints***
- Impacts of environmental regulations on IRP
  - Rule out certain portfolios as not meeting statutory requirements
  - Apply additional capital and O&M compliance costs to certain portfolios
  - Include constraint or cap on emissions
  - Include carbon price in dispatch

Example regulations relevant to IRP

- **Greenhouse gas (GHG) regulations (Section 111 of Clean Air Act)**
- **Federal Regional Haze regulations (NOx)**
- **Federal effluent limitation guidelines (ELG)**
- **Federal coal combustion residuals**
- **Good neighbor rule**
- **State renewable portfolio standards**
- **State energy efficiency requirements**
- **Potential future federal and state GHG policies**

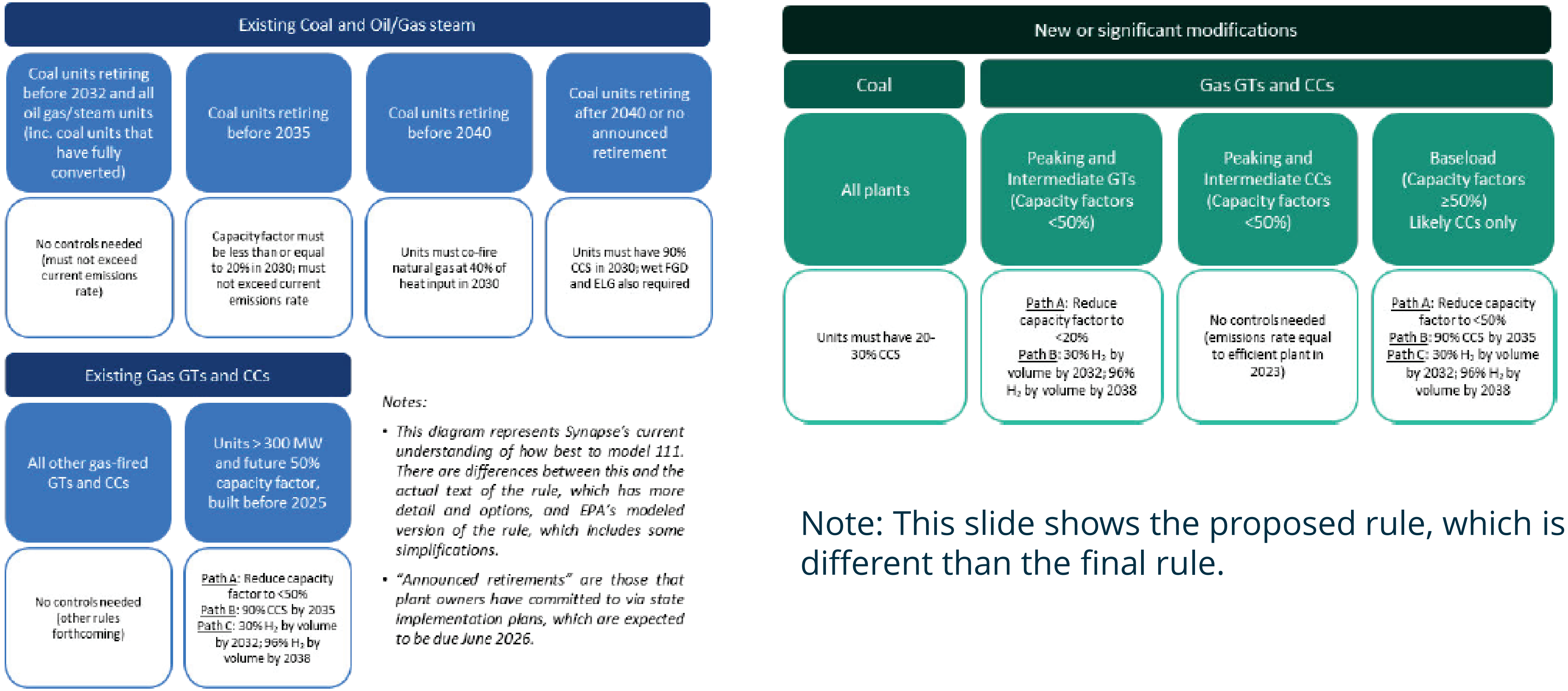
State and utility carbon reduction goals



Note: this is illustrative and not necessarily comprehensive or up-to-date

Carbon regulations (111d)

Figure 1: Synapse's understanding of EPA's Proposed Rule under Section 111 of the Clean Air Act



Note: This slide shows the proposed rule, which is different than the final rule.

Stakeholder engagement

IRP participants

- Utilities
- Regional transmission organizations (RTOs)
- State Public Utility Commissions
- State environmental regulators
- State legislatures, governors, and energy offices
- Stakeholders and intervenors

Stakeholders and intervenors

- Utility consumer advocates / Citizen utility boards
- State Attorneys General
- Cities and municipal governments
- Large industrial and data center customers
- Environmental groups
- Energy justice groups
- Resource developers
- Trade groups

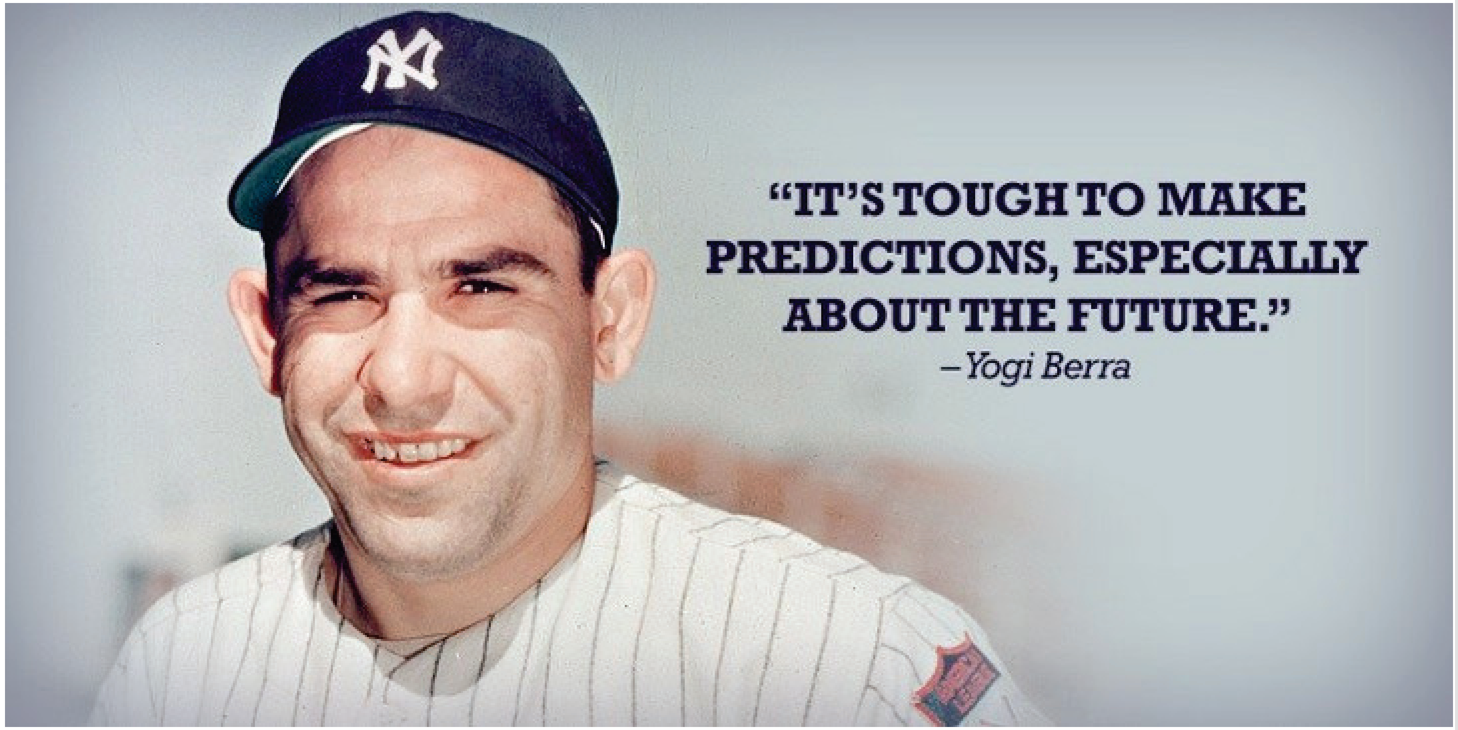
Engaging stakeholders

- Design a process that is engaging and responsive
- Remove barriers to participation
- Prioritize transparency
- Engage technical stakeholders
- Provide modeling licenses and data to technical intervenors

Load and DER forecasting

Load forecasting

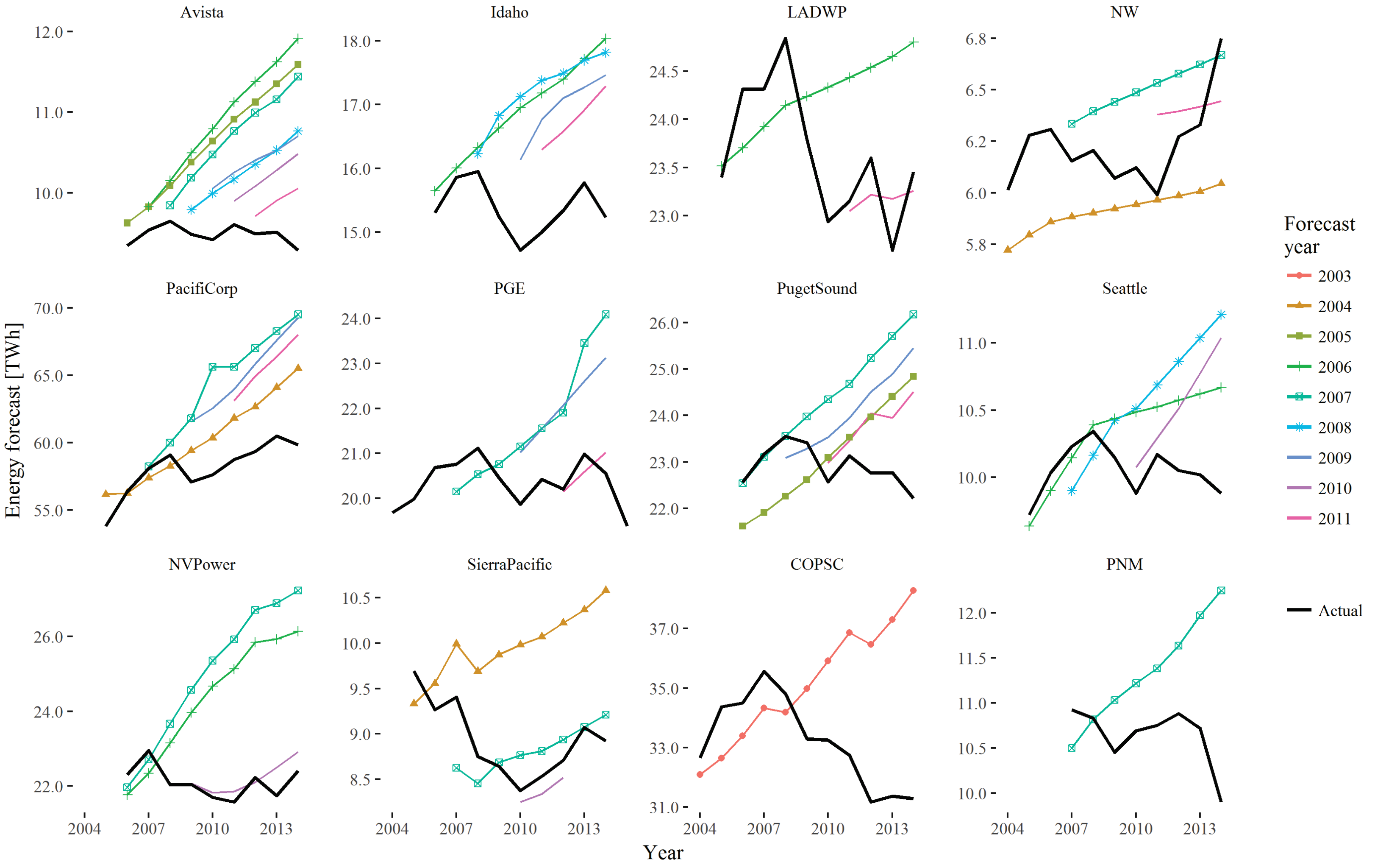
- Approach
  - Top-down — typical methods include econometric and time-series
  - Bottom-up — typical methods include statistically-adjusted end use (SAE) models
  - Hybrid
- Variables to predict
  - Energy consumption
  - Peak demand (although check best practice on RA assessments)
- Traditionally split by customer segment to match ratemaking forecasts



Credit: Henning Stein

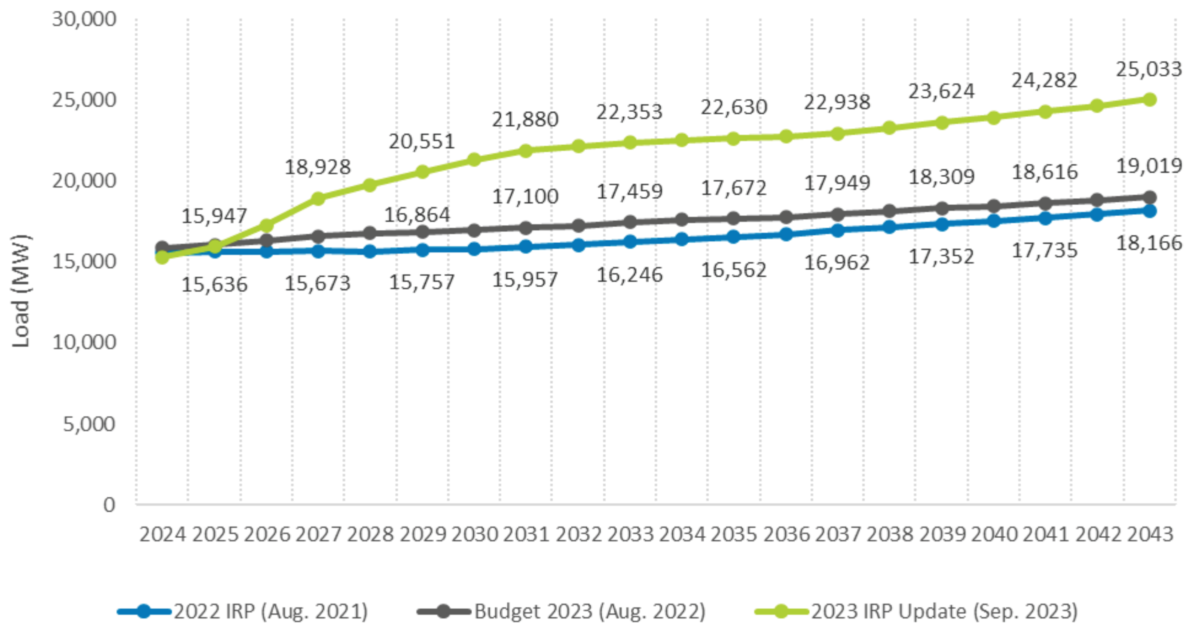
Yogi Berra was right

- Retrospective analysis of energy forecasts for 12 Western load-serving entities
- Most consistently over forecasted, even when recent trends showed little to no load growth
- Problem: asymmetric impacts of forecasting errors



Load forecasting: Best practices

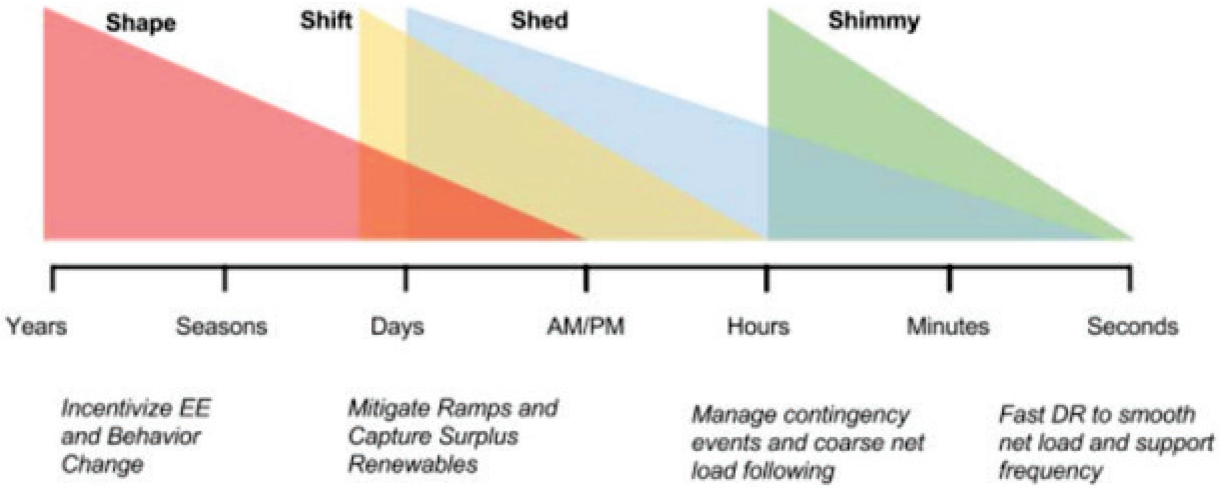
- Granularity and resolution
  - Hourly temporal resolution
  - Locational spatial resolution, matching models
- End use focus
  - Beneficial for new types of end uses
  - Separate end use forecasts
    - Adoption
    - Operation
    - Flexibility



Georgia Power 2023 IRP - Projected Winter Demand

Load flexibility in forecasting

- Traditional demand response
  - Continues to be treated separately via demand-side management and conservation studies
- New loads
  - Representing EV flexibility
    - Optimized EV charging; load shifting potential
  - Representing heat pump flexibility
    - Realistic pre-cooling and pre-heating estimates
- Flexibility in RA assessments (more later)



Source: LBNL's 2025 California Demand Response Potential Study – Phase 2

Forecasting large loads

- Data center, industrial, and manufacturing loads can significantly impact forecast outcomes, especially emerging after a decade and a half of stagnant demand growth

- A few strategies to forecast large loads
  - Require utility to incorporate meeting construction milestones, or allow utility to recover costs from load-driven investments
  - Hedge existing customer's risk by developing risk-sharing contracts for large new loads
- Integration strategies
  - Temporally: Flexibility
  - Spatially: Locational incentives to use available hosting capacity
  - Optimize timing/sequencing of load interconnection, rather than fulfilling individual customer needs
  - Analyze new load within IRP for least-cost solutions, tracking system costs to understand impacts and support cost allocation decisions

DER forecasting

- DER forecasting is conceptually similar to end use-based forecasting
  - Separately forecast **adoption of DER over time and space**, as well as modeling DER **operation**
  - Adoption and operation follow **economic logic**, but are strongly **influenced by policy, regulatory, and retail rate incentives**
- Best practice
  - Propensity of adoption method
  - Operation does not have a best practice → scenarios
- Transparency and consistency
  - Do not “hide” the DER forecast with the load forecast
  - If a Distribution System Plan is available, ensure the IRP uses the same assumptions and outcomes

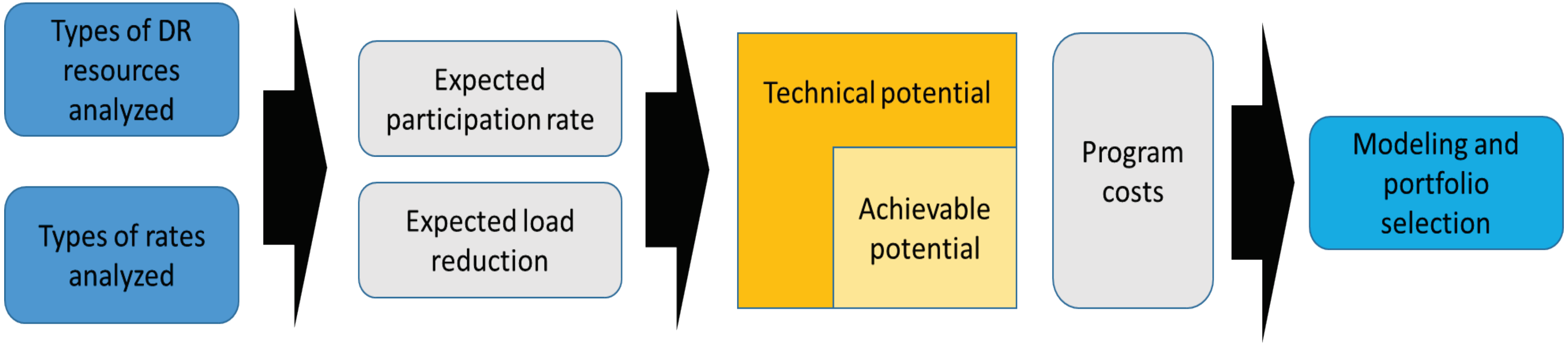
PV (top) and EV (bottom) DER forecasts from PGE’s 2023 IRP

Poll question: Forecasting

What are some approaches that can be used to address the high uncertainty of emerging large loads in resource planning?

Demand-side resources

Demand-side resources

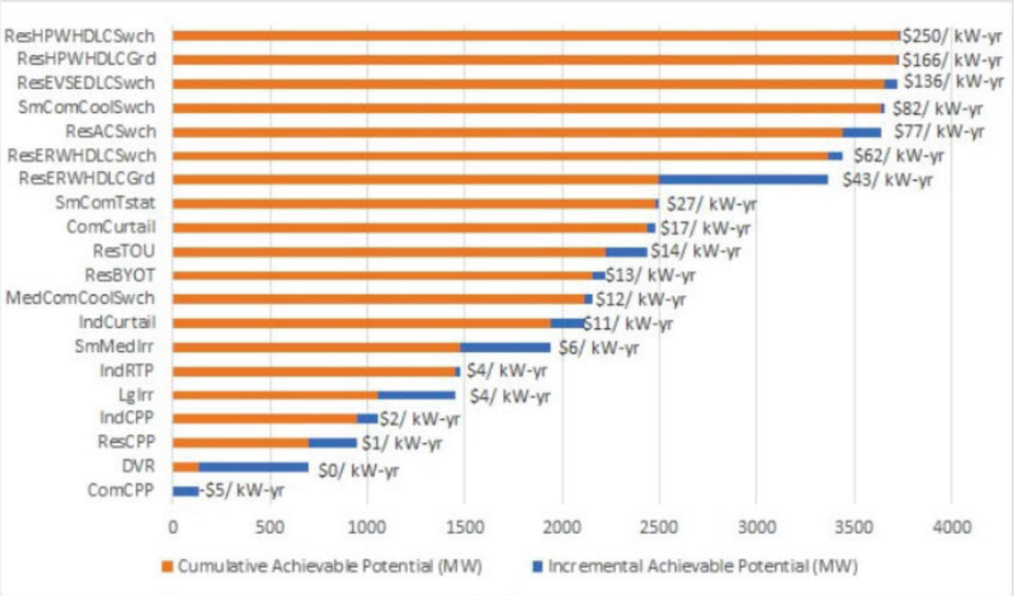


Source: Carvallo and Schwartz (2023), *The use of price-based demand response as a resource in electricity system planning*

- Traditionally, **energy efficiency** and **demand response** programs have been individually analyzed as "demand-side resources"
- Their characterization, modeling, and selection typically occur in an additional report called a Market Potential Study or the Conservation Potential Study
- The diagram above shows key steps for modeling demand-side resources in IRP

Modeling demand-side resources

- Two **main ways** to model demand-side resources in planning
  - **Load modifier** approach
  - **Competitive resource** approach
- Key best practices
  - Ensure consistent parameter assumptions
  - Bundle measures to reflect program implementation and evaluation practices
  - Ensure consistency with IRP scenarios
  - Incorporate all relevant benefits for demand side resources



Source: NWPCC 2021 – Supply curve for competitive resource approach

Supply-side resources

Resource characterization for new and existing resources

- Basic generator information
  - Generator operating life
  - Generator size
- Operating characteristics
  - Generator efficiency / heat rate
  - Resource operating shape
  - Ramping characteristics
  - Outage rate & schedule
  - Emission rates / installed environmental controls
- Resource costs
  - Fixed and variable operating costs
  - New resource capital costs
  - Sustaining capital costs
  - Renewable integration costs
  - Required transmission upgrades (interconnection costs)
- Other inputs
  - Capacity factor (for renewables)
  - Capacity contribution (effective load carrying capacity (ELCC) /firm capacity)

Resource characterization example

Nominal $	Heat Rate MMBtu/MWh	Variable Cost[1] $/MWh	Fixed Cost[3] $/kW-Year	Book Life Years	2017 Real $[2] $/kW
2X1 CC	6.59	40	197	36	1,233
1X1 CC	6.63	42	257	36	1,668
CT	10.07	74	58	36	476
Aero CT	9.32	59	198	36	1,680
Solar & Aero CT	9.32	58	235	35 (Solar) / 36 (CT)	3,366
Nuclear	10.50	12	1,048	60	9,133
Biomass	13.00	88	968	40	6,698
Fuel Cell	8.54	33	1,313	15	5,880
SCPC w/ CCS	11.06	165	636	55	5,366
IGCC w/ CCS	10.88	152	1,282	40	10,839
Solar	-	(10)	128	35	1,436
Onshore Wind	-	(9)	301	25	2,112
Offshore Wind	-	(9)	476	30	4,021
CVOW	-	(9)	2,841	25	25,838

(1) Variable cost for biomass, solar, solar & aero, onshore wind, offshore wind, and CVOW includes value for RECs.
(2) Values in this column represent overnight installed costs.
(4) Fixed costs include investment tax credits and gas firm transportation expenses.

New resource costs

- Generic, publicly available sources
  - Lazard Levelized Cost of Energy and Levelized Cost of Storage analyses
  - NREL Annual Technology Baseline
  - EIA Annual Energy Outlook
- All-source RFPs
  - Especially useful where costs are uncertain and changing fast
- Proprietary and/or utility-specific analyses
  - Navigant
  - Wood McKinsey
  - Burns and McDonell

Best practices

- **Use RFP results where possible as they reflect actual market data**
- **If RFP results are out of line with expectations, conduct supplemental analysis**
- **Use cost trajectories based on technology maturity curves**
- **Avoid simplifying assumptions that create systematic bias**
- **Include all tax credits and program incentives**

Timing of resource availability

- Challenge of balancing optimization modeling with accurate reflection of real-world risks and constraints
- Best practices
  - Model scenarios with and without constraints
  - Model expectations of how constraints will change over time
  - Be proactive with procurement
  - Utilize surplus interconnection / existing interconnection rights

Real-world challenges to timely resource deployment

- **Construction delays**
- **Siting and permitting challenges**
- **Local opposition (NIMBY)**
- **Interconnection queue backlog**
- **Supply chain constraints (COVID-19-related)**
- **Labor shortages (especially skilled labor)**

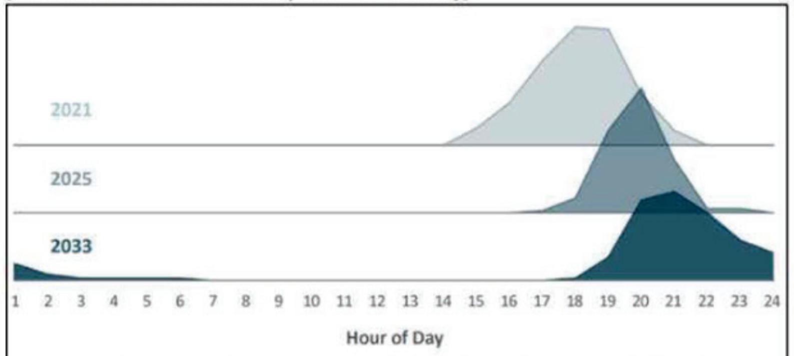
Firm capacity (1)

- Firm capacity contribution of resources
  - Installed capacity (ICAP)
  - Unforced capacity (UCAP — includes consideration of outages)
- Planned (unforced) and unplanned (forced) outages
- Firm fuel contracts
- Transmission congestion

Firm capacity (2)

- Effective load carrying capacity (ELCC)
  - Measurement of a resource's ability to generate electricity when the system is most likely to experience peak demand
  - Requires resource adequacy analysis to assess capacity value (or reliability contribution) that is tied to loss-of-load probability
  - As the penetration of a particular resource increases, the firm capacity credit given to additional "tranches" goes down

Figure 3. The Changing Profile of Reliability Risk in the Desert Southwest (Relative Loss of Load Risk by Hour of the Day)



The changing composition of the portfolio impacts the timing of reliability risks:
- High levels of solar shift the loss of load risk later into the evening
- Storage flattens the net peak, extending the loss of load risk into the late evening and early morning hours

Solar PV	Winter	Summer
Up to 1,000 MW	1%	40%
1,000 to 2,500 MW	1%	35%
2,500 to 3,700 MW	1%	25%
3,700+ MW	1%	10%

Renewable energy costs

- Renewable integration costs
  - Grid services and upgrades needed to support expanded renewable penetration
  - Costs are portfolio / resource specific
- Interconnection costs
  - Incremental costs of upgrading or adding transmission resources
  - Costs increase as renewable energy penetration increases on grid
  - Reforms are underway to address cost recovery

Avoidable forward-going costs

- For existing fossil resources, avoidable forward-going cost are from:
  - Near-term utility costs for capital expenditure schedules
  - Anticipated environmental compliance costs
- Best practices
  - Model forward-going capital costs that are avoidable with retirement in capacity expansion model (not in post-processing step) to capture benefits of early retirement
  - Benchmark cost projections against historical spending and industry projections
  - Model ramp-down of spending in advance of retirement

Modeling battery energy storage

- Many durations and technologies available
  - Short, medium, and long-duration
  - Mechanical, thermal, electrochemical, chemical
- Multiple uses / values
  - Firm capacity
  - Frequency response
  - Reserves
  - Fast ramping services (like combustion turbines or other fossil peaking resources)
  - Reduce renewable curtailment
  - Resiliency

Advanced technologies

- Model costs and risks of advanced technologies
- Be consistent in treatment of advanced technologies
- Pilot programs
    - Long duration energy storage pilots in Georgia, Virginia, New York, Colorado, Minnesota

Technology examples

- Carbon capture and storage / sequestration
- Hydrogen conversion / co-firing
- Small modular nuclear reactors
- Long-duration battery storage

Market interaction and transmission solutions

- Modeling transmission alternatives
  - Co-optimize transmission expansion and portfolio development
  - Incorporate regional transmission planning
  - Model tranches of transmission available as an alternative to generation build-out
- Modeling market interaction
  - Align capacity expansion modeling with regional resource availability
  - Model accurate representation of external markets

Commodity prices

Commodity price overview

- Commodity price forecasts are central to an IRP
- Fuel price forecasts generally are developed by an external entity
- Electricity market prices may be from an outside entity or developed by the utility as part of the IRP process
- Best practice is to also include:
  - Fuel supply limitations
  - Impacts of gas price volatility
  - Coal supply constraints

Fuel prices
- **Coal**
- **Natural Gas**
- **Uranium**

Market prices
- **Energy prices**
- **Capacity prices (in RTO/ISOs)**

Emission prices
- **Carbon dioxide (CO_2)**
- **Sulfur dioxide (SO_2)**
- **Oxides of nitrogen (NO_X)**

Fuel price forecasting

Coal

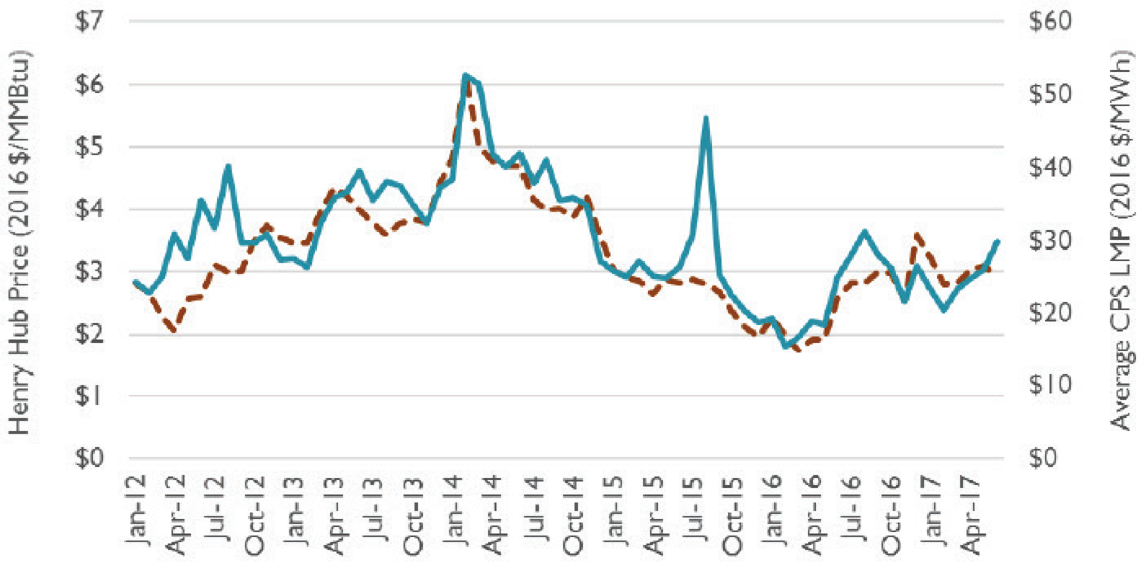
- Near-term prices often tied to existing contracts
- Longer-term prices based on fundamentals forecasts (e.g., AEO)
- Delivered prices can include substantial transportation costs
- Occasional issues specific to co-located coal units and mines

Natural Gas

- Near-term prices often tied to futures markets
- Longer-term prices based on fundamentals forecasts (e.g., AEO)
- Forecasts often tied to some central hub
  - Delivered price presented based on differential relative to hub
- Potential for substantial variation, volatility

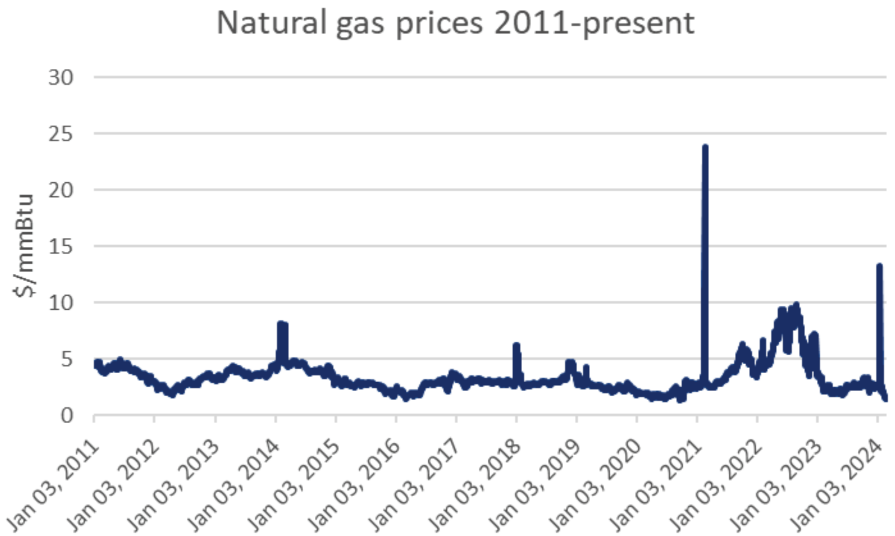
Market price forecasting

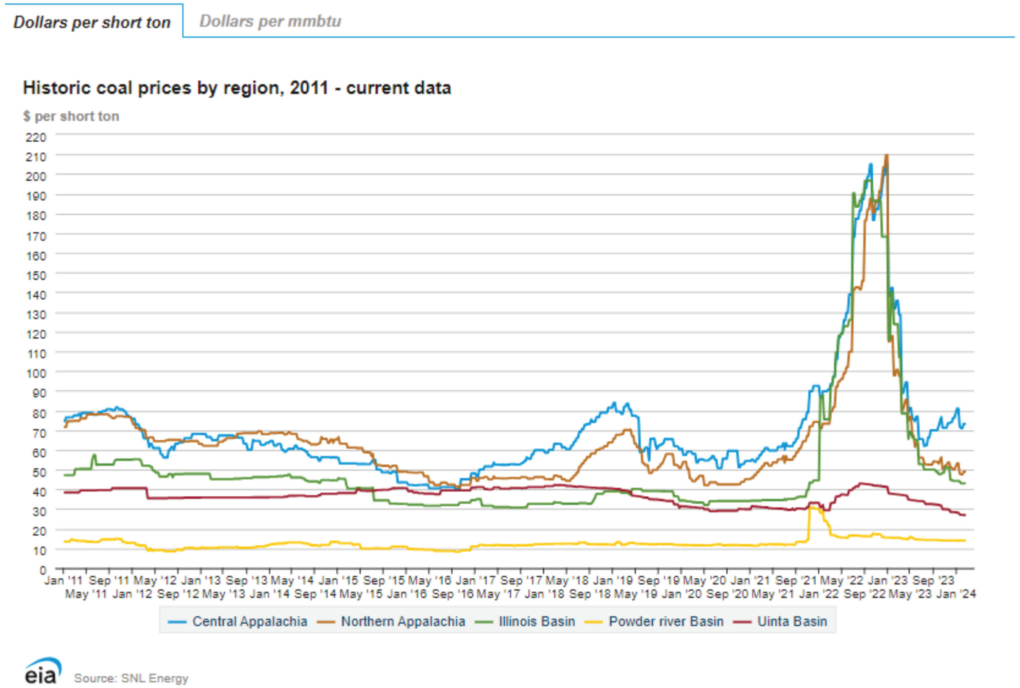
- Near-term prices often tied to futures markets
- Longer-term prices based on fundamentals forecasts (e.g., AEO)
- Should be synchronized with fuel price forecasts
    - Market prices often highly correlated with gas prices
    - Inclusion of a price per ton of CO2 often changes gas prices and electricity prices



Volatility and constraints in fuel supply

- Fuel supply limitations
- Impacts of gas price volatility
- Coal supply constraints



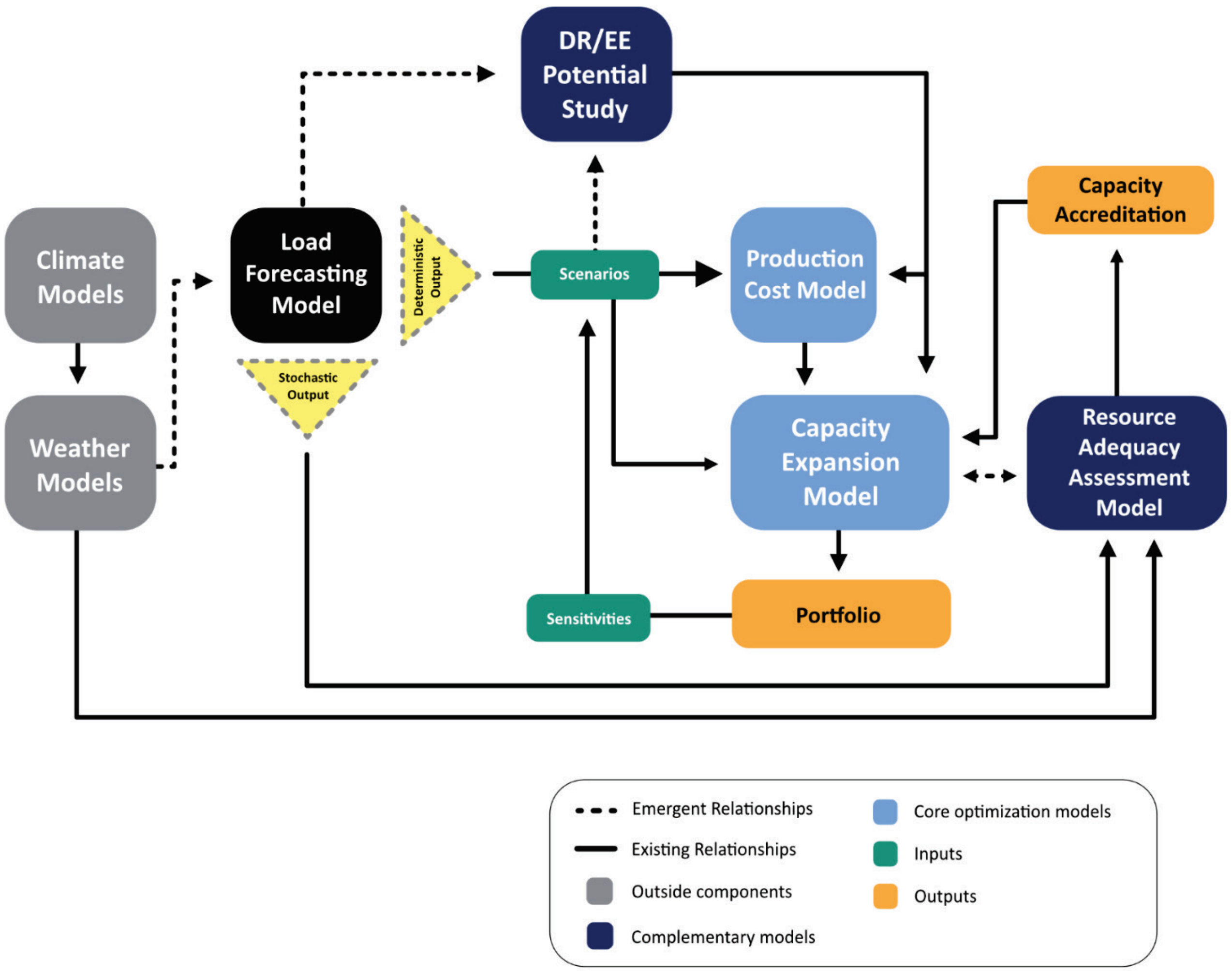


BREAK!

Models

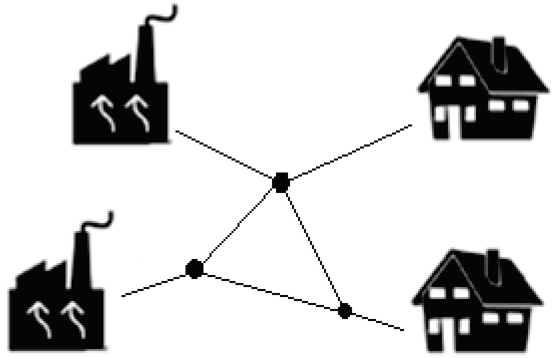
Modeling tools

- Modeling tools that simulate and optimize the electricity system are at the heart of a forward-looking planning process like IRP
- Diagram shows the traditional models used in IRP and how inputs and outputs relate. In addition, it shows some key parameters such as scenario design and sensitivities.
- We will explore three key models
  - Capacity expansion
  - Production cost
  - Reliability

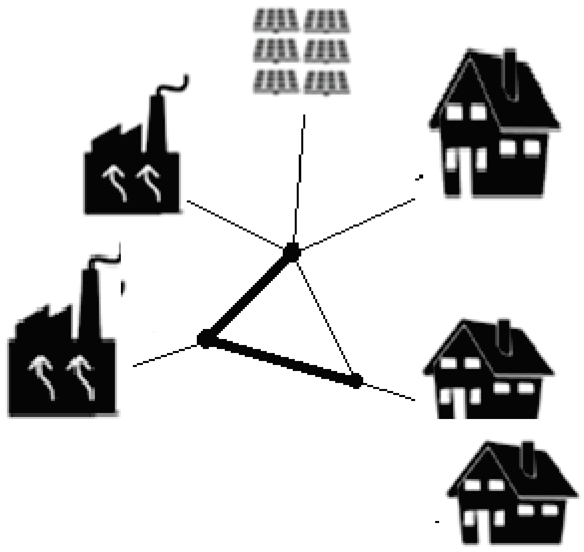


Key models: Capacity expansion

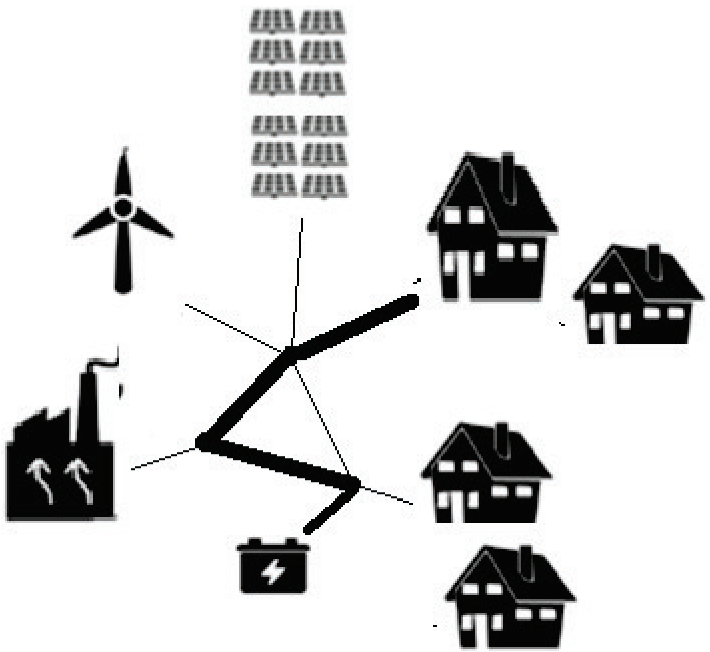
Investment Period 1 (e.g. 2025)



Investment Period 2 (e.g. 2030)

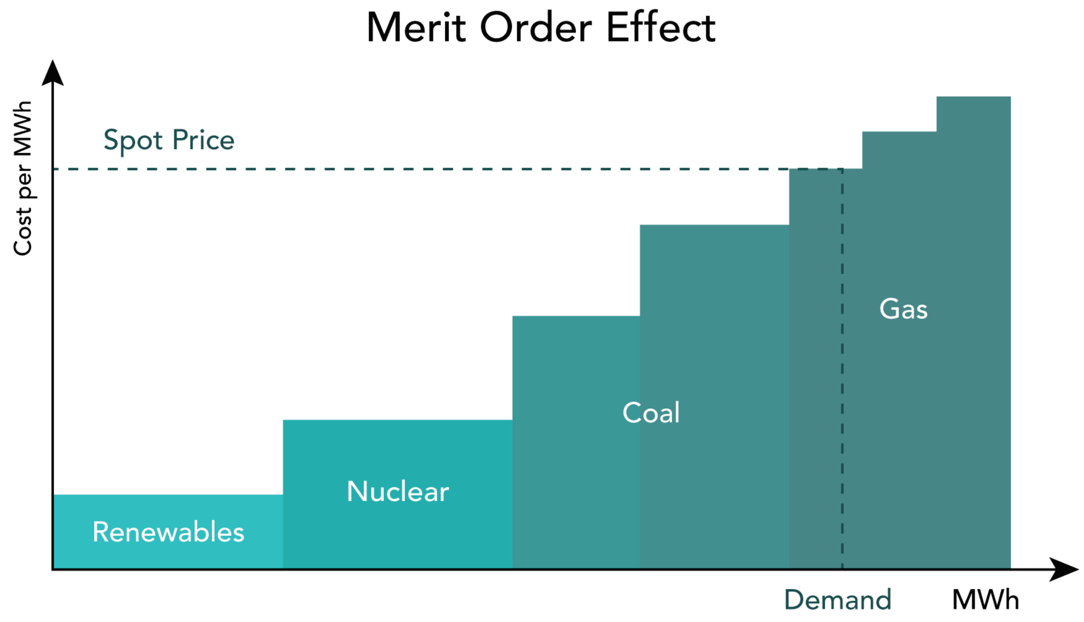


Investment Period 3 (e.g. 2035)



Key models: Production cost

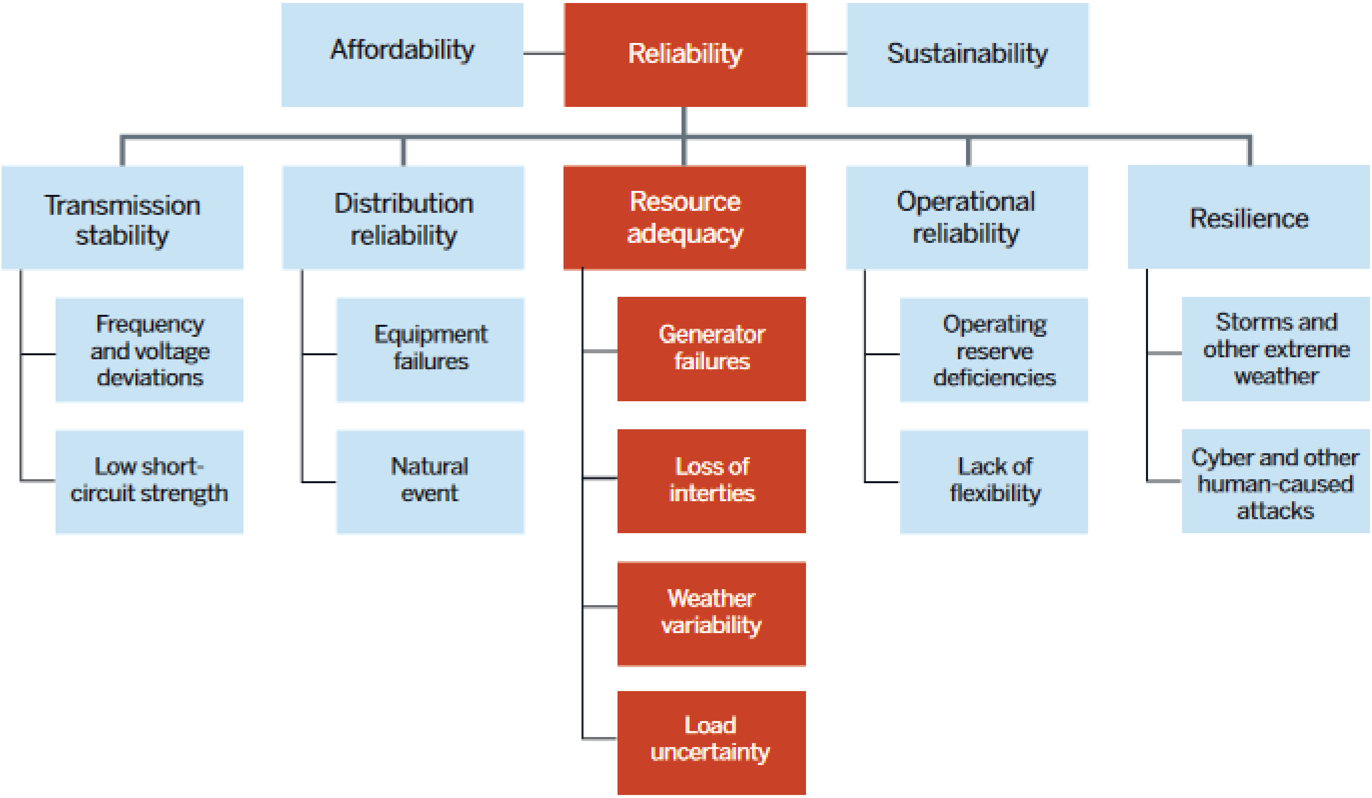
- Production cost models are used to determine the optimal **economic dispatch** of available resources based on their cost, availability, location within the grid, and other technical limits
- Economic dispatch is the amount of power each unit should produce in a given hour such that the total cost of operating the system is minimized
- Since many of these units require time to ramp up, they have to be committed. **Unit commitment** is a separate but related problem to economic dispatch.



Key models: Reliability (1)

- Reliability has many component
  - Key analytical component in IRP has been **resource adequacy (RA)**
- RA is the ability of the power system to meet load at every hour using supply- and demand-side resources
- An RA model simulates a simplified operation of a power system across thousands of “versions” that depends on probability distributions for weather, load, outages/failures, variable renewable energy production, etc.

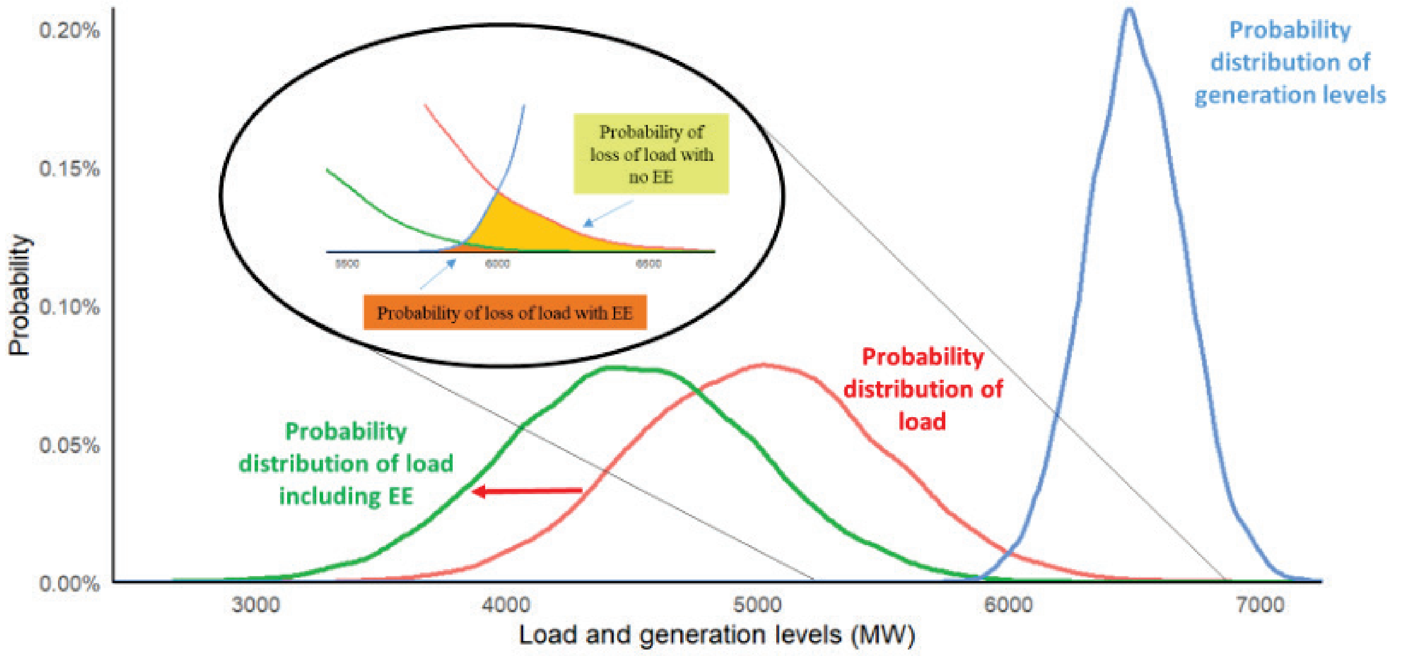
FIGURE 1
The Elements of Grid Reliability



Source: Energy Systems Integration Group.

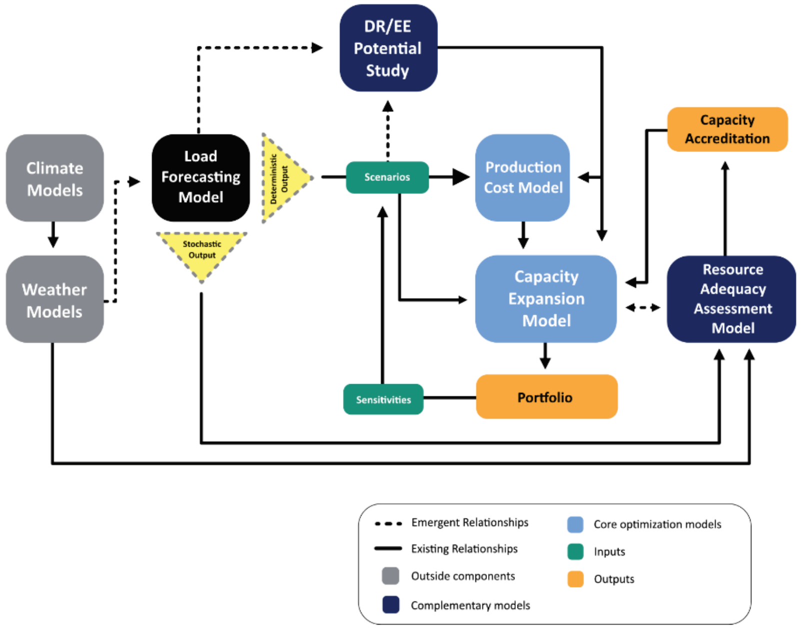
Key models: Reliability (2)

- RA models communicate the likelihood or probability of a shortfall
- The IRP should deploy enough resources to make this probability fall below one (or ideally more) measures of risk, such as the well-known “1 day in 10 years”
- Best practices
  - Link RA assessment with portfolio creation iteratively
  - Apply consistent accreditation framework to all resource types (ELCC vs Equivalent Forced Outage Rate Demand)
  - Assess adequacy at a regional level and model transmission



Best practices across models

- Ensure capacity expansion and production cost model are state-of-the-art
- Select spatial and temporal scales thoughtfully, including (i) temporal granularity and (ii) planning horizon
- Calibrate both models!
- Let optimization models optimize
  - Don’t force build decisions unless resources are under construction
  - Don’t force resource retirement decisions, unless testing specific scenarios
- Use stochastic approaches for robust portfolio creation
- Use models iteratively



Poll question: Models

What shortcomings do you see in current planning models or modeling approaches?

Scenario analysis

Defining scenarios

Scenarios represent a change to major assumptions and tend to portray a world or a future that looks markedly different from base assumptions.

- For example, TVA's 2019 IRP included six scenarios with input from its IRP working group.

	SCENARIOS
1	**CURRENT OUTLOOK** which represents TVA's current forecast for these key uncertainties and reflects modest economic growth offset by increasing efficiencies;
2	**ECONOMIC DOWNTURN** which represents a prolonged stagnation in the economy, resulting in declining loads (customers using less power) and delayed expansion of new generation;
3	**VALLEY LOAD GROWTH** which represents economic growth driven by migration into the Valley and a technology-driven boost to productivity, underscored by increased electrification of industry and transportation;
4	**DECARBONIZATION** which is driven by a strong push to curb greenhouse gas emissions due to concern over climate change, resulting in high CO_2 emission penalties and incentives for non-emitting technologies;
5	**RAPID DER ADOPTION** which is driven by growing consumer awareness and preference for energy choice, coupled with rapid advances in technologies, resulting in high penetration of distributed generation, storage and energy management;
6	**NO NUCLEAR EXTENSIONS** which is driven by a regulatory challenge to relicense existing nuclear plants and construct new, large-scale nuclear. This scenario also assumes subsidies to drive small modular reactor (SMR) technology advancements and improved economics.

Defining sensitivities

Sensitivities change a single key input to understand how that input affects or drives results, often across multiple scenarios. The goal of a sensitivity is to understand the sensitivity of results to a single variable.

- For example, TVA's 2019 IRP included 10 sensitivities

SENSITIVITY CASE Base Case comparison is the Current Outlook unless otherwise noted
Higher Natural Gas Prices
Lower Natural Gas Prices
Lower Wind Costs
Greater EE & DR Market Depth
Integration Cost & Flexibility Benefit
Pace & Magnitude of Solar Additions
Magnitude of Solar Additions (Valley Load Growth)
Higher Operating Costs for Coal Plants
More Stringent Carbon Constraints (Decarbonization)
Variation in Climate

Scenario vs. sensitivity analysis

Scenarios

- The capacity expansion model is generally reoptimized, resulting in a different preferred mix of resources over the planning period.

Utilities use the terms "scenario" and "sensitivity" differently, so be aware of the context!

Sensitivities

- The capacity expansion model may be reoptimized, resulting in a different preferred mix of resources over the planning period

or

- A resource portfolio may be fixed in order to test the robustness of a resource portfolio under changed conditions. Portfolios that perform better under sensitivity analysis might be given more consideration in the selection of an optimal plan.

Best practices for designing scenarios and sensitivities

Planners often face challenges during the scenario design process, including:

- The tension between modeling a full, comprehensive range of uncertainties and producing straightforward, informative results
- Balancing stakeholder requests with utility priorities and commission requirements
- The tension between minimizing shareholder risks and minimizing ratepayer costs
    - The interests of utility shareholders and ratepayers do not always align.

Best Practices

1. **Start with a robust base case that is designed to reflect a realistic view of the world and abide by all existing federal, state, and regulatory requirements**
2. **Include a fully-optimized scenario with limited constraints**
3. **Design scenarios to evaluate uncertainty and risk across a range of futures**
4. **Plan for and incorporate important regulatory factors by modeling all final, proposed, and likely regulations to allow time for proactive planning and identification of no-regrets actions.**

Scenario/sensitivity analysis example: Tucson Electric Power 2023 IRP

In TEP's 2023 IRP, the utility modeled 10 scenarios and layered on up to 3 sensitivities per scenario

Table 15. Portfolios Evaluated in TEP's 2023 IRP

Portfolio Number and Name	Description / Design Objectives	Sensitivity Tests
P01 - Solar + Storage	• Re-evaluates TEP's long-term plan acknowledged by the ACC in 2022 given new outlooks in future loads and resource costs and updated modeling capabilities.	High/Low Market Prices High/Low Capital Costs High/No Load Growth
P02 - Balanced Portfolio	• Adds 400 MW of eight new, fast-start, fast-ramping aeroderivative CTs brought into service in 2028 in lieu of an equivalently-reliable amount of future solar and storage.	High/Low Market Prices High/Low Capital Costs High/No Load Growth
P03 – SGS Early Retirement (2027)	• Retires SGS 2 five years early (2027), the same year as SGS 1. • Includes costs for coal contract liquidated damages, coal contract early termination costs, and cost recovery through treatment of SGS 2 as a lower-return regulatory asset.	High/Low Market Prices High/Low Capital Costs
P04 - SGS Retirement (2030)	• Retires both SGS units in 2030 instead of 2027 and 2032. • Assumes same amount of must-take coal volume but includes coal contract early termination costs.	High/Low Market Prices High/Low Capital Costs
P05 - SGS Retirement (2034)	• Retires both SGS units in 2034 instead of 2027 and 2032. • Extends annual must-take coal volumes through 2034. • Includes low-sulfur coal handling upgrades for future coal supply sources.	High/Low Market Prices High/Low Capital Costs
P06 - Heavy Solar	• Evaluates appropriateness of wind/solar capacity mix assumed in other portfolios. • Evaluates cost differences and system integration capabilities in the event market conditions, load patterns, or system operations favor relatively more solar. • Decreases future wind from 500 MW to 250 MW and adds solar (and storage if necessary) to reliably achieve the same amount of CO_2 reduction. • Assumes low capital cost only for solar.	High/Low Market Prices
P07 - Heavy Wind	• Evaluates appropriateness of wind/solar capacity mix assumed in other portfolios. • Evaluates cost differences and system integration capabilities in the event that market conditions, load patterns, or system operations favor relatively more wind. • Increase future wind from 500 MW to 750 MW and decrease solar (and storage if possible) to reliably achieve the same amount of CO_2 reduction. • Assumes low capital cost only for wind. Also assumes a $48/kW-year transmission wheeling cost for the additional 250 MW given the lack of available transmission capacity on the east side of TEP's transmission system, which is located closest to high-value wind resources in eastern New Mexico.	High/Low Market Prices
P08 - Pumped Hydro	• Replaces all Li-ion battery storage brought into service from 2033-2038 with an equivalently reliable amount of 10-hour storage brought into service in 2033 with ATB assumptions for cost and round-trip efficiency (80%) and a capacity credit of 75% based on interpretation of TEP's ELCC study. • Assumes reservoir would be located in northern Arizona and that only 300 MW could be transmitted before having to purchase additional capacity at $48/kW-year. • Relocates 1,000 MW of solar to the Four Corners area to support this remote storage and avoid transmission costs.	High/Low Market Prices
P09 - Small Modular Reactors	• Replaces all Li-ion battery storage brought into service from 2033-2038 with an equivalently-reliable amount of nuclear power brought into service in 2033.	High/Low Market Prices
P10 - Market and Transmission Reform	• Increases market depth by assuming 50% more import/export capability and 25% lower market prices.	

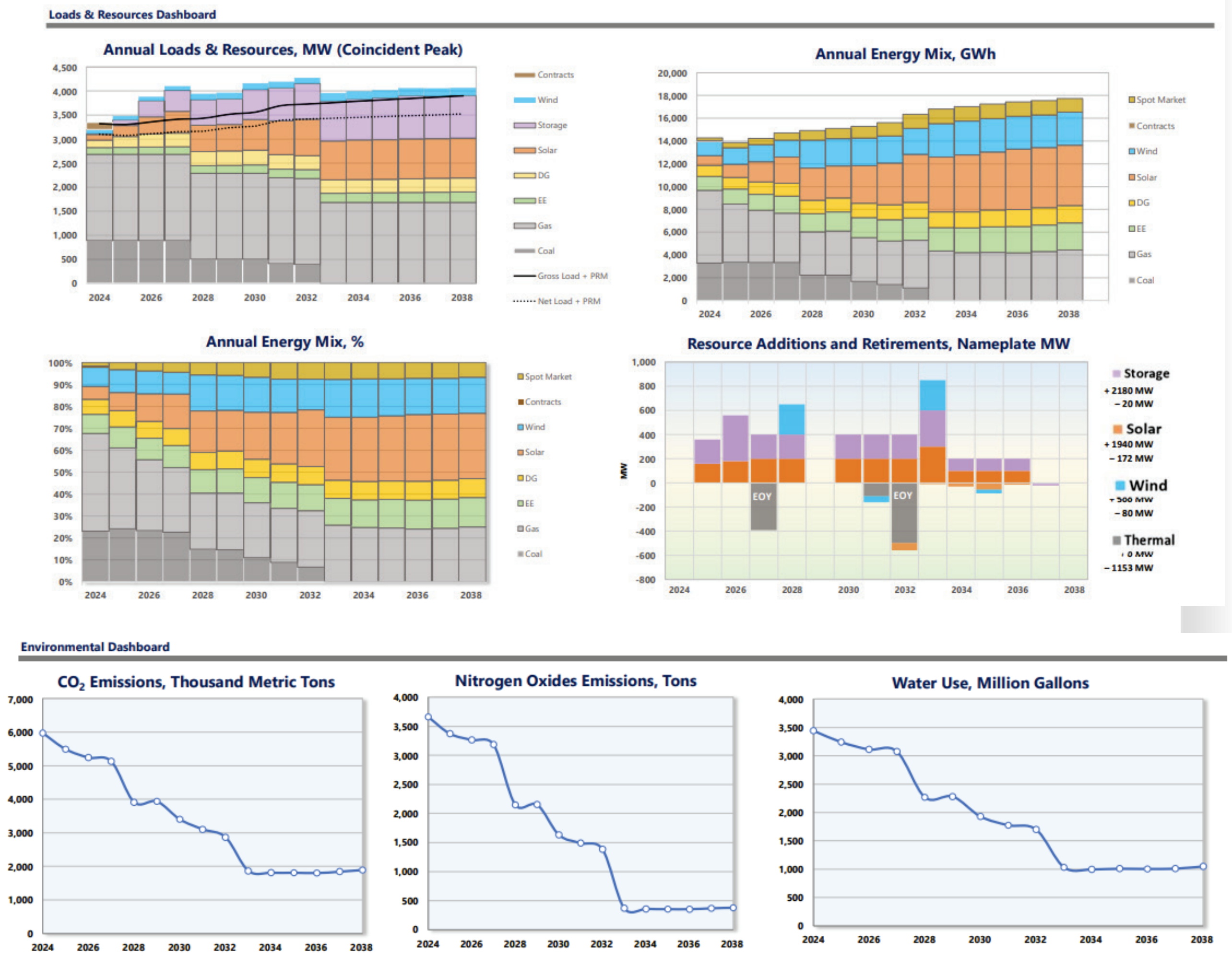
Poll question: Scenario analysis

In your jurisdiction, what is an example of a scenario that would be useful to include in an IRP?

Reporting results

It is important for IRP modelers to present the following information about each scenario:

- Load/demand forecast by year
- Capacity by year and resource type (existing and new additions)
- Generation and capacity factors by year and resource type
- Emissions by year and type (CO2 and other criteria pollutants)
- Plant retirements by year
- Cost



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	54%	65%	64%	69%	72%	74%	83%	84%	84%	84%	83%	83%

Source: TEP Portfolio Dashboard Summary

Valuing and comparing plans

After modeling is complete, utilities typically summarize results for stakeholders to facilitate comparison. Examples of metrics that are considered during plan evaluation include:

- Cost – net present value of revenue requirements (NPVRR) over the short-term and full study period
- Environmental cost or impact
- Reliability
- Fuel diversity
- Impact on customer rates and bills
- Local economic and job impacts

Best Practice: Use appropriate metrics to evaluate IRP results

- **At the outset of the IRP process, define core metrics that are aligned with region-specific needs and goals**
- **Collaborate with stakeholders and regulators when defining metrics**

Evaluating results example: TEP portfolio scorecard

TEP's scorecard presented metrics on cost as well as environmental impact.

Table 16. Portfolio Case Matrix Details

Portfolio #	Portfolio Name	NPV ($000)	Fuel NPV ($000)	Non-Fuel NPV ($000)	Cumulative Additions (2024-2038)					Environmental Results (2038)		
					Solar (MW)	Storage (MW)	Wind (MW)	Gas (MW)	Other (MW)	CO_2 Reduction	NOx Reduction	Water Reduction
TEP P01	Solar + Storage	$14,619	$3,188	$11,431	1,940	2,180	500	0	0	83%	96%	84%
TEP P02	Balanced Portfolio	$14,308	$3,364	$10,944	1,740	1,330	500	400	0	80%	95%	81%
TEP P03	Springerville Early Retirement (2027)	$14,755	$3,049	$11,706	1,940	2,180	500	0	0	83%	95%	84%
TEP P04	Springerville Retirement (2030)	$14,738	$3,152	$11,586	1,940	2,180	500	0	0	83%	96%	84%
TEP P05	Springerville Retirement (2034)	$14,669	$3,357	$11,311	1,940	2,180	500	0	0	83%	96%	84%
TEP P06	Heavy Solar	$14,425	$3,208	$11,218	2,440	1,930	250	0	0	83%	95%	83%
TEP P07	Heavy Wind	$14,594	$3,168	$11,426	1,740	2,080	750	0	0	83%	96%	84%
TEP P08	Pumped Hydro	$14,789	$3,238	$11,551	1,940	980	500	0	650	83%	96%	84%
TEP P09	Small Modular Reactors	$15,023	$3,120	$11,903	1,240	980	500	0	600	89%	97%	89%
TEP P10	Market and Transmission Reform	$14,292	$2,930	$11,431	1,940	2,180	500	0	0	82%	95%	83%

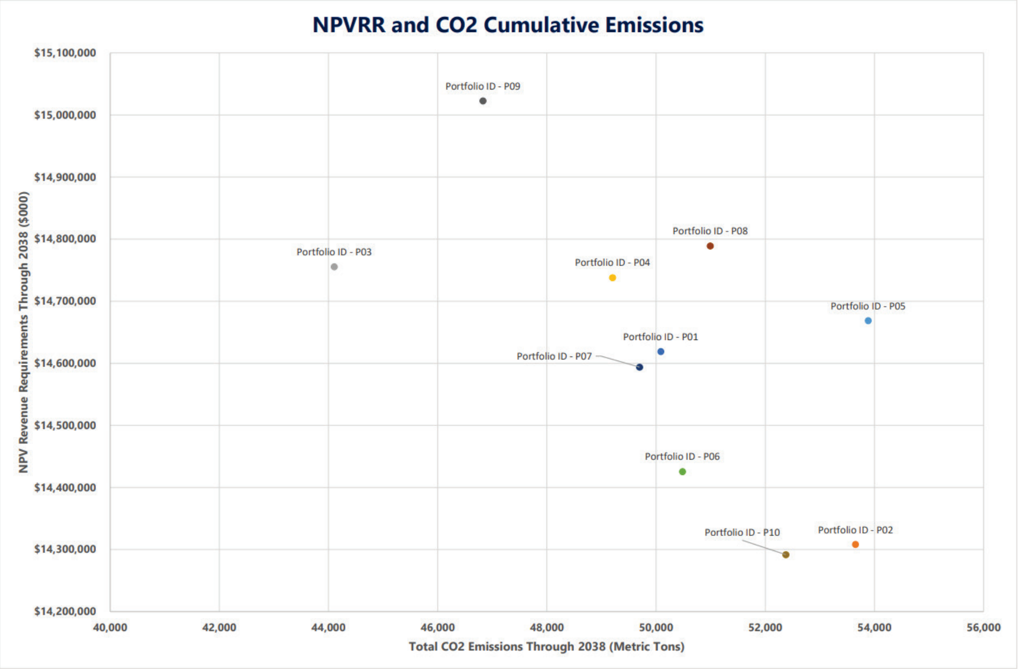
Preferred portfolio selection

Selecting a preferred resource plan is often a balance of cost and risk measures.

While minimizing cost is important for utility customers, the scenario with the lowest NPVRR is not necessarily the preferred portfolio.

Best Practice: Select a preferred portfolio

- **Justify any substantial deviations from the optimized portfolio when selecting a preferred portfolio**
- **Avoid developing preferred portfolios outside of the model that are not subject to the same level of sensitivity and risk analysis as the other scenarios.**



Source: TEP Portfolio Dashboard Summary

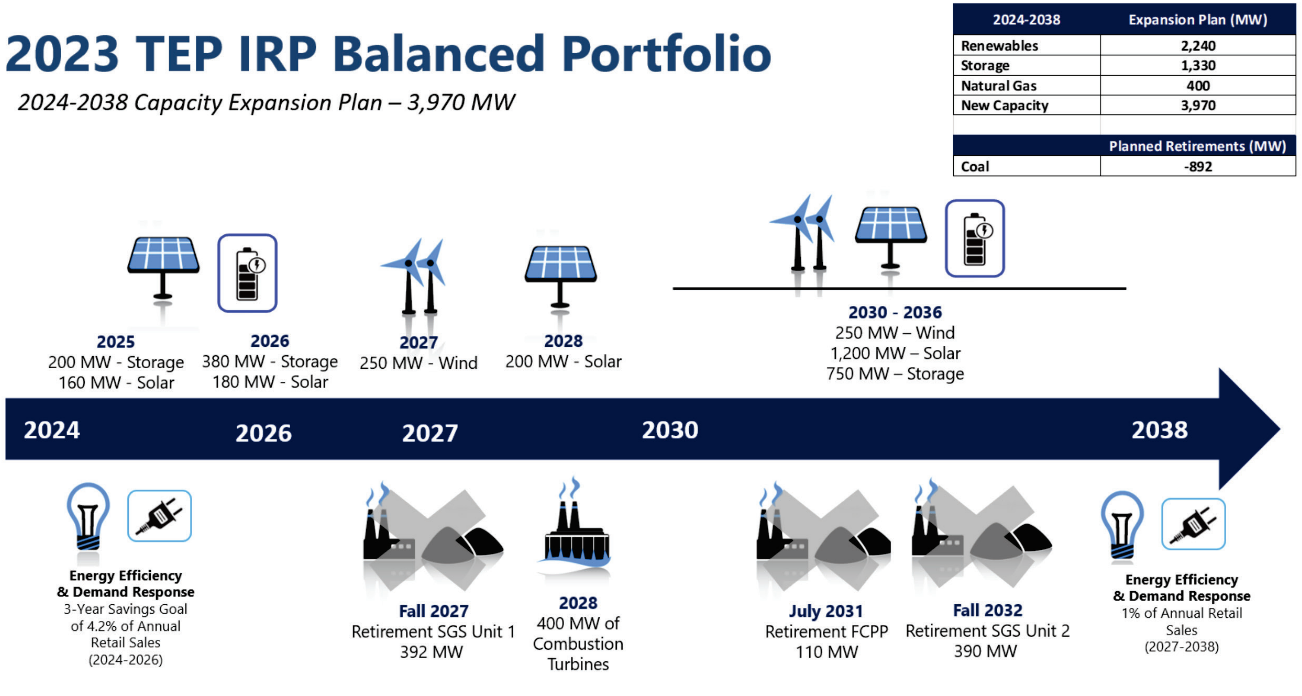
Preferred portfolio selection

It is important to select a preferred portfolio to guide near-term actions such as procurement.

Without a preferred portfolio, it is challenging for stakeholders and regulators to focus their feedback and oversight

The utility’s selection of a preferred portfolio does not necessarily tie the utility to that portfolio, especially if conditions change

Figure 63. Balanced Portfolio Project Timeline



Note: *TEP retires 1,183 MW of fossil generation, 172 MW of solar, 80 MW of wind, and 20 MW of energy storage by 2038.*

Integration of IRP with other proceedings

Other utility proceedings

- Utility procurement (requests for proposals)
- Transmission planning
- Rate cases
- Energy justice-related proceedings
- Natural gas planning

The Action Plan

- IRPs are massive efforts that may involve dozens of scenarios and thousands of result items
- The Action Plan requires utilities to clearly explain proposed procurement decisions, business development, and analysis needs for the near-term, anywhere between 1–4 years
- A well-developed Action Plan includes:
  - Individual identification of assets to be procured or request for proposals (RFPs) to be designed, including capacity needs, location, and timing
  - Identification of outstanding analytical aspects of the IRP that will continue to be studied in the near-term, either because new information may be available soon or because they will inform a procurement decision
  - List strategies to comply with near-term regulatory mandates and targets

Image source: https://medium.com/@TheBold/the-power-of-an-action-plan-6490791131a

Contact information

Devi Glick

dglick@synapse-energy.com

Shelley Kwok

skwok@synapse-energy.com

JP Carvallo

jpcarvallo@lbl.gov