New Jersey 2019 IEP

Technical Appendix

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EVOLVED ENERGY RESEARCH

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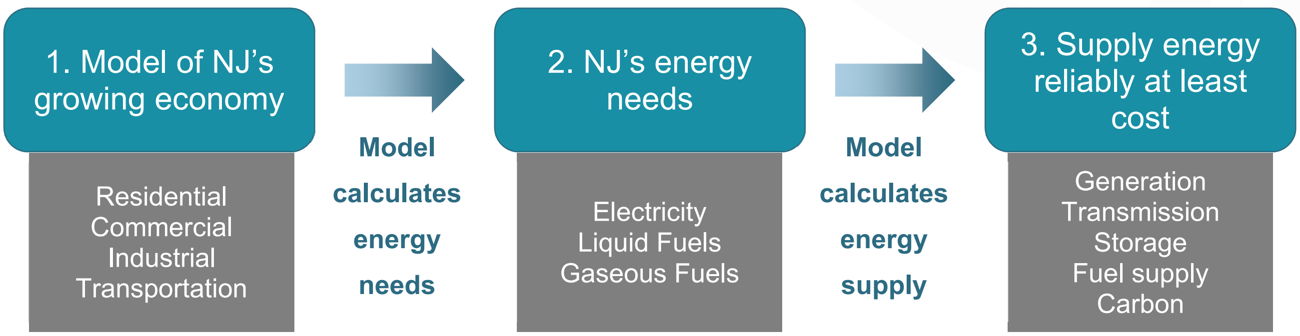
Modeling Overview

1.1. High Level Process Description

The IEP modeling approach calculates the energy needed to power New Jersey's economy, and the least-cost way to provide that energy without exceeding emissions targets. The steps of the analysis can be framed at a high level as shown in Figure 1.

Figure 1. High level description of IEP modeling approach



1. **Model New Jersey's energy needs by sector across the economy.** We use a bottom up stock rollover model of all energy using technologies in the economy called EnergyPATHWAYS (EP) to build a representation of how people use energy today and in the future. EP simulates the demand side scenarios of how technology stocks will evolve over time across all sectors of the economy. Approximately 30 economic subsectors are represented by stock rollover. Other sectors that lack the data to create a stock representation are modeled with evolving aggregate energy demands.

2. **Aggregate demand side energy needs required from the supply side optimization.** The previous step determines the energy required by each subsector of the economy from 2020 to 2050. Aggregating all of these demands constitutes the final energy demand that New Jersey has to serve through electricity and fuels supply.

3. **Least cost investment and operations of the supply side to meet clean energy goals.** We then use a capacity expansion model of energy supply investments and operations to determine the least cost way of serving New Jersey's changing energy needs. The

model we use is called the Regional Investment and Operations model (RIO). The model is not constrained by today's market systems (such as those in the electricity system); instead it minimizes the total cost of infrastructure and fuels invested in over time by optimizing investments and operations. For long-term planning, this approach is ideal, because rates, market designs, contract structures, and regulatory environments are all likely to see modifications by 2030 and change significantly by 2050. By looking at total cost, we identify what the least cost set of investments looks like, constrained by policy options in each scenario.

1.2. Description of Scenarios

The summary of IEP scenarios is given in Table 1. The two reference cases represent a world where the decarbonization policies of 100% clean electricity and 80% reductions in energy emissions by 2050 are not enforced. Reference 1 does not enforce the current clean energy policies. Reference 2 enforces clean energy policies, including the 2,000 MW storage mandate, 3,500 MW offshore wind mandate, 50% RPS by 2030, 330,000 electric vehicles by 2025, and energy efficiency goals. The Least Cost Case is the least constrained pathway to reach the decarbonization goals.

Each of the variation cases investigates the impact of a particular policy or uncertainty on the decisions and costs found in the Least Cost Case. These start with the Least Cost Case assumptions and change one or more of them to provide the comparison.

Table 1 Key questions answered by scenario

Name	Summary	Key question
Reference 1	No current or prospective energy policies	What are cost and emissions outcomes of "business as usual?"
Reference 2	Existing policy except GWRA & 100% Clean	What cost and emissions impact do existing policies have?
Least Cost	Fewest constraints. Meets emissions goals	If all options are open to New Jersey, what is the least cost pathway to meet goals?
Variation 1	Regional deep decarbonization	How does regional climate action affect New Jersey's cost to meet goals?
Variation 2	Reduced regional cooperation	How can NJ meet its goals without electricity resources located out of state?
Variation 3	Retain fuel use in buildings	How would NJ meet its goals if it kept gas in buildings, and at what cost?
Variation 4	Faster renewables & storage cost declines	How would cheaper clean energy affect costs and resource mix?

Variation 5	Nuclear retires and no new gas plants	How does minimizing thermal generation affect decarbonization costs?
Variation 6	Reduced transportation electrification	How would NJ meet its goals without high levels of electric vehicle adoption, and at what cost?

Scenario assumptions can be split into demand side assumptions (those that impact the assumed adoptions of different energy end use technologies in the economy) and supply side assumptions (those that impact the constraints on the least cost optimization of supplying the economy with energy). The full set of assumptions by scenario is shown in Table 2.

Table 2 Detailed scenario assumptions

		Reference 1	Reference 2	Least Cost	Variation 1	Variation 2	Variation 3	Variation 4	Variation 5	Variation 6
		BAU – No Clean Energy Act	Existing carve-outs. No emissions goals	All Options to meet Goals	Region achieves 80 by 50 goals	Reduced regional cooperatiorn	Retain gas use in buildings	Fast clean tech cost declines	No new gas generation. Nuclear retires	Reduced transport electrification
		Provides fossil-fuel based reference case	What is the cost of existing programs?	Least-cost 'base' route to NJ goals consistent w/ EMP.	How does regional cooperation reduce costs?	How can NJ meet its goals internally?	Impact of retaining gas use in buildings.	What are savings if technology continues its rapid advance?	Assess cost of 2020 NG moratorium and nuclear retirement	Impact of reduced EV adoption
	Emissions									
C1	**Economy-wide Emissions Constraint**	none	none	80% below 2006 in 2050	80% by 2050 applied PJM-wide	80% below 2006 in 2050	80% below 2006 in 2050	80% below 2006 in 2050	80% below 2006 in 2050	80% below 2006 in 2050
C2	**Electricity Emissions Constraint**	none	none	C-neutral by 2050	C-neutral by 2050	C-neutral by 2050	C-neutral by 2050	C-neutral by 2050	C-neutral by 2050	C-neutral by 2050
C3	**Renewable Portfolio Standard**	22.5% by 2021	50% by 2030	50% by 2030	50% by 2030	50% by 2030	50% by 2030	50% by 2030	50% by 2030	50% by 2030
	Transportation									
T1	**Light Duty Vehicles**	Only choose EVs if less expensive than ICE	330k EVs by 2025	330k EVs by 2025. ICE sales decrease to 0 in 2035	330k EVs by 2025. ICE sales decrease to 0 in 2035	330k EVs by 2025. ICE sales decrease to 0 in 2035	330k EVs by 2025. ICE sales decrease to 0 in 2035	330k EVs by 2025. ICE sales decrease to 0 in 2035	330k EVs by 2025. ICE sales decrease to 0 in 2035	200k EVs by 2025. EV's 50% in 2050
T2	**Medium Duty Vehicles**	No EVs	Continue business-as-usual	75% Electric in 2050	75% Electric in 2050	75% Electric in 2050	75% Electric in 2050	75% Electric in 2050	75% Electric in 2050	Continue business as usual
T3	**Heavy Duty Vehicles**	No EVs	Continue business-as-usual	50% EV by 2050: residual fuel mix optimized to meet 80x50	50% EV by 2050: residual fuel mix optimized to meet 80x50	50% EV by 2050: residual fuel mix optimized to meet 80x50	50% EV by 2050: residual fuel mix optimized to meet 80x50	50% EV by 2050: residual fuel mix optimized to meet 80x50	50% EV by 2050: residual fuel mix optimized to meet 80x50	Continue business as usual
T4	**Aviation**	Continue business-as-usual	Continue business-as-usual	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50	Jet fuel: fuel mix optimized to meet 80x50
	Building electrification									
B1	**Building retrofits**	No electrification target	No electrification target	90% electric by 2050. Rapid adoption in 2030	90% electric by 2050. Rapid adoption in 2030	90% electric by 2050. Rapid adoption in 2030	No electrification retrofits	90% electric by 2050. Rapid adoption in 2030	90% electric by 2050. Rapid adoption in 2030	90% electric by 2050. Rapid adoption in 2030
B2	**Delivered Fuels**	No electrification target	No electrification target	Transition to electric starting in 2030	Transition to electric starting in 2030	Transition to electric starting in 2030	No electrification target	Transition to electric starting in 2030	Transition to electric starting in 2030	Transition to electric starting in 2030
	Electricity									
E1	**PJM Carbon content**	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech	Eastern Interconnect C-neutral in 2050	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech	PJM meets state RPS & chooses least-cost tech
E2	**NJ able to purchase out-of-state renewable generation?**	No	No	Yes – up to transmission limit	Yes – up to transmission limit	No	Yes – up to transmission limit	Yes – up to transmission limit	Yes – up to transmission limit	Yes – up to transmission limit
E3	**Expanded transmission**	None	None	Allowed to expanded from 7 to 14 GW if least cost	Allowed to expanded from 7 to 14 GW if least cost	Kept at 7 GW	Allowed to expanded from 7 to 14 GW if least cost	Allowed to expanded from 7 to 14 GW if least cost	Allowed to expanded from 7 to 14 GW if least cost	Allowed to expanded from 7 to 14 GW if least cost
E4	**Efficiency**	No efficiency programs	Existing -2% electric, -0.75% gas	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025	Accelerated Efficiency. Best available tech by 2025
E5	**Nuclear**	Kept through permit. Then keep if least-cost	Kept through permit. Then keep if least-cost	Kept through permit. Then optimized to meet energy & emissions at least cost.	Kept through permit. Then optimized to meet energy & emissions at least cost.	Kept through permit. Then optimized to meet energy & emissions at least cost.	Kept through permit. Then optimized to meet energy & emissions at least cost.	Kept through permit. Then optimized to meet energy & emissions at least cost.	Kept through permit. Then retire	Kept through permit. Then optimized to meet energy & emissions at least cost.
E6	**Natural Gas Electricity Generation**	No restrictions. Chooses if least cost	No restrictions. Chooses if least cost	Optimize to meet emissions at least cost.	Optimize to meet emissions at least cost.	Optimize to meet emissions at least cost.	Optimize to meet emissions at least cost.	Optimize to meet emissions at least cost.	No new gas. Exisitng retires after 50 year life	Optimize to meet emissions at least cost.
E7	**PV**	Add 400+ MW/year through 2030	Add 400+ MW/year through 2030	Add 400+ MW/year in NJ to 2030. More if economic.	Add 400+ MW/year in NJ to 2030. More if economic.	Add 400+ MW/year in NJ to 2030. More if economic.	Add 400+ MW/year in NJ to 2030. More if economic.	Add 400+ MW/year in NJ to 2030. Lower cost.	Add 400+ MW/year in NJ to 2030. More if economic.	Add 400+ MW/year in NJ to 2030. More if economic.
E8	**Storage**	No restrictions. Chooses if least cost	2 GW by 2030	≥2 GW by 2030, then optimized to meet emissions at least cost.	≥2 GW by 2030, then optimized to meet emissions at least cost.	≥2 GW by 2030, then optimized to meet emissions at least cost.	≥2 GW by 2030, then optimized to meet emissions at least cost.	≥2 GW by 2030, then optimized to meet emissions at least cost. Lower cost.	≥2 GW by 2030, then optimized to meet emissions at least cost.	≥2 GW by 2030, then optimized to meet emissions at least cost.
E9	**Off-shore Wind**	No restrictions. Chooses if least cost	3.5 GW by 2030	≥3.5 GW by 2030, the optimized to meet emissions at least cost	≥3.5 GW by 2030, the optimized to meet emissions at least cost	≥3.5 GW by 2030, the optimized to meet emissions at least cost	≥3.5 GW by 2030, the optimized to meet emissions at least cost	≥3.5 GW by 2030, the optimized to meet emissions at least cost. Lower cost.	≥3.5 GW by 2030, the optimized to meet emissions at least cost	≥3.5 GW by 2030, the optimized to meet emissions at least cost

2. Scenario Results

The following section presents the results of each of the scenarios. Section 2.1 gives an overview of the implementation of each case and the major impacts associated with it. Section 2.2 describes the two Reference Cases. Section 2.3 describes the Least Cost Case. Section 2.4 describes each of the Variations. Section 2.5 presents the results figures and tables that the preceding sections reference when discussing results.

2.1. Implementation and major impacts

Table 3. Scenario implementation and major impacts

Variation	Description	Implementation	Major Impacts
Reference 1	No current or prospective energy policies	• No clean energy policy action taken going forward from 2020 • RPS constant at 22.5% going forward	• Emissions decline only 15%, driven by efficiency gains and limited fuel-switching to clean electricity • Electricity load increases slightly but far less than in the Least Cost Case • In-state gas and nuclear dominate electricity supply
Reference 2	Existing policy except GWRA & 100% Clean	• Existing policy included ○ 3.5 GW of offshore wind by 2030 ○ 2 GW of storage by 2030 ○ 330k EVs by 2025 ○ 50% RPS by 2030 ○ EE improvements	• Electricity emissions fall through 2035 as offshore and PJM wind reduce gas use • Transportation and building emissions reductions plateau after 2030 • Electricity load increases but still less than Least Cost Case • In-state gas generation offset by offshore and PJM wind
Least Cost	Least constrained case	• Central set of assumptions that all Variations are compared to • Aggressive electrification on the demand side • Least constrained set of options on the supply side • Full details in Table 2	• Central set of least cost resource decisions that Variations are compared to for assessing impacts of different policies or uncertainties
Variation 1	Regional deep decarbonization	• Eastern Interconnection pursues 100% clean electricity and 80x50 GHG target	• Decarbonization policies across the Eastern Interconnection increase demand for renewable generation and thus competition for the best resources

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			• As a result, NJ imports renewables with lower resource quality and higher transmission costs (i.e. higher up the supply curve)
Variation 2	Reduced regional cooperation	• Disallow new transmission and out of state resource procurement	• Losing access to out-of-state resources and transmission requires additional in-state resources • Firm capacity resources require additional biogas (2x Least Cost Case consumption)
Variation 3	Retain fuel use in buildings	• Zero electrification in residential and commerial buildings	• Higher emissions from natural gas use in buildings is primarily offset by increased biofuels in 2050 • Poor foundation for further GHG reductions: decarbonizing beyond 80x50 would be very expensive
Variation 4	Faster renewables & storage cost declines	• Low renewables and storage costs. Renewable generation prices are from NREL ATB 2019 Low forecasts. Storage prices are from International Renewable Energy Agency (IRENA) Low forecasts	• Increased storage build due to relatively more favorable storage pricing • Increased out-of-state solar imports relative to out-of-state wind • Reduction in biogas burn due to lower cost renewable energy

Variation 5	Nuclear retires and no new gas plants	• No new gas plants allowed to be built
		• Nuclear generators cannot extend beyond their existing licenses
			• Significant increase in offshore wind and energy storage build
			• Average storage duration increases to address lack of gas resource flexibility
			    ○ Least Cost: 8 hours in 2050
			    ○ Variation 5: 36 hours in 2050
			• Increased intertie capacity
			    ○ Gas is imported for reliability prior to 2050, replacing lost in-state gas from Least Cost Case
			• Additional out-of-state resources are imported to replace lost nuclear generation from Least Cost Case

Variation 6	Reduced transportation electrification	• Light-duty vehicle electrification is cut in half compared to the Least Cost Case (50% by 2050) • Medium- and heavy-duty vehicle electrification is zero by 2050	• Additional biofuels are used primarily to decarbonize liquid fuel consumption from freight trucks

2.2. Reference Cases

The reference cases provide a business-as-usual benchmark to assess the relative cost of the decarbonization cases against. No decarbonization policy does not mean no investments, as old technology wears out and needs to be replaced, fuels must be purchased, etc. By comparing spending in a business-as-usual case against spending in a decarbonization case, we can find the additional expense of the New Jersey 80x50 emissions target and 100% clean electricity.

The study looked at two reference cases. The first implements no clean energy policy. The second includes all of New Jersey's 2030 clean energy policy goals. By comparing decarbonization costs to the first, we can assess the incremental cost of implementing all clean energy policy, including those already active for 2030. By comparing to the second, we can evaluate the incremental costs of moving beyond existing policy and achieving deep carbon reductions and 100% clean electricity.

2.2.1. Reference 1

This represents an assumption of stasis in terms of policy and technology adoption. No policy is implemented beyond 2020. RPS remains at the same level as in 2020 (22.5%) and none of New Jersey's 2030 clean energy policy targets are implemented. On the technology side, technologies are replaced "like for like." For example, gas storage water heaters in the residential sector are replaced with newer gas storage water heaters. These new technology vintages have changing parameters of cost and efficiency but represent the same technology type and class (i.e. they use the same fuel and represent the same level of relative efficiency in the market). Final energy demand for Reference 1 is shown in Figure 3. Capacity build on the supply side is shown in Figure 5.

2.2.2. Reference 2

Reference 2 implements New Jersey's 2030 clean energy policy goals, reducing energy demand through efficiency and electric vehicle adoption, and building storage and offshore wind technologies in line with New Jersey's resource mandates. Reference 2 uses the same assumptions as Reference 1 for stock rollover. However, it assumes non-technology specific improvements in efficiency to reflect the efficiency goals. These are not reflected in the stock rollover, but instead implemented as an overall reduction in final energy demand for electricity and gas. Final energy demand for Reference 2 is shown in Figure 3. Capacity build on the supply side is shown in Figure 5.

2.3. Least Cost Case

The Least Cost Case is based on a set of demand side and supply side assumptions that underpin all of the Variation cases as well. Each Variation adjusts some element, or elements, of the Least Cost Case to investigate the impact of different policies or uncertainties.

2.3.1. Demand Side Assumptions and Final Energy Demand

The Least Cost Case assumes rapid adoption of electrification technologies, and rapid adoption of high efficiency technologies where the end-use is already electric (i.e. refrigeration) or where complete electrification is infeasible inside of New Jersey. In replacing like for like (i.e. electric appliances with electric), the best available technology replaces end of life stock from 2025 onwards in appliances. Our assumptions for how the demand side evolves are shown in Table 2.

Aggressive electrification of vehicles and buildings drives the changes seen in Least Cost Case final energy demand (Figure 3). Gasoline demand falls to almost zero as light-duty vehicles are 100% electrified by 2050. Demand for pipeline gas also falls significantly as 90% of buildings are transitioned from gas appliances to electric. The increased electricity demand from these two sectors, as well as electrification in the medium- and heavy-duty vehicles, doubles electric load by 2050. At the same time, technologies transition to more efficient versions, reducing final energy demand further. Final energy demand by sector is shown in Figure 4.

Table 5 shows the sales targets for electrification of vehicles and buildings. While sales transition rapidly (100% electric light-duty vehicle sales by 2035), it takes time for stocks to transition, because sales replace stocks on burn out at the end of their lives. The resulting stocks are shown in Table 6. 100% light-duty vehicle sales by 2035 reaches 100% electric vehicle stocks by 2050, for example.

2.3.2. Least cost energy supply side decisions

Resource capacity is shown in Figure 5 and Figure 6 Figure 6 at 5 year increments from 2020 to 2050. There is significant growth in capacity in the Least Cost Case and in the Variations. In the Least Cost Case, installed generating capacity is 3.5 times the capacity of today's fleet. This is partly due to the doubling of load due to electrification. The additional growth is due to the lower capacity factor of renewables compared to the thermal generation supplying New Jersey with electricity today.

Firm capacity increases from 12 GW to 17.5 GW by 2050. This is driven by the need for reliability when renewable output is low. By 2050 the least cost option for providing firm capacity is burning 100% clean gas (biogas and small amounts of hydrogen) in existing and new gas generators. While capacity increases, the utilization of the capacity drops significantly. The economic use of this capacity in 2050 is to provide energy during infrequent weather events that limit the quantity of available renewables. Burning limited amounts of biogas during these periods is more cost effective than building a high-duration battery energy storage fleet that would be discharged infrequently.

Economy wide, gas usage drops over time, shown in Figure 10, with the biofuels component of pipeline gas supply in 2050 feeding the electricity system to comply with the 100% Clean Electricity requirement. The remaining natural gas in 2050 is used for non-electrified space and water heating loads and industrial processes. Overall consumption declines by approximately 75% from 2020 to 2050.

Offshore wind and energy storage build exceed current mandates, with 11 GW of offshore wind and 9 GW of storage built by 2050. Nuclear is found to be cost effective and is extended beyond its current permit lifetimes.

New Jersey also imports energy from out-of-state resources (Figure 7), serving 21% of load by 2050 (Figure 8). Transmission expands from 7 GW to 9 GW to import additional out-of-state generation (Figure 9). It is more cost effective to build additional in-state resources than expand the transmission further to the maximum 14 GW allowed in the model assumptions.

2.3.3. Costs

Costs include demand-side equipment, such as vehicles and appliances, supply-side equipment, such as wind turbines and power plants, and their fuel and operating costs. The components of cost include the annualized capital costs of demand- and supply-side energy equipment investments, variable fuel costs, and fixed and variable operations and maintenance costs. This can be thought of as an "energy system revenue requirement" – the annual cost of producing, distributing and consuming energy in New Jersey.

The costs presented here do not include costs outside of the energy system or benefits from avoiding climate change and air pollution. All costs are in 2018 dollars.

Because costs include investments in technologies and fuels beyond the electricity system, they are not indicative of rate impacts. Investment in vehicles is a large component of costs for example, as is the investment in fuel for vehicles or the costs saved when not purchasing fuel in the case of electric vehicles.

Figure 11 shows the cost components of each of the cases relative to Reference Case 1. All costs on the positive side of the y axis are things that New Jersey spends more on than in Reference Case 1. An example is the electricity grid shown in light blue. Load growth from electrification requires additional T&D investment over Reference 1. All costs on the negative side of the y axis are things that New Jersey spends less on than in Reference Case 1. The largest savings when decarbonizing the New Jersey economy is avoided purchases of fossil fuel products. The difference between the positive components and the negative components gives the net cost to New Jersey per year of decarbonizing its economy. These are shown by the black diamonds. Figure 12 plots these net costs side by side to compare the annual costs of all variations relative to Reference Case 1.

Costs follow a similar pattern in many of the cases where there are early net cost increases as more expensive demand side equipment, such as electric vehicles, are invested in at the same time as transitioning the electricity system towards renewables. As technology costs decline in the future, net costs begin to drop as prices for clean technology become more cost effective relative to the equivalent reference investments made in the Reference Case.

In the Least Cost Case, this dynamic is clear going into 2045. Net costs tick upwards again to get to 2050 because of investments in offshore wind and the need for biofuels to displace natural gas in electricity production to achieve 100% Clean Electricity. The net cost trend versus each Variation is shown in Figure 12.

2.4. Variations

Variations vary one or more elements of the Least Cost Case to investigate different policies or uncertainties.

2.4.1. Variation 1 – Regional Deep Decarbonization

2.4.1.1. Demand Side Assumptions and Final Energy Demand

Variation 1 shares the same demand side assumptions as the Least Cost Case inside of New Jersey. However, in Variation 1 the same New Jersey demand side assumptions are extended to the entire region, driving aggressive electrification, growth of electricity demand, and reductions in fossil fuel use.

2.4.1.2. Least cost energy supply side decisions

Variation 1 investigates the impact where the entire Eastern Interconnect achieves 80x50 carbon reductions and 100% clean electricity. This is clearly the most desirable outcome, since blunting global temperature increases by controlling carbon concentrations in the atmosphere is a collective problem and requires all regions to decarbonize their economies. Without collective action from regions outside New Jersey, decarbonization policy will be ineffective.

Comparing Variation 1 to the Least Cost Case is challenging, because the rest of the region does not decarbonize in the Least Cost Case, so the total level of carbon reductions in the two cases is very different. Available out of state renewable sites are abundant in the Least Cost Case, and we assume regional cooperation such that New Jersey can access any renewable resource in PJM. We are therefore not testing coordination policy by comparing Variations 1 and 2.

The highest quality renewables (e.g., high capacity factor and low incremental transmission costs) are available to New Jersey in the Least Cost Case because other states are not building them in large quantities. In Variation 1, the loads in other states grow significantly due to electrification and they compete for the same renewable resources. Those high quality renewables that were available to New Jersey in the Least Cost Case face competing demands from other states across the Eastern Interconnection, and the result is increased costs driven by New Jersey importing clean electricity that is higher up the renewables supply curve.

What we might have expected to see was increased renewable resource diversity, providing New Jersey with a more dependable aggregate renewable resource, decreasing costs and driving lower levels of investment in storage and firm capacity. These diversity benefits are often observed between regions in other parts of the country: California and the Northwestern United States, for example. However, there is comparably little diversity across resources in PJM. Diversity is therefore a less important factor in reducing resource costs.

A more appropriate comparison for Variation 1 would be to compare it to a case where all states meet the same Eastern Interconnection wide decarbonization and clean energy standards, but “go it alone” by disallowing imports of renewables from other regions (like Variation 2 but applied to all states). The result would be close to comparing Variation 1 and Variation 2 for New Jersey: the cost of Variation 2 is higher.

2.4.1.3. Costs

The costs of Variation 1 exceed the Least Cost Case because of the increased competition for renewables to serve significantly increasing loads across the region combined with a 100% clean electricity standard. As noted above, comparing Variation 1 and the Least Cost Case is not an effective means of evaluating different levels of cooperation between states. Ideally we would have a scenario where states decarbonize across the Eastern Interconnection but limit renewable resource procurement to in-state only. Variation 2 may be a close estimate of New Jersey’s costs under that regime.

The actual costs to New Jersey of regional coordination when all states in the Eastern Interconnection meet emissions and clean energy goals will be dependent on market structures, and the form of those markets in the future is unknown.

2.4.2. Variation 2 – Reduced Regional Coordination

2.4.2.1. Demand Side Assumptions and Final Energy Demand

Variation 2 shares the same demand side assumptions as the Least Cost Case.

2.4.2.2. Least cost energy supply side decisions

By limiting renewable resource procurement to in-state only, additional energy primarily comes from offshore wind resources. By 2050, 21 GW of offshore wind are built in Variation 2, versus 11 GW in the Least Cost Case (Figure 6). Greater quantities of energy storage and firm capacity are also built due to the lost diversity of renewable output that out of state resources provide. Firm capacity is also used more frequently, with double the quantity of biogas burned in electricity in 2050 versus the Least Cost Case (Figure 8).

2.4.2.3. Costs

Costs in Variation 2 are higher than the Least Cost Case because of the restricted set of resources available to decarbonize the economy. Increased investment in offshore wind versus the lower cost out-of-state options, and the increased balancing resources noted above versus the Least Cost Case, drive higher costs.

2.4.3. Variation 3 – Retain Gas Use in Buildings

2.4.3.1. Demand Side Assumptions and Final Energy Demand

Variation 3 retains gas use in buildings. When compared to the Least Cost Case, the result is continued pipeline gas demand and reduced electricity required for fuel switched appliances. As shown in Figure 3 and Figure 4, total final energy demand is higher because of the lower efficiency of gas versus electric appliances. Sales shares of gas using appliances remain the same as business-as-usual (Table 5).

2.4.3.2. Least cost energy supply side decisions

Retaining gas in buildings increases overall energy demand compared to the Least Cost Case due to fewer electrification-related efficiency gains. There are now more emissions coming from natural gas combustion in buildings, so emissions reductions that previously came from electrification and decarbonizing electricity supply must come from elsewhere to compensate. All diesel fuel is decarbonized with biofuels in Variation 3 to reach the 80x50 target (Figure 10).

By retaining gas in buildings, New Jersey reduces the margin for error in reaching their goals. One mode of carbon reductions – building electrification – is removed, so the risk of not meeting decarbonization goals increases if other modes fail. Retaining gas and shifting to biofuels for decarbonization would also establish a poor foundation for possible further reductions in emissions beyond 80x50 in the future. Further biofuel use, and potentially synthetic fuels production, would be required, which is more expensive than electrification alternatives and would increase costs sharply beyond 80x50.

2.4.3.3. Costs

Retaining gas in buildings has lower annual investment costs in 2035 through 2045 because investments in electrification and the electricity sector expansion to support it are not being made (Figure 12). However, the lack of investment in these components of the energy system present in the Least Cost Case drives large quantities of biofuels in 2050 to reach the 80x50 target, pushing annual costs higher than in the Least Cost Case. As mentioned above, this is a poor foundation for maintaining or tightening the 80x50 emissions constraint beyond 2050. Electrification of buildings takes time because of the long lifetimes of household appliances. Electrifying the stock early through sales of efficient electric options is necessary to avoid large quantities of biofuels or potentially synthetic fuels in the future – both of which, at currently projected costs, are a more expensive option than electrification.

2.4.4. Variation 4 – Faster Renewables and Storage Cost Declines

2.4.4.1. Demand Side Assumptions and Final Energy Demand

Variation 4 shares the same demand side assumptions as the Least Cost Case.

2.4.4.2. Least cost energy supply side decisions

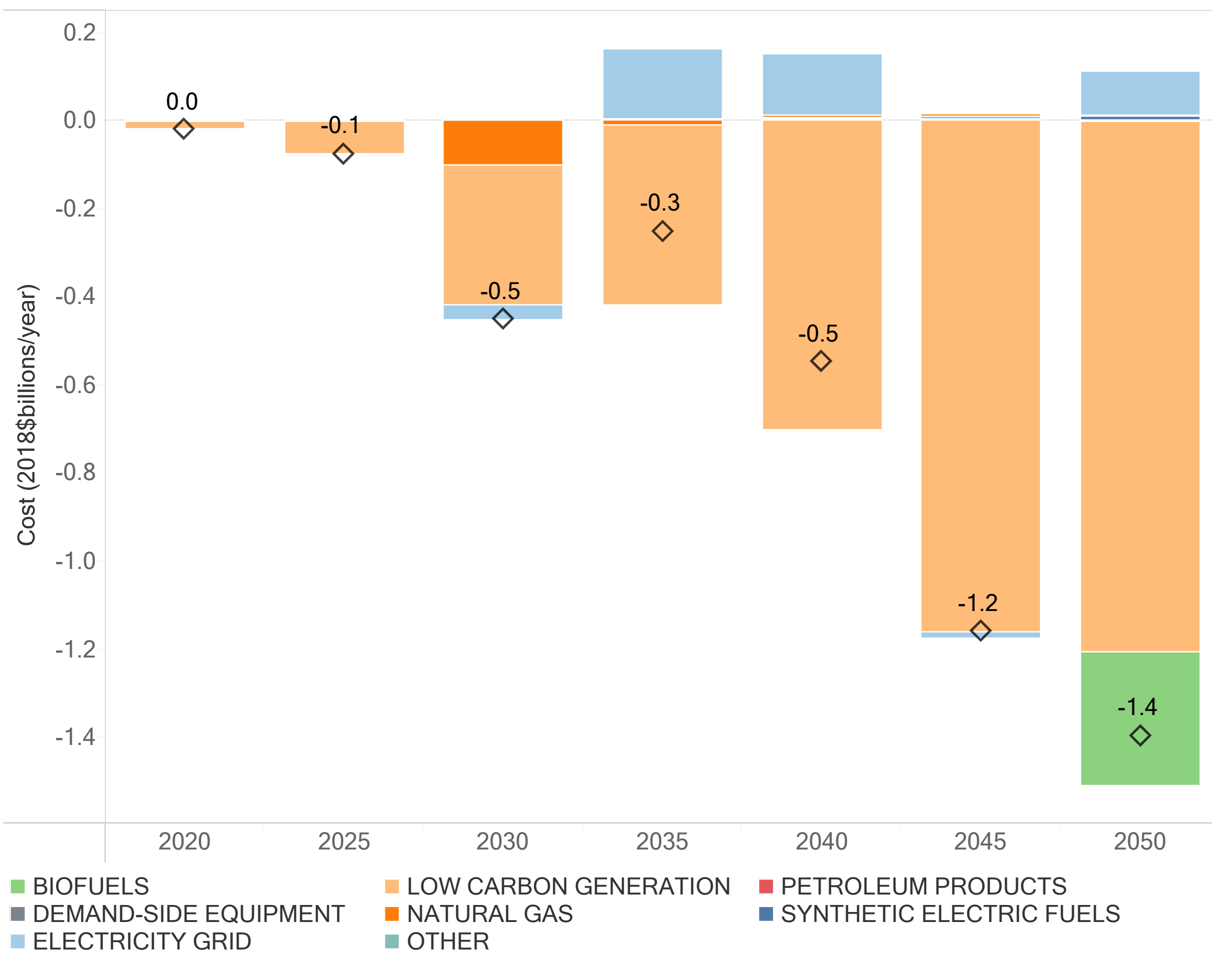
Past technology forecasts have often been high relative to actual realized costs. This case investigates the impact of lowering costs to more optimistic projections. We used renewable resource costs from NREL’s Annual Technology Baseline (ATB) “Low Technology Cost” scenario, and energy storage prices from the International Renewable Energy Agency (IRENA) Low forecast.

The impact on build decisions is relatively small. Energy storage build increases versus the Least Cost Case as storage pricing relative to firm capacity is lower. There is a slight reduction in firm capacity build (Figure 5 and Figure 6).

2.4.4.3. Costs

Costs for Variation 4 are not present in Figure 11 and Figure 12 because Reference Case 1 to which the cases are being compared to find net costs does not contain lower technology costs. Comparing to the Reference is only valid when we hold cost assumptions constant (lower cost renewables and storage may be built in greater quantities in the Reference if costs are lower). Instead, we can compare the costs to the Least Cost Case, shown in the following figure.

Figure 2. Annual costs of Variation 4 versus Least Cost Case



Lower projected costs for low-carbon technologies reduces the net cost of achieving the 80x50 target. This is particularly notable in the long-term, where New Jersey's electricity sector is 100%

clean, and renewables and energy storage play a significant role. However, it should be noted that projected cost reductions for these technologies over the next three decades are highly uncertain, in the same manner that exact fossil fuel prices in 2050 are unknown.

2.4.5. Variation 5 – Nuclear Retires and No New Gas Plants

2.4.5.1. Demand Side Assumptions and Final Energy Demand

Variation 5 shares the same demand side assumptions as the Least Cost Case.

2.4.5.2. Least cost energy supply side decisions

Variation 5 investigates the impact of reducing thermal generation in the electric sector by not allowing new gas plant builds and not extending nuclear beyond current permit lifetimes. Replacing the lost energy from nuclear requires significantly more offshore wind build by 2050, increasing from 11 GW in the Least Cost Case to 26 GW in Variation 5 (Figure 6). The loss of additional firm capacity from new gas builds drives additional need for storage, and storage capacity increases from 8 GW in the Least Cost Case in 2050 to 19.5 GW in Variation 5. However, the more significant impact is on storage duration with the average durations increasing from 8 hours in the Least Cost Case to 36 hours in Variation 5. Increased intertie capacity is also constructed to displace the lost in-state energy (Figure 9), allowing for greater imports of out of state renewables, and greater gas imports in earlier years when the emissions cap allows it.

2.4.5.3. Costs

Significant additional investment in renewables and storage are needed to replace the lost energy and capacity from nuclear and new gas capacity in 2050 (Figure 11).

2.4.6. Variation 6 – Reduced Transportation Electrification

2.4.6.1. Demand Side Assumptions and Final Energy Demand

Variation 6 retains fuel use for vehicles in the economy by dropping the rates of vehicle electrification relative to the Least Cost Case. This results in higher total demand because of the lower efficiency of internal combustion engines versus electric.

2.4.6.2. Least cost energy supply side decisions

Variation 6 examines the impact of reducing electrification of the vehicle fleets. Emissions that were previously reduced through electrification and decarbonization of electricity must be reduced using alternative strategies. The cost-optimal mechanism is to decarbonize diesel fuel by substituting fossil diesel with biofuels (Figure 10).

2.4.6.3. Costs

2.4.7. The costs of retaining fuel in vehicles is significantly higher than the Least Cost Case. Electric vehicles are more cost effective than internal combustion vehicles in the 2030s at forecasted fuel and vehicle prices. Cost Results Figures

Figure 11 shows this trend. There are reductions in investment for low carbon generation, the electricity grid, and demand side equipment relative to the Least Cost Case, but those savings are more than offset by reduced savings on petroleum product purchases and increased biofuels costs. Variation 6 net costs diverge further from the Least Cost case in 2040 and beyond as biofuels become necessary to displace emissions from diesel fuel (Figure 12).

2.5. Result Figures and Tables

2.5.1. Demand Side Results Figures

Figure 3. Final energy for scenarios with demand side differences

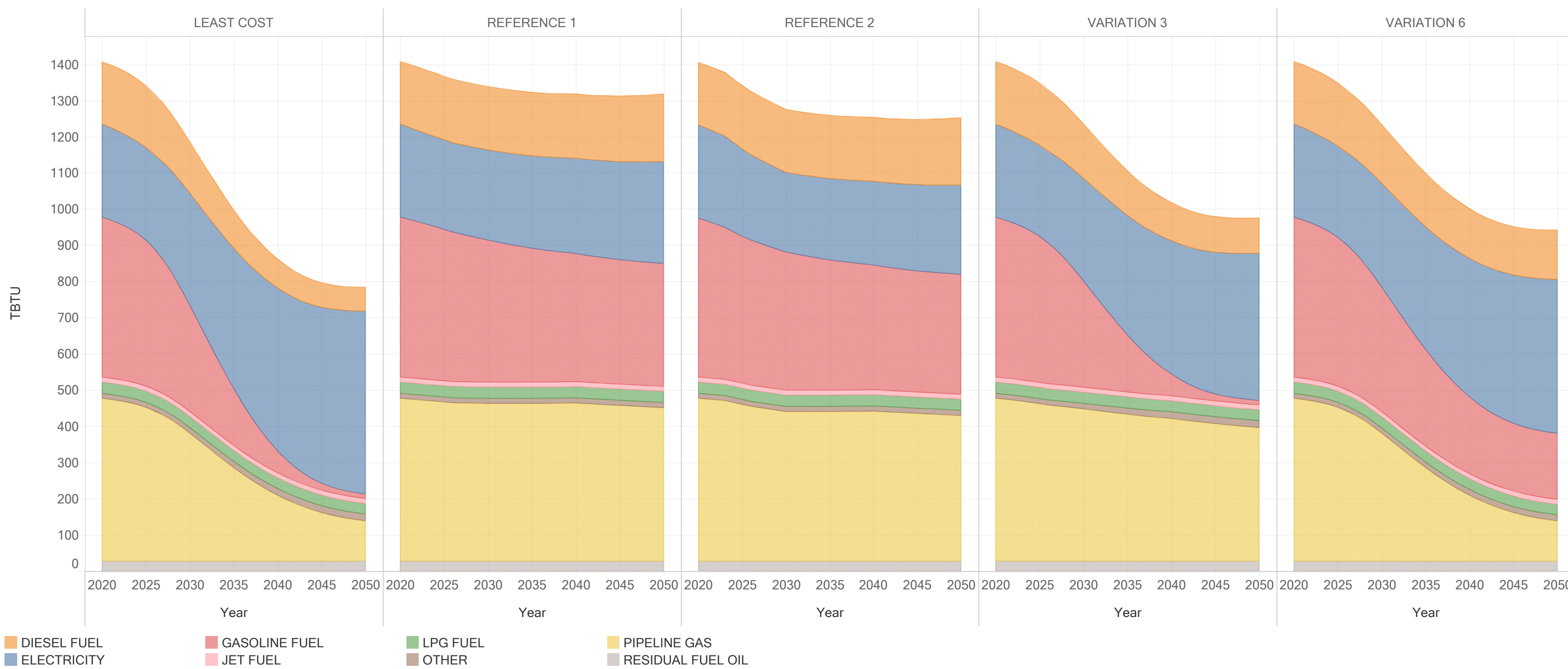
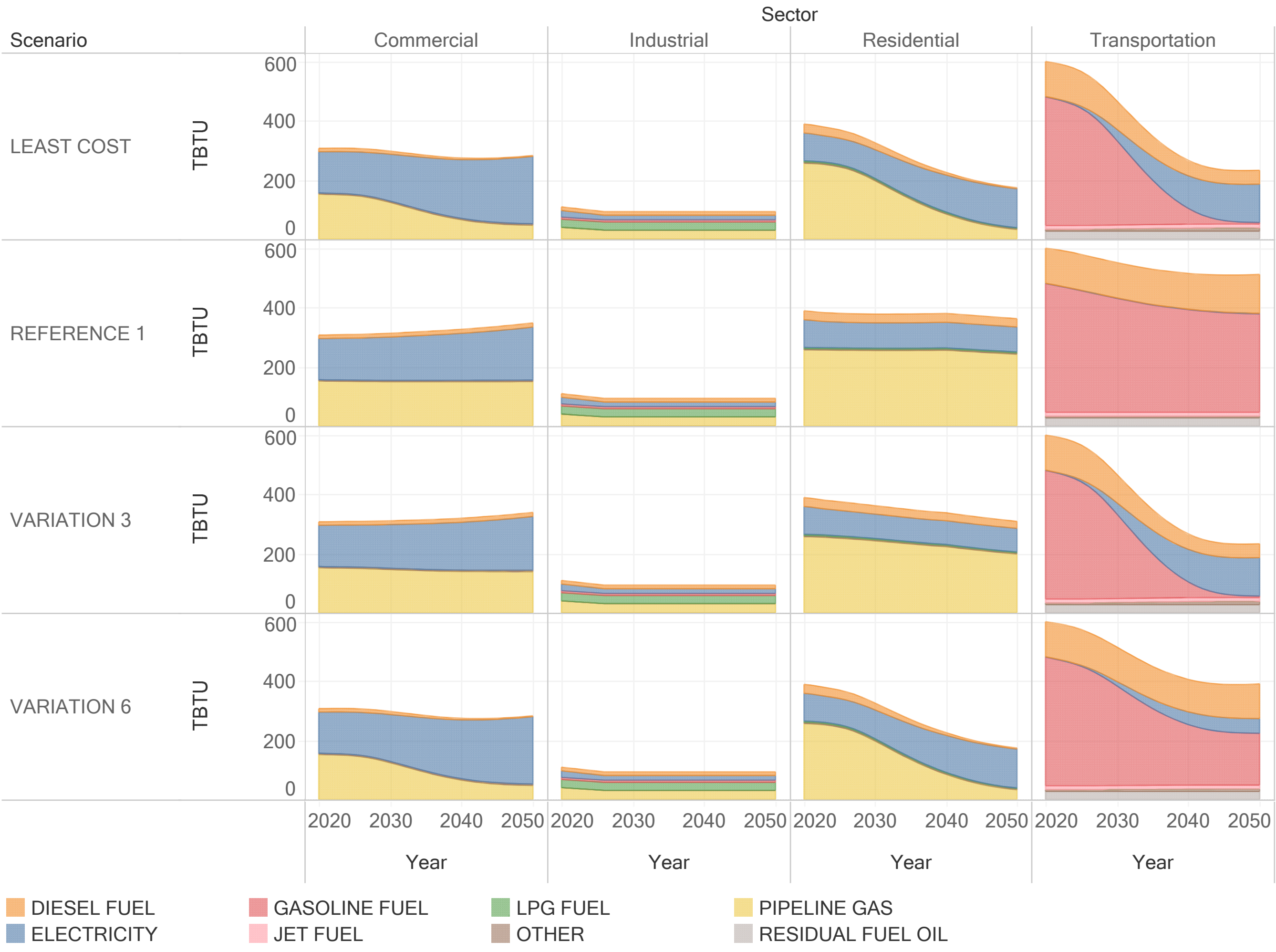


Figure 4. Final energy by sector



2.5.2. Supply Side Results Figures

Figure 5. Installed capacity

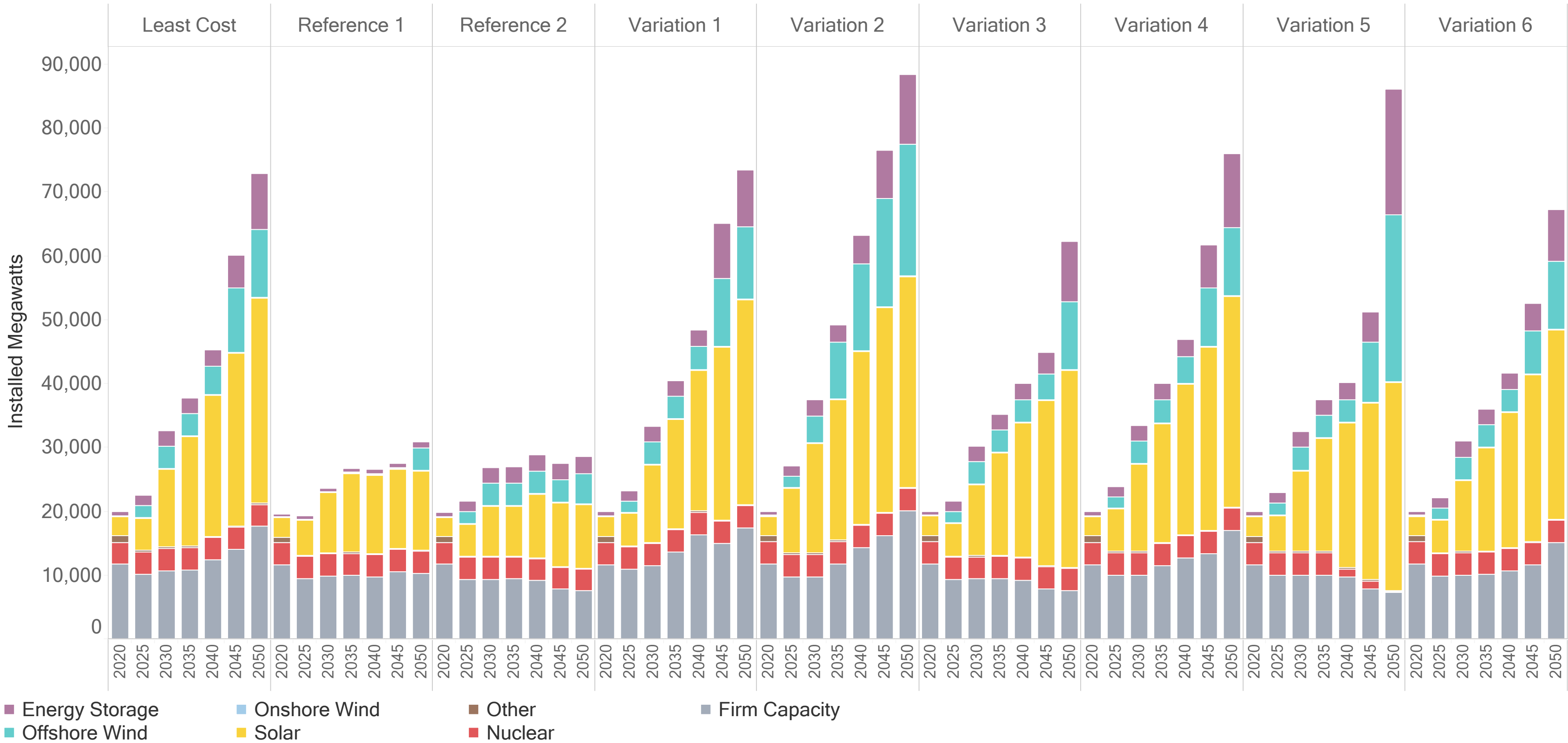


Figure 6. Installed capacity in New Jersey by type and year (MWs)

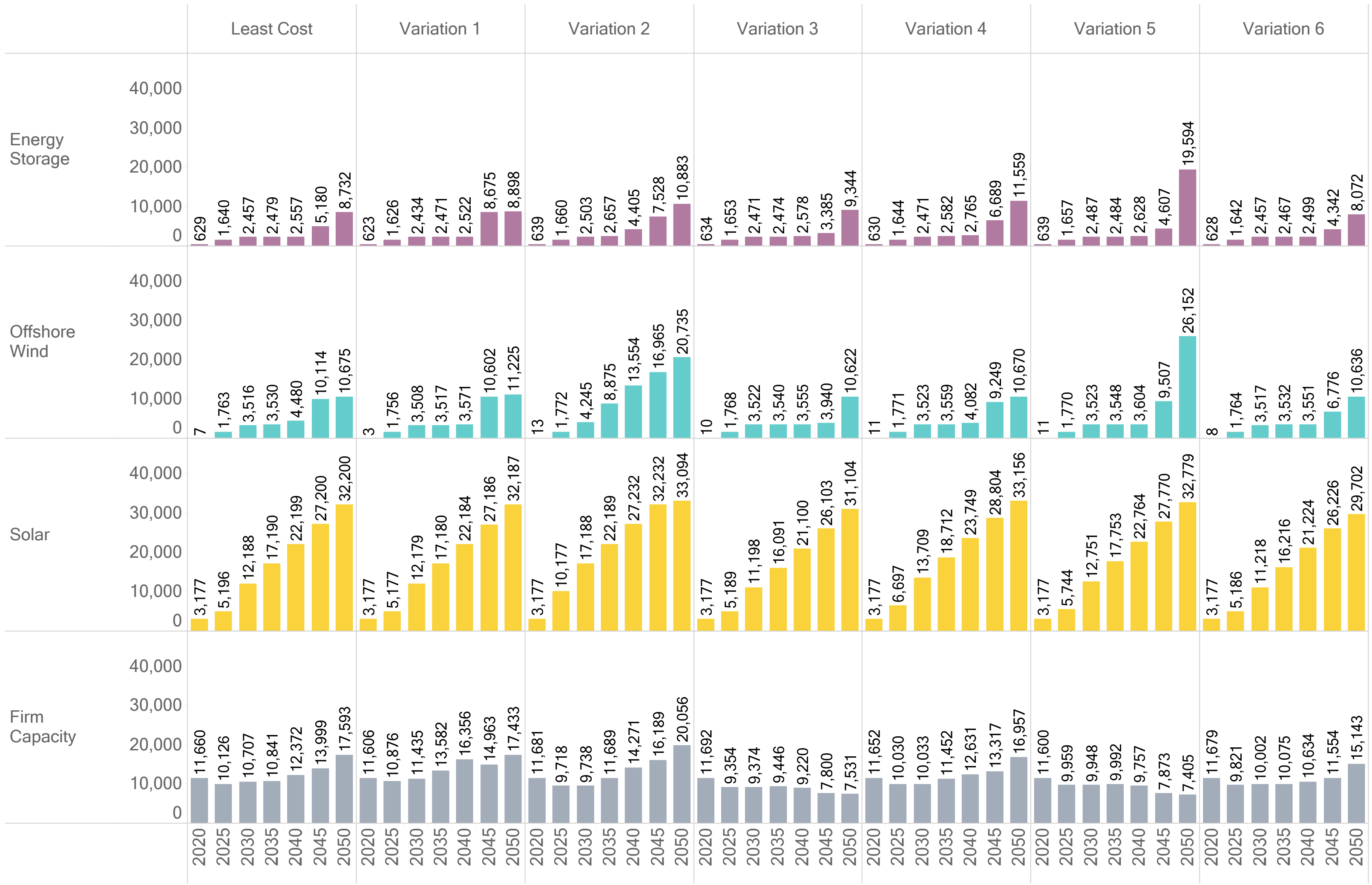


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Figure 7. Generation from designated out-of-state resources

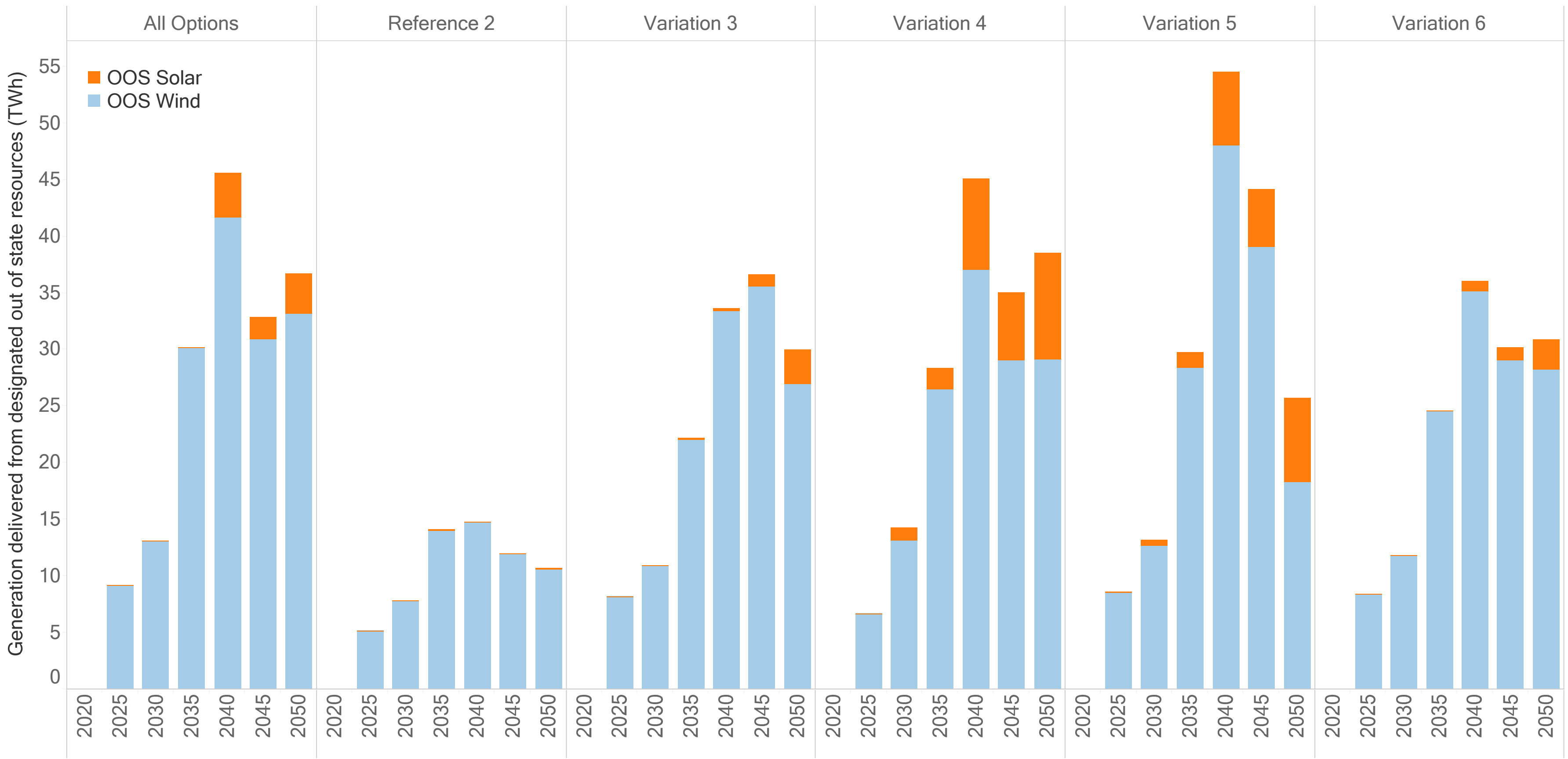


Figure 8. Electricity supply mix in 2050

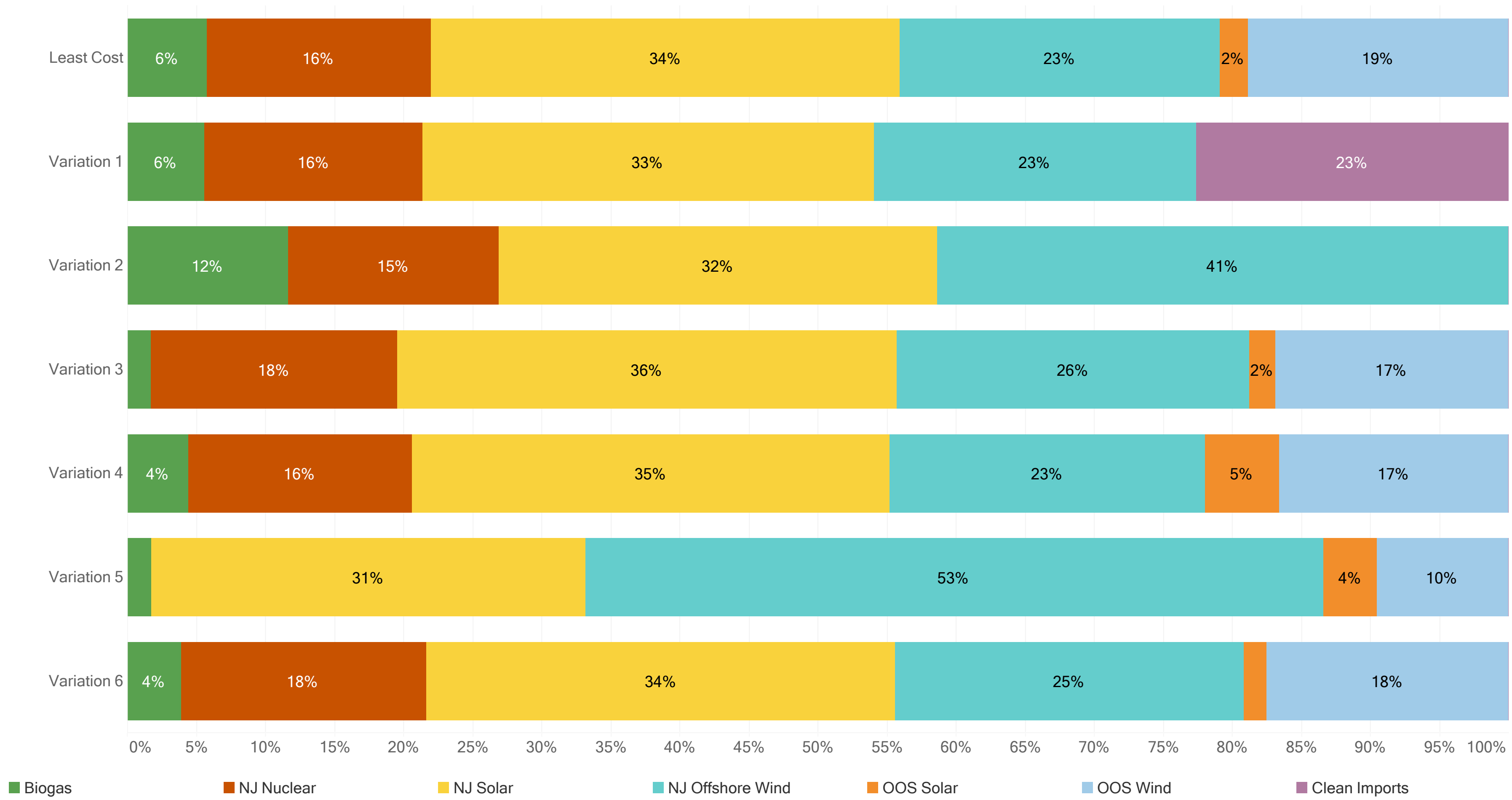


Figure 9. Transmission expansion between New Jersey and PJM

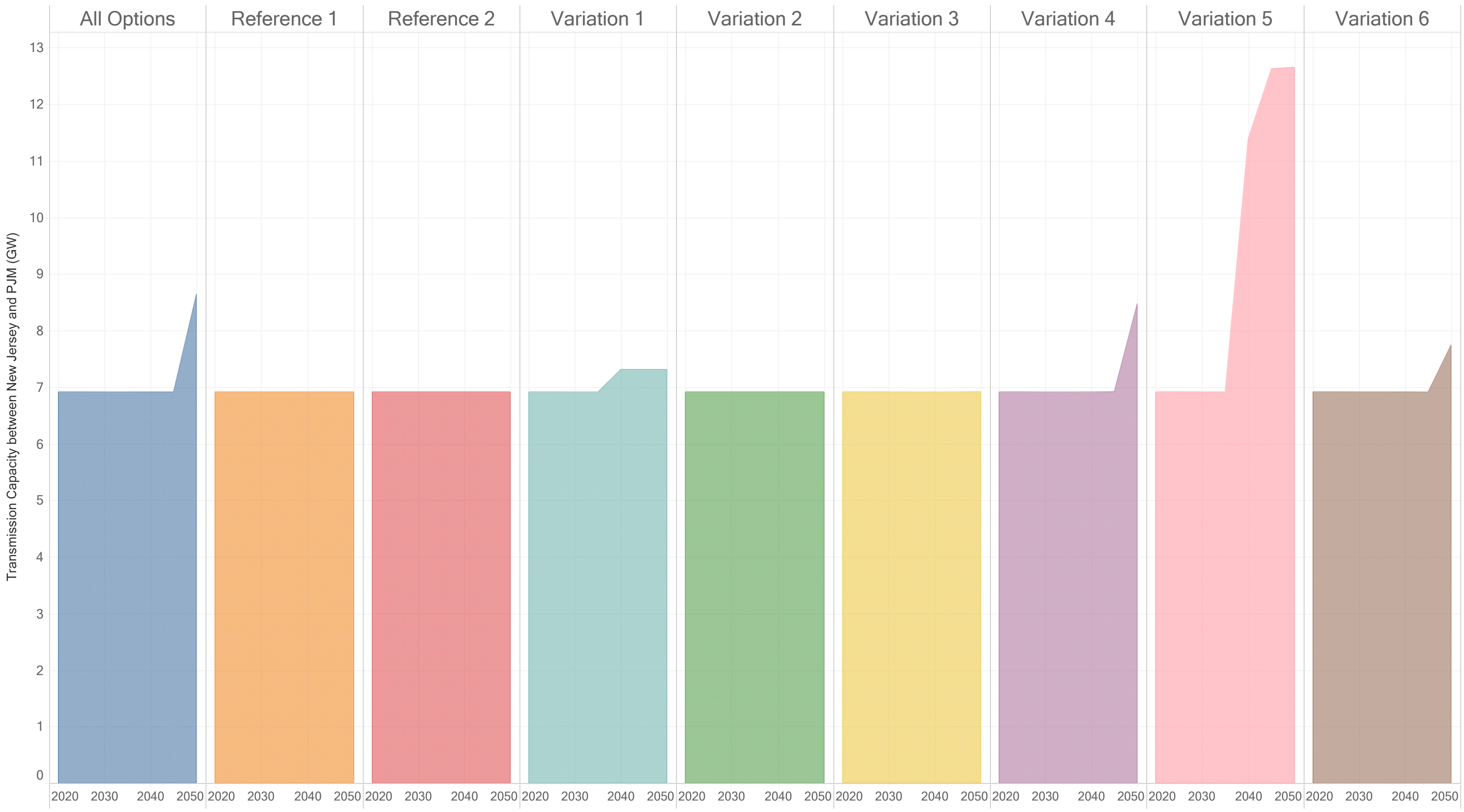
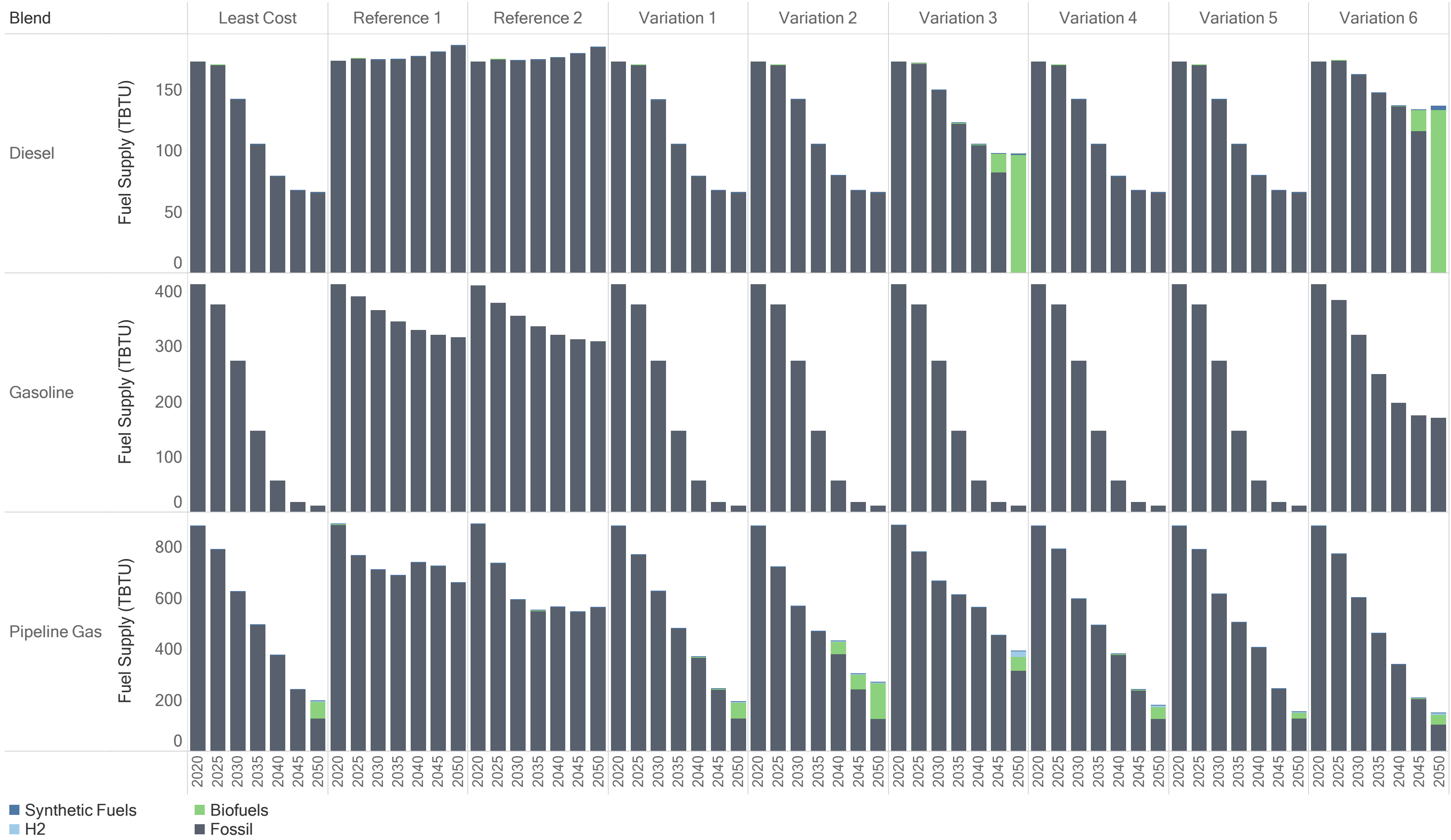


Figure 10. Diesel, gasoline, and pipeline gas consumption by fuel type



2.5.3. Cost Results Figures

Figure 11. Components of net energy system cost relative to Reference 1

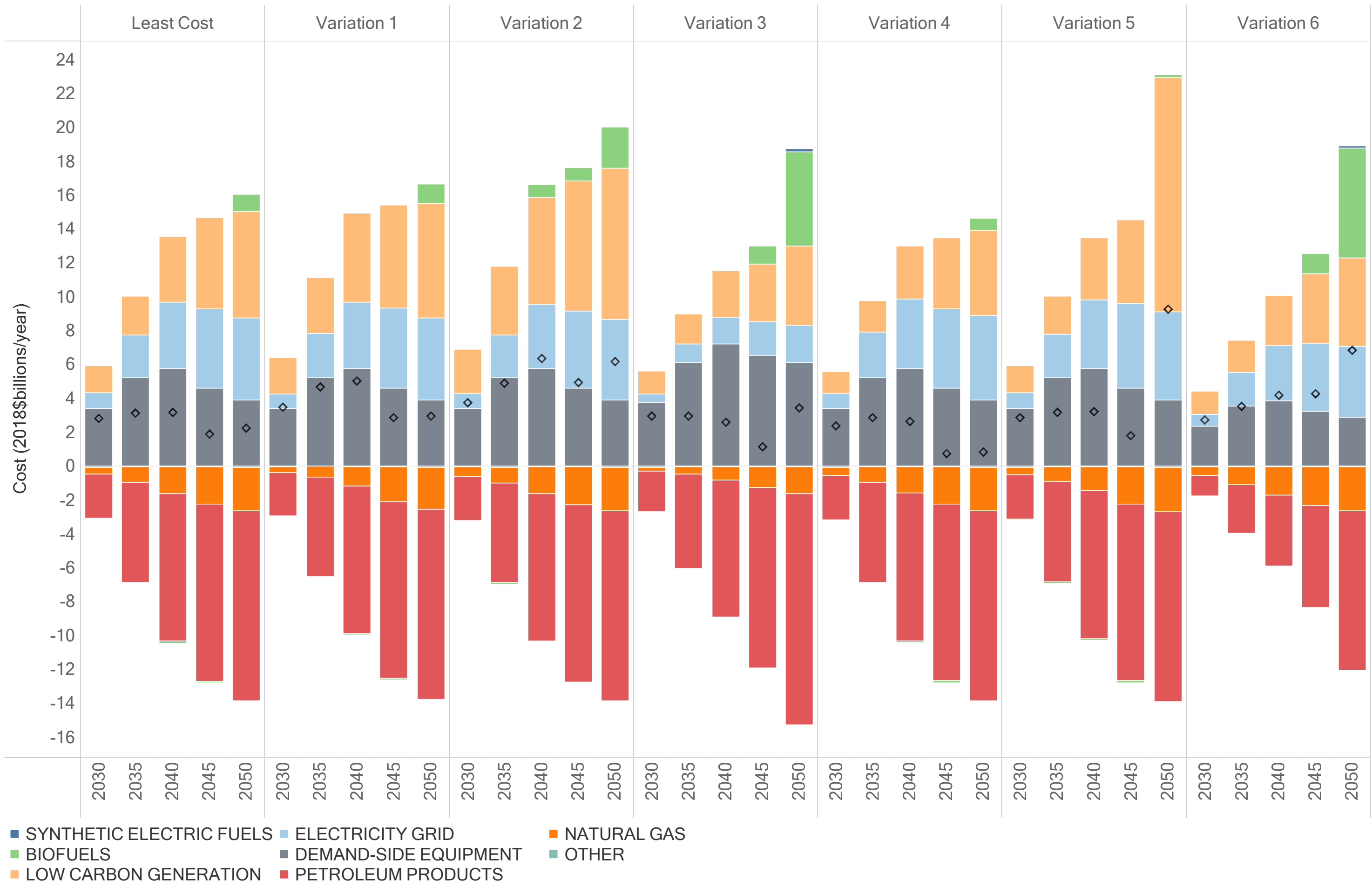


Figure 12. Net costs relative to Reference 1[1]

[1] An initial version of these cost outputs was shown at the public workshop on October 16th, 2019. Since that workshop, we identified errors in the outputs processing that have been corrected. Specifically, there was a discrepancy between the modeled durations of grid-scale battery storage in RIO and the durations used for cost estimations in EnergyPATHWAYS, and the price of biomass feedstocks optimized in RIO and the price used in the EnergyPATHWAYS total energy system cost calculation.

2.5.4. Demand Side Tables

The tables in this section show the sales shares (Table 5) and stock shares (Table 6) for eight demand technology groups, and the resulting final energy demand (Table 7) by sector and energy carrier for each scenario with unique demand side results. As noted in the case descriptions above, many of the variations share the same demand side assumptions as the Least Cost Case.

Table 4 Technology Groups

Technology Group	Description
Electric	Technologies that use electricity for end uses
HE Electric	High efficiency technologies that use electricity for end uses (where high efficiency technology options are available)
Fuel	Technologies that use liquid or gaseous fuels for end uses
HE Fuel	High efficiency technologies that use fuel for end uses (where available)
Other	Building shell technologies
HE Other	High efficiency building shell technologies
Hybrid	Hybrid electric and fuel end use technologies
Hydrogen	Hydrogen fueled technologies

The demand-side consists of over 380 technologies across all subsectors, but we aggregate here for presentation purposes to show broader trends in our input values. The stock shares shown are determined by stock rollover assumptions specified for each technology, including sales of replacement that technology on burn out, as well as the lifetimes of the infrastructure and the methodology described in section 5.3.1.2.

2.5.4.1. Sales Shares

Table 5 Sales shares

Sector	Subsector	Scenario	Technology	2020	2030	2040	2050
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	ELECTRIC	96%	3%	4%	5%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	HE ELECTRIC	3%	96%	96%	95%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	ELECTRIC	96%	94%	94%	94%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	HE ELECTRIC	3%	5%	5%	5%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	ELECTRIC	96%	5%	6%	8%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	HE ELECTRIC	3%	94%	93%	92%

COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	ELECTRIC	96%	3%	4%	5%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	HE ELECTRIC	3%	96%	96%	95%
COMMERCIAL	COMMERCIAL BUILDING SHELL	LEAST COST	HE OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	LEAST COST	OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	REF 1	HE OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	REF 1	OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 3	HE OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 3	OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 6	HE OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 6	OTHER	50%	50%	50%	50%
COMMERCIAL	COMMERCIAL COOKING	LEAST COST	ELECTRIC	96%	24%	14%	14%
COMMERCIAL	COMMERCIAL COOKING	LEAST COST	HE ELECTRIC	4%	76%	86%	86%
COMMERCIAL	COMMERCIAL COOKING	REF 1	ELECTRIC	96%	96%	95%	95%
COMMERCIAL	COMMERCIAL COOKING	REF 1	HE ELECTRIC	4%	4%	5%	5%
COMMERCIAL	COMMERCIAL COOKING	VAR 3	ELECTRIC	96%	24%	14%	14%
COMMERCIAL	COMMERCIAL COOKING	VAR 3	HE ELECTRIC	4%	76%	86%	86%
COMMERCIAL	COMMERCIAL COOKING	VAR 6	ELECTRIC	96%	24%	14%	14%
COMMERCIAL	COMMERCIAL COOKING	VAR 6	HE ELECTRIC	4%	76%	86%	86%
COMMERCIAL	COMMERCIAL LIGHTING	LEAST COST	ELECTRIC	12%	3%	3%	3%
COMMERCIAL	COMMERCIAL LIGHTING	LEAST COST	HE ELECTRIC	88%	97%	97%	97%
COMMERCIAL	COMMERCIAL LIGHTING	REF 1	ELECTRIC	12%	3%	3%	3%
COMMERCIAL	COMMERCIAL LIGHTING	REF 1	HE ELECTRIC	88%	97%	97%	97%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 3	ELECTRIC	12%	3%	3%	3%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 3	HE ELECTRIC	88%	97%	97%	97%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 6	ELECTRIC	12%	3%	3%	3%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 6	HE ELECTRIC	88%	97%	97%	97%
COMMERCIAL	COMMERCIAL REFRIGERATION	LEAST COST	ELECTRIC	99%	0%	0%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	LEAST COST	HE ELECTRIC	1%	100%	100%	100%
COMMERCIAL	COMMERCIAL REFRIGERATION	REF 1	ELECTRIC	99%	88%	85%	83%
COMMERCIAL	COMMERCIAL REFRIGERATION	REF 1	HE ELECTRIC	1%	12%	15%	17%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 3	ELECTRIC	99%	0%	0%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 3	HE ELECTRIC	1%	100%	100%	100%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 6	ELECTRIC	99%	0%	0%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 6	HE ELECTRIC	1%	100%	100%	100%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	ELECTRIC	5%	76%	87%	87%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	FUEL	88%	20%	9%	9%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	HE ELECTRIC	0%	1%	1%	1%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	HE FUEL	7%	3%	3%	3%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	ELECTRIC	5%	4%	5%	5%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	FUEL	88%	92%	92%	92%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	HE ELECTRIC	0%	1%	1%	1%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	HE FUEL	7%	3%	3%	3%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	ELECTRIC	5%	4%	5%	5%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	FUEL	88%	92%	92%	92%

COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	HE ELECTRIC	0%	1%	1%	1%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	HE FUEL	7%	3%	3%	3%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	ELECTRIC	5%	76%	87%	87%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	FUEL	88%	20%	9%	9%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	HE ELECTRIC	0%	1%	1%	1%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	HE FUEL	7%	3%	3%	3%
COMMERCIAL	COMMERCIAL VENTILATION	LEAST COST	ELECTRIC	67%	0%	0%	0%
COMMERCIAL	COMMERCIAL VENTILATION	LEAST COST	HE ELECTRIC	33%	100%	100%	100%
COMMERCIAL	COMMERCIAL VENTILATION	REF 1	ELECTRIC	67%	85%	85%	85%
COMMERCIAL	COMMERCIAL VENTILATION	REF 1	HE ELECTRIC	33%	15%	15%	15%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 3	ELECTRIC	67%	0%	0%	0%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 3	HE ELECTRIC	33%	100%	100%	100%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 6	ELECTRIC	67%	0%	0%	0%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 6	HE ELECTRIC	33%	100%	100%	100%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	ELECTRIC	5%	79%	90%	90%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	FUEL	53%	14%	6%	6%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	HE FUEL	42%	7%	3%	3%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	ELECTRIC	5%	5%	5%	5%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	FUEL	53%	65%	65%	65%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	HE FUEL	42%	30%	30%	30%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	ELECTRIC	5%	5%	5%	5%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	FUEL	53%	65%	65%	65%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	HE FUEL	42%	30%	30%	30%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	ELECTRIC	5%	79%	90%	90%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	FUEL	53%	14%	6%	6%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	HE FUEL	42%	7%	3%	3%
TRANSPORTATION	HEAVY DUTY TRUCKS	LEAST COST	ELECTRIC	1%	43%	50%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	LEAST COST	FUEL	99%	57%	50%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	REF 1	FUEL	100%	100%	100%	100%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 3	ELECTRIC	1%	43%	50%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 3	FUEL	99%	57%	50%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 6	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL BOILERS	LEAST COST	ELECTRIC	0%	9%	52%	73%
INDUSTRIAL	INDUSTRIAL BOILERS	LEAST COST	FUEL	100%	91%	48%	27%
INDUSTRIAL	INDUSTRIAL BOILERS	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 3	ELECTRIC	0%	9%	52%	73%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 3	FUEL	100%	91%	48%	27%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 6	ELECTRIC	0%	9%	52%	73%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 6	FUEL	100%	91%	48%	27%
INDUSTRIAL	INDUSTRIAL CURING	LEAST COST	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL CURING	LEAST COST	FUEL	100%	58%	26%	25%

INDUSTRIAL	INDUSTRIAL CURING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL CURING	VAR 3	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL CURING	VAR 3	FUEL	100%	58%	26%	25%
INDUSTRIAL	INDUSTRIAL CURING	VAR 6	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL CURING	VAR 6	FUEL	100%	58%	26%	25%
INDUSTRIAL	INDUSTRIAL DRYING	LEAST COST	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL DRYING	LEAST COST	FUEL	100%	58%	26%	25%
INDUSTRIAL	INDUSTRIAL DRYING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 3	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 3	FUEL	100%	58%	26%	25%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 6	ELECTRIC	0%	42%	74%	75%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 6	FUEL	100%	58%	26%	25%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	LEAST COST	ELECTRIC	94%	95%	97%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	LEAST COST	FUEL	6%	5%	3%	3%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	REF 1	ELECTRIC	94%	93%	93%	93%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	REF 1	FUEL	6%	7%	7%	7%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 3	ELECTRIC	94%	95%	97%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 3	FUEL	6%	5%	3%	3%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 6	ELECTRIC	94%	95%	97%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 6	FUEL	6%	5%	3%	3%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	LEAST COST	ELECTRIC	29%	58%	59%	61%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	LEAST COST	FUEL	71%	42%	41%	39%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	REF 1	ELECTRIC	29%	24%	24%	23%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	REF 1	FUEL	71%	76%	76%	77%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 3	ELECTRIC	29%	58%	59%	61%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 3	FUEL	71%	42%	41%	39%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 6	ELECTRIC	29%	58%	59%	61%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 6	FUEL	71%	42%	41%	39%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	LEAST COST	ELECTRIC	0%	50%	88%	89%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	LEAST COST	FUEL	100%	50%	12%	11%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 3	ELECTRIC	0%	50%	88%	89%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 3	FUEL	100%	50%	12%	11%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 6	ELECTRIC	0%	50%	88%	89%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 6	FUEL	100%	50%	12%	11%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	ELECTRIC	1%	84%	96%	96%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	FUEL	93%	11%	0%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	HYBRID	6%	1%	0%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	HYDROGEN	0%	4%	4%	4%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	ELECTRIC	0%	1%	1%	1%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	FUEL	94%	90%	89%	89%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	HYBRID	6%	9%	10%	10%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	HYDROGEN	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	ELECTRIC	1%	84%	96%	96%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	FUEL	93%	11%	0%	0%

TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	HYBRID	6%	1%	0%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	HYDROGEN	0%	4%	4%	4%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	ELECTRIC	1%	44%	50%	50%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	FUEL	94%	49%	42%	42%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	HYBRID	6%	5%	5%	5%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	HYDROGEN	0%	2%	2%	2%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	ELECTRIC	1%	84%	96%	96%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	FUEL	98%	12%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	HYDROGEN	0%	4%	4%	4%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	ELECTRIC	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	FUEL	100%	99%	99%	99%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	HYBRID	0%	1%	1%	1%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	HYDROGEN	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	ELECTRIC	1%	84%	96%	96%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	FUEL	98%	12%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	HYDROGEN	0%	4%	4%	4%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	ELECTRIC	1%	44%	50%	50%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	FUEL	99%	54%	47%	47%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	HYDROGEN	0%	2%	2%	2%
TRANSPORTATION	MEDIUM DUTY TRUCKS	LEAST COST	ELECTRIC	1%	65%	75%	75%
TRANSPORTATION	MEDIUM DUTY TRUCKS	LEAST COST	FUEL	99%	35%	25%	25%
TRANSPORTATION	MEDIUM DUTY TRUCKS	REF 1	FUEL	100%	100%	100%	100%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 3	ELECTRIC	1%	65%	75%	75%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 3	FUEL	99%	35%	25%	25%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 6	FUEL	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	LEAST COST	ELECTRIC	96%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	LEAST COST	HE ELECTRIC	4%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	REF 1	HE ELECTRIC	0%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 3	ELECTRIC	96%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 3	HE ELECTRIC	4%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 6	ELECTRIC	96%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 6	HE ELECTRIC	4%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	LEAST COST	HE OTHER	6%	69%	100%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	LEAST COST	OTHER	94%	31%	0%	0%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	REF 1	OTHER	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 3	HE OTHER	6%	69%	100%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 3	OTHER	94%	31%	0%	0%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 6	HE OTHER	6%	69%	100%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 6	OTHER	94%	31%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	ELECTRIC	64%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	FUEL	32%	0%	0%	0%

RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	REF 1	ELECTRIC	67%	66%	66%	66%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	REF 1	FUEL	33%	34%	34%	34%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	ELECTRIC	64%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	FUEL	32%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	ELECTRIC	64%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	FUEL	32%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	LEAST COST	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	LEAST COST	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 3	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 3	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 6	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 6	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL COOKING	LEAST COST	ELECTRIC	42%	92%	100%	100%
RESIDENTIAL	RESIDENTIAL COOKING	LEAST COST	FUEL	58%	8%	0%	0%
RESIDENTIAL	RESIDENTIAL COOKING	REF 1	ELECTRIC	41%	41%	41%	41%
RESIDENTIAL	RESIDENTIAL COOKING	REF 1	FUEL	59%	59%	59%	59%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 3	ELECTRIC	42%	92%	100%	100%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 3	FUEL	58%	8%	0%	0%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 6	ELECTRIC	42%	92%	100%	100%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 6	FUEL	58%	8%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	LEAST COST	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	LEAST COST	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 3	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 3	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 6	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 6	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	LEAST COST	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL FREEZING	LEAST COST	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 3	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 3	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 6	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 6	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL LIGHTING	LEAST COST	ELECTRIC	92%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL LIGHTING	LEAST COST	HE ELECTRIC	8%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL LIGHTING	REF 1	ELECTRIC	92%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL LIGHTING	REF 1	HE ELECTRIC	8%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 3	ELECTRIC	92%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 3	HE ELECTRIC	8%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 6	ELECTRIC	92%	0%	0%	0%

RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 6	HE ELECTRIC	8%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	LEAST COST	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	LEAST COST	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 3	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 3	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 6	ELECTRIC	97%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 6	HE ELECTRIC	3%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	LEAST COST	ELECTRIC	6%	79%	90%	90%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	LEAST COST	FUEL	94%	21%	10%	10%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	REF 1	ELECTRIC	5%	5%	5%	5%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	REF 1	FUEL	95%	95%	95%	95%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 3	ELECTRIC	5%	5%	5%	5%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 3	FUEL	95%	95%	95%	95%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 6	ELECTRIC	6%	79%	90%	90%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 6	FUEL	94%	21%	10%	10%
RESIDENTIAL	RESIDENTIAL WATER HEATING	LEAST COST	ELECTRIC	12%	80%	90%	90%
RESIDENTIAL	RESIDENTIAL WATER HEATING	LEAST COST	FUEL	88%	20%	10%	10%
RESIDENTIAL	RESIDENTIAL WATER HEATING	REF 1	ELECTRIC	12%	12%	12%	12%
RESIDENTIAL	RESIDENTIAL WATER HEATING	REF 1	FUEL	88%	88%	88%	88%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 3	ELECTRIC	12%	12%	12%	12%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 3	FUEL	88%	88%	88%	88%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 6	ELECTRIC	12%	80%	90%	90%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 6	FUEL	88%	20%	10%	10%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	ELECTRIC	1%	87%	100%	100%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	FUEL	78%	10%	0%	0%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	HYBRID	21%	3%	0%	0%
TRANSPORTATION	TRANSIT BUSES	REF 1	FUEL	79%	79%	79%	79%
TRANSPORTATION	TRANSIT BUSES	REF 1	HYBRID	21%	21%	21%	21%
TRANSPORTATION	TRANSIT BUSES	VAR 3	ELECTRIC	1%	87%	100%	100%
TRANSPORTATION	TRANSIT BUSES	VAR 3	FUEL	78%	10%	0%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 3	HYBRID	21%	3%	0%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 6	ELECTRIC	1%	87%	100%	100%
TRANSPORTATION	TRANSIT BUSES	VAR 6	FUEL	78%	10%	0%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 6	HYBRID	21%	3%	0%	0%

2.5.4.2. Stock Shares

Table 6 Stock shares

Sector	Subsector	Scenario	Technology	2020	2030	2040	2050
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	ELECTRIC	92%	48%	13%	5%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	LEAST COST	HE ELECTRIC	7%	51%	86%	94%

COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	ELECTRIC	92%	94%	93%	93%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	REF 1	HE ELECTRIC	7%	5%	5%	6%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	ELECTRIC	92%	49%	15%	8%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 3	HE ELECTRIC	7%	50%	84%	90%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	ELECTRIC	92%	48%	13%	5%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	FUEL	1%	1%	1%	1%
COMMERCIAL	COMMERCIAL AIR CONDITIONING	VAR 6	HE ELECTRIC	7%	51%	86%	94%
COMMERCIAL	COMMERCIAL BUILDING SHELL	LEAST COST	HE OTHER	18%	27%	34%	41%
COMMERCIAL	COMMERCIAL BUILDING SHELL	LEAST COST	OTHER	82%	73%	66%	59%
COMMERCIAL	COMMERCIAL BUILDING SHELL	REF 1	HE OTHER	18%	27%	34%	41%
COMMERCIAL	COMMERCIAL BUILDING SHELL	REF 1	OTHER	82%	73%	66%	59%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 3	HE OTHER	18%	27%	34%	41%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 3	OTHER	82%	73%	66%	59%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 6	HE OTHER	18%	27%	34%	41%
COMMERCIAL	COMMERCIAL BUILDING SHELL	VAR 6	OTHER	82%	73%	66%	59%
COMMERCIAL	COMMERCIAL COOKING	LEAST COST	ELECTRIC	96%	67%	17%	14%
COMMERCIAL	COMMERCIAL COOKING	LEAST COST	HE ELECTRIC	4%	33%	83%	86%
COMMERCIAL	COMMERCIAL COOKING	REF 1	ELECTRIC	96%	96%	95%	95%
COMMERCIAL	COMMERCIAL COOKING	REF 1	HE ELECTRIC	4%	4%	5%	5%
COMMERCIAL	COMMERCIAL COOKING	VAR 3	ELECTRIC	96%	67%	17%	14%
COMMERCIAL	COMMERCIAL COOKING	VAR 3	HE ELECTRIC	4%	33%	83%	86%
COMMERCIAL	COMMERCIAL COOKING	VAR 6	ELECTRIC	96%	67%	17%	14%
COMMERCIAL	COMMERCIAL COOKING	VAR 6	HE ELECTRIC	4%	33%	83%	86%
COMMERCIAL	COMMERCIAL LIGHTING	LEAST COST	ELECTRIC	7%	3%	5%	6%
COMMERCIAL	COMMERCIAL LIGHTING	LEAST COST	HE ELECTRIC	93%	97%	95%	94%
COMMERCIAL	COMMERCIAL LIGHTING	REF 1	ELECTRIC	7%	3%	5%	6%
COMMERCIAL	COMMERCIAL LIGHTING	REF 1	HE ELECTRIC	93%	97%	95%	94%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 3	ELECTRIC	7%	3%	5%	6%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 3	HE ELECTRIC	93%	97%	95%	94%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 6	ELECTRIC	7%	3%	5%	6%
COMMERCIAL	COMMERCIAL LIGHTING	VAR 6	HE ELECTRIC	93%	97%	95%	94%
COMMERCIAL	COMMERCIAL REFRIGERATION	LEAST COST	ELECTRIC	92%	26%	1%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	LEAST COST	HE ELECTRIC	8%	74%	99%	100%
COMMERCIAL	COMMERCIAL REFRIGERATION	REF 1	ELECTRIC	92%	88%	86%	83%
COMMERCIAL	COMMERCIAL REFRIGERATION	REF 1	HE ELECTRIC	8%	12%	14%	17%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 3	ELECTRIC	92%	26%	1%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 3	HE ELECTRIC	8%	74%	99%	100%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 6	ELECTRIC	92%	26%	1%	0%
COMMERCIAL	COMMERCIAL REFRIGERATION	VAR 6	HE ELECTRIC	8%	74%	99%	100%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	ELECTRIC	5%	22%	65%	84%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	FUEL	92%	74%	31%	13%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	HE ELECTRIC	0%	1%	0%	0%
COMMERCIAL	COMMERCIAL SPACE HEATING	LEAST COST	HE FUEL	3%	4%	3%	3%

COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	ELECTRIC	5%	4%	4%	5%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	FUEL	92%	91%	92%	92%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	HE ELECTRIC	0%	1%	0%	0%
COMMERCIAL	COMMERCIAL SPACE HEATING	REF 1	HE FUEL	3%	4%	3%	3%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	ELECTRIC	5%	4%	4%	5%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	FUEL	92%	91%	92%	92%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	HE ELECTRIC	0%	1%	0%	0%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 3	HE FUEL	3%	4%	3%	3%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	ELECTRIC	5%	22%	65%	84%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	FUEL	92%	74%	31%	13%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	HE ELECTRIC	0%	1%	0%	0%
COMMERCIAL	COMMERCIAL SPACE HEATING	VAR 6	HE FUEL	3%	4%	3%	3%
COMMERCIAL	COMMERCIAL VENTILATION	LEAST COST	ELECTRIC	85%	44%	11%	0%
COMMERCIAL	COMMERCIAL VENTILATION	LEAST COST	HE ELECTRIC	15%	56%	89%	100%
COMMERCIAL	COMMERCIAL VENTILATION	REF 1	ELECTRIC	85%	81%	83%	85%
COMMERCIAL	COMMERCIAL VENTILATION	REF 1	HE ELECTRIC	15%	19%	17%	15%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 3	ELECTRIC	85%	44%	11%	0%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 3	HE ELECTRIC	15%	56%	89%	100%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 6	ELECTRIC	85%	44%	11%	0%
COMMERCIAL	COMMERCIAL VENTILATION	VAR 6	HE ELECTRIC	15%	56%	89%	100%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	ELECTRIC	3%	27%	80%	90%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	FUEL	66%	45%	14%	7%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	LEAST COST	HE FUEL	31%	27%	6%	3%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	ELECTRIC	3%	3%	3%	3%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	FUEL	66%	62%	66%	66%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	REF 1	HE FUEL	31%	35%	31%	31%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	ELECTRIC	3%	3%	3%	3%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	FUEL	66%	62%	66%	66%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 3	HE FUEL	31%	35%	31%	31%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	ELECTRIC	3%	27%	80%	90%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	FUEL	66%	45%	14%	7%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	HE ELECTRIC	0%	0%	0%	0%
COMMERCIAL	COMMERCIAL WATER HEATING	VAR 6	HE FUEL	31%	27%	6%	3%
TRANSPORTATION	HEAVY DUTY TRUCKS	LEAST COST	ELECTRIC	0%	12%	42%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	LEAST COST	FUEL	100%	88%	58%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	REF 1	FUEL	100%	100%	100%	100%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 3	ELECTRIC	0%	12%	42%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 3	FUEL	100%	88%	58%	50%
TRANSPORTATION	HEAVY DUTY TRUCKS	VAR 6	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL BOILERS	LEAST COST	ELECTRIC	0%	2%	21%	56%
INDUSTRIAL	INDUSTRIAL BOILERS	LEAST COST	FUEL	100%	98%	79%	44%
INDUSTRIAL	INDUSTRIAL BOILERS	REF 1	FUEL	100%	100%	100%	100%

INDUSTRIAL	INDUSTRIAL BOILERS	VAR 3	ELECTRIC	0%	2%	21%	56%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 3	FUEL	100%	98%	79%	44%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 6	ELECTRIC	0%	2%	21%	56%
INDUSTRIAL	INDUSTRIAL BOILERS	VAR 6	FUEL	100%	98%	79%	44%
INDUSTRIAL	INDUSTRIAL CURING	LEAST COST	ELECTRIC	0%	9%	52%	74%
INDUSTRIAL	INDUSTRIAL CURING	LEAST COST	FUEL	100%	91%	48%	26%
INDUSTRIAL	INDUSTRIAL CURING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL CURING	VAR 3	ELECTRIC	0%	9%	52%	74%
INDUSTRIAL	INDUSTRIAL CURING	VAR 3	FUEL	100%	91%	48%	26%
INDUSTRIAL	INDUSTRIAL CURING	VAR 6	ELECTRIC	0%	9%	52%	74%
INDUSTRIAL	INDUSTRIAL CURING	VAR 6	FUEL	100%	91%	48%	26%
INDUSTRIAL	INDUSTRIAL DRYING	LEAST COST	ELECTRIC	0%	10%	54%	74%
INDUSTRIAL	INDUSTRIAL DRYING	LEAST COST	FUEL	100%	90%	46%	26%
INDUSTRIAL	INDUSTRIAL DRYING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 3	ELECTRIC	0%	10%	54%	74%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 3	FUEL	100%	90%	46%	26%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 6	ELECTRIC	0%	10%	54%	74%
INDUSTRIAL	INDUSTRIAL DRYING	VAR 6	FUEL	100%	90%	46%	26%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	LEAST COST	ELECTRIC	92%	92%	95%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	LEAST COST	FUEL	8%	8%	5%	3%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	REF 1	ELECTRIC	92%	92%	93%	93%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	REF 1	FUEL	8%	8%	7%	7%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 3	ELECTRIC	92%	92%	95%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 3	FUEL	8%	8%	5%	3%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 6	ELECTRIC	92%	92%	95%	97%
INDUSTRIAL	INDUSTRIAL MACHINE DRIVES	VAR 6	FUEL	8%	8%	5%	3%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	LEAST COST	ELECTRIC	26%	46%	58%	60%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	LEAST COST	FUEL	74%	54%	42%	40%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	REF 1	ELECTRIC	26%	25%	24%	23%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	REF 1	FUEL	74%	75%	76%	77%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 3	ELECTRIC	26%	46%	58%	60%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 3	FUEL	74%	54%	42%	40%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 6	ELECTRIC	26%	46%	58%	60%
INDUSTRIAL	INDUSTRIAL PROCESS HEAT	VAR 6	FUEL	74%	54%	42%	40%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	LEAST COST	ELECTRIC	0%	11%	61%	87%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	LEAST COST	FUEL	100%	89%	39%	13%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	REF 1	FUEL	100%	100%	100%	100%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 3	ELECTRIC	0%	11%	61%	87%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 3	FUEL	100%	89%	39%	13%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 6	ELECTRIC	0%	11%	61%	87%
INDUSTRIAL	INDUSTRIAL SPACE HEATING	VAR 6	FUEL	100%	89%	39%	13%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	ELECTRIC	0%	26%	82%	95%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	FUEL	94%	68%	13%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	HYBRID	6%	5%	1%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	LEAST COST	HYDROGEN	0%	1%	4%	4%

TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	ELECTRIC	0%	0%	1%	1%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	FUEL	94%	93%	90%	89%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	HYBRID	6%	7%	9%	10%
TRANSPORTATION	LIGHT DUTY AUTOS	REF 1	HYDROGEN	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	ELECTRIC	0%	26%	82%	95%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	FUEL	94%	68%	13%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	HYBRID	6%	5%	1%	0%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 3	HYDROGEN	0%	1%	4%	4%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	ELECTRIC	0%	13%	43%	50%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	FUEL	94%	80%	50%	42%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	HYBRID	6%	6%	5%	5%
TRANSPORTATION	LIGHT DUTY AUTOS	VAR 6	HYDROGEN	0%	1%	2%	2%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	ELECTRIC	0%	23%	81%	95%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	FUEL	99%	75%	16%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	LEAST COST	HYDROGEN	0%	1%	4%	4%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	ELECTRIC	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	FUEL	100%	99%	99%	99%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	HYBRID	0%	0%	1%	1%
TRANSPORTATION	LIGHT DUTY TRUCKS	REF 1	HYDROGEN	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	ELECTRIC	0%	23%	81%	95%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	FUEL	99%	75%	16%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 3	HYDROGEN	0%	1%	4%	4%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	ELECTRIC	0%	12%	42%	50%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	FUEL	100%	87%	56%	47%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	HYBRID	0%	0%	0%	0%
TRANSPORTATION	LIGHT DUTY TRUCKS	VAR 6	HYDROGEN	0%	1%	2%	2%
TRANSPORTATION	MEDIUM DUTY TRUCKS	LEAST COST	ELECTRIC	0%	14%	55%	75%
TRANSPORTATION	MEDIUM DUTY TRUCKS	LEAST COST	FUEL	100%	86%	45%	25%
TRANSPORTATION	MEDIUM DUTY TRUCKS	REF 1	FUEL	100%	100%	100%	100%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 3	ELECTRIC	0%	14%	55%	75%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 3	FUEL	100%	86%	45%	25%
TRANSPORTATION	MEDIUM DUTY TRUCKS	VAR 6	FUEL	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	LEAST COST	ELECTRIC	99%	48%	3%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	LEAST COST	HE ELECTRIC	1%	52%	97%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	REF 1	HE ELECTRIC	0%	0%	0%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 3	ELECTRIC	99%	48%	3%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 3	HE ELECTRIC	1%	52%	97%	100%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 6	ELECTRIC	99%	48%	3%	0%
RESIDENTIAL	RESIDENTIAL AIR CONDITIONING	VAR 6	HE ELECTRIC	1%	52%	97%	100%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	LEAST COST	HE OTHER	0%	10%	31%	47%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	LEAST COST	OTHER	100%	90%	69%	53%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	REF 1	OTHER	100%	100%	100%	100%

RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 3	HE OTHER	0%	10%	31%	47%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 3	OTHER	100%	90%	69%	53%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 6	HE OTHER	0%	10%	31%	47%
RESIDENTIAL	RESIDENTIAL BUILDING SHELL	VAR 6	OTHER	100%	90%	69%	53%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	ELECTRIC	67%	31%	1%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	FUEL	33%	16%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	LEAST COST	HE ELECTRIC	0%	54%	99%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	REF 1	ELECTRIC	67%	67%	66%	66%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	REF 1	FUEL	33%	33%	34%	34%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	ELECTRIC	67%	31%	1%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	FUEL	33%	16%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 3	HE ELECTRIC	0%	54%	99%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	ELECTRIC	67%	31%	1%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	FUEL	33%	16%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES DRYING	VAR 6	HE ELECTRIC	0%	54%	99%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	LEAST COST	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	LEAST COST	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 3	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 3	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 6	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL CLOTHES WASHING	VAR 6	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL COOKING	LEAST COST	ELECTRIC	41%	53%	83%	100%
RESIDENTIAL	RESIDENTIAL COOKING	LEAST COST	FUEL	59%	47%	17%	0%
RESIDENTIAL	RESIDENTIAL COOKING	REF 1	ELECTRIC	41%	41%	41%	41%
RESIDENTIAL	RESIDENTIAL COOKING	REF 1	FUEL	59%	59%	59%	59%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 3	ELECTRIC	41%	53%	83%	100%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 3	FUEL	59%	47%	17%	0%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 6	ELECTRIC	41%	53%	83%	100%
RESIDENTIAL	RESIDENTIAL COOKING	VAR 6	FUEL	59%	47%	17%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	LEAST COST	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	LEAST COST	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 3	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 3	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 6	ELECTRIC	100%	43%	0%	0%
RESIDENTIAL	RESIDENTIAL DISHWASHING	VAR 6	HE ELECTRIC	0%	57%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	LEAST COST	ELECTRIC	100%	58%	18%	1%
RESIDENTIAL	RESIDENTIAL FREEZING	LEAST COST	HE ELECTRIC	0%	42%	82%	99%
RESIDENTIAL	RESIDENTIAL FREEZING	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 3	ELECTRIC	100%	58%	18%	1%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 3	HE ELECTRIC	0%	42%	82%	99%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 6	ELECTRIC	100%	58%	18%	1%
RESIDENTIAL	RESIDENTIAL FREEZING	VAR 6	HE ELECTRIC	0%	42%	82%	99%
RESIDENTIAL	RESIDENTIAL LIGHTING	LEAST COST	ELECTRIC	89%	52%	14%	4%

RESIDENTIAL	RESIDENTIAL LIGHTING	LEAST COST	HE ELECTRIC	11%	48%	86%	96%
RESIDENTIAL	RESIDENTIAL LIGHTING	REF 1	ELECTRIC	89%	52%	14%	4%
RESIDENTIAL	RESIDENTIAL LIGHTING	REF 1	HE ELECTRIC	11%	48%	86%	96%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 3	ELECTRIC	89%	52%	14%	4%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 3	HE ELECTRIC	11%	48%	86%	96%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 6	ELECTRIC	89%	52%	14%	4%
RESIDENTIAL	RESIDENTIAL LIGHTING	VAR 6	HE ELECTRIC	11%	48%	86%	96%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	LEAST COST	ELECTRIC	100%	49%	7%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	LEAST COST	HE ELECTRIC	0%	51%	93%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	REF 1	ELECTRIC	100%	100%	100%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 3	ELECTRIC	100%	49%	7%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 3	HE ELECTRIC	0%	51%	93%	100%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 6	ELECTRIC	100%	49%	7%	0%
RESIDENTIAL	RESIDENTIAL REFRIGERATION	VAR 6	HE ELECTRIC	0%	51%	93%	100%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	LEAST COST	ELECTRIC	5%	21%	63%	86%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	LEAST COST	FUEL	95%	79%	37%	14%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	REF 1	ELECTRIC	5%	5%	5%	5%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	REF 1	FUEL	95%	95%	95%	95%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 3	ELECTRIC	5%	5%	5%	5%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 3	FUEL	95%	95%	95%	95%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 6	ELECTRIC	5%	21%	63%	86%
RESIDENTIAL	RESIDENTIAL SPACE HEATING	VAR 6	FUEL	95%	79%	37%	14%
RESIDENTIAL	RESIDENTIAL WATER HEATING	LEAST COST	ELECTRIC	16%	46%	89%	93%
RESIDENTIAL	RESIDENTIAL WATER HEATING	LEAST COST	FUEL	84%	54%	11%	7%
RESIDENTIAL	RESIDENTIAL WATER HEATING	REF 1	ELECTRIC	16%	16%	16%	16%
RESIDENTIAL	RESIDENTIAL WATER HEATING	REF 1	FUEL	84%	84%	84%	84%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 3	ELECTRIC	16%	16%	16%	16%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 3	FUEL	84%	84%	84%	84%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 6	ELECTRIC	16%	46%	89%	93%
RESIDENTIAL	RESIDENTIAL WATER HEATING	VAR 6	FUEL	84%	54%	11%	7%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	ELECTRIC	0%	35%	98%	100%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	FUEL	78%	51%	2%	0%
TRANSPORTATION	TRANSIT BUSES	LEAST COST	HYBRID	21%	14%	1%	0%
TRANSPORTATION	TRANSIT BUSES	REF 1	FUEL	79%	79%	79%	79%
TRANSPORTATION	TRANSIT BUSES	REF 1	HYBRID	21%	21%	21%	21%
TRANSPORTATION	TRANSIT BUSES	VAR 3	ELECTRIC	0%	35%	98%	100%
TRANSPORTATION	TRANSIT BUSES	VAR 3	FUEL	78%	51%	2%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 3	HYBRID	21%	14%	1%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 6	ELECTRIC	0%	35%	98%	100%
TRANSPORTATION	TRANSIT BUSES	VAR 6	FUEL	78%	51%	2%	0%
TRANSPORTATION	TRANSIT BUSES	VAR 6	HYBRID	21%	14%	1%	0%

2.5.4.3. Final Energy Demand

Table 7 Final energy demand by sector and energy carrier for each scenario

Sector	Scenario	Final Energy (TBTU)	2020	2030	2040	2050
COMMERCIAL	LEAST COST	DIESEL FUEL	11.59	10.65	5.60	2.92
COMMERCIAL	LEAST COST	ELECTRICITY	139.07	158.38	198.78	227.86
COMMERCIAL	LEAST COST	PIPELINE GAS	152.50	124.57	65.79	47.40
COMMERCIAL	LEAST COST	SOLAR	0.02	0.03	0.01	0.00
COMMERCIAL	LEAST COST	STEAM	3.96	4.25	4.54	4.83
COMMERCIAL	REF 1	DIESEL FUEL	11.59	13.03	13.92	14.27
COMMERCIAL	REF 1	ELECTRICITY	139.07	146.64	158.85	179.22
COMMERCIAL	REF 1	PIPELINE GAS	152.50	149.69	149.66	150.13
COMMERCIAL	REF 1	SOLAR	0.02	0.03	0.03	0.03
COMMERCIAL	REF 1	STEAM	3.96	4.25	4.54	4.83
COMMERCIAL	REF 2	DIESEL FUEL	11.59	13.03	13.92	14.27
COMMERCIAL	REF 2	ELECTRICITY	139.07	113.71	124.16	142.11
COMMERCIAL	REF 2	PIPELINE GAS	152.50	127.32	127.25	128.36
COMMERCIAL	REF 2	SOLAR	0.02	0.03	0.03	0.03
COMMERCIAL	REF 2	STEAM	3.96	4.25	4.54	4.83
COMMERCIAL	VAR 3	DIESEL FUEL	11.59	13.03	13.92	14.27
COMMERCIAL	VAR 3	ELECTRICITY	139.07	147.43	161.64	181.33
COMMERCIAL	VAR 3	PIPELINE GAS	152.50	146.24	139.60	139.08
COMMERCIAL	VAR 3	SOLAR	0.02	0.03	0.03	0.03
COMMERCIAL	VAR 3	STEAM	3.96	4.25	4.54	4.83
COMMERCIAL	VAR 6	DIESEL FUEL	11.59	10.65	5.60	2.92
COMMERCIAL	VAR 6	ELECTRICITY	139.07	158.38	198.78	227.86
COMMERCIAL	VAR 6	PIPELINE GAS	152.50	124.57	65.79	47.40
COMMERCIAL	VAR 6	SOLAR	0.02	0.03	0.01	0.00
COMMERCIAL	VAR 6	STEAM	3.96	4.25	4.54	4.83
INDUSTRIAL	LEAST COST	DIESEL FUEL	12.40	12.40	12.40	12.40
INDUSTRIAL	LEAST COST	ELECTRICITY	22.30	15.77	15.77	15.77
INDUSTRIAL	LEAST COST	GASOLINE FUEL	7.26	7.26	7.26	7.26
INDUSTRIAL	LEAST COST	LPG FUEL	27.20	27.20	27.20	27.20
INDUSTRIAL	LEAST COST	PIPELINE GAS	40.27	30.94	30.94	30.94
INDUSTRIAL	REF 1	DIESEL FUEL	12.40	12.40	12.40	12.40
INDUSTRIAL	REF 1	ELECTRICITY	22.30	15.77	15.77	15.77
INDUSTRIAL	REF 1	GASOLINE FUEL	7.26	7.26	7.26	7.26
INDUSTRIAL	REF 1	LPG FUEL	27.20	27.20	27.20	27.20
INDUSTRIAL	REF 1	PIPELINE GAS	40.27	30.94	30.94	30.94
INDUSTRIAL	REF 2	DIESEL FUEL	12.40	12.40	12.40	12.40
INDUSTRIAL	REF 2	ELECTRICITY	22.30	15.77	15.77	15.77
INDUSTRIAL	REF 2	GASOLINE FUEL	7.26	7.26	7.26	7.26
INDUSTRIAL	REF 2	LPG FUEL	27.20	27.20	27.20	27.20
INDUSTRIAL	REF 2	PIPELINE GAS	40.27	30.94	30.94	30.94

INDUSTRIAL	VAR 3	DIESEL FUEL	12.40	12.40	12.40	12.40
INDUSTRIAL	VAR 3	ELECTRICITY	22.30	15.77	15.77	15.77
INDUSTRIAL	VAR 3	GASOLINE FUEL	7.26	7.26	7.26	7.26
INDUSTRIAL	VAR 3	LPG FUEL	27.20	27.20	27.20	27.20
INDUSTRIAL	VAR 3	PIPELINE GAS	40.27	30.94	30.94	30.94
INDUSTRIAL	VAR 6	DIESEL FUEL	12.40	12.40	12.40	12.40
INDUSTRIAL	VAR 6	ELECTRICITY	22.30	15.77	15.77	15.77
INDUSTRIAL	VAR 6	GASOLINE FUEL	7.26	7.26	7.26	7.26
INDUSTRIAL	VAR 6	LPG FUEL	27.20	27.20	27.20	27.20
INDUSTRIAL	VAR 6	PIPELINE GAS	40.27	30.94	30.94	30.94
RESIDENTIAL	LEAST COST	BIOMASS - WOOD	3.94	4.08	4.15	3.91
RESIDENTIAL	LEAST COST	COAL	0.00	0.00	0.00	0.00
RESIDENTIAL	LEAST COST	DIESEL FUEL	30.36	23.21	9.42	3.75
RESIDENTIAL	LEAST COST	ELECTRICITY	93.91	97.47	125.10	131.69
RESIDENTIAL	LEAST COST	KEROSENE FUEL	0.09	0.10	0.10	0.09
RESIDENTIAL	LEAST COST	LPG FUEL	3.86	3.35	2.38	1.63
RESIDENTIAL	LEAST COST	PIPELINE GAS	257.11	198.03	85.42	33.17
RESIDENTIAL	REF 1	BIOMASS - WOOD	3.94	4.08	4.15	3.91
RESIDENTIAL	REF 1	COAL	0.00	0.00	0.00	0.00
RESIDENTIAL	REF 1	DIESEL FUEL	30.41	29.80	30.09	28.27
RESIDENTIAL	REF 1	ELECTRICITY	93.86	85.35	86.65	84.34
RESIDENTIAL	REF 1	KEROSENE FUEL	0.09	0.10	0.10	0.09
RESIDENTIAL	REF 1	LPG FUEL	3.87	3.69	3.59	3.43
RESIDENTIAL	REF 1	PIPELINE GAS	257.40	255.23	256.21	242.83
RESIDENTIAL	REF 2	BIOMASS - WOOD	3.94	4.08	4.15	3.91
RESIDENTIAL	REF 2	COAL	0.00	0.00	0.00	0.00
RESIDENTIAL	REF 2	DIESEL FUEL	30.41	29.80	30.09	28.27
RESIDENTIAL	REF 2	ELECTRICITY	93.86	85.35	86.65	84.34
RESIDENTIAL	REF 2	KEROSENE FUEL	0.09	0.10	0.10	0.09
RESIDENTIAL	REF 2	LPG FUEL	3.87	3.69	3.59	3.43
RESIDENTIAL	REF 2	PIPELINE GAS	257.40	255.23	256.21	242.83
RESIDENTIAL	VAR 3	BIOMASS - WOOD	3.94	4.08	4.15	3.91
RESIDENTIAL	VAR 3	COAL	0.00	0.00	0.00	0.00
RESIDENTIAL	VAR 3	DIESEL FUEL	30.39	28.66	26.88	23.90
RESIDENTIAL	VAR 3	ELECTRICITY	93.85	82.43	80.29	79.60
RESIDENTIAL	VAR 3	KEROSENE FUEL	0.09	0.10	0.10	0.09
RESIDENTIAL	VAR 3	LPG FUEL	3.87	3.57	2.98	2.40
RESIDENTIAL	VAR 3	PIPELINE GAS	257.27	243.22	223.59	199.00
RESIDENTIAL	VAR 6	BIOMASS - WOOD	3.94	4.08	4.15	3.91
RESIDENTIAL	VAR 6	COAL	0.00	0.00	0.00	0.00
RESIDENTIAL	VAR 6	DIESEL FUEL	30.36	23.21	9.42	3.75
RESIDENTIAL	VAR 6	ELECTRICITY	93.91	97.47	125.10	131.69
RESIDENTIAL	VAR 6	KEROSENE FUEL	0.09	0.10	0.10	0.09
RESIDENTIAL	VAR 6	LPG FUEL	3.86	3.35	2.38	1.63
RESIDENTIAL	VAR 6	PIPELINE GAS	257.11	198.03	85.42	33.17

TRANSPORTATION	LEAST COST	COMPRESSED PIPELINE GAS	1.00	0.65	0.15	0.12
TRANSPORTATION	LEAST COST	DIESEL FUEL	118.56	96.14	52.39	46.97
TRANSPORTATION	LEAST COST	ELECTRICITY	1.21	37.80	110.25	129.72
TRANSPORTATION	LEAST COST	GASOLINE FUEL	434.41	286.05	53.39	5.15
TRANSPORTATION	LEAST COST	JET FUEL	13.83	13.83	13.83	13.83
TRANSPORTATION	LEAST COST	LIQUEFIED PIPELINE GAS	0.00	0.03	0.08	0.11
TRANSPORTATION	LEAST COST	LIQUID HYDROGEN	0.01	1.71	5.04	5.40
TRANSPORTATION	LEAST COST	LPG FUEL	0.00	0.00	0.00	0.00
TRANSPORTATION	LEAST COST	LUBRICANTS	4.32	4.34	4.40	4.45
TRANSPORTATION	LEAST COST	RESIDUAL FUEL OIL	27.42	27.42	27.42	27.42
TRANSPORTATION	REF 1	COMPRESSED PIPELINE GAS	1.00	0.88	0.80	0.81
TRANSPORTATION	REF 1	DIESEL FUEL	118.71	119.73	121.09	131.66
TRANSPORTATION	REF 1	ELECTRICITY	1.02	1.25	1.64	1.89
TRANSPORTATION	REF 1	GASOLINE FUEL	434.81	384.98	346.60	332.30
TRANSPORTATION	REF 1	JET FUEL	13.83	13.83	13.83	13.83
TRANSPORTATION	REF 1	LIQUEFIED PIPELINE GAS	0.00	0.03	0.08	0.11
TRANSPORTATION	REF 1	LIQUID HYDROGEN	0.02	0.06	0.07	0.07
TRANSPORTATION	REF 1	LPG FUEL	0.00	0.00	0.00	0.00
TRANSPORTATION	REF 1	LUBRICANTS	4.32	4.34	4.40	4.45
TRANSPORTATION	REF 1	RESIDUAL FUEL OIL	27.42	27.42	27.42	27.42
TRANSPORTATION	REF 2	COMPRESSED PIPELINE GAS	1.07	1.01	0.91	0.91
TRANSPORTATION	REF 2	DIESEL FUEL	118.54	119.06	120.18	130.67
TRANSPORTATION	REF 2	ELECTRICITY	2.04	4.62	4.63	4.58
TRANSPORTATION	REF 2	GASOLINE FUEL	431.50	374.03	337.06	324.05
TRANSPORTATION	REF 2	JET FUEL	13.83	13.83	13.83	13.83
TRANSPORTATION	REF 2	LIQUEFIED PIPELINE GAS	0.00	0.03	0.08	0.11
TRANSPORTATION	REF 2	LIQUID HYDROGEN	0.02	0.06	0.07	0.07
TRANSPORTATION	REF 2	LPG FUEL	0.00	0.00	0.00	0.00
TRANSPORTATION	REF 2	LUBRICANTS	4.32	4.34	4.40	4.45
TRANSPORTATION	REF 2	RESIDUAL FUEL OIL	27.42	27.42	27.42	27.42
TRANSPORTATION	VAR 3	COMPRESSED PIPELINE GAS	1.00	0.65	0.15	0.12
TRANSPORTATION	VAR 3	DIESEL FUEL	118.56	96.14	52.39	46.97
TRANSPORTATION	VAR 3	ELECTRICITY	1.21	37.80	110.25	129.72
TRANSPORTATION	VAR 3	GASOLINE FUEL	434.41	286.05	53.39	5.15
TRANSPORTATION	VAR 3	JET FUEL	13.83	13.83	13.83	13.83
TRANSPORTATION	VAR 3	LIQUEFIED PIPELINE GAS	0.00	0.03	0.08	0.11
TRANSPORTATION	VAR 3	LIQUID HYDROGEN	0.01	1.71	5.04	5.40
TRANSPORTATION	VAR 3	LPG FUEL	0.00	0.00	0.00	0.00
TRANSPORTATION	VAR 3	LUBRICANTS	4.32	4.34	4.40	4.45
TRANSPORTATION	VAR 3	RESIDUAL FUEL OIL	27.42	27.42	27.42	27.42
TRANSPORTATION	VAR 6	COMPRESSED PIPELINE GAS	1.00	0.70	0.31	0.30
TRANSPORTATION	VAR 6	DIESEL FUEL	118.70	116.23	109.79	117.53
TRANSPORTATION	VAR 6	ELECTRICITY	1.05	15.00	43.09	49.71
TRANSPORTATION	VAR 6	GASOLINE FUEL	434.76	337.01	204.71	174.99
TRANSPORTATION	VAR 6	JET FUEL	13.83	13.83	13.83	13.83

TRANSPORTATION	VAR 6	LIQUEFIED PIPELINE GAS	0.00	0.03	0.08	0.11
TRANSPORTATION	VAR 6	LIQUID HYDROGEN	0.01	0.85	2.52	2.70
TRANSPORTATION	VAR 6	LPG FUEL	0.00	0.00	0.00	0.00
TRANSPORTATION	VAR 6	LUBRICANTS	4.32	4.34	4.40	4.45
TRANSPORTATION	VAR 6	RESIDUAL FUEL OIL	27.42	27.42	27.42	27.42

3. Putting the Costs in Context

The increased annual net costs of the Least Cost Case over the reference case are difficult to contextualize. To put these in context, we compare the net costs to gross state product, and we show the increase in total annual energy spending over the Business as Usual Case.

3.1. Gross State Product

Gross State Product for New Jersey in 2018 was $625 billion dollars. We project Gross State Product into the future using US GDP growth rates from the EIA Annual Energy Outlook 2019. The net costs of the Least Cost Case relative to Reference Case 1 amount to 0.4% in 2030 and 0.2% in 2050 on projected Gross State Product.

Table 8. Least Cost Case net costs as percentage of Gross State Product

Gross State Product	2018	2030	2050
Gross state product (2018$bil/yr)	$625	$787	$1,138
Least Cost Net costs (2018$bil/yr)	-	$2.8	$2.2
Percent of GDP	-	0.4%	0.2%

3.2. Total Energy Spending

Total energy spending includes all investments in supply side energy infrastructure, fuels, and operations and maintenance, and incremental costs of demand side equipment relative to their equivalent reference investment in Reference Case 1. Total spending in 2030 and 2050 for Reference Case 1 is $28.0 billion/yr and $30.2 billion/yr, respectively. Total spending in the Least Cost Case is 10% higher in 2030 and 7% higher in 2050.

Table 9. Comparison of total energy spending

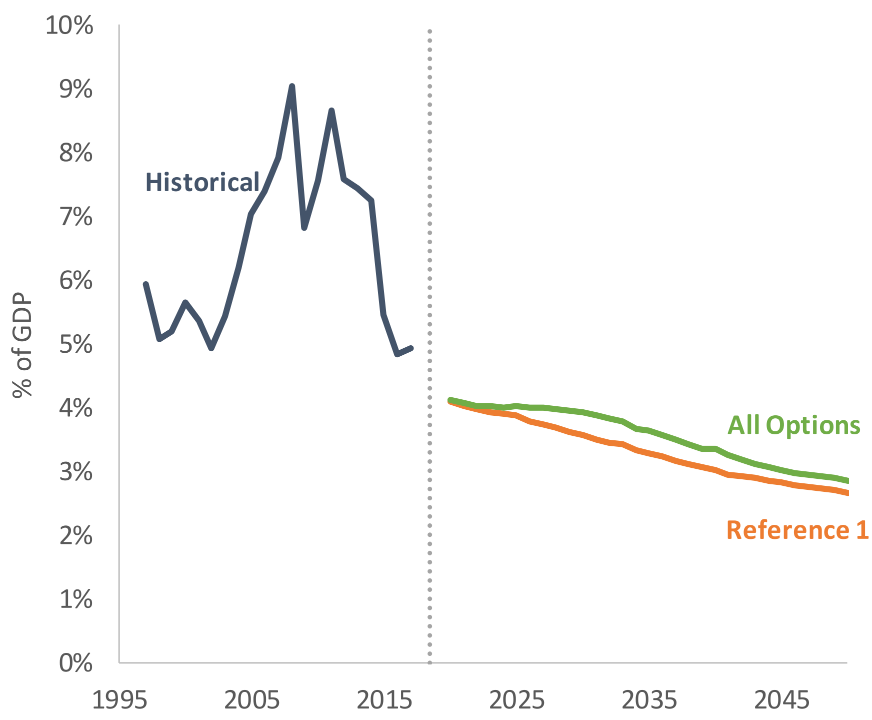
Total Energy Spending	2030	2050
Reference 1: BAU (2018$bil/yr)	$28.0	$30.2
Least Cost Case (2018$bil/yr)	$30.8	$32.4
Percentage Increase over Ref1	10%	7%

3.3. Historical Context

Costs can also be compared to historical spending. Historically, spending on the energy system has represented 5-9% of state GDP. Fossil fuel prices play a large role in the total and the variance of this number because they make up a large portion of present day energy spending.

The share of spending on energy as a percentage of Gross State Product is projected to decrease over time. The state's economy will be less dependent on energy use in the future, and energy intensity is declining with business as usual efficiency, notably from light-duty vehicle fuel economy improvements. Figure 13 shows the historical and projected spending on energy.

Figure 13. Historical and projected energy spending as percentage of Gross State Product

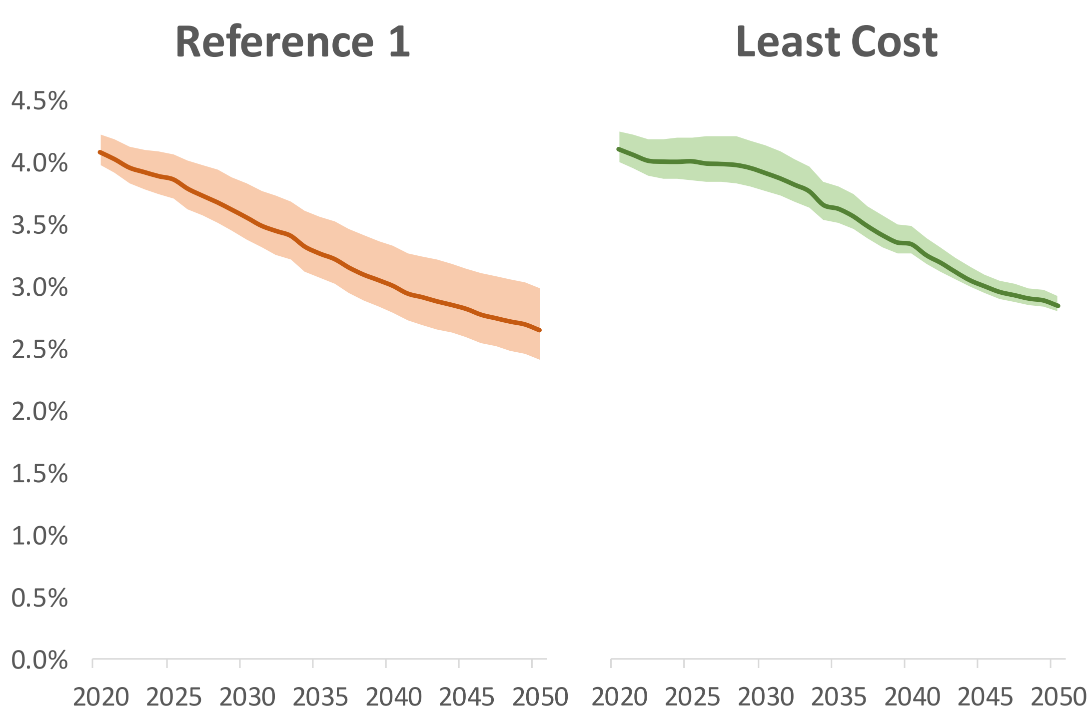


3.4. Fuel Price Volatility

Projected spending relies on fuel price projections from EIA's Annual Energy Outlook 2019. Decarbonization strategies help New Jersey reduce its exposure to the impacts of volatile fuel prices through reduced fossil fuel consumption. Decarbonization therefore acts as a hedge against these prices that are dictated by international markets and geopolitical events, potentially increasing energy security.

Figure 14 reflects the range of uncertainty around oil and gas prices based on EIA's fossil fuel price projection sensitivities from "Low oil and gas resource and technology" and "High oil and gas resource and technology" scenarios. These estimate price impacts from current projected fossil fuel reserves being larger or smaller than expected, and rates of technological improvement that reduce costs and increase productivity of fuel recovery being higher or lower than expected. Oil prices change +10%/-12% and natural gas prices change +70%/-30% in 2050.The Least Cost case shows a smaller uncertainty band due to reduced fossil fuel expenditures over time, whereas Reference 1's uncertainty band increases over time. Future prices may be more volatile than captured by these ranges since they do not reflect geopolitical price impacts.

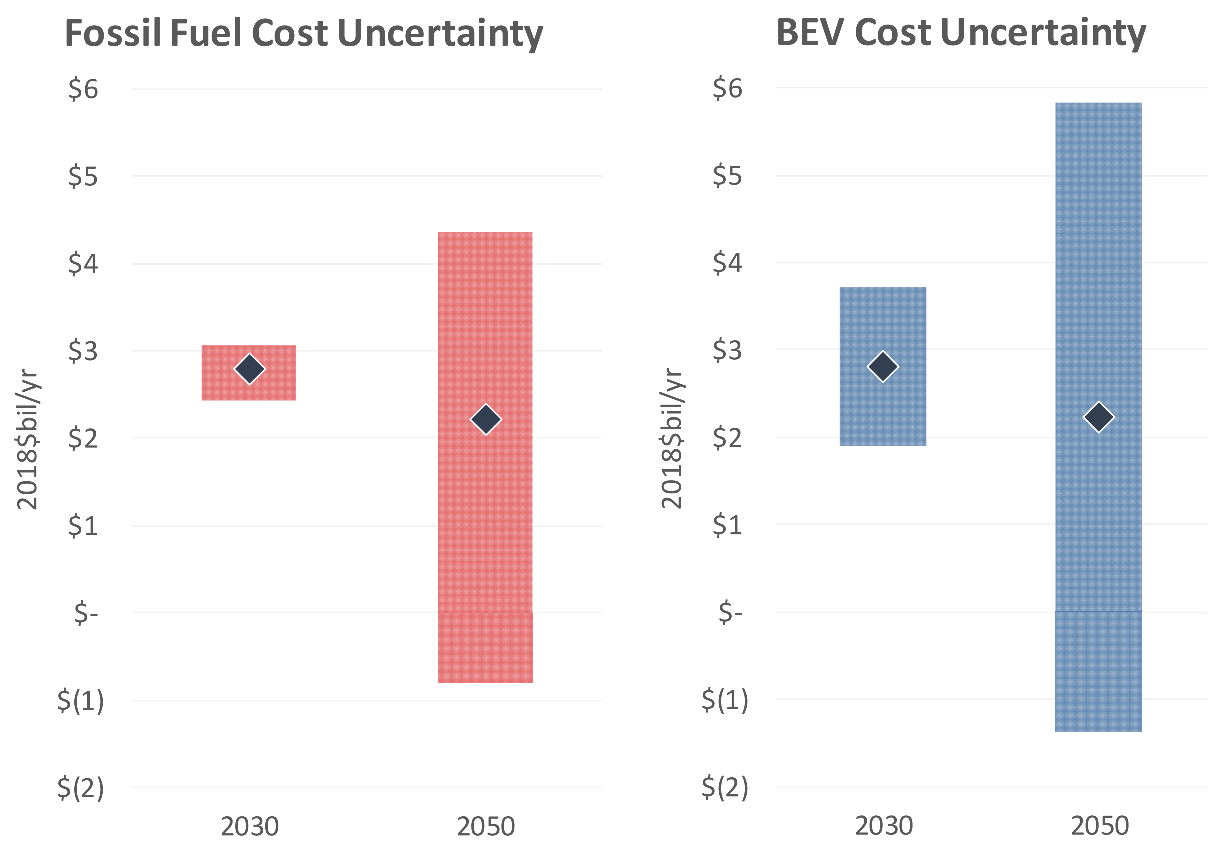
Figure 14. Impact of changes in fuel price on total energy spending as a percentage of Gross State Product



3.5. Cost Uncertainty

The costs of deeply decarbonizing New Jersey's energy system are highly uncertain, and this uncertainty increases with time. They are particularly sensitive to fuel and vehicle costs because these are such a large portion of spending. Looking at these two sources of uncertainty, we show the range into which the cost of the Least Cost Case falls with different assumptions about fuel and vehicle price. Fuel prices use the same range as the previous section and we adjust electric vehicle costs by +/-10% of the baseline assumption in order to illustrate its importance.

Figure 15. Net cost sensitivity of changing fossil fuel and vehicle prices



The impact of fuel costs is significant, with higher fuel costs resulting in net savings for New Jersey. Changing vehicle prices have an even more pronounced effect on the relative cost of decarbonization. Recent experience in renewable and storage markets have shown that forecasts often overestimate future prices for developing technologies and every year forecasts tend to drop. If this dynamic happens for electric vehicles, New Jersey may see net benefits of decarbonizing the economy.

4. Key Scenario Assumptions

This section describes common system assumptions underpinning the scenarios.

4.1. Emissions Constraint

Table 10 below shows the annual total emissions constraint, forecasted non-energy emissions, and the remaining emissions budget for energy and industrial process CO_2 in this analysis. The economy wide emissions target is from the Global Warming Response Act, capping emissions in 2020 at 1990 levels and emissions in 2050 at 80% below 2006 levels. We assume a linear tightening of the cap between 2020 and 2050. Historical emissions are from New Jersey Department of Environmental Protection GHG Inventory. Non-energy emissions from 2020 through 2050 for the emission constrained cases are based on forecasts by New Jersey Department of Environmental Protection of changes in non-energy emissions and potential non-energy mitigation measures that may be employed. The Reference Cases have no emissions constraints.

Table 10 Emissions targets to meet 80x50 GWRA goals by 2050 (MMT CO_2e)

Year	Economy Wide Cap	Non- Energy	Energy	% Reduction in Energy vs 2006
		Historical		
1990	125.7	16.6	109.1	
2006	128.6	7.4	121.2	
		Modeled Emissions Cap		
2020	125.7	6.5	119.2	2%
2025	109.0	5.9	103.2	15%
2030	92.4	5.3	87.1	28%
2035	75.7	4.7	71.1	41%
2040	59.0	4.0	55.0	55%
2045	42.4	3.4	39.0	68%
2050	25.7	2.8	22.9	81%

4.2. Electricity Emissions Accounting

We assume an accounting mechanism in the future that counts all emissions from in-state generation and allows New Jersey to count out of state clean energy resources as clean imports without having to build dedicated transmission to the resource to ensure physical deliverability. The mechanism has the following components:

- Accounts for all emissions from generation within New Jersey's borders. This includes emissions from generation that is exported to PJM or New York and not used by NJ. All emissions from electricity generation in NJ count toward NJ's emissions budget.
- Imported megawatt-hours are tagged as zero emissions coming into New Jersey if a renewable resource designated to supply energy to New Jersey is simultaneously producing those megawatt-hours somewhere in PJM.
- Hourly basis, renewable production must be happening simultaneously to imports to tag those imports as zero emissions.
- Total imports from designated NJ out-of-state renewables are limited by the available transmission into NJ from PJM in every hour. New Jersey's hourly imports are capped by total transmission headroom.
- In years prior to 2050, unspecified imports can also come into NJ but are tagged with the emissions rate of gas generation.
- Resources designated to supply energy to New Jersey must come from dedicated new construction renewable generation.
- New Jersey pays for the share of capital cost of the designated resource associated with the megawatt-hours of energy it imports.
- Avoids double counting of emissions reductions from renewables.

Each hour, we calculate ε_h, emissions associated with electricity generation using:

$\varepsilon_h = \varepsilon_{NJ,Gen,h} + (I_h \times e_{PJM})$

where

$I_h = D_{NJ,h} - G_{NJ,h} - G_{PPA,h}$ (or, =0 if the calculation is <0)

Symbols are

- ε_h is the electricity emissions in the given hour (tons of CO_2 equivalent)
- $\varepsilon_{NJ,Gen,h}$ is the entirety of emissions associated with electricity generation inside of New Jersey's borders.
- I_h is the effective imported electricity in a given hour [MWh]. If I_h is <0 in a given hour, it is set equal to zero for the emission calculation. However, we still account for revenue to NJ for electricity exports; but there is no ability to export emissions.
- e_{PJM} is the emissions factor for PJM [tons/MWh]. This PJM emissions factor is only calculated once per year, not each hour. This is set to the emissions factor of a PJM combined cycle gas plant, which is assumed to be on the margin at times that New Jersey is importing.
- $D_{NJ,h}$ is the total electricity demand in NJ in the given hour [MWh]
- $G_{NJ,h}$ is the total electricity generation from within NJ's borders in the given hour [MWh]. Emissions from $G_{NJ,h}$ are accounted for in the term $\varepsilon_{NJ,Gen,h}$.
- $G_{PPA,h}$ is the generation from out-of-state renewables imported into NJ resulting from the investment by a NJ load entity [MWh]. In each hour, $G_{PPA,h}$ cannot exceed the transmission capacity from PJM into NJ – this capacity is ~7 GW today and, in most scenarios, we allow the model to add another 7 GW of transmission capacity into NJ if it is cost effective. The model does account for the increased cost of this transmission. We also require that out-of-state clean resources (included in $G_{PPA,h}$) have a transmission connection to PJM (or build one) but we do not require any kind of dedicated transmission directly from the new resource to NJ.

Total emissions, ε, are calculated by summing ε_h over all 8760 hours in each year.

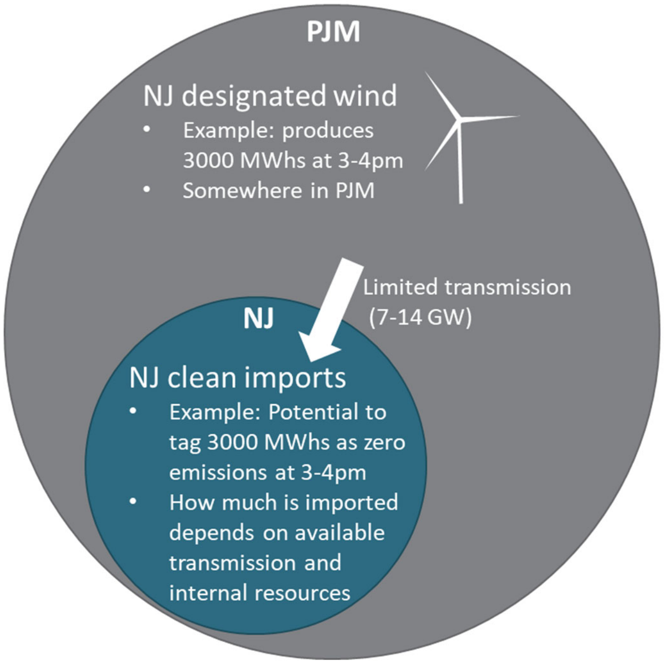
To meet the 100% Clean Energy, ε must decrease to zero in 2050. To meet the GWRA, total NJ emissions, of which ε is one component, must decrease to 24.1 MMT in 2050.

This calculation is used in the Least Cost scenario and Alternative scenarios 2 to 6. In Alternative scenario 1, the entire Eastern Interconnect goes to 100% Clean Energy. In this case, the region is carbon constrained, not just NJ.

Out of state generation is an important component of the Least Cost Case and significantly reduces cost over procuring all clean energy resources in-state, as shown by the cost comparison to Variation 2. However, out of state clean energy production assumes a level of coordination with PJM to enable imports to be counted as clean energy towards New Jersey's policy goals.

Figure 16 shows a simple example of this concept where wind can generate energy somewhere in PJM. Building the wind resource incurs the capital cost of the resource itself and the cost of the local intertie into the PJM system. New Jersey can count imports across its interties to PJM as clean, up to the simultaneous hourly output of the designated resource. Whether New Jersey can import this energy or not depends on whether there is available transmission capacity on the interties to do so, and whether New Jersey needs the energy (there may be clean energy resources internal to the state that are already sufficiently meeting load). New Jersey pays for the share of energy from the resource that they import. The remaining output from the resource avoids investments in PJM.

Figure 16. Treatment of New Jersey designated out of state resources



4.3. Model Topology

We model the Eastern Interconnection to capture the interactions between New Jersey and the region that surrounds it. The Eastern Interconnection is broken into 6 transmission zones with greater transmission granularity closer to New Jersey to best capture the impact of transmission constraints. The zones include New Jersey, New York ISO, ISO New England, PJM East, PJM West, and the rest of the Eastern Interconnection.

Existing transmission capacity between zones was developed in consultation with PJM. Our transmission assumptions for 2020 between New Jersey and surrounding regions are as follows:

- PJM to New Jersey
    - 6,917 MW, the average PJM Eastern Interface limit from 2018, and recommended by PJM to represent current transmission flow limits.
- New Jersey to New York
    - PJM-NY Interface: 2400 (flow)/-1000 (counterflow), recommended by PJM.

        - Includes JK, A, and 5018 lines
    - PJM-NY Merchant Lines
        - Neptune: 660/-660 MW
        - Hudson (HTP): 660/0 MW (We assume this changes to two way flow 660/-660 MW in 2025)
        - Linden (VFT): 315/-315 MW

There are no studies that identify the potential for expanding transmission capacity in the future. In this study, we assumed that transmission capacity could be doubled between NJ and PJM at a cost of $1040/kilowatt. This allows investigation of whether expanding transmission is cost effective option in reaching the 2050 decarbonization goals.

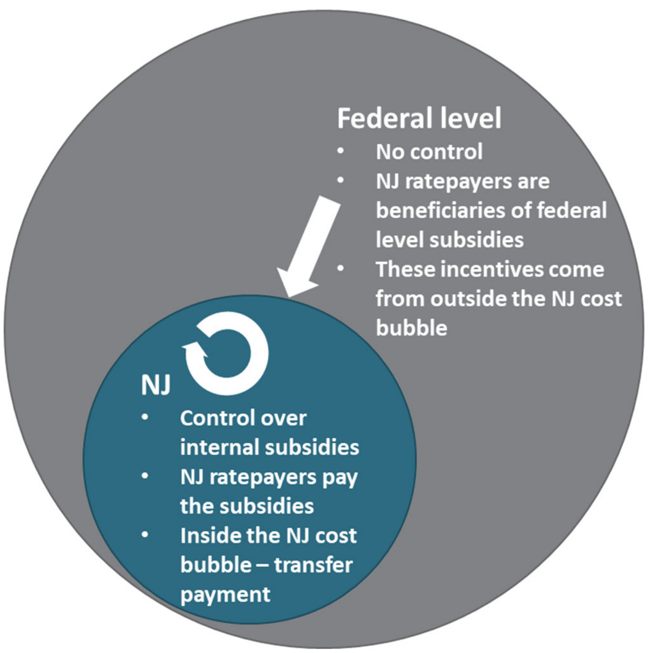
4.4. Incentives

As discussed in section 1.1, the model optimizes investments based on their actual costs including capital, operations and maintenance, and fuel costs, rather than either what a resource would be paid for its services in today's markets, or after local incentives have been deducted. This is because the design of markets and incentives should be influenced by what the least cost set of investments are and not the other way around. Present day markets and incentives are tools to achieve the best outcomes for the state. Those tools will need to change over time as the system changes. The exception to this rule are incentives that New Jersey does not directly contribute to. These represent injections of capital into New Jersey and not just redistribution within it. This includes the federal investment tax credit (ITC). This has been included in analysis at 26% in 2020 and 10% in the years afterwards.

Figure 17 illustrates why we make this differentiation between local and federal incentives. In the case of incentive programs within New Jersey, the money for incentives is collected from New Jersey residents and then distributed back into the New Jersey economy to support particular industries. The capital and operating costs of an incentivized industry remain the same as they did before, but they now receive higher payments for their products. There are many good reasons for incentive programs, for example supporting industries whose costs are not fully covered because their full value is not recognized in markets. However, we do not model market based compensation for services. We model the full value of energy supply technologies and their full costs to determine which are part of a least cost portfolio of resources in the future. If resources identified as part of the least cost portfolio cannot cover their costs under current market structures, then an incentive may be one of several candidate policies to support those resources. However, current local incentives should not be factored in when comparing future resource options.

Federal incentives are different because these come from outside of New Jersey, so these are a net benefit to New Jersey residents. New Jersey also cannot control Federal incentives. Therefore, federal incentives are included in the analysis because they impact total costs for New Jersey. We have included the federal ITC in our analysis as continuing at 10% throughout the study period. This incentive may end at some point in the future, but there is no current expiry date.

Figure 17. Federal versus New Jersey Incentives



4.4.1. A note on the Regional Greenhouse Gas Initiative (RGGI)

RGGI carbon allowances are not included in the model. Within New Jersey, investments in carbon reducing infrastructure and energy system operations are capped by the 80x50 goals, which are far more stringent than RGGI. RGGI grants (reinvestment in energy efficiency for example) are also not accounted for in the model. We account for the full efficient technology price and not the subsidized price under a RGGI program. Assuming New Jersey permit payments equal the reinvestment in NJ energy equipment then there's no net loss or gain (some fraction may not be energy related though).

4.5. T&D Costs

Transmission and distribution investments make up a large component of the cost differences between the Reference Cases and the Least Cost Case and its variants. Electrification of vehicles and buildings increases load significantly with a commensurate increase in the infrastructure necessary to serve that load. Unfortunately, T&D costs in the future are highly uncertain. Sources of uncertainty include:

- No historical precedent for the magnitude and duration of forecasted growth in available data.
- T&D costs are highly localized, varying significantly between regions of the country, so it is hard to apply costs from other regions.
- The forecasted load growth is partially from electrifying heating loads that switch the system to winter peaking. Since the system is currently summer peaking, some potential slack exists initially for this growth to happen without significant cost.
- Smart grid infrastructure may change the costs of load growth related T&D versus T&D driven by load growth in the past.

Given these uncertainties, we took a simple approach to estimating the scale of T&D investment costs while avoiding the false precision of employing a more complex methodology in the absence of adequate data. Our approach was to hold present day $/kWh costs for T&D

(taken from EIA AEO 2019 for the RFCE region containing New Jersey) constant in future years. Investment in T&D grows with the growth in demand, but we do not reflect dynamics that could either increase or decrease the $/kWh cost of T&D over time.

4.6. Resource Potentials

Resource potentials were taken from the sources described in Section 9. NREL resource potential estimates for offshore wind and onshore renewable resources were supplemented with New Jersey provided estimates of solar potential. Behind-the-meter solar potential was taken from the New Jersey Renewable Energy Market Assessment conducted by Navigant. These estimates were scaled up to reflect improvements in solar PV energy density since the study was conducted. Estimates of grid scale solar PV potential were provided by New Jersey BPU.

- Rooftop PV: 27 GW (scaled from Navigant, 2004)
- Grid supply PV: 27 GW (includes large community solar installations)
- Total in-state PV potential: 54 GW

4.7. Nuclear Extension

The permits of the New Jersey nuclear fleet expire in 2036, 2040, and 2046. In the Least Cost Case, we include the option of extending these nuclear permits. If the nuclear permits are extended, there is a cost associated with doing so taken from EPA assumptions on nuclear permit extensions. The results show that it is economic to extend nuclear in the Least Cost Case. Variation 5 investigates the impact of not allowing these permits to be extended together with disallowing construction of new gas plants.

5. EnergyPATHWAYS

The following section describes the EnergyPATHWAYS model used to build the demand side technology stock representation of the New Jersey economy as well as the surrounding regions. Included are detailed descriptions of the logic used to build an energy demand representation for technologies that differ in data availability. The sources used to create the demand side representation are given in Section 8.

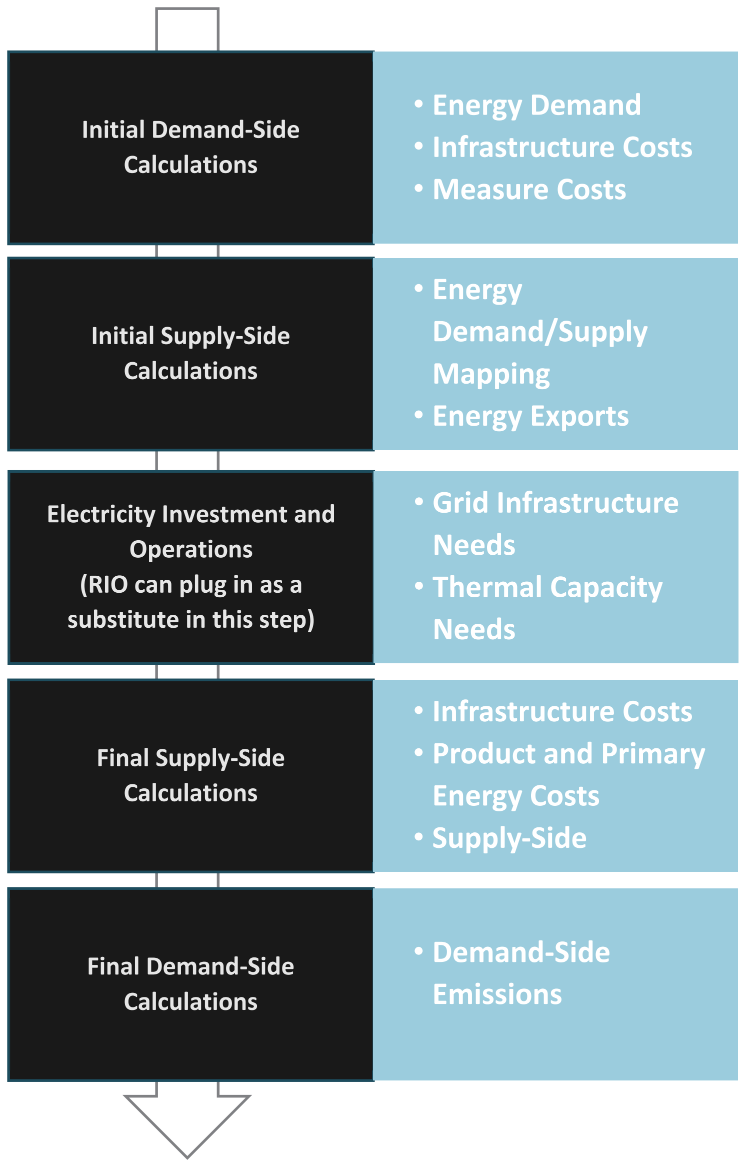
The EnergyPATHWAYS model is a comprehensive energy accounting and analysis framework specifically designed to examine the large-scale energy system transformations. It accounts for the costs and emissions associated with producing, transforming, delivering, and consuming energy in an economy. It has strengths in infrastructure accounting and electricity operations that separate it from models of similar types. It is used, as it has been in this analysis, to calculate the impacts of energy system decisions out into the future in terms of infrastructure; emissions, and cost impacts to energy consumers and the economy more broadly.

The model works using decision-making "stasis" as a baseline. This means, for example, that when projecting energy demand for residential space heating, EnergyPATHWAYS implicitly assume that consumers will replace their water heater with a water heater of a similar type. This baseline does, however, include efficiency gains and technology development either required by codes and standards or reasonably anticipated based on techno-economic projections. If there are deviations from the current system in terms of technology deployment, these are made explicit in our scenario definitions with the application of measures, which represent explicit user-defined changes to the baseline. An example of this is the electrification of vehicles in the Least Cost Case. These can take the form of adjustments of sales shares measures - changes in the relative penetration of technology adoption in a defined year; or stock measures - changes to the amount of technology deployment by a defined year.

5.1. Model Structure

EnergyPATHWAYS projects energy demand and costs in subsectors based on explicit user-decisions about technology adoption (i.e. electric vehicle adoption) and activity levels (i.e. reduced VMTs). Used in standalone form, these projections of energy demand across energy carriers are then sent to the supply-side of the EnergyPATHWAYS model, which calculates upstream energy flows, primary energy usage, infrastructure requirements, emissions, and costs of supplying energy. However, the Regional Investment and Operations model (RIO) plugs into the step and provides more sophisticated supply side planning and optimization. We have used the RIO model in New Jersey. The supply-side outputs of this step are then combined with the demand-side outputs to calculate the total energy flows, emissions, and costs of the modeled energy system. Figure 18 shows the basic calculation steps for EnergyPATHWAYS as well as the outputs from each step.

Figure 18 EnergyPATHWAYS calculation steps



In the following section EnergyPATHWAYS separately detail the demand-side and supply-side of this calculation framework.

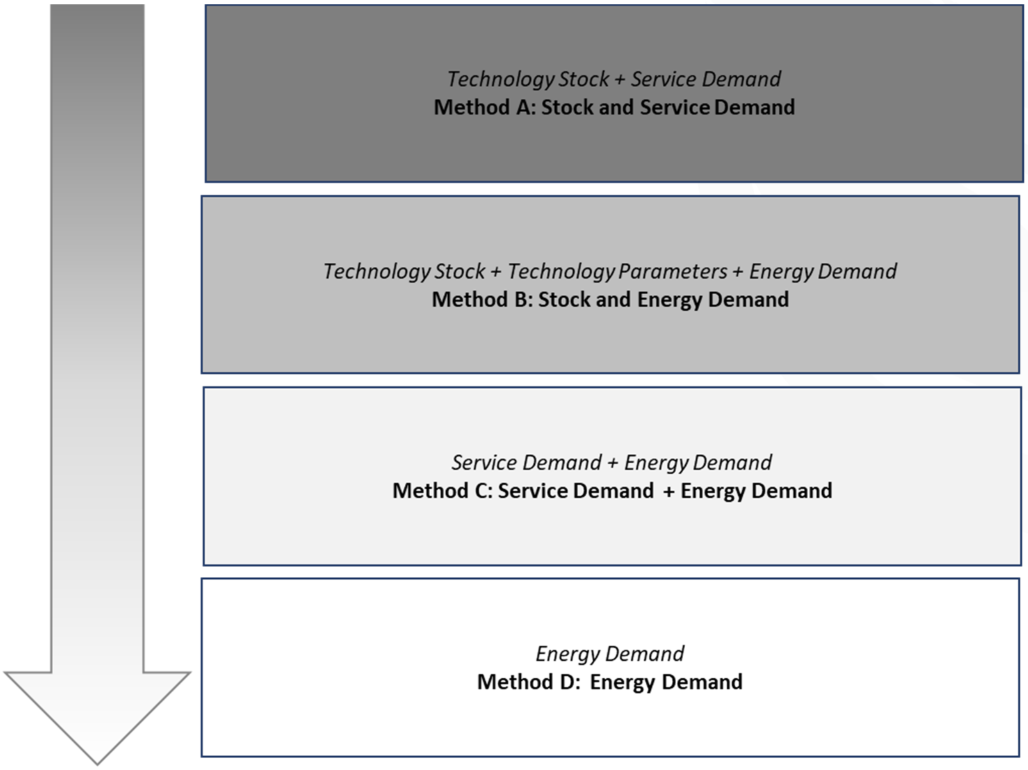
5.2. Subsectors

Subsectors represent separately modeled units of demand for energy services. These are often referred to as end-uses in other modeling frameworks. EnergyPATHWAYS is flexible in the configuration of these subsectors and the choices in the subsector detail rendered depends heavily on data availability. The high level of detail in subsectors in the EnergyPATHWAYS database represents the availability of numerous high-quality data sources for the energy economy, which allows us to represent demand for energy services on a highly detailed, granular basis. We will describe the calculations for individual subsectors on the demand-side in this document, but assessing the total demand is simply the summation of these calculations for all subsectors.

5.3. Energy Demand Projection

Data availability informs subsector granularity and informs the methods used in each subsector. The flow diagram below represents the decision matrix used to determine the potential methods used to detail an individual energy demand subsector. The arrow downward indicates a progression from most-preferred to least-preferred methodology for detailing a subsector. More preferred methods allow for more explicit interventions of measures and better accounting for costs and energy impacts of concrete actions. Each method for projecting energy demand is described below.

Figure 19. Methods for projecting energy demand



5.3.1. Method A: Stock and Service Demand

This method is the most explicit representation of energy demand possible in the EnergyPATHWAYS framework. It has a high data requirement, however, as many end-uses are not homogenous enough to represent with technology stocks and others do not have measurements of energy service demand. When they do, EnergyPATHWAYS uses the following formula to calculate energy demand from the subsector.

Equation 1

$$E_{ycr} = \sum_{v \in V} \sum_{t=T} U_{yvtcr} * f_{vtc} * d_{yr} * (1 - R_{yrc})$$

Where

E = Energy demand in year y of energy carrier c in region r

U_{yvtcr} = Normalized share of service demand in year y of vintage v of technology t for energy carrier c in region r

f_{vtc} = Efficiency (energy/service) of vintage v of technology t using energy carrier c

d_{yr} = Total service demand input aggregated for year y in region r

R_{yrc} = Unitized service demand reductions for year y in region r for energy carrier c. Service demand reductions are calculated from input service demand measures, which change the baseline energy service demand levels.

5.3.1.1. Service Demand Share (U)

The normalized share of service demand is calculated as a function of the technology stock (S), service demand modifiers (M), and energy carrier utility factors (C). Below is the decomposition of *U* into its component parts of *S* and *M and C.*

Equation 2

$$U_{yvtr} = \frac{S_{yvtr} * M_{yvtr} * C_{tc}}{\sum_{v \in V} \sum_{t \in T} S_{yvtr} * M_{yvtr}}$$

Where

S_{yvtr} = Technology stock in year y of vintage v of technology t in region r

M_{yvtr} = Service demand modifier in year y for vintage v for vintage t in region r

C_{tc} = Utility factor for energy carrier c for technology t

The calculation of these are detailed in the sections below

5.3.1.2. Technology Stock (S)

The composition of the technology stock is governed by technology stock rollover mechanics in the model, technology inputs (lifetime parameters, technology decay parameters), initial technology stock states, and the application of sales share or stock measures. The section below describes the ways in which these model variables can affect the eventual calculation of technology share.

5.3.1.2.1. Initial Stock

The model uses an initial representation of the technology stock to project forward. This usually represents a single-year stock representation based on customer survey data (I.e. U.S. Commercial Building Energy Consumption Survey data informs 2012 technology stock estimates) but can also be "specified" into the future, where the composition of the stock is determined exogenously. At the end of this initial stock specification, the model uses technology parameters and rollover mechanics to determine stock compositions by year.

5.3.1.2.2. Stock Decay and Replacement

EnergyPATHWAYS allows for technology stocks to decay using linear representations or Weibull distributions, which are typical functions used to represent technology reliability and failure rates. These parameters are governed by a combination of technology lifetime parameters. Technology lifetimes can be entered as minimum and maximum lifetimes or as an average lifetime with a variance.

After the conclusion of the initial stock specification period, the model decays existing stock based on the age of the stock, technology lifetimes, and specified decay functions. This stock decay in a year (y) must be replaced with technologies of vintage (v) *v = y*. The share of replacements in vintage v is equal to the share of replacements unless this default is overridden with exogenously specified sales share or stock measures. This share of sales is also used to inform the share of technologies deployed to meet any stock growth.

5.3.1.2.3. Sales Share Measures

Sales share measures override the pattern of technologies replacing themselves in the stock rollover.

An example of a sales share measure is shown below for two technologies – A and B - that are represented equally in the initial stock and have the same decay parameters. EnergyPATHWAYS apply a sales share measure in the year 2020 that requires 80% of new sales in 2020 to be technology A and 20% to be technology B. The first equation shows the calculation in the absence of this sales share measure. The second shows the stock rollover governed with the new sales share measure.

S = Stock

D = Stock decay

G = Year on year stock growth

R = Stock decay replacement

N = New Sales

a = Technology A

b = Technology B

Before Measure (i.e. Baseline)

S_{2019} = 100

S_{a2019} = 50

S_{b2019} = 50

D_{2020} = 10

D_{a2020} = 5

D_{b2020} = 5

S_{2020} = 110

$G_{2020} = S_{2020} - S_{2019} = 110 - 100 = 10$

$R_{a2020} = D_{a2020}$ = 5

$R_{b2020} = D_{b2020}$ = 5

$G_{a2020} = \frac{D_{a2020}}{D_{2020}} * G_{2020}$ = 5/10 * 10 =5

$G_{b2020} = \frac{D_{b2020}}{D_{2020}} * G_{2020}$ = 5/10 * 10 = 5

$N_{a2020} = R_{a2020} + G_{a2020}$ = 5 + 5 = 10

$N_{b2020} = R_{b2020} + G_{b2020}$ = 5 + 5 = 10

$S_{a2020} = S_{a2019} + D_{a2020} + N_{a2020}$ = 50 – 5 + 10 = 55

$S_{b2020} = S_{b2019} + D_{b2020} + N_{b2020}$ = 50 – 5 + 10 = 55

After Sales Share Measure

S_{2019} = 100

S_{a2019} = 50

S_{b2019} = 50

D_{2020} = 10

D_{a2020} = 5

D_{b2020} = 5

S_{2020} = 110

$G_{2020} = S_{2020} - S_{2019} = 110 - 100 = 10$

R_{a2020} = $D_{2020} * H_{a2020}$ = 10 * .8 = 8

R_{b2020} = $D_{2020} * H_{b2020}$ = 10 * .2 = 2

G_{a2020} = $G_{2020} * H_{a2020}$ = 10 * .8 = 8

G_{b2020} = $G_{2020} * H_{b2020}$ = 10 * .2 = 2

N_{a2020} = $R_{a2020} + G_{a2020}$ = 8 + 8 = 16

N_{b2020} = $R_{b2020} + G_{b2020}$ = 2 + 2 = 4

S_{a2020} = $S_{a2019} + D_{a2020} + N_{a2020}$ = 50 – 5 + 16 = 61

S_{b2020} = $S_{b2019} + D_{b2020} + N_{b2020}$ = 50 – 5 + 4 = 49

This shows a very basic example of the role that sales share measures play to influence the stock of technology. In the context of energy demand, these technologies can use different energy carriers (i.e. gasoline internal combustion engine vehicles to electric vehicles) and/or have different efficiency characteristic.

Though not shown in the above example, the stock is tracked on a vintaged basis, so decay of technology A in 2020 in the above example would be decay in 2020 of all vintages before 2020. In the years immediately succeeding the deployment of vintage cohort, there is very little technology retirement given the shape of the decay functions. As a vintage approaches the end of their anticipated useful life, however, retirement accelerates.

5.3.1.2.4. Stock Specification Measures

EnergyPATHWAYS also allows for stock specification measures, which create exogenous specification of technology stocks along the year index (i.e. existing stock in a year), as opposed to sales share measures which operate along the vintage index (i.e. sales in a year). They both interact with the same basic stock rollover mechanics in the model but are interpreted differently by the model.

In the example below, EnergyPATHWAYS replicate the stock in 2020 of our previous sales share example where Technology A is 61 units in 2020 and Technology B is 49 Units.

After Stock Specification Measure

S_{2019} = 100

S_{a2019} = 50

S_{b2019} = 50

D_{2020} = 10

D_{a2020} = 5

D_{b2020} = 5

S_{2020} = 110

$G_{2020} = S_{2020} - S_{2019} = 110 - 100 = 10$

N_{a2020} = $S_{a2020} - S_{a2019} + D_{a2020}$ = 61 – 50 + 5 = 16

S_{b2020} = $S_{2020} - S_{a2020}$ = 110 – 61 = 49

N_{b2020} = $S_{b2020} - S_{b2019} + D_{b2020}$ = 49 – 50 + 5 = 4

H_{a2020} =$\frac{N_{a2020}}{N_{2020}}$ = .8

H_{b2020} =$\frac{N_{b2020}}{N_{2020}}$ = .2

R_{a2020} = $D_{2020} * H_{a2020}$ = 10 * .8 = 8

R_{b2020} = $D_{2020} * H_{b2020}$ = 10 * .2 = 2

G_{a2020} = $G_{2020} * H_{a2020}$ = 10 * .8 = 8

G_{b2020} = $G_{2020} * H_{b2020}$ = 10 * .2 = 2

The model uses the stock specifications to produce sales shares that result in the specified stock. Where a stock specification measure requires more new sales than are available through natural rollover decay and stock growth, the model early-retires infrastructure to increase the pool of available sales based on the probability of retirement for given combination of vintage and technology. The model separately tracks physical and financial lifetimes, so even though technologies may be taken out of service, they are still paid for. Further discussion of this accounting can be found in 5.3.2.1.

5.3.1.3. Service Demand Modifier (M)

Many energy models use stock technology share as a proxy for service demand share. This makes the implicit assumption that all technologies of all vintages in a stock are used equally. This assumption obfuscates some key dynamics that influence the pace and nature of energy system transformation. For example, new heavy-duty vehicles are used heavily at the beginning of their useful life but are sold to owners who operate them for reduced duty-cycles later in their lifecycles. This means that electrification of this fleet would accelerate the rollover of electrified miles faster than it would accelerate the rollover of the trucks themselves. Similar dynamics are at play in other vehicle subsectors. In subsectors like residential space heating, the distribution of current technology stock is correlated with its utilization. Even within the same region, with the same climactic conditions, the choice of heating technology informs its usage. Homes that have baseboard electric heating, for example, are often seasonal homes with limited heating loads.

EnergyPATHWAYS has two methods for determining the discrepancy between stock shares and service demand shares. First, technologies can have the input of a *service demand modifier*. This is used an adjustment between stock share and service demand share.

Using the example stock of Technology, A and B, the formula below shows the impact of service demand modifier on the service demand share.[2]

$S_{2019} = 100$

$S_{a2019} = 50$

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[2] EnergyPATHWAYS again ignore the index of vintage (v) for simplicity, but this is an important index to reflect technology utilization determined by age.

$S_{a2020} = 50$

$x_{a2019} = \frac{S_{a2019}}{S_{2019}} = \frac{50}{100} = .5$

$x_{b2019} = \frac{S_{b2019}}{S_{2019}} = \frac{50}{100} = .5$

$M_{a2019} = 2$

$M_{b2019} = 1$

$U_{a2019} = \frac{S_{a2019} * M_{a2019}}{\sum_{t=a..b} S_{t2019} * M_{t2019}} = \frac{50*2}{150} = .667$

$U_{b2019} = \frac{S_{b2019} * M_{b2019}}{\sum_{t=T} S_{t2019} * M_{t2019}} = \frac{50*1}{150} = .333$

When service demand modifiers aren't entered for individual technologies, they can potentially still be calculated using input data. For example, if the service demand input data is entered with the index of t, the model calculates service demand modifiers by dividing stock and service demand inputs.

Equation 3

$M_{tyr} = \frac{s_{tyr}}{d_{tyr}}$

Where

M_{ty} = Service demand modifier for technology t in year y in region r

s_{tyr} = Stock input data for technology t in year y in region r

d_{tyr} = Energy demand input data for technology t in year y in region r

5.3.1.3.1. Energy Carrier Utility Factors (C)

Energy carrier utility factors are technology inputs that allocates a share of the technology's service demand to energy carriers. The model currently supports up to two energy carriers per technology. This allows EnergyPATHWAYS to support analysis of dual-fuel technologies, like plug-in-hybrid electric vehicles. The input structure is defined as a primary energy carrier with a utility factor (0 – 1) and a secondary energy carrier that has a utility factor of 1 – the primary utility factor.

5.3.1.4. Method B: Stock and Energy Demand

Method B is like Method A in almost all its components except for the calculation of the service demand term. In Method A, service demand is an input. In Method B, the energy demand of a subsector is input as a substitute. From this input, EnergyPATHWAYS must take the additional step of deriving service demand, based on stock and technology inputs.

Equation 4

$$E_{ycr} = \sum_{v \in V} \sum_{t=T} U_{yvtcr} * f_{vtc} * D_{yr} * (1 - R_{yrc})$$

Where

E = Energy demand in year y of energy carrier c in region r

U = Normalized share of service demand in year y of vintage v of technology t for energy carrier c in region r

f = Efficiency (energy/service) of vintage v of technology t using energy carrier c

D = Total service demand calculated for year y in region r

R_{yrc} = Unitized service demand reductions for year y in region r for energy carrier c

5.3.1.4.1. Total Service Demand (D)

Total service demand is calculated using stock shares, technology efficiency inputs, and energy demand inputs. The intent of this step is to derive a service demand term (D) that allows us to use the same calculation framework as Method A.

Equation 5

$$D_{yr} = \sum_{v \in V} \sum_{c \in C} \sum_{t=T} U_{yvtcr} * f_{vtc} * e_{ycr}$$

Where

D_{yr} = Total service demand in year y in region r

f_{vtc} = Efficiency (energy/service) of vintage v of technology t using energy carrier c

e_{ycr} = Input energy data in year y of carrier c in region r

5.3.1.5. Method C: Service and Service Efficiency

Method C is used when EnergyPATHWAYS do not have sufficient input data, either at the technology level or the stock level, to parameterize a stock rollover. Instead EnergyPATHWAYS replace the stock terms in the energy demand calculation with a service efficiency term (j). This is an exogenous input that substitutes for the stock rollover dynamics and outputs in the model.

Equation 6

$$E_{ycr} = j_{ycr} * d_{yr} * R_{yrc} - O_{yrc}$$

where

E_{ycr} = Energy demand in year y for energy carrier c in region r

j_{ycr} = Service efficiency (energy/service) of subsector in year y for energy carrier c in region r

d_{yr} = Input service demand for year y in region r

R_{yrc} = Unitized service demand multiplier for year y in region r for energy carrier c

O_{yrc} = Energy efficiency savings in year y in region r for energy carrier c

5.3.1.5.1. Energy Efficiency Savings (O)

Energy efficiency savings are a result of specified energy efficiency measures in the model. These take the form of prescribed levels of energy savings measures that are netted off the baseline projection of energy usage.

5.3.1.6. Method D: Energy Demand

The final method is simply the use of an exogenous specification of energy demand. This is used for subsectors where there is neither the data necessary to populate a stock rollover nor any data available to decompose energy use from its underlying service demand.

Equation 7

$$E_{ycr} = e_{ycr} - O_{yrc}$$

Where

E_{ycr} = Energy demand in year y for energy carrier c in region r

e_{ycr} = Input baseline energy demand in year y for energy carrier c in region r

O_{yrc} = Energy efficiency savings in year y in region r for energy carrier c

5.3.2. Demand-Side Costs

Cost calculations for the demand-side are separable into technology stock costs and measure costs (energy efficiency and service demand measures).

5.3.2.1. Technology Stock Costs

EnergyPATHWAYS uses vintaged technology cost characteristics as well as the calculated stock rollover to calculate the total costs associated with technology used to provide energy services.[3]

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ins} + C_{yr}^{fs} + C_{yr}^{fom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fs} = Total levelized fuel switching costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

5.3.2.1.1. Technology Stock Capital Costs

The model uses information from the physical stock rollover used to project energy demand, with a few modifications. First, the model uses a different estimate of technology life. The financial equivalent of the physical "decay" of the technology stock is the depreciation of the asset. EnergyPATHWAYS uses a linear function with a maximum and minimum life of the mean

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[3] Levelized costs are the principal cost metric reported, but the model also calculates annual costs (i.e. the cost in 2020 of all technology sold).

technology life, meaning that all financial decay takes place in one year (i.e. the asset comes off of the financial books). This is referred to as the "book life" of the asset.

To provide a concrete example of this, a 2020 technology vintage with a book life of 15 years is maintained in the financial stock in its entirety for the 15 years before it is financially "retired" in 2035. This financial stock estimate, in addition to being used in the capital costs calculation, is used for calculating installation costs and fuel switching costs.

Equation 8

$$C_{yr}^{cap} = \sum_{v \in V} \sum_{t \in T} S_{tvyr}^{fin} * W_{tvr}^{cap}$$

Where

C_{yr}^{cap} = Total levelized technology costs in year y in region r

W_{tvr}^{cap} = Levelized capital costs for technology t for vintage v in region r

S_{tvyr}^{fin} = Financial stock of technology t and vintage v in year y in region r

EnergyPATHWAYS primarily use this separate financial accounting so that EnergyPATHWAYS accurately account for the costs of early-retirement of technology. There is no way to financially early-retire an asset, so physical early retirement increases overall costs (by increasing the overall financial stock).

5.3.2.1.2. Levelized Capital Costs (W)

EnergyPATHWAYS levelized technology costs over the mean of their projected useful lives (referred to as book life). This is either the input mean lifetime parameter of the arithmetic mean of the technology's max and min lifetimes. EnergyPATHWAYS additionally assess a cost of capital on this levelization of the technology's upfront costs. While this may seem an unsuitable assumption for technologies that could be considered "out-of-pocket" purchases, EnergyPATHWAYS assume that all consumer purchases are made using backstop financing options. This is the implicit assumption that if "out-of-pocket" purchases were reduced, the amount needed to be financed on larger purchases like vehicles and homes could be reduced in-kind.

$$W_{tvr}^{cap} = \frac{d_t * z_{tvr}^{cap} * (1 + d_t)^{l_t^{book}}}{(1 + d_t)^{l^{book}} - 1}$$

Where

W_{tvr}^{cap} = Levelized capital costs for technology t for vintage v in region r

d_t = Discount rate of technology t

z_{tvr}^{cap} = Capital costs of technology t in vintage v in region r

l_t^{book}= Book life of technology t

5.3.2.2. Technology Stock Installation Costs

Installation costs represent costs incurred when putting a technology into service. The methodology for calculating these is the same as that used to calculate capital costs. These are levelized in a similar manner.

5.3.2.3. Technology Stock Fuel Switching Costs

Fuel switching costs represent costs incurred for a technology only when switching from a technology with a different primary energy carrier. This input is used for technologies like gas furnaces that may need additional gas piping if they are being placed in service in a household that had a diesel furnace. Calculating these costs requires the additional step of determining the number of equipment sales in a given year associated with switching fuels.

$$C_{yr}^{fs} = \sum_{v \in V} \sum_{t \in T} S_{tvyr}^{fs} * W_{tvr}^{fs}$$

Where

S_{tvyr}^{fs} = Financial stock associated with fuel-switched equipment installations

W_{tvr}^{fs} = Levelized fuel-switching costs for technology t for vintage v in region r

d_t = Discount rate of technology t

z_{tvr}^{fs} = Fuel switching costs for technology t in vintage v in region r

5.3.2.4. Technology Stock Fixed Operations and Maintenance Costs

Fixed operations and maintenance (O&M) costs are the only stock costs that utilize physical and not financial representations of technology stock. This is because O&M costs are assessed annually and are only incurred on technologies that remain in service. If equipment has been retired, then it no longer has ongoing O&M costs.

$$C_{yr}^{fom} = \sum_{v\in V} \sum_{t\in T} S_{tyvr} * W_{tvr}^{fom}$$

Where

S_{tyvr}= Technology stock of technology t in year y of vintage v in region r

W_{tvr}^{fom} = Fixed O&M costs for technology t for vintage v in region r

5.3.3. Measure Costs

Measure costs are assessed for interventions either at the service demand (service demand measures) or energy demand levels (energy efficiency measures). While these measures are abstracted from technology-level inputs, EnergyPATHWAYS uses a similar methodology for these measures as EnergyPATHWAYS do for technology stock costs. EnergyPATHWAYS use measure savings to create "stocks" of energy efficiency or service demand savings. These measure stocks are vintaged like technology stocks and EnergyPATHWAYS use analogous inputs like capital costs and useful lives to calculate measure costs.

5.3.3.1. Service Demand Measure Costs

Service demand measure costs are costs associated with achieving service demand reductions. In many cases, no costs are assessed for these activities as they represent conservation or improved land-use planning that occurs at zero or negative-costs.

Equation 9

$$C_{yr}^{sd} = \sum_{v\in V} \sum_{m\in M} S_{mvyr}^{sd} * W_{mvr}^{sd}$$

Where

C_{yr}^{sd} = Total service demand measure costs

S^{sd}_{mvyr} = Financial stock of service demand reductions from measure m of vintage v in year y in region r

W^{sd}_{mvr} = Levelized per-unit service demand reduction costs

5.3.3.2. Energy Efficiency Measure Costs

Energy efficiency costs are costs associated the reduction of energy demand. These are representative of incremental equipment costs or costs associated with non-technology interventions like behavioral energy efficiency.

Equation 10

$$C^{ee}_{yr} = \sum_{v \in V} \sum_{m \in M} S^{ee}_{mvyr} * W^{ee}_{mvr}$$

Where

C^{ee}_{yr} = Total energy efficiency measure costs

S^{sd}_{mvyr} = Financial stock of energy demand reductions from measure m of vintage v in year y in region r

W^{ee}_{mvr} = Levelized per-unit energy efficiency costs

5.4. Supply

5.4.1. Supply Nodes

Supply nodes represent the fundamental unit of analysis on the supply-side and are analogous to subsectors on the demand-side. We will primarily describe the calculations for individual supply nodes in this document, but assessing the total costs and emissions from the supply-side is just the summation of all supply nodes for a year and region.

5.4.2. I/O Matrix

There is one principal difference between supply nodes and subsectors that explains the divergent approaches taken for calculating them; energy flows through supply nodes must be solved concurrently due to a number of dependencies between nodes. As an example, it is not possible to know the flows through the gas transmission pipeline node without knowing the energy flow through gas power plant nodes. This tenet requires a fundamentally different supply-side structure. To solve the supply-side, EnergyPATHWAYS leverages techniques from economic modeling by arranging supply nodes in an input-output matrix, where coefficients of a node represent units of other supply nodes required to produce the output product of that node.

Consider a simplified representation of upstream energy supply with four supply nodes:

a. Electric Grid

b. Gas Power Plant

c. Gas Transmission Pipeline

d. Primary Natural Gas

This is a system that only delivers final energy to the demand-side in the form of electricity from the electric grid. It also has the following characteristics:

1. The gas transmission pipeline has a loss factor of 2% from leakage. It also uses grid electricity to power compressor stations and requires .05 units of grid electricity for every unit of delivered gas.

2. The gas power plant has a heat rate of 8530 Btu/kWh, which means that it requires 2.5 (8530 Btu/kWh/3412 Btu/kWh) units of gas from the transmission pipeline for every unit of electricity generation.

3. The electricity grid has a loss factor of 5%, so it needs 1.05 units of electricity generation to deliver 1 unit of electricity to its terminus.

The I/O matrix for this system is shown below in tabular form Table 11 as well as in matrix form below

Table 11 Tabular I/O Matrix

	Natural Gas	Gas Transmission Pipeline	Gas Power Plant	Electric Grid
Natural Gas		**1.02**		
Gas Transmission Pipeline			**2.5**	

Gas Power Plant				**1.05**
Electric Grid		**.05**		

Equation 11

$$A = \begin{pmatrix} & 1.05 & & \\ & & 2.5 & \\ & & & 1.05 \\ & .05 & & \end{pmatrix}$$

With this I/O matrix, if we know the demand for energy from a node (supplied from the demand-side of the EnergyPATHWAYS model), we can calculate energy flows through every upstream supply node. To continue the example, if 100 units of electricity are demanded:

$$d = \begin{pmatrix} 0 \\ 0 \\ 0 \\ 100 \end{pmatrix}$$

We can calculate the energy flow through each node using the equation, which represents the inverted matrix multiplied the demand term.

$$x = (I - A)^{-1} * d$$

This gives us the following result:

$$x = \begin{pmatrix} 308 \\ 302 \\ 121 \\ 115 \end{pmatrix}$$

We use the I/O structure in much more complicated ways, and most of the supply-side calculations are focused on populating I/O coefficients and solving throughput through each node, which allows us to calculate infrastructure needs, costs, resource usage, and greenhouse gas emissions associated with energy supply

There are six distinct types of nodes that represent different components of the energy supply system. These will be examined individually in all of the supply-side calculation descriptions. The list below details some of their basic functionality.

1. **Conversion Nodes –** Conversion nodes represent units of infrastructure specified at the technology level (i.e. gas combined cycle power plant) that have a primary purpose of converting the outputs of one supply node to the inputs of another supply node. Gas power plants in the above example are a conversion node, converting the output of the gas transmission pipeline to the inputs of the electric grid.

2. **Delivery Nodes –** Delivery nodes represent infrastructure specified at a non-technology level. The gas transmission pipeline is an example of a delivery node. A transmission pipeline system is the aggregation of miles of pipeline, hundreds of compressor stations, and storage facilities. We represent it as an aggregation of these components. The role of delivery nodes is to deliver the outputs of one supply node to a different physical location in the system required so that they can be used as inputs to another supply node. In the above example, gas transmission pipelines deliver natural gas from gas fields to gas power plants, which are not co-located with the resource.

3. **Primary Nodes –** Primary nodes are used for energy accounting, but they generally represent the terminus of the energy supply chain. That is, absent some exceptions, their coefficients are generally zero.

4. **Product Nodes –** Product nodes are used to represent energy products where it is not possible to endogenously build up the costs and emissions through to their primary energy source. For example, we represent refined fuels as product nodes, generally, so that the price of these refined fuels can be divorced from the price of their primary oil inputs.

5. **Blend Nodes –** Blend nodes are non-physical control nodes in the energy supply chain. These are the locations in the energy system that we apply measures to change the relative inputs to other supply nodes. There are no blend nodes in the simplified example above, but an alternative energy supply system may add a biogas product node and place a blend node between the gas transmission pipeline and the primary natural gas node. This blend node would be used to control the relative inputs to the gas transmission pipeline (between natural gas and biogas).

6. Electric Storage Nodes – Electric storage nodes are nodes that provide a unique role in the electricity dispatch functionality of EnergyPATHWAYS.

5.4.3. Energy Flows

5.4.3.1. Coefficient Determination (A – Matrix)

The determination of coefficients is unique to supply-node types. For primary, product, and delivery nodes, these efficiencies are exogenously specified by year and region.

5.4.3.2. Conversion Nodes

Conversion node efficiencies are calculated as the weighted averages of the online technology stocks. We use both stock and capacity factor terms because we want the energy-weighted efficiency, not capacity-weighted.

Equation 12

$$X_{ynr} = \sum_{t \in T} \sum_{v \in V} \frac{S_{tvyr} * u_{tvyr}}{\sum_{t \in T} \sum_{v \in V} S_{tvyr} * u_{tvyr}} * f_{tvnr}$$

Where

X_{ynr} = Input coefficients in year y of node n in region r

S_{tvyr} = Technology stock of technology t in year of vintage v in year y in region r

U_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

f_{vntr} = Input requirements (efficiency) of technology t of vintage v using node n in region r

5.4.3.2.1. Blend Nodes

Blend node coefficients are user-determined. Blend measures determine the coefficients in each blend node in every year y and region r. Where measures haven't been specified, or are incomplete (i.e. coefficients don't sum to at least 1 as required) blend nodes have a user-specified "residual" supply node that supplies the remainder.

There are two blend nodes in the model that are treated differently than other blend nodes and both are related to the electricity dispatch functionality in EnergyPATHWAYS which will be described in further detail in the following sections. The primary purpose of the electricity dispatch functionality is to develop coefficients for the Electricity Blend Node and Thermal Dispatch Node.

Bulk Electricity Blend Node

The coefficients of the bulk electricity blend node, before EnergyPATHWAYS calculates an electricity dispatch, are user-determined. For example, a user may specify that they would like 50% of the bulk electricity energy to come from solar power plants and 50% of the energy to come from wind power plants. The electricity dispatch is used to calculate the feasibility of these selections given the hourly electricity profiles of the generation as well as the online balancing resources like energy storage, hydro, flexible electric fuel production (hydrogen electrolysis and power-to-gas), and flexible end-use loads. If sufficient balancing resources are available to balance the 50% wind and 50% solar system, in this case, then the coefficients of the node remain the same. If the dispatch finds, however, that residual thermal resources are required to supply electricity (i.e. the wind and solar generation cannot be completely balanced against demand) then the model calculates the need for residual energy supply from the Thermal Dispatch Node (which always functions as the residual node of the Bulk Electricity Blend Node). This results in a situation where the coefficients of the Bulk Electricity Blend Node are greater than 1 (.5 wind; .5 solar; >0 Thermal Dispatch). Coefficients greater than 1 in this case represent the curtailment of the unbalanced wind and solar generation.

Thermal Dispatch Node

Energy requirements of the Thermal Dispatch Node are determined in the electricity dispatch process briefly described above. The coefficients of the Thermal Dispatch Node are determined in the thermal dispatch, which occurs after all other electricity dispatch processes and functions as the residual to the electricity dispatch. In this process, the share of the Thermal Dispatch Node output that come from different thermal resources like gas combined-cycle generators, gas combustion turbines, and coal power plants is determined using an economic dispatch stack model. Given the resource stack online in a year y, the model determines the share of generation that comes from each input node to the Thermal Dispatch Node and also determines the capacity factor of every vintage v and technology t combination in that supply node. The thermal dispatch process, therefore, influences both the overall flow through each node as well as the capacity factor term (U) in the efficiency determination.

5.4.3.3. Energy Demands

5.4.3.3.1. Demand Mapping

To help develop the (d) term in the matrix calculations described in section 5.4.2, EnergyPATHWAYS must map the demand for energy carriers calculated on the demand-side to specific supply-nodes. In the simplified energy system example, electricity as a final energy carrier, for example, maps to the Electric Grid supply node.

5.4.3.3.2. Energy Export Specifications

In addition to demand-side energy requirements, the energy supply system must also meet export demands, that is demand for energy products that aren't used to satisfy endogenous energy service demands. These products aren't ultimately consumed in the model, but their upstream impacts must still be accounted for.

5.4.3.3.3. Total Demand

Total demand is therefore the sum of endogenous energy demands from the demand-side of EnergyPATHWAYS as well as any specified energy exports.

Equation 13

$$D_{yrn} = D_{yrn}^{end} + D_{yrn}^{exp}$$

Where

D_{yrn} = Total energy demand in year y in region r for supply node n

D_{yrn}^{end} = Endogenous energy demand in year y in region r for supply node n

D_{yrn}^{exp} = Export energy demand in year y in region r for supply node n

This total demand term is then multiplied by the inverted coefficient matrix to determine energy flows through each node.

5.4.4. Infrastructure Requirements

Infrastructure is represented only in delivery and conversion supply nodes. In delivery nodes, this infrastructure is represented at the aggregate node-level. In conversion nodes, infrastructure is represented in technology stocks similarly to stocks on the demand-side. The sections below detail the basic calculations used to determine the infrastructure capacity needs associated with energy flows through the supply node.

5.4.4.1. Delivery Nodes

The infrastructure capacity required is determined by Equation 14 below:

Equation 14

$$I_{yr} = \frac{E_{yr}}{u_{yr} * 8760}$$

Where

u_{yr}[4] = Utilization (capacity) factor in year y in region r

E_{yr} = Energy flow through node in year y in region r

h = Hours in a year, or 8760

5.4.4.2. Conversion Nodes

Conversion nodes are specified on a technology-basis, and a conversion node can contain multiple technologies to produce the energy flow required by the supply system. The operations of these nodes are analogous to the demand-side in terms of stock rollover mechanics, with sales shares and specified stock measures determining the makeup of the total stock. The only difference is that the size of the total stock is determined by the demand for energy production for the supply node, which is different than on the demand-side, where the size of the total stock is an exogenous input.

The formula to determine the size of the total stock remains the essentially the same as the one used to determine the size of the total delivery stock. However, the average cap factor of the

[4] Capacity factors of delivery nodes are endogenous inputs to the model except in the special cases of the Electricity Transmission Grid Node and the Electricity Distribution Grid node, where capacity factors are determined in the electricity dispatch.

node is a calculated term determined by the weighted average capacity factor of the stock in the previous year:

Equation 15

$$U_{yr} = \frac{\sum_{t \in T} \sum_{v \in V} S_{tvy-1r} * u_{tvyr}}{\sum_{t \in T} \sum_{v \in V} S_{tvy-1r}}$$

Where

U_{yr} = Utilization (capacity) factor in year y in region r

S_{tvy-1r} = Technology stock of technology t in year of vintage v in year y-1 in region r

u_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

5.4.5. Emissions

There are two categories of greenhouse gas emissions in the model. First, there are physical emissions. These are traditional emissions associated with the combustion of fuels, and they represent the greenhouse gas emissions embodied in a unit of energy. For example, natural gas has an emissions rate of 53.06 kG/MMBTU of consumption while coal has an emissions rate of 95.52 kG/MMBTU. Physical emissions are accounted for on the supply-side in the supply nodes where fuels are consumed, which can occur in primary, product, delivery, and conversion nodes. Emissions, or consumption, coefficients, that is the units of fuel consumed can be a subset of energy coefficients. While the gas transmission pipeline may require 1.03 units of natural gas, it only consumes .03 units. Gas power plants, however, consume all 2.5 units of gas required. Equation 16 shows the calculation of physical emissions in a node:

Equation 16

$$G_{yr}^{phy} = \sum_{n \in N} X_{yrn}^{con} * E_{yr} * B_{yrn}^{phy}$$

Where

G_{yr}^{phy} = Physical greenhouse gas emissions in year y in region r

X_{yrn}^{con} = Consumption coefficients in year y in region r of node n

E_{yr}= Energy flow through node in year y in region r

B_{yrn}^{phy} = Emissions rates (emissions/energy) in year y in region r of input nodes n.

Emissions rates are either a function of a direct connection in the I/O matrix to a node with an emissions coefficient or they are "passed through" delivery nodes, which don't consume them. Gas power plants in the supplied example take the emission rates from the Natural Gas Node, despite being linked in the I/O matrix only through the delivery node of Gas Transmission Pipeline.

The second type of emissions are accounting emissions. These are not associated with the consumption of energy products elsewhere in the energy system. Instead, these are a function of energy production in a node.[5] Accounting emissions rates are commonly associated with carbon capture and sequestration supply nodes or with biomass. Accounting emissions are calculated using:

Equation 17

$$G_{yr}^{acc} = E_{yr} * B_{yrn}^{acc}$$

Where

G_{yr}^{acc} = Accounting greenhouse gas emissions in the node in year y in region r

E_{yr} = Energy flow through the node in year y in region r

B_{yr}^{acc} = Node accounting emissions rate

For primary, product, and delivery nodes, the accounting emissions rate in year y in region r is exogenously specified. For conversion nodes, this is an energy-weighted stock average.

[5] For example, biomass may have a positive physical emissions rate, but if the biomass is considered to be zero-carbon, it would offset that with a negative accounting emissions rate. For accounting purposes, this would result in the Biomass Node showing negative greenhouse gas emissions and the supply nodes that use biomass, for example Biomass Power Plants, recording positive greenhouse gas emissions.

$$B_{yr}^{acc} = \frac{\sum_{t \in T} \sum_{v \in V} S_{tvyr} * b_{tvyr}^{acc}}{\sum_{t \in T} \sum_{v \in V} S_{tvyr}}$$

Where

B_{yr}^{acc} = Energy weighted average of node accounting emissions factor in year y in region r

S_{tvyr} = Stock of technology t of vintage v in year y in region r

b_{tvyr}^{acc} = Exogenous inputs of accounting emissions rate for technology t of vintage v in year y in region r

5.4.6. Costs

Costs are calculated using different methodologies for those nodes with infrastructure (delivery, conversion, and electric storage) and those without represented infrastructure (primary and product).

5.4.6.1. Primary and Product Nodes

Primary and product nodes are calculated as the multiplication of the energy flow through a node and an exogenously specified cost for that energy.

$$C_{yr} = E_{yr} * w_{yr}$$

Where

C_{yr} = total costs of supplying energy from node in year y in region r

E_{yr}= Energy flow through node in year y in region r

w_{yr}= Exogenous cost input for node in year y in region r

5.4.6.2. Delivery Nodes

Delivery node cost inputs are entered as per-energy unit tariffs. We use and adjust for any changes for the ratio of on-the-books capital assets and node throughput. This is done to account for dramatic changes in the utilization rate of capital assets in these nodes. This allows EnergyPATHWAYS to calculate and demonstrate potential death spirals for energy delivery systems, whereas the demand for energy from a node declines faster than the capital assets can depreciate. This pegs the tariff of the delivery node to the existing utilization rates of capital assets and increases them when that relationship diverges.

Equation 18

$$C_{yr} = \left(\frac{\frac{S_{yr}}{S_{yr}^{fin}}}{\sum_{y\in 1} \frac{S_{yr}}{S_{yr}^{fin}}} * \frac{\sum_{y\in 1} u_{yr}}{u_{yr}} * q * w_{yr} + (1-q) * w_{yr} \right) * E_{yr}$$

Where

C_{yr} = Total costs of delivery node in year y in region r

S_{yr}= Physical stock of delivery node in year y in region r

S_{yr}^{fin} = Financial stock of delivery node in year y in region r

u_{yr} = Exogenously specified utilization rate of delivery node in year y in region r

q = Share of tariff related to throughput-related capital assets, which are the only share of the tariff subjected to this adjustment.

w_{yr} = Exogenous tariff input for delivery node in year y in region r

E_{yr} = Energy flow through node in year y in region r

5.4.6.3. Conversion Nodes

Conversion node cost accounting is similar to the cost accounting of stocks on the demand-side with terms for capital, installation, and fixed O&M cost components. Instead of fuel switching costs, however the equation substitutes a variable O&M term.

Equation 19

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ins} + C_{yr}^{fom} + C_{yr}^{vom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

There is no difference in the calculation of the capital, installation, and fixed O&M terms from the demand-side, so reference calculation for calculating those components of technology stocks in section 5.3.2.1.

5.4.6.3.1. Variable O&M Costs

Variable O&M costs are calculated as the energy weighted average of technology stock variable O&M costs.

$$C_{yr}^{vom} = \sum_{t \in T} \sum_{v \in V} \frac{S_{tvyr} * u_{tvyr}}{\sum_{t \in T} \sum_{v \in V} S_{tvyr} * u_{tvyr}} * w_{tvry}^{vom} * E_{yr}$$

Where

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

S_{tvyr} = Technology stock of technology t in year of vintage v in year y in region r

U_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

w_{tvry}^{vom} = Exogenous input of variable operations and maintenance costs for technology t of vintage v in region r in year y

E_{yr} = Energy flow through node in year y in region r

5.4.6.4. Electric Storage Nodes

Electric storage nodes are a special case of node used in the electricity dispatch. They add an additional term, which is a capital energy cost, to the equation used to calculate the costs for conversion nodes. This is the cost for the storage energy capacity, which is additive with the storage power capacity.

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ecap} C_{yr}^{ins} + C_{yr}^{fom} + C_{yr}^{vom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

C_{yr}^{ecap} = Total levelized energy capital costs in year y in region r

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

5.4.6.4.1. Energy Capacity Costs

Energy storage nodes have specified durations, defined as the ability to discharge at maximum power capacity over a specified period of time, and also have an input of energy capital costs, which are levelized like all capital investments.

Equation 20

$$C_{yr}^{ecap} = \sum_{v \in V} \sum_{t \in T} S_{tvyr}^{fin} * d_t * W_{tvr}^{ecap}$$

Where

C_{yr}^{ecap} = Total levelized energy capacity capital costs in year y in region r

W_{tvr}^{ecap} = Levelized energy capacity capital costs for technology t for vintage v in region r

d_t = Exogenously specified discharge duration of technology t

S_{tvyr}^{fin} = Financial stock of technology t and vintage v in year y in region r

6. RIO and EnergyPATHWAYS integration

EnergyPATHWAYS is a scenario analysis tool, with a focus on detailed and explicit accounting of energy system decisions. The Regional Investment and Operations (RIO) platform is a complementary optimization approach where we develop a subset of decisions on the energy supply-side that benefit from linear optimization techniques to develop a co-optimization of fuel and supply-side infrastructure decisions under different scenarios of energy demand and emissions constraints. RIO is utilized to inform two types of EnergyPATHWAYS measures:

- **Stock Measures**

RIO can be used to optimize capacity decisions in electricity generation (e.g. wind, solar, etc.), electricity storage, and fuel conversion processes.

- **Blend Measures**

RIO can also be used to optimize blend ratios for fuel. This allows for optimal determinations of bio-based, fossil-based, or electrically produced fuels (i.e. hydrogen, or synthetic natural gas produced from power-to-gas technologies).

RIO is also used as the tool for assessing the reliability of the electricity system, with hourly dispatch representations for all zones and resources including thermal, electricity storage, fixed output (i.e. renewables), and flexible loads (fuel production, direct air capture, etc.)

6.1. EnergyPATHWAYS/RIO Integration

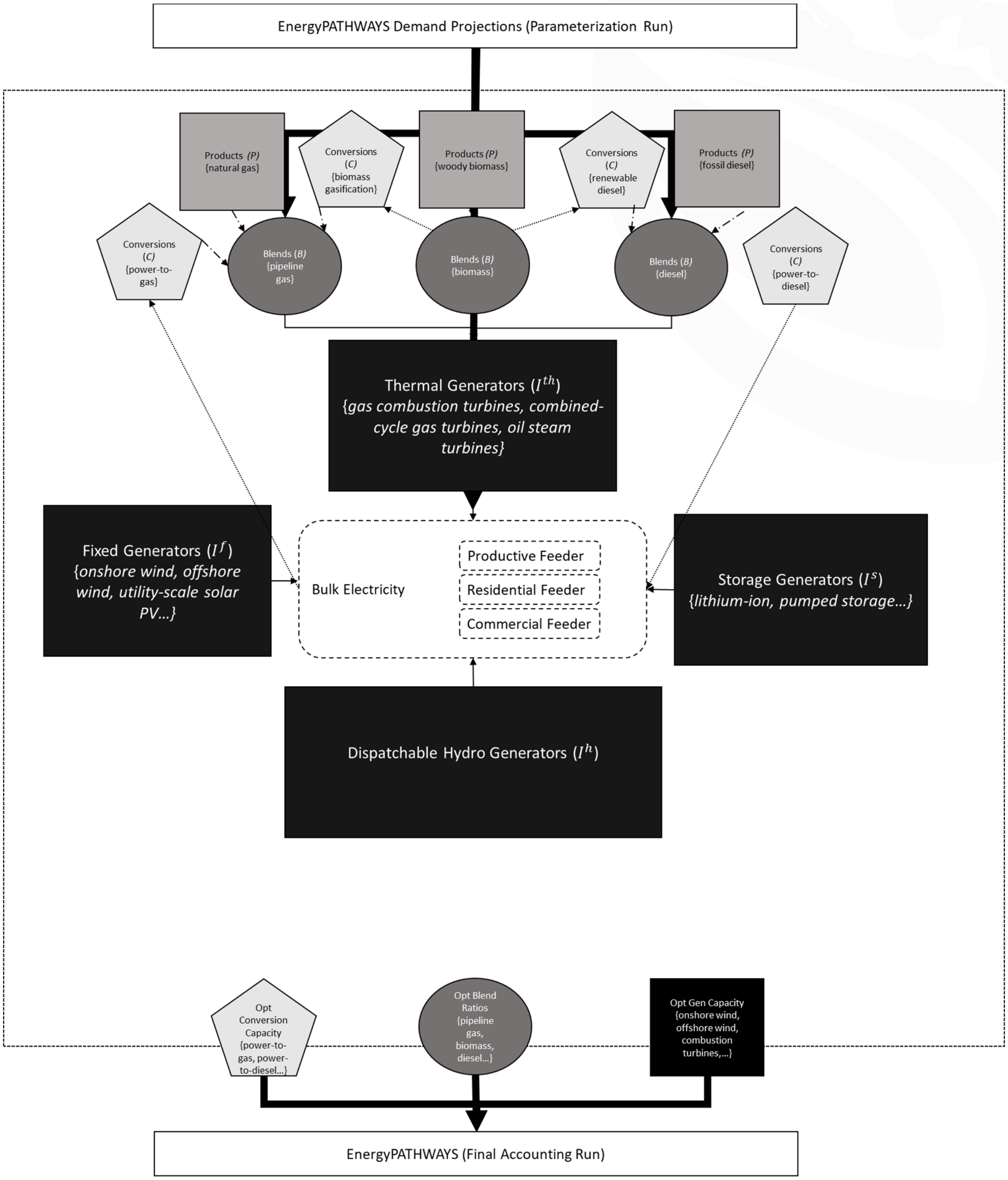
The EnergyPATHWAYS/RIO integration is a multi-step process where:

- EnergyPATHWAYS is used to define energy demand scenarios as parameterizations for RIO optimizations.
- RIO is used to optimize investments in EnergyPATHWAYS conversion supply nodes and determine optimal blends of fuel components.
- Optimized energy decisions are returned to EnergyPATHWAYS where they are input into the EnergyPATHWAYS accounting framework as stock measures or blend measures. This allows us to validate and represent the optimal scenario with the comprehensive accounting detail of EnergyPATHWAYS.

7. Regional Investment and Operations model (RIO)

The following sections will detail the specific features of the RIO optimization framework. The model is designed with a focus on electricity system operations and reliability. It also integrates a fuels module that optimizes fuel production capacity expansion, storage, and use under emissions constraints.

Figure 20 EnergyPATHWAYS/RIO Integration Schematic

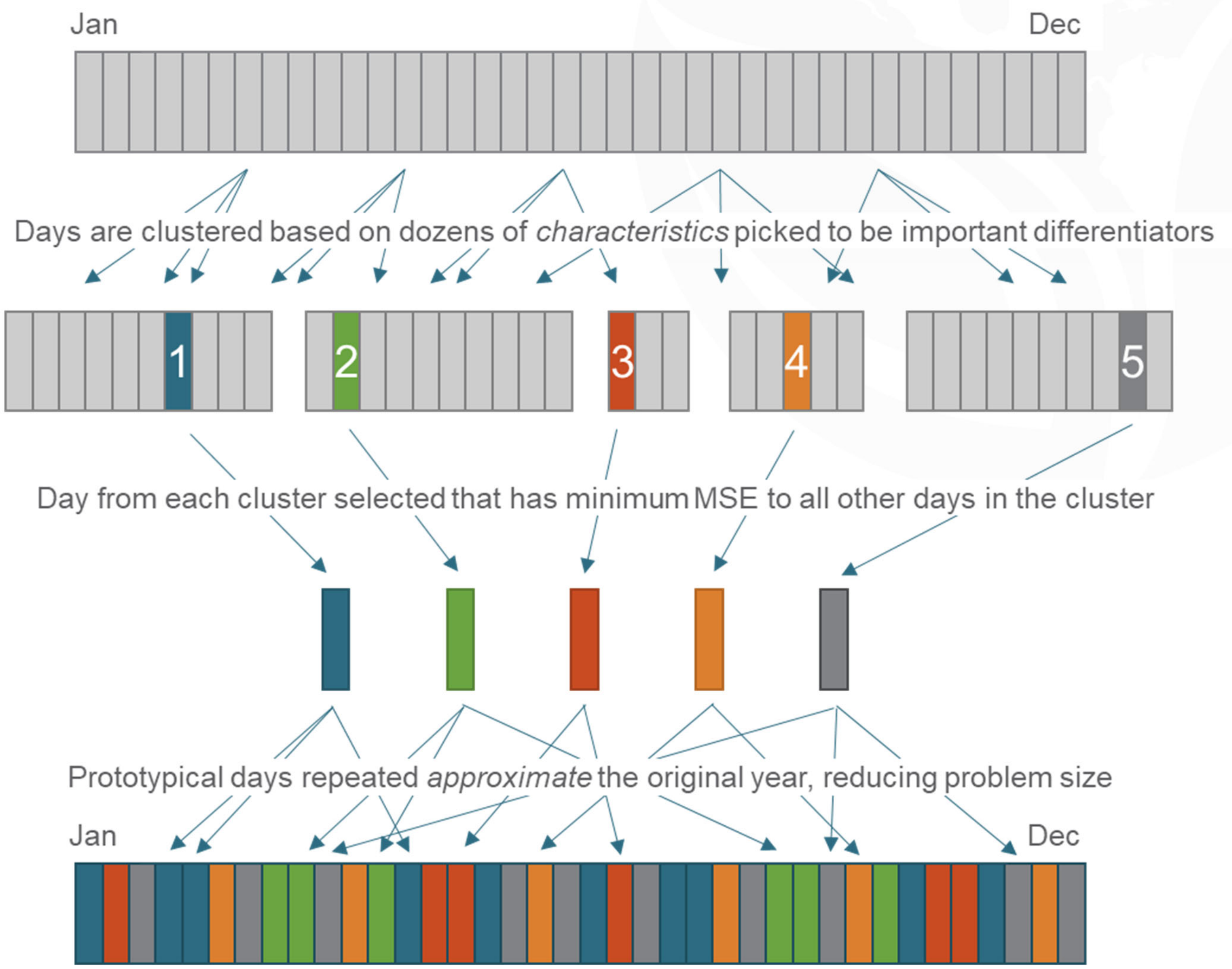


7.1. Operations days selection

RIO utilizes the 8760 hourly profiles for electricity demand and generation from EnergyPATHWAYS and optimizes operations for a subset of representative days (sample days) and maps them to the rest of the year. Operations are performed over sequential hourly timesteps. To ensure that the sample days can reasonably represent the full set of days over the year, RIO uses clustering algorithms on the initial 8760 data sets. The clustering process is designed to identify days that represent a diverse set of potential system conditions, including different fixed generation profiles and load shapes. The number of sample days impacts the total runtime of the model. A balance is struck in the day selection process between representation of system conditions through number of sample days, and model runtime. Clustering and sample day selection occurs for each model year in the time horizon. This process is shown in Figure 21 below. The starting dataset is the EnergyPATHWAYS load and generation shapes, scaled to system conditions for the model year being sampled and mapped. Load shapes come directly from EnergyPATWHAYS accounting runs. The coincidence of fixed generation profiles (i.e. renewables) and load determine when important events for investment decision making occur during the year. For example, annual peak load and low load events may be the coincident occurrence of relatively high loads and relatively low renewables, and the inverse, respectively. However, renewable build is determined by RIO decision making. To ensure that the sample days in each model year are representative of the events that define investment decisions, renewable scaling happens for expected levels of renewables in future years as well as a range of renewables proportional builds (for example, predominantly wind, predominantly solar). The sample days are then selected to be representative of system conditions under all possible renewable build decisions by RIO.

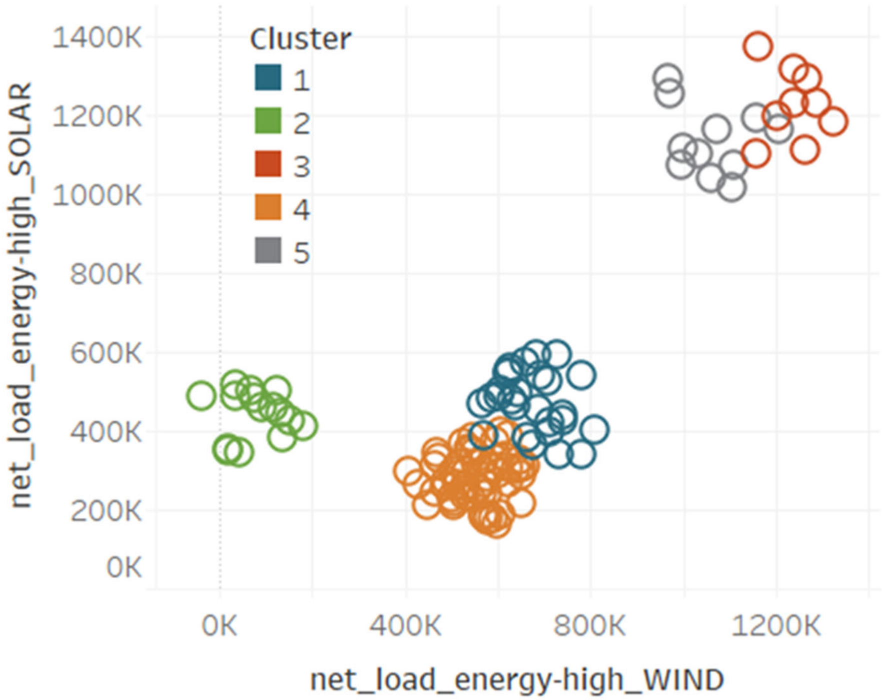
As Figure 21 shows, the scaled historical days are clustered based on a number of characteristics. These include different metrics describing every day in the data set. Examples include peak daily load, peak daily net load, lowest daily solar output, largest daily ramping event etc. The result is a set of clusters of days with similar characteristics. One day within each cluster is selected to represent the rest by minimizing mean square error (MSE). As described in the previous section, RIO determines short-term operations for each of these representative days. For long-term operations, each representative day is mapped back to the chronological historical data series, with the representative day in place of every other day from its cluster.

Figure 21 Conceptual diagram of sampling and day matching process



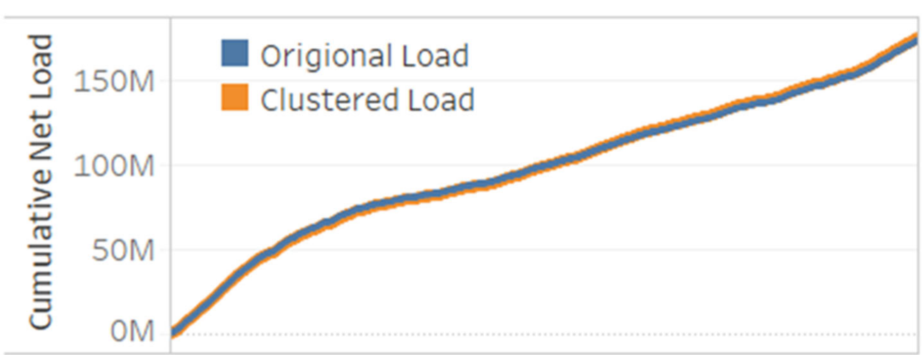
The clustering process depends on many characteristics of the coincident load and renewable shapes and uses statistical clustering algorithms to determine the best set of sample days. Figure 22 shows a simple, two characteristic, example of clustering. In this case the two characteristics are net load with high proportional solar build and net load with high proportional wind build. Selecting sample days that both represent the full spectrum of potential net load, as well as be representative for both the solar and the wind case, is important. The clustering algorithm has identified 5 clusters (a low number, but appropriate for the conceptual example) that ensure the sample days will represent the full range of net load differences among days and remain representative regardless of whether RIO chooses to build a high solar system or a high wind system.

Figure 22 Simple, two characteristic, example of clustering



Mapping the clustered days back to the chronological historical dataset, the newly created year of sample days can be validated by checking that metrics describing the original historical dataset match those of the new set. Cumulative net load in Figure 23 is one example. These are related to the characteristics used to select the sample days in the clustering process such as peak load, largest ramp etc. and the distribution of these over the whole year.

Figure 23 Comparison of original and clustered load



7.2. Operations

Time sequential operations are an important component of determining value of a portfolio of resources.[6] All resources have a set of attributes they can contribute to the grid, including, for example, energy, capacity, ancillary services, and flexibility. They work in complimentary fashion to serve the needs of the system. Whether a portfolio of resources is optimal or not depends on whether it can maintain system reliability, and whether it is cheaper than other portfolios. RIO determines the least cost dispatch for each one of the sample days to determine the least cost investments to make.

Operations are split into short-term and long-term operations in RIO. This is a division between those resources that do not have any multiday constraints on their operations, i.e. they can operate in the same way regardless of system conditions, and those resources that will operate differently depending on system condition trends that last longer than a day. An example of the former is a gas generator that can produce the same output regardless of system conditions over time, and an example of the latter is a long-duration storage system whose state of charge is drawn down over time when there is not enough energy to charge it. The long-term category includes all long-term storage mediums.

Operational decisions determine the value of one investment over another, so it is important to capture the detailed contributions and interactions of the many different types of resource that RIO can build.

Important factors captured in operations are:

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[6] Though typically an hour, the timestep of time sequential operations can be set to any length of time. For example, investment decisions in some systems may be insensitive to whether the time step is 1 hour or 2 hours. Having the option of setting timestep length for operations is another way of reducing model computation while preserving detail around important model components.

- Maximum operating levels – how many resources are needed to meet peak load conditions?
- Planning reserves – are there enough resources to meet planning reserve margins?
- Energy – what resources are required to ensure total daily energy budgets are met?

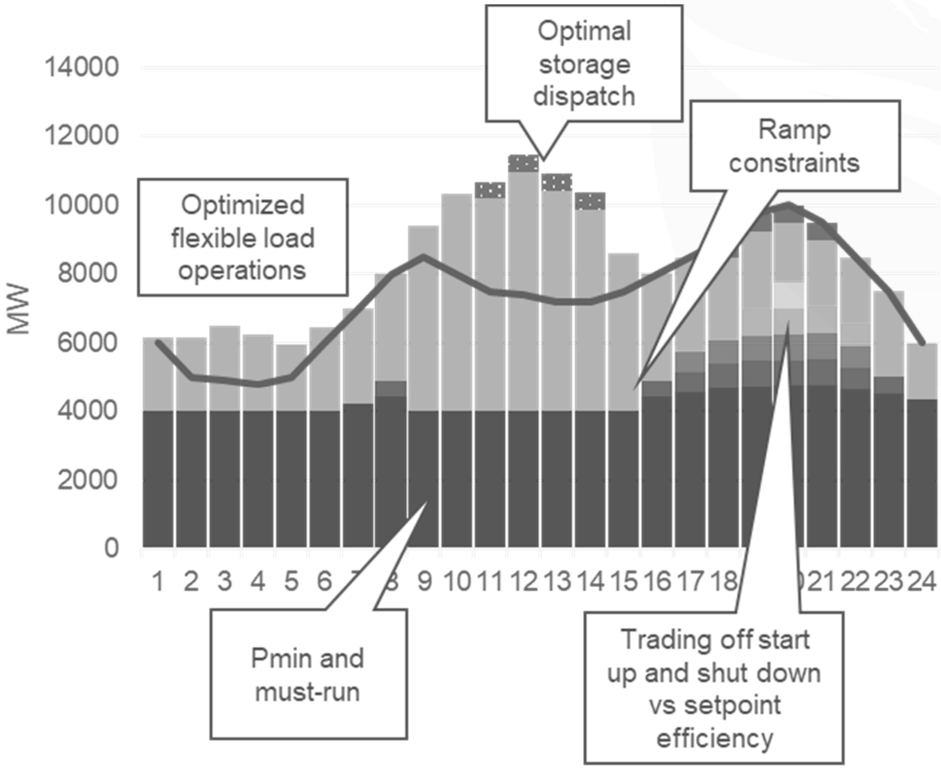
RIO can constrain operations based on constraints that are similar to those used in production simulation. These include:

- Resource minimum and maximum generation levels
- Resource efficiency at different set points
- Thermal generator linearized commitment constraints
- Start up and shut down costs
- Resource must run schedules
- Resource contribution to reserves
- Storage charge and discharge constraints
- Storage efficiency constraints
- Energy budgets and operational constraints for hydro resources

Figure 24 below shows a conceptual daily dispatch. Thermal generation minimum generation level is constrained by Pmin and must run. RIO trades off the cost of starting up and shutting down generation, the available generator headroom for reserves, and the efficiency of operating the generators at sub optimal set points to find the best thermal generator dispatch. The short-term storage reservation is also optimally dispatched. These operational decisions drive concurrent capacity build decisions by determining the relative value of different potential resources.[7]

[7] In this integration with EnergyPATHWAYS, RIO is configured to run without enforcing constraints on thermal operating states. This means that constraints for minimum generation

Figure 24 Example RIO daily dispatch



7.2.1. Thermal Generator Operations

To reduce runtimes, generators are aggregated in RIO by common operating and cost attributes. These are by technology and vintage when the operating costs and characteristics vary significantly by installation year. Each modeled aggregation of generators contains a set of identical generators.

7.2.2. Hydro Operating Constraints

Hydro behavior is constrained by historical data on how fast the hydro system can ramp,[8] the minimum and maximum discharge by hour, and the degree to which hydro energy can be shifted from one period to another. Summed daily hydro output over user defined periods of the year must fall within a cumulative energy envelope. For example, the energy envelope

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levels; startup and shutdown costs; efficiency penalties for deviation from optimal generator setpoints; and operating reserves are not included.

[8] Hydro ramp constraints not enforced in this integration

could be defined by 4 seasons: spring, summer, autumn, and winter. In this case, the cumulative energy envelope would have 4 sets of upper and lower bounds that constrain energy release in each period.

7.2.3. Storage Operating Constraints

Storage is constrained by maximum discharge rates dependent on built capacity. In addition, the model tracks storage state of charge hour to hour, including losses into and out of the storage medium. Storage, like all technologies, is dispatched with perfect foresight. Storage can operate through both short term and long term operations. In short term operations, storage is dispatched on an hourly basis within each sample day, as with all other dispatchable technology types. Short term storage dispatch shifts energy stored within a sample day and discharges it within the same sample day, such that the short term storage device is energy neutral across the day. In long term operations, storage can charge energy on one day and discharge it into another. This allows for optimal use of storage to address longer cycle reliability needs, such as providing energy on low renewable generation days, and participation in longer cycle energy arbitrage opportunities.

7.3. Reliability

The conditions that will stress electricity systems in the future and define reliability need will shift in nature compared to today. Capacity is the principle need for reliable system operations when the dominant sources of energy are thermal. Peak load conditions set the requirement for capacity because generation can be controlled to meet the load and fuel supplies are not constrained. As the system transitions to high renewable output, the defining metric of reliability need is not peak load but net load (load net of renewables). Periods with the lowest renewable output may drive the most need for other types of reliable energy even if they don't align with peak gross load periods. In addition to that, resources will become increasingly energy constrained. Storage can only inject the energy it has in charge into the system. Reliability is therefore increasingly driven by energy need as well as capacity need.

In the future, the defining reliability periods may be when renewables have unusually low output, and when that low output is sustained for unusually long periods. To model a reliable system in the future, both capacity and energy needs driven by the impact of weather events and seasonal changes on renewable output and load need to be captured.

To ensure we capture the impacts of these changing conditions on reliability, we enforce a planning reserve requirement on load in every modeled hour. This "planning demand" is found by scaling load up to account for the possibility that demand in each hour could be greater than expected. At the same time, we determine a dependable contribution of each resource to meeting the planning demand. Dependability is defined as the output of each resource that can be relied upon during reliability events. The planning demand must be met or exceeded by the summed dependable contributions of available resources in each hour.

7.3.1. Dependability

The dependable contribution from thermal resources is derated nameplate, reflecting forced outage rates. Renewable dependable contribution is the derated hourly output, reflecting that renewable output could be even lower than expected. This renewable derate is generally not important because the events that define reliability-driven investment are those where renewable output is low anyway. Hourly output in these periods may be 10% of renewable nameplate. For energy constrained resources such as hydro and storage, dependable contribution is derated hourly output. By using derated hourly output we can capture both the risk that it is not available because of forced outage, and the risk that it is not available because it has exhausted its stored energy supply.

7.3.2. Transmission

Normally transmission imports would be a source of reliable capacity to a state, since the resources on the other end of the line are dispatchable in current day systems. In the model of New Jersey, reliability of the intertie depends on the source of the New Jersey designated out-of-state generation in later years. Since imports are tied to the hourly production of out-of-state renewable resources, imports have the same dependability as those resources. Imports are therefore only as reliable as the renewable resources generating them and do not have high dependable contributions during periods of low renewable generation when at 100% clean electricity. This drives investment in in-state firm capacity to ensure system reliability.

7.4. Resource build decisions

Concurrently with optimal operational decisions, the model makes resource build decisions that together produce the lowest total system cost. The addition of new capacity is limited by the rate at which capacity can be constructed year on year, and the total quantity of capacity that can be constructed by a future year. The model has the ability to economically retire resources, early, extend resources if eligible, incurring additional maintenance costs, or repower mothballed resources. In New Jersey we have only allowed nuclear to be extended beyond its permitted lifetime if the option to do so is part of the least cost solution.

7.5. Transmission constraints

Transmission flows are constrained by the capacity of the line. If optimal transmission build by RIO is selected as an option, transmission additions are equal in flow capacity in both directions of the line. However, existing transmission does not have to have equally sized paths in each direction. Transmission additions are capped by a maximum addition by path and year.

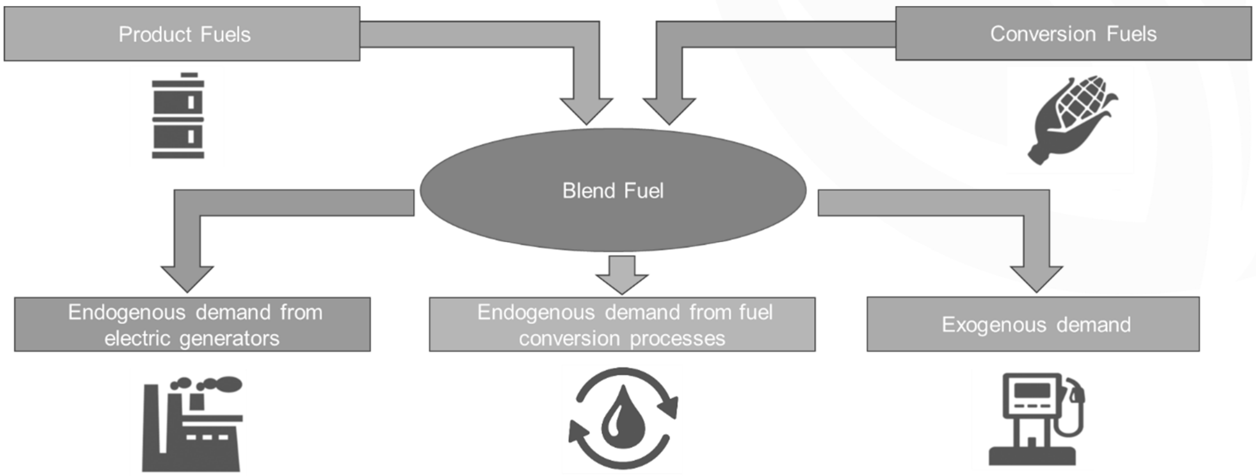
The user specifies a schedule of transmission path flow capacities for every model year in the future. RIO can run with fixed transmission schedules or the user can select optimal transmission expansion.

We have included the option for transmission expansion between New Jersey and PJM up to a maximum of 14 GW. The model selects the level of expansion of the line that minimizes total cost.

7.6. Fuels

In addition to generator operating decisions, RIO also optimizes the fuel blend that a generator is eligible to receive, while also allowing fuels produced by electricity to contribute to fuel stocks. This functionality is what allows RIO to extend beyond the electricity sector and optimize the entire energy supply side. Fuels can come from conventional fuel products (product fuels) or through converting something else into fuel using electricity (conversion fuels). By fueling generation with eligible blends, created from fuels that each have their own cost trajectory over time, or conversion infrastructure capacity costs, RIO can optimize the fuels burned as well as the generator investments and operations to burn them. One use of this is the realistic transition to clean fuels where fuel blends begin to include biofuels, and generation investments and operational decisions are driven by the changing costs of the blend over a generator's lifetime.

Figure 25 RIO fuels schematic



8. Demand-Side Data Sources

The database of the energy economy used in this analysis has high geographical resolution on technology stocks; technology cost and performance; built infrastructure and resource potential as well as high temporal resolution on electricity loads by end-use as well as renewable generation profiles. EnergyPATHWAYS leverages many of the same input files used to populate the National Energy Modeling System (NEMS) used by the United States Energy Information Administration (EIA) to forecast their Annual Energy Outlook.

The model of the energy economy is separated into 65 energy-using demand subsectors. Subsectors, like residential space heating, represent energy-use associated with the performance of an energy-service. A description of the methods EnergyPATHWAYS use to project energy-service demands, energy demands, and ultimately cost and emissions associated with the performance of that service is found in Section 5.3. On the supply-side, the model is separated into interconnected nodes, which are associated with the production, transformation, and delivery of energy to demand subsectors. A description of how the data described in this section is used in the model calculations is found in Section 5.

8.1. Demand – Side Data Description

Table 12 lists all the subsectors in the database grouped by demand sector. It also specifies the methodology used to calculate energy demand in each subsector.

Table 12 Sectors, subsectors, and method of demand energy projection

Sector	Subsector	Method
residential	residential water heating	B
residential	residential furnace fans	D
residential	residential clothes drying	A
residential	residential dishwashing	A
residential	residential refrigeration	A
residential	residential freezing	A

residential	residential cooking	B
residential	residential secondary heating	D
residential	residential other appliances	D
residential	residential clothes washing	A
residential	residential lighting	A
residential	residential other - electric	D
residential	residential air conditioning	B
residential	residential space heating	B
commercial	commercial water heating	A
commercial	commercial ventilation	A
commercial	office equipment (p.c.)	D
commercial	office equipment (non-p.c.)	D
commercial	commercial space heating	A
commercial	commercial air conditioning	A
commercial	commercial lighting	A
commercial	district services	D
commercial	commercial refrigeration	A
commercial	commercial cooking	A
commercial	commercial other	D
transportation	heavy duty trucks	A
transportation	international shipping	D
transportation	recreational boats	D
transportation	transit buses	A
transportation	military use	D
transportation	lubricants	D
transportation	medium duty trucks	A

transportation	aviation	C
transportation	motorcycles	D
transportation	domestic shipping	D
transportation	passenger rail	C
transportation	school and intercity buses	A
transportation	freight rail	C
transportation	light duty trucks	A
transportation	light duty autos	A
industry	metal and other non-metallic mining	D
industry	aluminum industry	D
industry	balance of manufacturing other	D
industry	plastic and rubber products	D
industry	wood products	D
industry	bulk chemicals	D
industry	glass and glass products	D
industry	cement	D
industry	industrial space heating	B
industry	agriculture-other	D
industry	industrial drying	B
industry	industrial curing	B
industry	industrial machine drives	B
industry	agriculture-crops	D
industry	fabricated metal products	D
industry	machinery	D
industry	computer and electronic products	D
industry	transportation equipment	D

industry	construction	D
industry	iron and steel	D
industry	food and kindred products	D
industry	paper and allied products	D
industry	industrial boilers	B
industry	electrical equip., appliances, and components	D
industry	industrial process heat	B

The methods for representing demand-side subsectors are described in section 5.3. Table 13 describes the input data used to populate stock representations in the subsectors that employ Method A. and Table 15 describes the energy service demand inputs.

Table 13 Demand stock data

Subsector	Unit	Service Demand Dependent	Driver	Input Data: Geography	Input Data: Year(s)	Source
Residential Lighting	Bulbs per housing unit	No	Total square footage	US	2012	(U.S. Energy Information Administration 2017)
Residential Clothes Washing	Clothes washer	No	Households	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Clothes Drying	Clothes dryer	No	Households	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Dishwashing	Dishwashers per household	No	Households	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Refrigeration	Cubic feet	No	Households	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Freezing	Cubic feet	No	Households	Census division	2009	(U.S. Energy Information Administration 2013)
Commercial Water Heating	Capacity factor	No	Com square feet	Census division	2012	(U.S. Energy Information Administration 2012)

Commercial Space Heating	Capacity factor	No	Com square feet	Census division	2012-2013	(U.S. Energy Information Administration 2012)
Commercial Air Conditioning	Capacity factor	No	Com square feet	Census division	2012	(U.S. Energy Information Administration 2012)
Commercial Lighting	Capacity factor	No	n/a	Census division	2012	(U.S. Energy Information Administration 2012)
Commercial Refrigeration	Capacity factor	No	Com square feet	Census division	2012	(U.S. Energy Information Administration 2012)
Commercial Cooking	Capacity factor	No	Com square feet	Census division	2012	(U.S. Energy Information Administration 2012)
Commercial Ventilation	Capacity factor	No	Com square feet	Census division	2012	(U.S. Energy Information Administration 2012)
Light Duty Autos	Car per mile travelled	Yes	n/a	US	2012; 2020; 2030; 2040	(U.S. Energy Information Administration 2015)
Light Duty Trucks	Truck per mile travelled	Yes	n/a	US	2012; 2020; 2030; 2040	(U.S. Energy Information Administration 2015)
Medium Duty Trucks	Truck	Yes	n/a	US	2015	(TA Engineering Inc. 2012)
Heavy Duty Trucks	Truck	Yes	n/a	US	2011	(TA Engineering Inc. 2012)
Transit Buses	Bus	Yes	n/a	US	2014	(Brooker et al. 2015)

Subsector	Unit	Stock Dependent	Driver	Input Data: Geography	Input Data: Year(s)	Source
Residential Lighting	klm-hr per housing unit	No	Total square feet	US	2012	(Ashe et al. 2012)
Residential Clothes Washing	Cu. Ft. Cycle	Yes	n/a	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Clothes Drying	Pound	Yes	n/a	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Dishwashing	Cycle	Yes	n/a	Census division	2009	(U.S. Energy Information Administration 2013)

Residential Refrigeration	Cu. Ft.	Yes	n/a	Census division	2009	(U.S. Energy Information Administration 2013)
Residential Freezing	Cu. Ft.	Yes	n/a	Census division	2009	(U.S. Energy Information Administration 2013)
Commercial Water Heating	Terabtu	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Space Heating	Terabtu	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Air Conditioning	Terabtu	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Lighting	gigalumen_year	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Refrigeration	Terabtu	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Cooking	Terabtu	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Ventilation	gigacubic_foot	No	Com square feet	Census division	2012 - 2050	(U.S. Energy Information Administration 2017)
Light Duty Autos	Gigamile	No	n/a	US	2007; 2015-2050	(U.S. Energy Information Administration 2017)
Light Duty Trucks	Gigamile	No		US	2012-2050	(U.S. Energy Information Administration 2017)
Medium Duty Trucks	Mile	No		US	2015-2050	(U.S. Energy Information Administration 2017)
Heavy Duty Trucks	Mile	No	N/A	US	2015-2050	(U.S. Energy Information Administration 2017)
Transit Buses	Mile	No	Population	Census division	1995-2008	(U.S. Energy Information Administration 2017)

Demand subsectors with technology stock also require technology-specific parameters for cost and performance. These input sources by subsector and technology-type are show below in Table 14.

Table 14 Demand technology inputs

Subsector	Technologies	Source
Residential Space Heating and Air Conditioning	Air source heat pump (ducted)	Cost: (Jadun et al. 2017) Efficiency: NREL building simulations in support of (Jadun et al. 2017)
	Ductless mini-split heat pump	Cost: (Dentz, Podorson, and Varshney 2014) Efficiency: NREL building simulations in support of (Jadun et al. 2017)
	Remainder	(Navigant 2014)
Residential Water Heating	Heat pump water heater	(Jadun et al. 2017)
	Remainder	(Navigant 2014)
Residential Remaining Subsectors	All	(Navigant 2014)
Commercial Space Heating and Air Conditioning	Air source heat pump	(Jadun et al. 2017)
	Remainder	(Navigant 2014)
Commercial Water Heating	Heat pump water heater	(Jadun et al. 2017)
	Remainder	(Navigant 2014)
Commercial Lighting	All	(U.S. Energy Information Administration 2017)
Commercial Building Shell	All	(U.S. Energy Information Administration 2017)
Light-duty Vehicles	Battery electric vehicle and plug-in hybrid electric vehicle NREL EFS Low cost trajectory for electric vehicles (recent trends since this study indicate faster cost declines than expected)	(Jadun et al. 2017)
	Hydrogen fuel cell vehicle	(TA Engineering Inc. 2012)

	Remainder	Efficiency: (Navigant 2014) Cost: (TA Engineering Inc. 2012)
Medium Duty Vehicles	Battery electric	(Jadun et al. 2017)
	Hydrogen fuel cell	(den Boer et al. 2013)
	Remainder (CNG, diesel, etc.)	(TA Engineering Inc. 2012)
Heavy Duty Vehicles	Battery electric	(Jadun et al. 2017)
	Hydrogen fuel cell	(Fulton and Miller 2015)
	Reference diesel, gasoline and propane	(TA Engineering Inc. 2012)
	Diesel hybrid and liquefied pipeline gas	(TA Engineering Inc. 2012)
Transit Buses	All	(Jadun et al. 2017; Brooker et al. 2015)
Industrial Space Heating	Air source heat pump	(Jadun et al. 2017)
	Furnace	(Navigant 2014))
Industrial Boilers	All	(Jadun et al. 2017)
Industrial Process Heat	All	(Jadun et al. 2017)
Industrial Curing	All	(Jadun et al. 2017)
Industrial Drying	All	(Jadun et al. 2017)
Industrial Machine Drives	All	(Jadun et al. 2017)

Table 15 Service demand inputs

Subsector	Unit	Stock Dependent	Driver	Input Data: Geography	Downscaling method	Input Data: Year(s)	Source
Residential Lighting	klm-hr per housing unit	No	Total sq ft	US	Households 2010	2012	(Ashe et al. 2012)
Residential Water Heating	Terabtu	No	Households	NJ	n/a	2012	(ENERNOC, 2012)
Residential Space Heating	Terabtu	No	Households	NJ	n/a	2012	(ENERNOC, 2012)

Residential Clothes Washing	Cu. Ft. Cycle	Yes	n/a	Census division	Stock	2009	(U.S. Energy Information Administration 2013)
Residential Clothes Drying	Pound	Yes	n/a	Census division	Stock	2009	(U.S. Energy Information Administration 2013)
Residential Dishwashing	Cycle	Yes	n/a	Census division	Stock	2009	(U.S. Energy Information Administration 2013)
Residential Refrigeration	Cu. Ft.	Yes	n/a	Census division	Stock	2009	(U.S. Energy Information Administration 2013)
Residential Freezing	Cu. Ft.	Yes	n/a	Census division	Stock	2009	(U.S. Energy Information Administration 2013)
Commercial Water Heating	Terabtu	No	Com square feet	Census division	Employment in all industries (NAICS, no code) 2007	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Space Heating	Terabtu	No	Com square feet	Census division	HDD x com_sq_ft	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Air Conditioning	Terabtu	No	Com square feet	Census division	CDD x com_sq_ft	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Lighting	gigalumen_year	No	Com square feet	Census division	Employment in all industries (NAICS, no code) 2007	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Refrigeration	Terabtu	No	Com square feet	Census division	Employment in all industries (NAICS, no code) 2007	2012 - 2050	(U.S. Energy Information Administration 2017)
Commercial Cooking	Terabtu	No	Com square feet	Census division	Employment in all industries (NAICS, no code) 2007	2012 - 2050	(U.S. Energy Information Administration 2017)

Commercial Ventilation	gigacubic_foot	No	Com square feet	Census division	Employment in all industries (NAICS, no code) 2007	2012 - 2050	(U.S. Energy Information Administration 2017)
Light Duty Autos	Gigamile	No	MD + HD VMT Historical	US	LDV VMT Share	2007; 2015-2050	(U.S. Energy Information Administration 2017)
Light Duty Trucks	Gigamile	No	MD + HD VMT Historical	US	LDV VMT Share	2012-2050	(U.S. Energy Information Administration 2017)
Medium Duty Trucks	Mile	No	gasoline sales volumes	US	MDV VMT Share	2015-2050	(U.S. Energy Information Administration 2017)
Heavy Duty Trucks	Mile	No		US	HDV VMT Share	2015-2050	(U.S. Energy Information Administration 2017)
Transit Buses	Mile	No	Population	Census division	Square miles	1995-2008	(U.S. Energy Information Administration 2017)
Light Duty Autos	Mile	No	VMT Historical	NJ	LDV VMT Share	2018	New Jersey DEP
Light Duty Trucks	Mile	No	VMT Historical	NJ	LDV VMT Share	2018	New Jersey DEP
Medium Duty Trucks	Mile	No	VMT Historical	NJ	MDV VMT Share	2018	New Jersey DEP
Heavy Duty Trucks	Mile	No	VMT Historical	NJ	HDV VMT Share	2018	New Jersey DEP
Transit Buses	Mile	No	VMT Historical	NJ	HDV VMT Share	2018	New Jersey DEP

Table 16 describes stock input data sources for subsectors that uses Method B. Table 17 describes energy demand input sources.

Table 16 Equipment stock data sources for Method B subsectors

Subsector	Unit	Service Demand Dependent	Driver	Input Data: Geography	Downscaling method	Input Data: Year(s)	Source

Residential Water Heating	Water heater	No	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)
Residential Space Heating	Space heater	No	Households	Census division	Households 2010	2009-2015	(U.S. Energy Information Administration 2017)
Residential Air Conditioning	Air conditioner	No	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)
Residential Cooking	Cooktop	No	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)
Industrial Boilers	Capacity factor[9]	Yes	n/a	US	Value of Shipments	2015	By Assumption
Industrial Process Heat	Capacity factor	Yes	n/a	US	Value of Shipments	2015	By Assumption
Industrial Space Heating	Capacity factor	Yes	n/a	US	Value of Shipments	2015	By Assumption
Industrial Machine Drives	Capacity factor	Yes	n/a	US	Value of Shipments	2015	By Assumption
Industrial Curing	Capacity factor	No	n/a	US	Value of Shipments	2015	By Assumption
Industrial Drying	Capacity factor	No	n/a	US	Value of Shipments	2015	By Assumption

Table 17 Energy demand data sources for Method B subsectors

Subsector	Unit	Driver	Input Data: Geography	Downscaling method	Input Data: Year(s)	Source
Residential Water Heating	MMBTU	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)

[9] The model uses an assumed capacity factor to translate energy service demand into equipment stocks in units of service demand/hour.

Residential Space Heating	MMBTU	HDD; occupied square feet	Census division	HDD x residential square footage	2009-2015	(U.S. Energy Information Administration 2017)
Residential Air Conditioning	MMBTU	CDD	Census division	CDD x residential square footage	2009	(U.S. Energy Information Administration 2013)
Residential Cooking	MMBTU	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)
Industrial Boilers	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Process Heat	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Space Heating	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Machine Drives	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Curing	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Drying	USD	Value of shipments	Census region	Earnings in manufacturing (NAICS 31-33) 2007	2011-2050	(U.S. Energy Information Administration 2017)
Industrial Chemical and Pharmaceutical	TBtu	Sectoral employment	NJ	n/a	2012	(ENERNOC, 2012)
Industrial Paper	TBtu	Sectoral employment	NJ	n/a	2012	(ENERNOC, 2012)
Industrial Food	TBtu	Sectoral employment	NJ	n/a	2012	(ENERNOC, 2012)
Industrial Miscellaneous	TBtu	Sectoral employment	NJ	n/a	2012	(ENERNOC, 2012)

Table 18 includes the service demand projections for subsectors represented with Method C (5.3.1.5). Table 19 includes the service efficiency for Method C subsectors.

Table 18 Service demand data sources for Method C subsectors

Subsector	Unit	Stock Dependent	Driver	Input Data: Geography	Input Data: Year(s)	Source
Iron and Steel CO2 Capture	Tonnes of BOF Steel Production	No	Subsector value of output	Census region	2011-2050	(U.S. Energy Information Administration 2017)
Cement CO2 Capture	Tonnes of Clinker Production	No	Subsector value of output	Census region	2011-2050	(U.S. Energy Information Administration 2017)

Table 19 Service efficiency data sources

Subsector	Unit	Stock Dependent	Driver	Input Data: Geography	Input Data: Year(s)	Source
Iron and Steel CO2 Capture	MMBTU/Tonne of CO2	No		US	2018	(Kuramochi et al. 2012)
Cement CO2 Capture	MMBTU/Tonne of CO2	No		US	2018	(Kuramochi et al. 2012)

Table 20 shows baseline energy demand projection input data sources for subsectors employing Method D (5.3.1.6).

Table 20 Energy demand data sources for Method D subsectors

Subsector	Unit	Driver	Input Data: Geography	Downscaling method	Input Data: Year(s)	Source
Residential computers and related	MMBTU	Households	Census division	Households 2010	2009-2050	(U.S. Energy Information Administration 2017)
Residential televisions and related	MMBTU	Households	Census division	Households 2010	2009-2050	(U.S. Energy Information Administration 2017)
Residential Secondary Heating	MMBTU per household	Households; HDD	Census division	Households 2010	2010	(U.S. Energy Information

						Administration 2017)
Residential other uses	MMBTU	Households	Census division	Households 2010	2009-2050	(U.S. Energy Information Administration 2017)
Residential Furnace Fans	MMBTU	Households	Census division	Households 2010	2009	(U.S. Energy Information Administration 2013)
Office Equipment (P.C.)	Quads	Office space	US	Employment in all industries (NAICS, no code) 2007	2015-2050	(U.S. Energy Information Administration 2017)
Office Equipment (Non-P.C.)	Quads	Office space	US	Employment in all industries (NAICS, no code) 2007	2015-2050	(U.S. Energy Information Administration 2017)
Commercial Other	Quads	Commercial square footage	US	Employment in all industries (NAICS, no code) 2007	2015-2050	(U.S. Energy Information Administration 2017)
Non-CHP District Services	kilobtu per square feet	Commercial square footage	Census division	Households 2010	2012	(U.S. Energy Information Administration 2017)
CHP District Services	Terabtu	Commercial square footage	US	Households 2010	2015-2050	(U.S. Energy Information Administration 2017)
Domestic Shipping	Terabtu	n/a	US	Marine Fuel Use	2015-2050	(U.S. Energy Information Administration 2017)
Military Use	Terabtu	n/a	US	Households 2010	2015-2050	(U.S. Energy Information Administration 2017)
Motorcycles	Terabtu	Population	US	Households 2010	2012-2050	(U.S. Energy Information Administration 2017)
Lubricants	Terabtu	Population	US	Households 2010	2015-2050	(U.S. Energy Information Administration 2017)

International Shipping	Terabtu	n/a	US	Marine Fuel Use	2015-2050	(U.S. Energy Information Administration 2017)
Recreational Boats	Terabtu	n/a	US	Households 2010	2015-2050	(U.S. Energy Information Administration 2017)
School and intercity buses	Terabtu	Passenger miles, population	US	BUSES VMT Share	2015-2050	(U.S. Energy Information Administration 2017)
Passenger rail	Terabtu	Rail passenger miles	Census division	Rail Fuel Use	2015-2050	(U.S. Energy Information Administration 2017)
Freight rail	Terabtu	Gigaton mile service demand	Census division	Rail Fuel Use	2015-2050	(U.S. Energy Information Administration 2017)
Aviation	Terabtu	Seat miles, population	US	Aviation Fuel Use	2015-2050	(U.S. Energy Information Administration 2017)
Various Industrial Subsectors [1]	Terabtu	Subsector value of output	Census region	Value of shipments	2011-2050	(U.S. Energy Information Administration 2017)

9.Supply-Side Data Sources

Table 21 Supply-side data sources

Data Category	Data Description	Source
Transmission grid	Transmission between zones taken from EPA eGRID Updated with input from PJM for Interties between New Jersey and surrounding regions	(U.S. Environmental Protection Agency 2018a)
Transmission expansion cost	The intertie between PJM and New Jersey was the only line allowed to expand. The cost was derived from cost per megawatt-mile estimates from NREL's Regional Energy Deployment System Model.	(Cohen et al., 2019)

Nuclear extension costs	Costs of extending nuclear plants beyond current licenses, sourced from EPA	(U.S. Environmental Protection Agency 2018b)
Renewable potential	Renewable potential is classified into different classes of resource quality. These are sourced from NREL	(Cohen et al., 2019)
Solar potential	Rooftop PV potential is from the Navigant New Jersey Renewable Energy Market Assessment projections for 2020, scaled up to account for the greater energy density of current solar PV technology versus when the study was conducted Grid scale PV potential was provided by BPU	(Navigant, 2004)
Biomass feedstocks	Available biomass for New Jersey is taken from the DOE Billion Ton Study, scaled by population to find an equitable biomass allocation of US production to New Jersey	(Langholtz et al., 2016)
Fossil fuel prices	Fossil fuel price projections are taken from the EIA annual Energy Outlook 2019	(U.S. Energy Information Administration, 2019)
Conversion technologies	The cost of conversion technologies to produce hydrogen and synthetic fuels are taken from the European Union Commission ASSET Study	(European Commission, 2018)
Energy storage costs	Energy storage costs are provided by RMI experts. Energy storage sensitivity pricing for the low technology cost cases are taken from the International Renewable Energy Agency (IRENA)	Rocky Mountain Institute (International Renewable Energy Agency, 2017)
Electricity generation costs	Capex and operations and maintenance costs for new generation are taken from NREL's Annual Technology Baseline 2019	(National Renewable Energy Agency, 2019)
Direct air capture	Costs for direct air capture are taken from Keith et al. estimates for nth plant	(Keith et al., 2018)

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