Deep Decarb Study Update: Technical Report



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Background

Motivation and context

- In 2017, Portland General Electric (PGE) commissioned Evolved Energy Research (EER) to undertake an independent study exploring pathways to deep decarbonization for its service territory ("Deep Decarb Study")
 - Study evaluated an economy-wide reduction in GHG emissions of 80 percent below 1990 levels by 2050
- Since then, Oregon has adopted two keynote environmental policies limiting greenhouse gas (GHG) emissions
 - **1.** House Bill (HB 2021) establishes emissions reduction targets for PGE's electricity mix; and
 - 2. Climate Protection Program (CPP) limits GHG emissions associated with the use of fossil fuels in buildings, industry and transportation



Purpose and scope

- The *Deep Decarb Study Update* explores pathways that achieve the HB 2021 and CPP emissions targets ("study policy targets") for PGE's service territory
- Questions posed:
 - What are the opportunities and challenges of achieving the study policy targets?
 - What are the result implications for electricity system operations and planning?
 - What are the cross-sectoral impacts of the two policy targets?





Study policy targets



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Modeling Approaches and Assumptions



Modeling Framework



Study expands variables considered in the IRP





High-level description of modeling approach

• Modeling projects energy demand for PGE's service territory and the leastcost way to provide that energy under policy constraints





Analysis covers PGE's entire energy system

- Study includes a detailed representation of the PGE service territory's energy system, including infrastructure stocks and energy demands for buildings, industry and transportation
- Cost-optimal portfolios for electricity and fuels are developed to achieve policy goals at least-cost





Paired modeling framework





Demand-side modeling



PATHWAYS

- Scenario-based, bottom-up energy model (not optimization-based)
- Characterizes rollover of stock over time
- Simulates the change in total energy demand and load shape for every end-use
- Illustration of model inputs and outputs for light-duty vehicles



Supply-side modeling

Regional Investment and Operations (RIO) model

- Capacity expansion tool producing cost-optimal resource portfolios across the electric and fuels sectors
 - Least-cost energy supply mix to achieve emissions targets
- Simulates hourly electricity operations and annual investment decisions
- Electricity and fuels are co-optimized to identify sector coupling opportunities
 - Example: production of hydrogen from electrolysis





Analysis combines scenario-based and optimized decisions

Decision	Scenario-based (Exogenous)	Optimized (Endogenous)
Energy demand projections: End-use appliance and vehicle adoption		
Baseline electricity resources: Existing resources, planned additions, planned retirements		
Customer-sited resource additions: Residential and non-residential solar and storage build		
End-use load flexibility characteristics: Share of load that is flexible; # hours load can be delayed/advanced		
Supply-side resource investments: Transmission-sited renewables, storage, thermal, H ₂ production		
Hourly electricity system operations: resource and flexible load dispatch, storage charge/discharge		
Pipeline gas and liquid fuel supply: fossil and low-carbon fuel mix		

Key modeling assumptions

Common across all scenarios

Assumption	Value	Notes
Modeled years for capacity expansion and hourly operations	2022, 2025, 2030, 2035, 2040, 2045, 2050	Modeled years captures key HB 2021 and CPP policy milestones
Sample days per year	60	Electricity operations sampled with 60 days in each modeled year (1,440 hours/year). The 60 days are chosen independently in future years based on clustering around gross load and renewable production.
Weather year in electricity system	2011	Weather-matched load, wind and solar hourly profiles
Hydro year	Average	Long-run average hydro generation
Discount rate (real cost of capital)	3.94%	Derived from PGE's nominal after-tax WACC of 6.14% and long-term inflation of 2.12%. Assumption is used to levelize technology capital costs and to discount future costs in the optimization.



Modeling result considerations

- Our modeling results may differ from PGE's IRP and DSP due to the use of alternative models and the inclusion of direct access loads in our scope
- Scenarios do not reflect PGE's business plan or future resource acquisitions
- This study's modeling approach and results do not replace existing tools or processes used by PGE, such as defining "need" for resource adequacy or identifying optimal portfolios





Electricity Sector

Topology



Topology overview

- We developed a 16-zone representation of PGE's system to better understand certain distribution-level impacts that aren't visible with a system-wide view
- Bulk transmission system is connected to 15 "feeder archetypes" that cluster PGE's ~700 feeders based on shared characteristics
- PGE's system is modeled as an island where all modeled generation is to serve PGE load (i.e., no imports or exports)





Feeder archetypes: overview

- We developed 15 feeder archetypes to represent PGE's distribution system to better understand the impacts of customer-sited solar and storage, end-use electrification and flexible load
 - This approach expands on the original Decarb Study's distribution-level representation, which categorized feeders as residential, commercial or industrial
- PGE provided two datasets that were used to develop feeder archetypes
 - Consumption: historical annual kWh by residential, commercial and industrial customers by feeder
 - Weak link report: historical peak load and weak link by feeder
- We used historical data to develop 5 'customer category' and 3 'feeder utilization' bins which combine to define 15 feeder archetypes
 - Data from 2019 was used to avoid potential distortions associated with extreme weather and COVID-19 in the 2020 and 2021 data



Feeder archetypes: customer category bin

- We defined 5 customer category bins based on the type of load dominant on each feeder (residential, commercial, industrial, or a blend)
- Approximately half of all residential consumption occurs on residential-oriented feeders, while most of the remainder is on mixed building use feeders
- Industrial load is also concentrated, while commercial load is spread out

Customer Category Bin	Criteria (% of annual consumption)	Feeder Count	Res kWh Share Com kWh Share		Ind kWh share	
Residential-oriented	>= 65% residential	175	51%	16	%	1%
Commerical-oriented	>= 65% commercial	109	5%	32	%	2%
Industrial-oriented	>= 65% industrial	76	0%	3	%	75%
Mixed building	>= 75% (residential+commercial)	176	37%	38	%	5%
Mixed business	>= 75% (commercial+industrial)	55	7%	12	%	17%
Total		591	100%	10)%	100%

Feeder archetypes: feeder utilization bin (present-day)

- Feeder utilization is defined by peak load divided by its weak link
 - Planning threshold to trigger upgrades is 67%
- Feeders categorized into low, medium and high bins

Feeder Utilization Bin	Criteria [utilization = peak load / weak link]	Feeder Count
Low utilization	0% to 33%	162
Medium utilization	33% to 53%	243
High utilization	53% to 100%	186
Total		591



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Feeder archetypes: allocation of projected load

- The 15 feeder archetypes characterize today's customers on the distribution system
- For future load growth, we assume:
 - Residential, commercial and industrial load increases in proportion to its current share
 - Transportation load is allocated according to the table to the right, with most light-duty vehicle charging occurring at home (60-70%), whereas freight trucks charge on C&I feeders

End-use	Residential	Commercial	Industrial
Light-duty autos	70%	25%	5%
Light-duty trucks	60%	35%	5%
Medium duty trucks	0%	50%	50%
Heavy duty trucks	0%	0%	100%

Allocation of Projected Transportation Load to Feeder Type



Feeder archetypes: distribution system upgrade

- Each feeder archetype's present-day utilization of based on the median of feeders assigned to that archetype
- We quantify growth in the distribution system ${}^{\bullet}$ by maintaining a 67% feeder utilization
- For example, a feeder archetype with a present-day peak load of 60 MW and nominal capacity of 100 MW (e.g., 60% utilization) could increase peak demand by 7 MW without triggering upgrades
 - A peak demand increase greater than 7 MW would trigger an upgrade to the feeder to achieve exactly 67% utilization
 - This is a simplification since real-world distribution upgrades are made in larger increments

Year	Peak Load (MW) [A]	Feeder Capacity (MW) [B]	Feeder Utilization (%) [C=A/B]
Today	60	100	60%
Future	67	100	67%
	70	105	67%
	80	120	67%
	90	135	67%
	100	150	67%

Example: Distribution System Growth



Feeder archetypes: key metrics

Feeder Archetype #	Customer Category Bin	Feeder Utilization Bin	Feeder Count	Residential load (% total)	Commercial load (% total)	Industrial load (% total)	Present-day Feeder Utilization (% nominal weak link)
1	Residential-oriented	High	59	22%	7%	0%	64%
2	Residential-oriented	Medium	60	18%	5%	0%	44%
3	Residential-oriented	Low	56	12%	3%	0%	27%
4	Commerical-oriented	High	24	2%	9%	1%	57%
5	Commerical-oriented	Medium	51	2%	17%	1%	43%
6	Commerical-oriented	Low	34	1%	6%	0%	21%
7	Industrial-oriented	High	27	0%	1%	26%	65%
8	Industrial-oriented	Medium	34	0%	2%	40%	47%
9	Industrial-oriented	Low	15	0%	0%	8%	20%
10	Mixed building	High	53	13%	14%	2%	62%
11	Mixed building	Medium	76	16%	16%	2%	44%
12	Mixed building	Low	47	7%	7%	1%	27%
13	Mixed business	High	23	4%	6%	9%	63%
14	Mixed business	Medium	22	3%	4%	7%	44%
15	Mixed business	Low	10	0%	1%	1%	19%
			591	100%	100%	100%	





Electricity Sector

Resources



Overview of resources

- Projected resources fall into three categories (baseline; new customer-sited; and new supply-side) and each has their own modeling approach
- PGE provided baseline resource data, including available capacity for individual utility-owned and contracted resources for each year through 2050
 - Resources are assumed to stay online throughout the study horizon unless they have a specified retirement date or are economically retired

Baseline Resources: Common across Scenarios

- Existing resources
- Planned retirements
- Planned additions

New Customer-sited Resources: Scenario-based

- New customer-sited solar and storage
- Quantity over time is an exogenous input

New Supply-side Resources: Optimized

- New supply-side renewables, storage, thermal
- Optimized deployment to meet energy, capacity and emission constraints



Thermal resources: existing

• Existing coal

 PGE's share of Colstrip units 3 and 4 are out of the resource mix by the end of 2025

• Existing gas

- Operations are constrained by HB 2021 CO₂ budget starting in 2030
- Resources can limit emissions by reducing generation if burning natural gas, and alternatively burn zero carbon fuels as needed
- There are no specified retirements, but resources can economically retire

Fuel Limits for Existing Gas Resources (maximum % of fuel consumed)

Туре	Fuel	2022- 2029	2030- 2039	2040- 2050
Fossil	Natural gas	100%	100%	0%
Zero	RNG: anaerobic digestion	0%	100%	100%
	RNG: thermal gasification	0%	100%	100%
Carbon	SNG: power-to-gas	0%	100%	100%
	H ₂ : electrolysis	0%	50%	50%



Thermal resources: new

- HB 2021 prevents construction of new thermal resources that burn natural gas
- Turbines utilizing 100% renewable electricity-derived hydrogen represent a promising option to deploy new dispatchable thermal resources
 - <u>Turbine manufacturers</u> and <u>electric utilities</u> are actively pursuing this opportunity
- To understand the impact of this advanced technology, we allow for new H₂ combustion turbine (CT) and combined cycle (CC) resources in one scenario
 - Cost and performance is based on gas resource equivalents from the 2019 IRP plus a 25% capital cost premium







- We represent PGE's fleet of hydro resources, including utility-owned resources, Mid-C project shares and contracts with public utility districts
- Operational flexibility from these resources is limited by monthly energy budgets, minimum and maximum generation constraints
 - PGE provided resource-specific data used in IRP modeling
- We assume PGE's long-term PPA in the Pelton/Round Butte project, which currently expires in 2040, continues through the study horizon (2050)



Renewable resources: supply-side

- We represent seven supply-side renewable resources from the IRP
- Onshore wind and solar PV resources are represented at diverse locations across the Pacific Northwest, resulting in both annual and hourly profile diversity
- Technology-specific constraints
 - Offshore wind (Oregon South): availability is limited to one scenario due to the nascent status of floating offshore wind technology
 - Onshore wind (Montana): maximum build rate limited to 200 MW/year to reflect potential transmission access constraints
 - Geothermal: excluded from analysis due to viability concerns

Technology	Scenario Availability
Solar PV: Central Oregon	
Solar PV: Oregon Gorge	
Solar PV: Willamette Valley	٨Ш
Onshore wind: Oregon Gorge	All
Onshore wind: Southeast Washington	
Onshore wind: Montana	
Offshore wind: Oregon South	Limited
Geothermal	Excluded



Energy storage resources: supply-side

Battery storage

- Costs are consistent with the 2023 IRP and are separated into capacity (\$/kW) and energy (\$/kWh) components
- Resources are assumed to be located within PGE's system and do not require a BPA wheel
- Optimal average duration of battery storage fleet (up to 24 hours) in each year is a modeling result

Pumped storage

- Cost and performance is consistent with the 2023 IRP
- Duration is limited to 10 hours and total potential is up to 500 MW



• We include the following proxy resources are added by 2025 in all scenarios

Resource	Namplate Capacity (MW)
Onshore wind	312
Solar PV	120
Battery storage: 4-hr	470
Total	902



Customer-sited resources: solar and storage

- PGE DRP team provided two adoption trajectories
 - Base: equivalent to AdopDER's reference case PV + storage scenario
 - Aspirational: reflects more ambitious deployment that may result from more amenable tariffs, program bundles, or other market/regulatory changes
- Resources allocated to feeder archetype zones based on load-ratio share
- Solar and storage cost inputs developed using the following steps
 - 1. Calculated the ratio of customer-sited to utilityscale technology costs from NREL's Annual Technology Baseline 2021
 - 2. Applied the ratios from step #1 to supply-side cost estimates from the 2023 IRP



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Customer-sited resources: solar and storage

- Aspirational trajectory developed using the following approach
 - Reviewed NREL's Energy Futures Study for distributed solar and storage adoption under "base" and "aggressive" deployment scenarios
 - Calculated the ratio of the aggressive and base deployment scenarios (2.2 for battery storage; 1.5 for solar)
 - Applied ratios to the AdopDER high scenario





Flexible end-use load

- Flexible end-use load automatically shifts with changing grid conditions for short-term balancing
 - Total consumption does not change
- Total potential in each year depends on the level of electrification
- Economic benefit: avoid/defer supply-side resources and T&D infrastructure
 - Less supply-side energy storage and renewables (more efficient use of variable RE)
 - Moderates incremental T&D infrastructure to meet increasing loads


Flexible end-use load

- Modeled flexibility is provided by air conditioning, space heating and water heating in buildings, as well as electric vehicle charging
- Flexibility is constrained by three parameters
 - 1. Number of hours load can be delayed
 - 2. Number of hours load can be advanced
 - 3. Percent of load that is flexible
- Base and Aspirational parameters by end-use are shown in the table to the right

Flexible Load Parameters: Base (Aspirational)

End-Use	# hours load can be delayed	# hours load can be advanced	% of load that is flexible
Res & com air conditioning	1 (2)	1 (2)	10% (75%)
Res & com space heating	1 (2)	1 (2)	10% (75%)
Res & com water heating	2 (3)	2 (3)	10% (75%)
Battery electric vehicles	8 (8)	0 (0)	33% (100%)





• We model five additional resources and our approach is summarized below

Resources	Service	Approach
Demand response	Capacity (not	 Include DR quantities from the 2019 IRP (up to 211 MW by 2025) Incremental to flexible end-use load
Dispatchable standby generation	dispatched	 Include DSG quantities from the 2019 IRP (up to 137 MW by 2025)
Bilateral capacity contracts		 Include existing contracts and their expiration; no specific renewals
Capacity fill		 Reflects a proxy resource to acquire capacity, including existing contracts Cost: \$110/kW-yr from 2019 IRP Update Quantity: unlimited (2022-2029) and up to 500 MW thereafter (2030-2050)
Market purchases	Energy	 Assume generic electricity market purchases with a market heat rate of 8,000 Btu/kWh to both cost and assign emissions Quantity: unlimited (2022-2029) and zero thereafter (2030-2050)





- Reliability is assessed across all modeled hours, explicitly accounting for both variations in demand and supply
- Reserve requirement must be met or exceeded in every hour by the supply of resources that are adjusted by their dependability

Reliability Consideration	Load/Resource	Reliability Contribution	Description
Reserve Requirement	Load	106% of gross load	Represents weather-related risk of load exceeding that sampled
Reserve Supply	Thermal	95% of nameplate	Derated by generator forced outage rate
	Hydro	95% of hourly generation	For energy-limited resources, hourly production is used to
	Energy storage	95% of hourly discharge	ensure sustained peaking capability
	Renewables	80% of hourly generation	Higher derate due to weather-related risk





- Our approach is advantageous to pre-computed reliability assessments, because it accommodates changing load shapes and growing flexible load
- Any pre-computed reliability assessment implicitly assumes a static load shape, which is not a realistic assumption with high electrification
- No economic capacity expansion model can completely substitute for a lossof-load probability study, but different models offer different levels of rigor





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Load



- We project PGE load through 2050 by combining two components
 - 1. <u>Baseline load</u>: PGE provided annual load by customer class through 2050
 - 2. <u>Electrification load</u>: includes scenario-specific load impacts from end-use electrification
- Nearly 90% of baseline load growth is attributable to the industrial sector
- PGE further provided characteristics of the residential building stock, includine customer growth and space heating by technology



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Transportation assumptions

- Scenarios are primarily differentiated by the future freight truck fleet, specifically battery electric vehicle (BEV) and hydrogen fuel cell vehicle (HFCV) shares
- We assume new passenger (light-duty) vehicles are 100% BEV by 2035 in all scenarios

Vehicle Sales Shares in 2035 (% vehicles solid)

End-Use	High Electrification	Low Electrification
Medium-duty trucks Heavy-duty trucks: short-haul	BEV: 100% HFCV: 0% ICE: 0%	BEV: 50% HFCV: 50% ICE: 0%
Heavy-duty trucks: long-haul	BEV: 80% HFCV: 20% ICE: 0%	BEV: 0% HFCV: 80% ICE: 20%



Building assumptions

- High Electrification demand-side scenario is characterized by high levels of air source heat pump (ASHP) adoption for space heating and cooling
- Low Electrification relies on high efficiency gas equipment with some hybrid gas-electric adoption

Predominant End-use Technologies in Buildings

End-Use	High Electrification	Low Electrification		
Space Conditioning	Air source heat pumpElectric resistance	 High efficiency gas furnace High efficiency air conditioner Hybrid ASHP 		
Water Heating	 Heat pump water heater 	 High efficiency gas water heater 		
Other	• Best available technolo	Best available technology		





Fuels



- Reducing emissions associated with fuels covered by the CPP can be accomplished through three strategies
- **#1 Energy efficiency**
 - Example: adopting a high-efficiency gas water heater
- #2 Fuel switching
 - Switching from liquid fuel or pipeline gas to electricity (electrification) or hydrogen
- #3 Zero carbon fuel (ZCF)
 - Utilizing "drop-in" synthetic fuels derived from biomass or electricity



Pipeline gas: supply options

Category	Fuel	Description	Notes
Fossil	Natural gas	Fossil methane	Use is limited by CPP caps
R g ZCF	Renewable natural gas (RNG)	 Methane produced from anerobic digestion or thermal gasification of biomass 	 Quantity is limited by biomass feedstock potential assumptions
	Power-to-gas (P2G)	 Carbon-neutral synthetic gas produced via methanation of H₂ and CO₂ 	 Assumed to be imported from outside PGE's territory Quantity is unlimited
	H ₂ electrolysis	• Hydrogen from electrolysis directly injected into the pipeline	 Quantity is limited to up to 7% in the pipeline



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Liquid fuels: supply options

Category	Fuel Description		Notes
Fossil	Various	Refined fossil diesel, gasoline, LPG	Use is limited by CPP caps
Biofuel • Liquid hydrocarbons produced from bion feedstocks		 Liquid hydrocarbons produced from biomass feedstocks 	 Quantity is limited by biomass feedstock potential assumptions
ZCF	Power-to-liquids	 Synthetic liquid hydrocarbon produced via Fischer-Tropsch using H₂ and CO₂ 	 Assumed to be imported from outside PGE's territory Quantity is unlimited





- Electrolysis of water is the principal source of hydrogen production
- Cost and performance is derived from the International Renewable Energy Agency's 2020 report: <u>Green Hydrogen Cost Reduction: Scaling up</u> <u>Electrolysers to Meet the 1.5^oC Climate Goal</u>
- Electrolyzers provide hourly flexible demand in the electricity sector and decarbonized fuel for power generation, fuel cell vehicles and/or boilers (heat production)



 Biomass feedstocks are used in a variety of biofuel production (conversion) processes to decarbonize fuel that is not electrified or in existing gas resources to meet HB 2021 limits





Biomass feedstock potential

• Biomass feedstock potential that is available to PGE's service territory is derived from two sources:

Source	Feedstocks	Assumptions
ODOE 2018 Renewable Natural Gas Inventory	 Agricultural Manure Food Waste Landfill Waste Water Agricultural Industry Residuals Forest Industry Residuals 	 Potential for Oregon is allocated to PGE's service territory based on its share of the state population (46%).
DOE Billion-Ton Study	 Energy Crops (herbaceous) 	 National potential is reduced by 50%. PGE service territory's allocation of national supply is its population-weighted share (0.6%).



Additional fuel cost assumptions

• Zero carbon fuel imports

- In the future, it is likely that some zero carbon fuel required to meet the CPP will need to be "imported" from outside PGE's service territory since biomass potential is limited and uncertain, and synthetic electric fuel production at scale has substantial electricity system requirements to produce H₂ and capture CO₂
- As a result, we allow for imported zero carbon electric fuels (hydrogen, pipeline gas, liquid fuel) as a backstop resource to address emission constraints

• Fossil fuels

 Natural gas and refined petroleum product costs follow the Energy Information Administration's Annual Energy Outlook 2021 Reference trajectory



CPP emissions cap for PGE's service territory

- CPP establishes separate emission caps for natural gas and fossil liquid fuels at the state-level
- We apply the CPP limits to PGE's service territory by
 - 1. Estimating present-day (2022) emissions; and
 - 2. Applying % reduction (relative to 2022) consistent with the state through 2050

	2022	2030	2040	2050	
Natural gas					
Mt CO ₂	4.5	3.1	1.6	0.4	
% below 2022	0%	-31%	-63%	-90%	
Liquid fuels					
Mt CO ₂	8.7	6.6	3.5	1.0	
% below 2022	0%	-25%	-60%	-89%	





Scenarios



Four pathways designed to meet the study policy targets

1. Electric Economy

- Electrify buildings, industry & transportation to the extent possible to meet CPP targets
- Deploy primarily transmission-sited (supply-side) resources to meet HB 2021

2. Consumer Transformation

- Electrify homes & businesses, while consumers actively participate to provide flexibility
- Very high customer-sited solar and storage adoption, plus end-use load flexibility

3. Advanced Technology

- Assess the impact of nascent clean energy technologies
- Understand broad impacts of offshore wind and hydrogen use in power generation

4. Clean Fuels

- Maintain gas use in buildings and decarbonize fuel supply
- Prolific use of hydrogen in transportation and industry

Scenario framework answers key questions





High-level assumptions table

Values are for 2050 unless specified otherwise

		Electric Economy [S1]	Consumer Transformation [S2]	Advanced Technology [S3]	Clean Fuels [S4]
Demand	End-use electrification	High Electrification			Low Electrification
side	Load Flexibility	Base	Aspirational	Same as S1	Same as S1
	Customer-sited resources	Base	Aspirational	Same as S1	Same as S1
Electricity Supply	Supply-side resources	Onshore wind, solar PV and energy storage Allow offshore wind and H ₂ turbines			Same as S1
	Existing thermal resources	- Colstrip : planned exit - Existing gas-fired resources : burn NG and then ZCF as needed (100% ZCF by 2040)
Fuel Supply	Zero-carbon fuels	Minimal deployment since emissions reductions are primarily from demand-side High reductions			High RNG and H ₂ use





Results

- The results in this section are presented as follows
- The **Electric Economy** scenario is presented first with an in-depth focus on how the PGE service territory energy system transforms to meet the study policy targets
- Next, the Consumer Transformation, Advanced Technology and Clean Fuels pathways are presented in the context of how the results differ relative to the Electric Economy scenarios





Emissions and Energy demand

Electric Economy



Covered CO₂ emissions

- Emissions covered by HB 2021 and CPP are approximately 20 Mt CO₂ today
 - Emissions associated with liquid fuel consumption, overwhelmingly found in transportation, make up almost half of all emissions
- Abatement is front-loaded during the first decade primarily due to HB 2021's 2030 carbon target
- Emissions decline to under 1 Mt by 2050



Final energy demand

- Final energy demand defined
 - <u>Includes</u>: energy used in the delivery of services such as heating or transportation (e.g., includes pipeline gas consumed in a furnace to provide heat)
 - <u>Excludes</u>: energy consumed in converting to other forms of energy (e.g., excludes pipeline gas consumed in a power plant and electricity consumed in electrolysis)
- Aggressive electrification in the building, industrial and transportation sectors results in large declines in demand for pipeline gas and liquid fuels
 - Electricity consumption more than doubles





Final energy demand by sector

- The largest transformation takes place in the buildings and transportation sectors, driven by aggressive end-us electrification
 - Heat pumps shift pipeline gas consumption to electricity in buildings
 - BEVs shift liquid fuel consumption to electricity in transportation
- Industrial sector demand continues to grow due to baseline growth embedded in PGE's load forecast and assumed switching from gas to electricity

Final Energy Demand









Electricity Sector Results

Electric Economy



Load terminology

- The following slides present load at various levels of consumption
- The diagram to the right presents the sources of demand that are included at each level

Transmission-level load End-use load Retail electricity sales All end-use electricity consumption, including: Appliances (lighting; refrigerators; televisions) HVAC equipment (heat pumps; ventilation) **Electric vehicles Electricity transmission and distribution losses Conversion load** Transmission-connected technologies, including: Electrolysis • Electric boilers . **Energy storage** Net losses



Retail electricity sales

Excludes customer-sited generation impacts

- Long-term load growth is driven by on-road transportation electrification and base industrial growth
- Electrification of heating services in buildings increases electricity consumption, but most pronounced impact is to hourly load shape (as opposed to total consumption)
- Sales forecast significantly exceeds PGE's base forecast for 2050, which includes limited electrification



Hourly system load

Excludes flexible load impacts

Excluding Transportation

MWh



Including Transportation

MWh





Transmission-level load

- Transmission-level load reflects:
 - 1. <u>End-use</u>: retail electricity sales grossed up for T&D losses
 - 2. <u>Energy storage losses</u>: charge minus discharge
 - 3. <u>Electrolysis</u>: electricity consumed to produce hydrogen
 - 4. <u>Electric boiler</u>: electricity consumed to produce steam



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Transmission-level load

Electricity generation

- PGE's generation mix rapidly shifts from a hydro-thermal dominated mix to wind and solar-oriented
 - Gas generation decreases from 42% of total in 2022 to 14% by 2030
- Cost-optimal 100% clean generation mix (2040-2050):
 - <u>Solar</u>: 35%
 - <u>Onshore wind</u>: 55%
 - <u>Hydro</u>: 5%
 - <u>Gas (zero-carbon)</u>: 5%



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Installed capacity: today through 2030

- PGE's total installed capacity more than doubles by 2030 as energy, reliability and emission constraints bind
- Colstrip exit and expiration of contracts (e.g., PUD hydro) introduces a large capacity and energy gap that can only be met with renewables and storage
- Size of installed capacity is large since the incremental sources generally are low utilization (e.g., capacity factor 20-40%)



Installed capacity through 2050

Installed Capacity

MW



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Installed capacity: renewable technologies

- Onshore wind resources are accessed across the Columbia River Gorge, southeast Washington and Montana to take advantage of profile diversity
 - Montana wind's high winter production is important to serving electrified building heating load
- Solar PV deployment is more homogenous because the higher capacity factor in central Oregon outweighs profile diversity

Installed Capacity






Installed capacity: storage

- In the absence of new thermal resources, storage is the principal resource to meet capacity needs and provide flexibility
- However, the duration needed to maintain reliability far exceeds the typical 4-hour duration installed today
 - Average duration is 8 hours in 2030 and 10 hours by 2040
- Batteries' shorter lifetime (15 years) creates the opportunity to adjust the storage fleet's average duration up or down over time as needed
- Pumped storage is not economic in this scenario



Annual resource additions

- The rate at which need renewable and storage resources are added exceeds 1,000 MW/year from 2026-2035 in order to meet HB 2021 and maintain reliability
- CPP-driven electrification maintains high levels of resource investment through 2050





Fuel for existing thermal resources

- HB 2021 emission limits are met through 2035 by reducing thermal resource generation and natural gas use
- Starting in 2040, fuel supply is 100% decarbonized, including ~40% hydrogen and ~60% RNG (biomass-derived)



📕 Pipeline Gas 📃 Hydrogen

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Distribution system

- We approximate total distribution system capacity by summing the capacity of each feeder archetype
 - Approximately equivalent to the sum of each individual feeder's weak link
- Most distribution capacity upgrades are triggered post-2030
- Total simulated distribution capacity grows by one third from today to 2050



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Fuels Sector Results

Electric Economy



Pipeline gas

- Most reductions in natural gasrelated emissions are from electrifying heat in buildings, while industrial demand reductions are more modest
- The stringency of the CPP natural gas cap necessitates some zero carbon fuel consumption



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Liquid fuels

- Nearly all diesel- and gasolinerelated emission reductions occur from transportation electrification
- A very small amount of zero carbon fuel is needed to reach the CPP non-natural gas cap, particularly in the near-term when liquid fuel demand remains high





Results

Consumer Transformation



Distribution system comparison

- A combination of customer-sited solar and storage, plus load shifting contributes to avoiding growth on the distribution system
- Approximately 500 MW of nominal capacity is avoided by 2050 and most of this occurs on residential-oriented feeders (discussed on the next slide)



Distribution impacts by feeder archetype

- Most avoided distribution capacity occurs on residential-oriented feeders that are already near the planning threshold (67%)
 - Most light-duty vehicle charging (and associated load flexibility) takes places on residential feeders
- Feeders that have low to medium present-day utilization can absorb large amounts of incremental load growth prior to triggering upgrades
- Industrial-oriented feeders show very little difference due to high assumed base load growth and no end-use with flexibility



Distribution System Capacity



Illustration of distribution-sited resource impact

- On very cold winter days that set the distribution peak, flexible load is challenged by the persistence of high loads across the day and customersited solar quality is low
- In particular, the ability of electric vehicles to shift consumption is limited since there is a dual morning and evening heating load



Black line = net distribution-level load sered by supply-side resources

Additional considerations

- On operationally challenging days, one of the ways to engage customers and realize further distribution deferral benefits is to implement critical peak pricing over sustained time (e.g., all day) to *reduce* rather than shift load
 - Specifically, voluntary vehicle load shedding on peak days would produce significant reductions
- In addition to programs that reduce consumption, customer-sited resources could be targeted on feeders near the planning threshold
- Furthermore, thermal ratings in the winter are typically higher than summer ratings, which provides additional distribution system capacity





Results

Advanced Technology



Resource mix comparison

- H₂ turbines and offshore wind are both economic (~2 GW deployment for each) with nearand long-term impacts on PGE's resource mix
- These technologies primarily displace supply-side solar and storage resources, and make more efficient use of renewable electricity
 - Total installed capacity requirements decrease by nearly 10 GW by 2050
 - Curtailment is ~2/3 lower

Installed Capacity: 2030-2050







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Hourly dispatch comparison

Sample day in winter 2050

 Higher levels of dispatchable resources (H₂ turbines) and renewables with strong output in the winter (offshore wind) reduce the need for high-duration storage to meet challenging system conditions



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Generation, MW



Results Clean Fuels



Energy demand comparison

Clean Fuels pathway retains significant use of gas in buildings, while expanding direct hydrogen consumption in freight transportation





As a result, retail electricity sales are ~10,000 GWh lower by 2050 relative to the Electric Economy scenario

Retail Electricity Sales





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Distribution system comparison

- Lower residential and commercial building electrification translates into lower distribution system growth
- However, upgrades are still needed due to extensive passenger transportation electrification and base industrial load growth



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Fuels supply comparison

- The trade-off with lower electricity sector delivery (T&D) and generation infrastructure is the extensive use of expensive (\$20/MMBtu+) zero carbon fuels
- Zero carbon fuel consumption in 2050 to meet CPP is more than triple
 - Gasoline demand reductions from passenger transportation drive lead to most demand reductions



Liquid Fuels and Pipeline Gas Supply TBtu

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Results

Cost Comparison





- Scope of costs is limited to energy system (both electricity and fuels) costs
 - Annualized capital costs of supply- and demand-side equipment
 - Fixed and variable O&M costs
 - Variable fuel costs
- Cost impacts from alternative pathways are measured by comparing each scenario to the Electric Economy scenario
- Costs are presented in 2021 dollars



Consumer Transformation

- In the near-term, economic benefits primarily accrue from avoiding supplyside resource costs since flexible load and customer-sited resources supporting renewable integration
- Long-term benefits primarily shift to avoided electric delivery costs costs as economy-wide electrification is widespread
 - Renewable integration challenges also shift to long-duration balancing, whereas flexible load and customer-sited storage generally address short-duration issues



Incremental Cost (relative to Electric Economy) \$mil

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- Cost savings from H2 turbines and offshore wind are large and apparent due to the substantial energy and capacity gap in 2030 that must be met with carbon-free resources
 - Supply-side storage and solar are primarily avoided
- Savings continue to grow as the HB 2021 emissions constraint becomes more binding and electricity supplydemand imbalances are harder to resolve with energy storage alone



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Clean Fuels

- A strategy of clean fuels to meet the CPP – as opposed to electrification is increasingly expensive over time as a larger share of demand needs to be met by expensive zero-carbon fuels
- Lower electrification does avoid electricity infrastrure, but these cost savings are offset by expensive biofuels
 - For example, the marginal cost of pipeline gas is ~\$25/MMBtu in 2050



Incremental Cost (relative to Electric Economy) \$mil

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Summary



- The results of the analysis demonstrate the feasibility of PGE achieving compliance with HB 2021 and CPP
- We use scenarios to evaluate alternate strategies to meet the emissions reductions required by those policies
- Through this process, we have identified key insights and important implications for PGE



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Zero-carbon resource growth

- Meeting policy targets requires new renewable and storage procurement at an unprecedented scale and pace
- In the Electric Economy scenario, PGE adds ~1,500 MW/year of renewables and storage from 2026-2035
- Both technology and geographic diversity is key metrics for 2040:
 - Wind:solar generation ratio of 60:40
 - Montana wind is ~20% of total generation
 - When offshore wind is allowed as a resource, 1.5 GW is added (15% of generation)
- In the absence of new thermal, battery storage provides capacity and flexibility
 - Average duration of the battery storage fleet is 7 hours in 2030 and 10 hours by 2040





- Since PGE cannot build new thermal resources that burn fossil fuels, existing resources continue operations through 2050, supporting system reliability
 - Existing gas resources switch from natural gas to zero carbon fuel in 2040, in compliance with the CPP
- If new thermal resources (H₂ turbines) can be constructed, it complements existing gas resources and reduces over-reliance on battery storage
 - Significantly less resource procurement is needed
 - Renewable curtailment is reduced by two-thirds



Distributed resources

- Benefit of flexible load and increased penetration of customer-sited solar and storage is twofold
 - Align load with renewable production profile
 - Mitigate distribution upgrades
- Battery electric vehicle charging represents the largest opportunity to avoid distribution peak impacts
- Economic benefits could be maximized with:
 - Resources are targeted on feeders that are already near their planning threshold or anticipated to grow rapidly
 - Implement critical peak pricing over a sustained time (all day) to reduce rather than shift load to another time of day –specifically voluntary vehicle load shedding



Electrification versus clean fuels

- Clean fuels may be a viable alternative to electrification in meeting CPP targets, but they carry higher costs and risks
- Total zero carbon fuel consumption required in 2050 is 3x higher in the Clean Fuels scenario relative to Electric Economy
- Cost and availability of clean fuels in 2050 is also highly uncertain & all biomass-derived fuel potential would be required



CPP implications for PGE

- Oregon's CPP does not directly regulate PGE but it has important implications for the electric sector
- PGE should expect significant building and transportation electrification as a CPP compliance strategy
- This will increase total load, but also affect load characreristics in other ways
 - Electrifying heat in buildings will eventually transform PGE's system from a dual peaking to distinctly winter peaking system
 - Electric vehicle charging introduces valuable flexibility that can help avoid distribution system upgrades if managed carefully
 - Electrolyzers serving hydrogen demand in the industrial and transportation sectors introduce large, flexible electric loads that can absorb otherwise curtailed renewable generation





Thank You

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Update: directional impact of legislation on PGE strategy





Customer Demand

Oregon could see upwards of \$40 billion of investment over the next ten years, with tens of thousands of jobs and \$2-3 billion in local tax revenue.

Additional funding for transportation electrification, domestic semiconductor production/R&D, and IIJA funding for manufacturing to provide upward pressure on demand.¹

PGE long-term load forecast revised upward by 1% per year in response.



Price impact

Increased funding of renewable and carbon-free energy sources, credits expanded and extended:

60% solar ITC
\$35/MWh wind PTC
60% offshore wind PTC
30% storage ITC
\$31/MWh nuclear PTC

Leveled playing field through transferability and normalization fixes.



Technology availability

IIJA and IRA funding aims to make new technologies commercially feasible: EV adoption, solar and storage credits, and loan programs for customers.

Funding available for transmission projects.

ITC expanded to include offshore wind

Nuclear tax credits

Carbon capture and storage credits



Long-term earnings power

Legislative action drives potential for strategic capital investment while providing downward pressure on per-unit prices through tax credits.

Technology neutral tax incentives, grants, and funds for customer-sited technology will reduce customer rate impacts of decarbonizing.

Legislative action on normalization and transferability reduces earnings drag and makes solar ownership feasible.

Partnership in pursuit of grant funding likely to add to strategic capital opportunities.