# Pathways towards 100% carbon reduction for electric utility power systems

WÄRTSILÄ BUSINESS WHITE PAPER

Electric utilities and government agencies are moving towards 100% carbon-free energy. Despite the enthusiasm behind this goal there are a considerable number of open questions. For example, what is the cost of a "carbon-free" system versus a "carbon-neutral system"? And what are these costs relative to? This work addresses these questions by determining the costs and carbon reduction trajectories associated with 100% targets.

TABLE OF CONTENTS

# Table of contents

# Executive summary

The "path to 100%" is characterized by estimating costs for a representative U.S. utility as it transitions across a typical 20-year planning horizon, from moderate renewable penetration in year one to 100% in year twenty, assuming one of two pathways: carbon-free (no thermal in final year or beyond), or carbon-neutral (combustion of renewable fuels only in final year and beyond). These costs are then compared to the same utility assuming no carbon requirements and investment decisions driven purely by economics. Renewable fuels are here considered to be the product of power-to-gas, where excess renewable energy is used for synthetic, renewable methane production, using carbon sequestered from air. Results show that a utility can achieve 80% carbon reduction based purely on economics, with no subsidies, mandates or renewable requirements. Moving to a purely carbon-free power system will cost 30-35% more (over 20 years), in large part due to massive investments in renewable energy and traditional energy storage systems. Once the 100% carbon-free state is achieved, all-in energy costs ($/MWh) are almost double that of the 80% system. In contrast, a carbon-neutral system with power-to-gas is found to be the least expensive option, while achieving net-zero carbon emissions.

These results indicate that utilities leveraging Power-to-Gas technologies can simultaneously

- Meet net-zero carbon emission goals suggested by the IPCC
- Maintain reliability and energy security
- Install flexible thermal capacity to support renewables, free from stranded asset concerns
- Minimize costs to ratepayers



# 1. Introduction and background

State, provincial, municipal and in some cases national governments are declaring mandatory targets for 100% carbon reduction for electric utilities. These regulatory targets are often considered renewable mandates as it is commonly understood that wind, solar, hydro and other renewable energy sources are needed to replace fossil-fuel power plants in a zero-carbon emissions future. In the United States, as of mid-2019 more than 130 cities and municipalities have committed to 100% renewable energy, as well as 10 counties [1]. The entire states of Hawaii, California, Nevada, New Mexico, New York and Washington, as well the District of Columbia (Washington DC) and Puerto Rico have committed to 100% renewable as well. More local and state governments are expected to follow. A growing number of investor owned utilities are making 100% commitments, whether the states they supply energy to mandate the requirement or not [2,3]. Internationally countries such as Denmark [4] and Scotland [5] have officially committed to 100% renewable, many more nations are considering it, and the literature is full of a growing number of studies affirming that 100% renewable systems are cost effective and "doable". In most cases, the metrics that define compliance are often de-coupled from strict renewable requirements, quantified using metrics such as carbon intensity (e.g., 0 g/kWh of $CO_2$ emissions), thus potentially allowing for nuclear and combustion of biofuels and synthetic renewable fuels to meet the goals. The terms 100% renewable, 100% carbon-free and 100% carbon-neutral are often used interchangeably in public discourse, although power systems designed to meet any specific definition can be dramatically different from those designed to meet others.

Practically all of the targets (to date) have final implementation schedules in the 2040 to 2050 time frame, which are aligned with the International Panel on Climate Change (IPCC) reporting that in order to prevent negative impacts of anthropogenic climate change "Global net human-caused emissions of carbon dioxide would need to fall by about 45 percent from 2010 levels by 2030, reaching 'net zero" around 2050" [6] . Note that the IPCC recommendations refer to all human activity, including home heating and cooking, transportation and agriculture, while the majority of 100% renewable mandates apply only to electric utility systems. Electricity generation in the United States was responsible for approximately 30% of $CO_2$ generation in 2017 (Fig.1-1). As other industrial sectors "decarbonize" they will become more reliant on utility infrastructure to supply carbon-free or carbon-neutral energy, in effect increasing utility load.

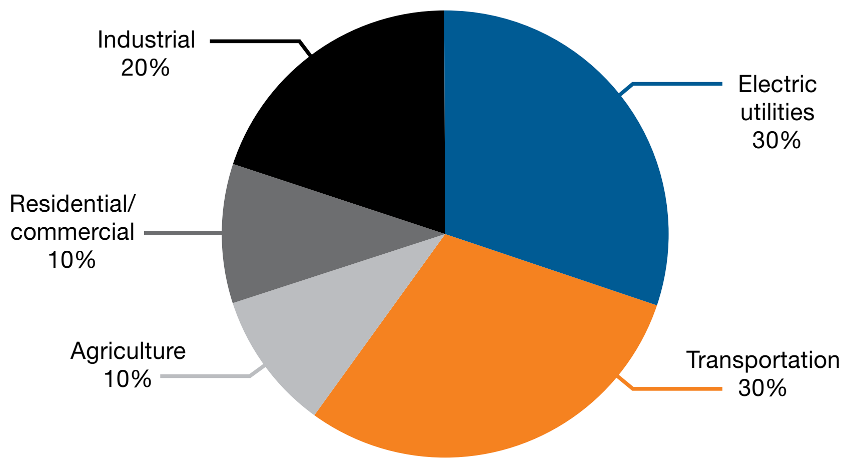


**Figure 1-1.** Carbon sources by sector for the United States (2017 [7])

While many smaller systems (industrial loads, data centers, small municipalities or electric-cooperatives) can contractually arrange for delivery of MWh from existing or purpose-built wind/solar and boast they have gone 100% renewable, larger regional grids and/or utility systems have a much larger and more complex problem to solve. They can serve customer bases of hundreds of thousands to tens of millions of people, have rigorous reliability commitments, and must consider replacing Gigawatts of thermal assets with an entirely new system dependent on variable renewable energy (VRE) sources (e.g., wind & solar), complemented by some form of energy storage. Energy storage is necessary to time-shift supply and delivery of MWh, as VRE output is rarely coincident with demand.

Utilities appear ready to take on this task. Most regional and large utility system plans rely on forward cost-curves of wind, solar and energy storage, that all show economies of scale that are expected to cause the installed costs of these technologies to go down year after year. What may not be economical now, especially in low natural-gas price environments like the USA, are expected to be far more economical 10, 20 and 30 years from now when the targets must be met. While the drive for this transition is based on climate change concerns, a growing number of industry and regulatory executives believe that a 100% renewable system will ultimately be more affordable than the status quo given the rapidly falling costs of wind, solar and Li-Ion batteries. What's good for the environment may also be good for the bank account.

While there is a growing consensus towards 100% renewable, or carbon-free systems, there is still quite a bit of debate over what this means, as well as many open questions. Is a 100% renewable system less expensive? Less expensive than what? What does "100%" mean? 100% carbon-free? Or 100% carbon-neutral (what the IPCC refers to as "net zero")? The purpose of this work is to address some of this uncertainty by asking the following questions which are tested against a representative utility.

1. What is the cost-optimal path for long-term planning, assuming no carbon goals?

2. What if the same utility were required to be 100% carbon-free, meaning that at the end of the planning horizon only renewable energy, nuclear and traditional forms of energy storage were allowed?

3. What if the same utility were required to be 100% carbon-neutral, similar to 2) above but allowing for production and use of renewable, synthetic fuels?

4. Once the utility finishes the "path to 100", what is the actual cost of carbon-free vs. carbon-neutral in the long-term?

To address these questions, we employ a 20-year resource planning approach to a representative utility currently at a moderate renewable penetration and planning to have a carbon intensity of 0 g/kWh at the end of the 20-year horizon (100% carbon-free). The goal of the approach is to determine the investments associated with traveling the path to 100% assuming carbon-free versus carbon-neutral, and how these vary from a cost-optimal system.

# 2. The utility system

The utility chosen for this analysis is representative of many utilities and has been subject to the same factors influencing the historical and expected future capacity mix of electric utilities in general. These include

- Falling natural gas prices
- Regulatory pressures against coal combustion
- Economies of scale leading to falling prices for wind, solar and storage capacity
- Greater commitments towards high renewable power systems.

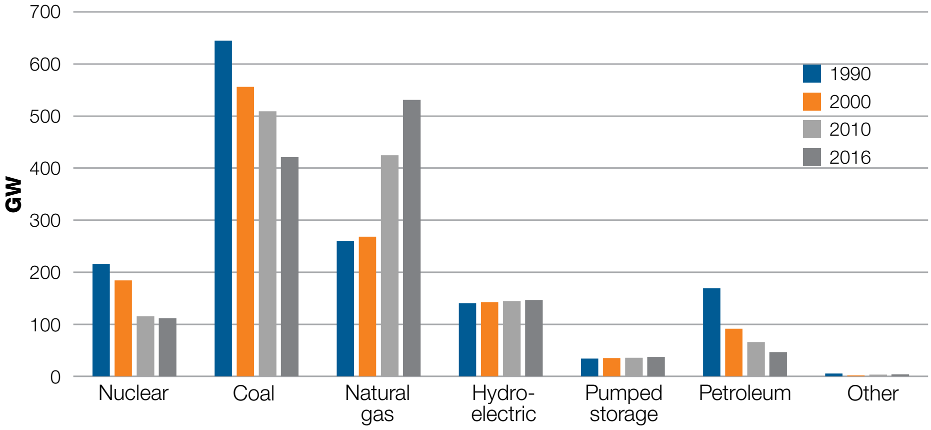


**Figure 2-1.** Changing U.S. utility dispatchable resource mix 1990-2016. Data Source: US EIA [8]

Parallel with falling coal capacity and increasing natural gas reliance, utilities have substantially increase wind and solar capacity, a trend that is expected to continue.

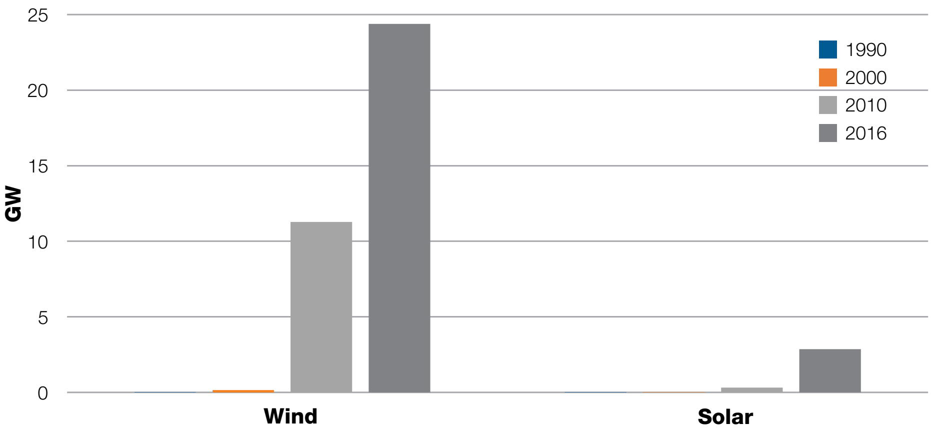


**Figure 2-2.** Increasing wind and solar capacity 1990-2016. Note that this data only refers to utility-owned capacity, and not to renewable energy or capacity provided from third parties via Power Purchase Agreements. Data Source: US EIA [8].

This work used Public Service of New Mexico (PNM) as a focal utility. PNM is an investor owned utility in the state of New Mexico (USA), with a peak load of approximately 2 GW and serving over 500,000 customers. PNM was chosen because its capacity mix is reflective of US national averages and due to the preponderance of publicly available data for this utility. Like many utilities PNM had a legacy reliance on coal. Currently PNM is divesting itself of coal, producing ever greater shares of energy from wind and solar, and ultimately aims to produce 100% of its energy from carbon-free sources (thus allowing for retaining its share of the Palo Verde Nuclear Station). The historical and expected future capacity mixes for PNM (Fig. 2-3) show trends mirroring the US average trends (Figs 2-1 & 2-2).

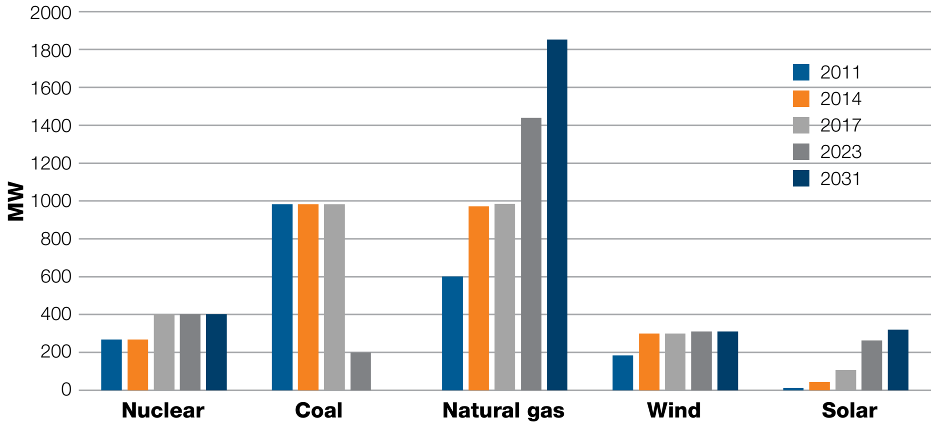


**Figure 2-3.** PNM historical and anticipated future capacity mix 2011 through 2031. Wind and solar here include PPA capacity. Data sources: PNM Integrated Resource Plans for 2011 [9], 2014 [10] and 2017 [11]

PNM has a partial ownership of the San Juan coal plant (783 MW) and 200 MW at the Four Corners coal plant which are scheduled to retire in 2022 and 2031 respectively. These coal retirements, additional gas capacity (which is higher efficiency than coal) and greater renewable penetrations allow PNM to anticipate 70% of their energy will be from carbon-free sources by 2032 [12]. In March 2019 the State of New Mexico passed the Energy Transition Act (ETA), which set goals of 80% and 100% carbon-free energy from investor owned utilities by 2030 and 2045 respectively. On Earth Day, April 22, 2019, PNM announced it would meet the 100% requirement by 2040, five years ahead of the RPS requirement [13]. The long-term plans for PNM to achieve these goals are yet to be presented publicly and will make use of information not contained in documents publicly available today.

The capacity mix of PNM is representative of the US Utility Industry, and their aggressive renewable goals place them at the forefront of utilities willing to take on the challenge of 100% carbon-free. Therefore, PNM is used as a test-bed for the questions asked that are relevant to the electric utility industry. In this work we use the existing capacity of PNM as of the year 2017 and take into consideration announced coal retirements. For modeling purposes, the existing capacity of PNM is as follows;

**Existing capacity**

| Generating station | Technology | Fuel-type | Capacity available to serve PNM load (MW) | Heat Rate (Mbtu/MWh) | VOM ($/MWh) | FOM ($/kW-year)* | Start Cost ($/Start) |
|---|---|---|---|---|---|---|---|
| Palo Verde units 1, 2, 3 | Nuclear | Nuclear | 402 | 10.3 | NA | NA | NA |
| San Juan units 1, 2, 3, 4 | Steam turbine | Coal | 783 | 10.5 | NA | NA | 20,000 |
| Four Corners units 4, 5 | Steam turbine | Coal | 200 | 11.2 | NA | NA | 20,000 |
| Afton combined cycle | Combined cycle | Gas | 230 | 8.1 | 3.7 | 31 | 8,050 |
| luna combined cycle | Combined cycle | Gas | 189 | 8.2 | 3.7 | 24 | 6,475 |
| Rio Bravo | Gas turbine | Gas | 138 | 12.1 | 3 | 7 | 6,900 |
| Valencia | Gas turbine | Gas | 150 | 10.2 | 7 | 7 | 7,250 |
| Lordsburg units 1, 2 | Gas turbine | Gas | 80 | 11.3 | 5.5 | 25 | 0 |
| La Luz | Gas turbine | Gas | 40 | 11.2 | 5.5 | 32 | 0 |
| Reeves units 1, 2, 3 | Steam turbine | Gas | 154 | 14.2 | 4 | 20 | 5,000 |
| Solar | Photovoltaic | Solar | 107 | NA | 0.2 | 15 | NA |
| Wind | Wind-turbine | Wind | 302 | NA | 0.3 | 15 | NA |
| | | **Total** | **2775** | | | | |

* Adapted from [11] and other sources (NA for units kept or retired for all scenarios)

**Table 1.** Capacity resources owned or contracted by the utility.

# 3. Future new build and other considerations for modeling future scenarios

### 3.1 LOAD AND FUEL PRICING

Our intent is to model potential future capacity mixes across a planning horizon 2020-2040, necessitating a source of future expected loads and gas prices. Load data and fuel pricing was taken from the latest publicly available Integrated Resource Plan [11] at the time this work was being done.

### 3.2 NEW-BUILD GENERATION OPTIONS

While PNM expects to be 100% reliant on carbon-free sources by 2040, there are significant coal retirements in 2022 and 2031 which may be filled by natural gas generators, until both wind/solar and energy storage "close the loop" by 2040. The suite of new-build options is shown in Table 2.

**New-build candidates**

| Potential New Build | Technology | Energy Source | Unit Size | Heat Rate (MBtu/MWh) | VOM ($/MWh) | FOM ($/kW-year) | Start Cost ($/Start) | Build Cost ($/kW) |
|---|---|---|---|---|---|---|---|---|
| Reciprocating Engines | Medium Speed Reciprocating Engine | Gas | 18.7 | 8.2 | 5.5 | 31 | 0 | 800* |
| Aeroderivative GT | Gas Turbine | Gas | 40 | 9 | 3.5 | 32 | 0 | 800* |
| Frame-type GT | Gas Turbine | Gas | 187 | 10 | 1.5 | 32 | 15,000 | 600* |
| Storage (2 hour) | Li-Ion battery | Varied | per MW | NA | 0 | 15 | NA | ** |
| Storage (4 hour) | Li-Ion battery | Varied | per MW | NA | 0 | 20 | NA | ** |
| Storage (8 hour) | Li-Ion battery | Varied | per MW | NA | 0 | 25 | NA | ** |
| PtG Converter | Direct Air Carbon Capture | Varied | per MW | NA | 0 | 23.1 | NA | *** |
| Solar | Photovoltaic | Solar | per MW | NA | 0.2 | 15 | NA | **** |
| Wind | Wind-turbine | Wind | per MW | NA | 0.3 | 15 | NA | **** |

* Adapted from [11] and other sources
** See Storage Section for pricing curves
*** See PtG section for pricing curves and other details
**** See Wind and Solar section (s) for pricing curves

**Table 2.** New-build candidates and parameters used for capacity-expansion modeling.

### 3.3 NEW BUILD WIND AND SOLAR PRICING AND CHARACTERISTICS

The following forward pricing curves were used for wind and solar capacity additions.

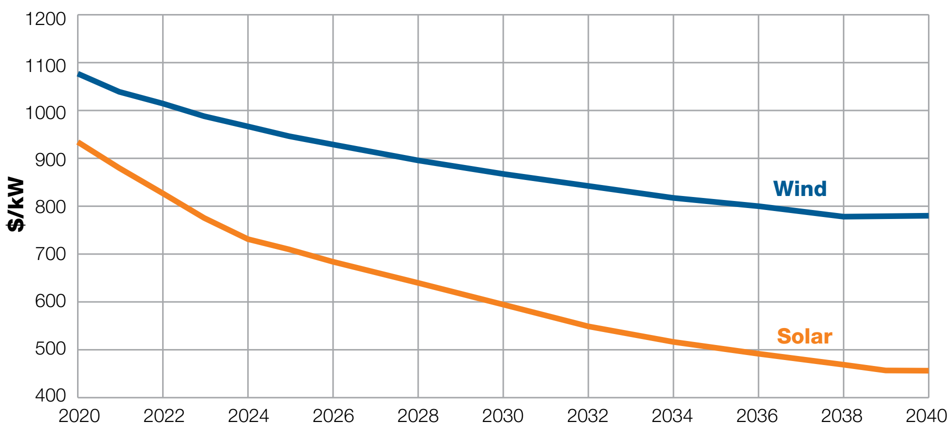


**Figure 3.3-1.** Build costs ($/kW) used for Wind and Solar capacity, adapted from [14]

Wind and solar profiles are weather and season dependent, and rarely coincide with demand. To account for the actual behavior of wind/solar generation, a total of 30 sites in New Mexico were randomly drawn from data sets compiled by the US National Renewable Energy Laboratory (NREL) for wind [15] and solar [16] profiles. The data is maintained by NREL in 5-minute time resolution. For modeling purposes this information was averaged at the hourly time scale, to provide an average hourly annual profile for both wind and solar.

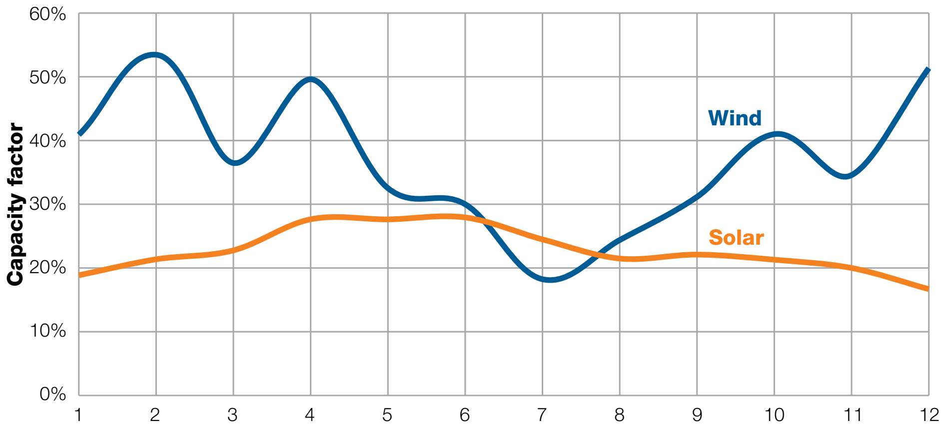


**Figure 3.3-2.** Monthly average wind and solar capacity factors for New Mexico, USA (derived from [15] and [16]).

### 3.4 ENERGY STORAGE CHARACTERIZATION

For modeling purposes, and concurrent with PNMs own analyses, Li-Ion batteries are considered here for new-build storage options. The expected "learning curve" for Li-Ion batteries is a constantly moving target with continuous updates and revisions, driven by increased demand for energy storage and battery OEMs striving for cost minimization. For our purposes, the following pricing assumptions were made for 2, 4 and 8 hour Li-Ion systems. Round trip efficiency was set at 85% and min and max discharge levels set at 20% and 90% respectively.

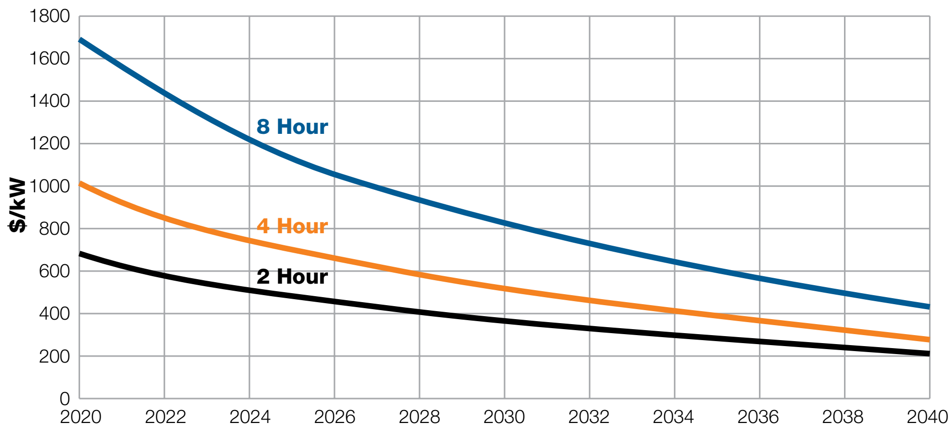


**Figure 3.4-1.** Build costs ($/kW) for 2, 4 and 8 hour duration Lithium-Ion battery storage, adapted from [14]

### 3.5 SEASONAL AND WEATHER IMPACTS ON RENEWABLE GENERATION AND THE NEED FOR LONG-TERM STORAGE

Given Power-to-gas is a rather new technology in the electric utility industry, some explanation is here provided as to its purpose in addition to the modeling characteristics. Traditional energy storage (e.g. batteries, compressed air, pumped hydro) are short duration (less than 12 hours) and have widespread use time-shifting renewable energy on a day to day basis. There is an additional type of time-shifting that will be required as utilities aggressively expand renewable penetration towards a 100% system (however defined); time shifting that spans days to weeks.

The reason long-duration time shifting is important is related to the variability of wind and solar, both of which have seasonal trends. Solar produces the least energy in winter months when day lengths are shortest, and wind generally has reductions in output in the late summer across the U.S. (Fig. 3.5-1). Unlike solar, wind seasonal patterns vary with geographic location (Fig. 3.5-2). New Mexico (on average) tends to have peak wind capacity factors in the winter months, and minimum capacity factors in late summer (Fig 3.3-2).

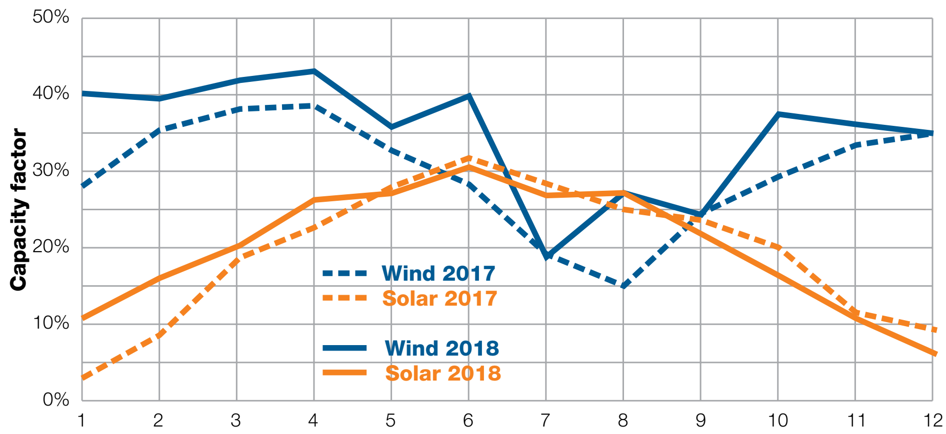


**Figure 3.5-1.** US Average Monthly Wind & Solar capacity factors for 2017 and 2018. Data Source: US Energy Information Agency [17]

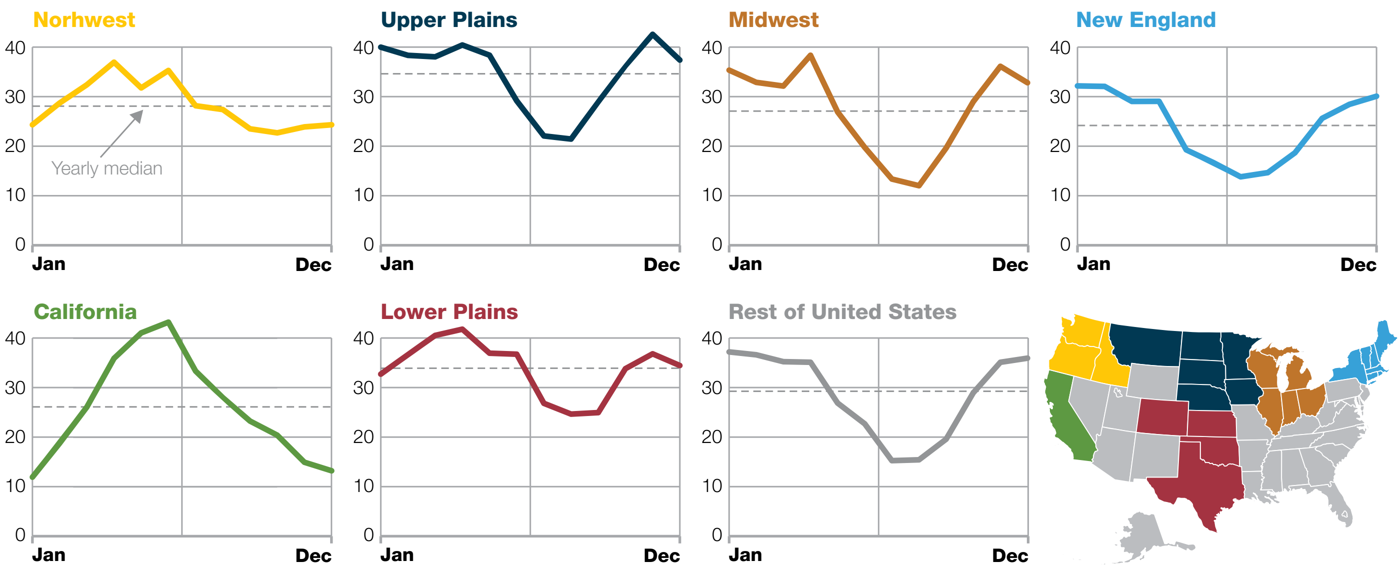


**Figure 3.5-2.** Wind seasonal capacity factors across the USA. Figure from US Energy Information Agency [18]

While PNM does not employ hydro resources, hydro facilities experience seasonal patterns and are subject to dramatic reduction in energy throughput during droughts. For example, in California hydro resources have provided (on average) 18% of in-state electricity generation, but this number fell to 7% in 2015 due to a multi-year drought [19]. Brazil had a 12-year average of 91% of electric generation from hydro, falling to 71% in 2015 due to a 3-year drought [20].

In addition to seasonal variations, renewables are also subject to unforeseen but not unexpected weather events that can lead to multi-day (or multi-week) periods of little to no energy production. Examples include the United Kingdom experiencing 9 days of little to no output from wind farms in 2018 [21], and New England (USA) experiencing dramatically reduced solar output across a 16 day period due to snow cover [22]. These multi-day weather events compound the challenges of seasonal variability. At present thermal facilities are called on to fill the gaps left by missing renewable energy, but for 100% carbon free/neutral systems alternatives are required. For these reasons multi-day storage systems are necessary and can be provided renewable by power-to-gas.

### 3.6 CHARACTERIZATION OF POWER-TO-GAS (METHANE)

As utility systems attain greater renewable penetrations, seasonal trends or drought impacts on renewable energy throughput have greater impacts on the reliability and affordability of the power system. 100% carbon neutral/free systems must install enough capacity (with the right capabilities) to meet energy needs in worst-case scenarios. At a minimum, to assure reliability and avoid blackouts, utility system planners and policy makers need to account for seasonal trends in availability of renewable resources. Energy storage systems designed for daily shifting with <12 hour duration are not cost optimal for long-term storage and energy time-shifting in high renewable power systems [23].

One form of long-term energy storage is generation of synthetic methane using renewable energy. Synthetic methane is created in a multi-step process. Electricity powers hydrolysis to extract Hydrogen from water. A separate process uses electricity for direct-air carbon capture (DACC), a process by which Carbon is pulled from the air. A third process (called methanation) combines hydrogen and carbon to form renewable methane, CH4. Synthetic methane in this context is renewable insofar as the electricity powering the process is provided by renewable (wind, solar primarily) or other carbon-free sources (such as hydro or nuclear). The ingredients (water and air) are also renewable, their consumption does not alter the mass balance of either on a global basis. The final fuel is carbon-neutral. All carbon in the fuel is sequestered from the atmosphere, therefore any release of $CO_2$ upon combustion is net-zero. The process results in no net increase in $CO_2$ emissions, and is therefore carbon-neutral, or in effect carbon-free.

One benefit of renewable methane is that it can be stored and transferred using already existing natural gas infrastructure to generate power on demand using gas fired generators utilities already own [24]. The intent is not to power the system entirely with carbon-neutral methane, but rather to store the fuel for long-term time shifting, meeting MWh needs in months when wind, solar or hydro output are minimized.

For this work power-to-gas is characterized as follows: Direct-Air-Capture of $CO_2$ is coupled with hydrolysis (for Hydrogen) and a methanation process to generate synthetic, renewable methane, CH4. The process is collectively called “Power-to-Gas”, or PtG, and is assumed to be 60% efficient, powered entirely by renewable or carbon-free energy; that is, for every MWh of energy put into the PtG process, 0.6 MWh of useable CH4 is produced for long-term storage and use. Simulation of PtG was enabled through use of the PLEXOS™ “Gas Module”, used for Long-term capacity expansion simulations (discussed in Section 5.0 below). Forward pricing curves for PtG (Fig 3.6-1) were developed in consultation with Lappeenranta University of Technology in Finland [25], with pricing curves corresponding with published values in the literature (e.g., see [26])

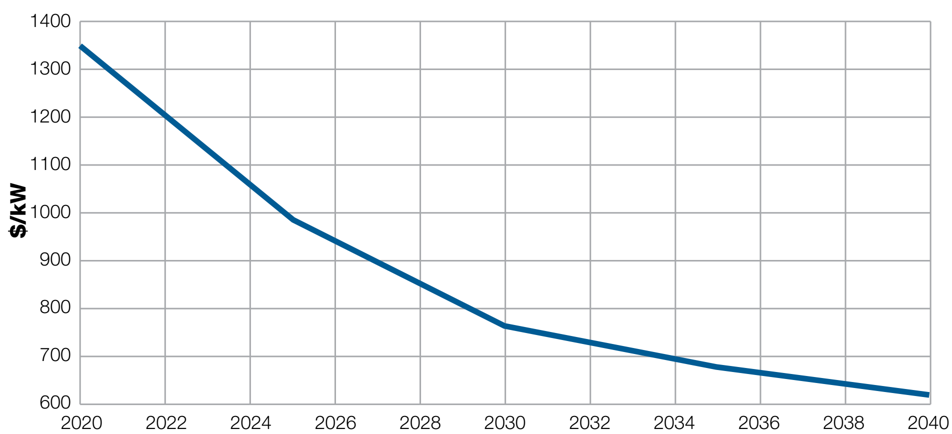


**Figure 3.6-1.** Assumed Capital Costs for PtG systems used in the analysis, on a $/kW basis, and where “kW” refers to the power needed to produce synthetic CH4.

# 4. Scenario definitions

Four scenarios were modeled in a long-term planning context.

- **Scenario 1 – Cost-Optimal Case (No Renewable Requirements):** Cost optimization drives capacity choice, no renewable or carbon mandates.
- **Scenario 2 – 100% Carbon-Free:** Utility must be 100% carbon-free at end of 20-year planning horizon. New thermal is allowed within the planning horizon, but all thermal must be retired by last year of horizon.
- **Scenario 3 – 100% Carbon-Free, no new thermal:** Same as Scenario 2, but all new capacity across horizon must be non-thermal (no new thermal at all).
- **Scenario 4 – 100% Carbon-Neutral, leveraging renewable fuels (PtG):** Renewable methane allowed for carbon-neutral thermal generation in final year of horizon when system is required to be 100% carbon-neutral.

# 5. Long-term planning approach

Long-term planning refers to a utility planning today for expected conditions 10, 20, 30 years into the future. A practical reason for the need for such plans is that permitting, tendering, and building a power plant can take 5-10 years in some cases. In the context of the United States, this process is formally called Integrated Resource Planning (IRP). The goal of an IRP is to provide a plan to deliver affordable and reliable energy to ratepayers. A utility portfolio plan is considered affordable in most contexts by proving it is the lowest cost. The most common way a utility determines the "least-cost portfolio" is through use of capacity expansion models (CEMs).

### 5.1 CAPACITY EXPANSION MODEL (CEM)

A capacity expansion model is a mathematical optimization tool that accounts for utility assets and their running costs, expected retirements of assets, a pool of potential new-build generation options, and information on load growth and future fuel prices, as well as the expected generation patterns of VREs like wind and solar. The CEM model finds the specific combination of new-builds and the dates of their installation (by year) across a planning horizon (typically 20 years) that minimizes total cost to ratepayers.

For this work we used the PLEXOS™ software package, in particular the Chrono LTPlan module(s) was applied to the PNM system;

- Across a 20 year planning horizon (2020-2040) with
- Hourly time step- accounting for hourly load and renewable output
- Integer build (thermal)- allowing only whole units of new gas capacity to be installed
- Linear build (Wind, Solar, Storage, PtG)- allows the capacity of these technologies to be optimally installed by year on a "per MW" basis.
- Linear Dispatch- Units are committed on a "per MW" basis, as opposed to integer dispatch (binary on/off).
- Start Cost accounted for (for all technologies for which start costs apply).
- Fixed 15% Capacity Reserve Margin throughout (to be respected every year across the planning horizon).

Each of the 4 scenarios were modeled as described above in a long-term planning context. For each scenario annual and cumulative data was recorded for

- New capacity and retirements across horizon
- Fuel, Fixed O&M and Capital Expenditures (FuelEx, FOM, CapEx respectively)
- $CO_2$ generation
- Proportion of energy from Carbon-Free sources (to be 100% in Scenarios 2, 3 and 4 by 2040).

# 6. Results

### 6.1 CARBON REDUCTION BY SCENARIO

All four scenarios yield dramatic carbon reductions in 2023 and 2033 time frames as thermal retirements are replaced with less carbon intensive replacement options. The three "100%" cases had zero $CO_2$ emissions in the last year of the horizon (in compliance with RPS expectations). The Cost-Optimal case final year $CO_2$ emissions were 80% less than the starting year. The 100% Carbon-Free and 100% Carbon-neutral with PtG curves overlap.

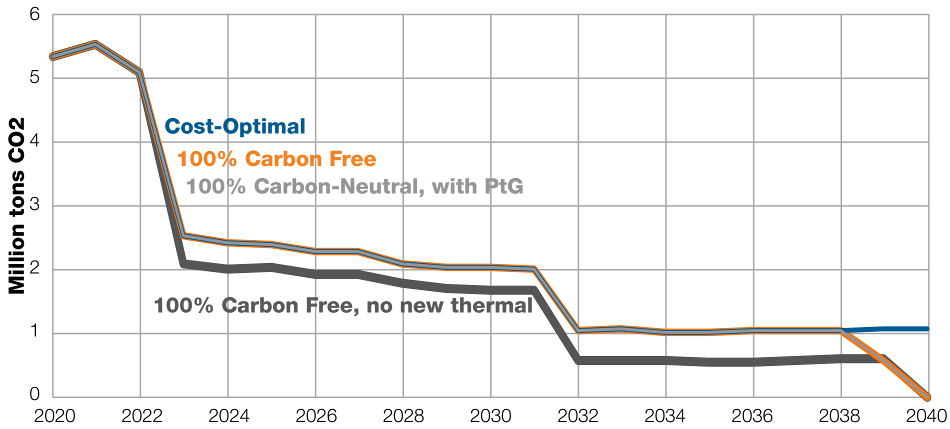


**Figure 6.1-1.** $CO_2$ emissions by year for each of the four Scenarios.

### 6.2 ANNUAL CAPACITY ADDITIONS (AND RETIREMENTS) BY SCENARIO

In all four scenarios coal retirements occur as scheduled in 2023 and 2033. In all scenarios except "no new thermal", the initial coal retirement is offset by addition of flexible (Recip) and peaking (GT) gas capacity. Later coal retirements (2033) in all cases are offset by a mixture of wind, solar and energy storage. In the final year of the horizon for 100% carbon free cases (Fig 6.2-1 B & C) all thermal capacity must be retired as of 2040, necessitating massive buildouts of wind, solar and energy storage. For the carbon neutral PtG scenario (Fig 6.2-1 D) the entire thermal fleet is retained to meet load/reliability as needed, with renewable fuel provided by PtG assets. Large investments in wind and solar are still added in the PtG scenario, with substantially less energy storage than the prior 3 Scenarios.

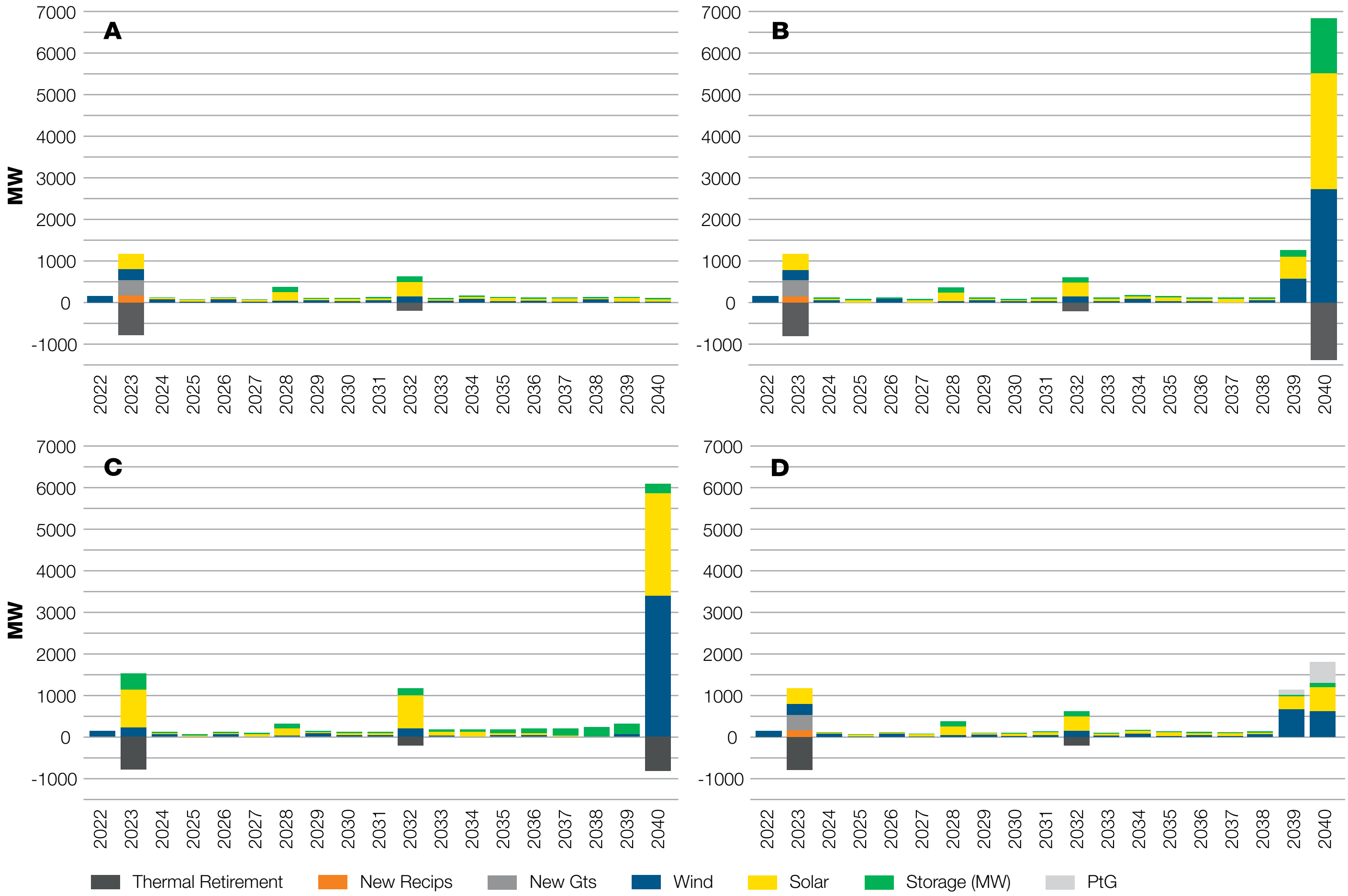


**Figure 6.2-1.** Annual capacity additions (and retirements) by Scenario. Cost-Optimal (A), 100% Carbon Free (B), 100% Carbon Free, no new thermal (C), 100% Carbon Neutral, with PtG (D)

Further detail is provided on the capacity (MW) and energy (MWh) characteristics of traditional energy storage buildouts across scenarios (Fig. 6.2-2). Traditional energy storage (batteries) were selected by the capacity expansion model as either 4 or 8 hour duration, with shorter durations (1 hour) not chosen due to higher capital costs on a per-MWh basis. The average ensemble storage durations of the Cost Optimal and PtG scenarios were 4.2 and 4.9 hours respectively, while for the 100% Carbon-free scenarios durations were approximately 7 hours for each.

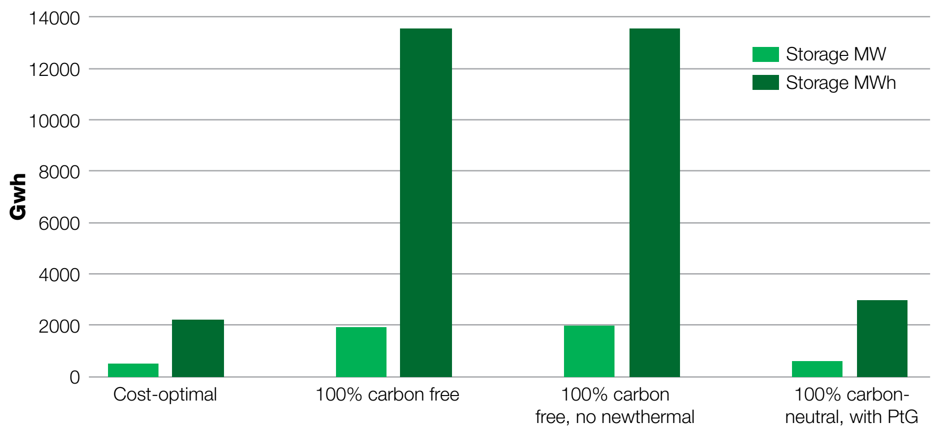


**Figure 6.2-2.** Total Traditional (Battery) Storage Capacity and GWh installed by Scenario, year 2040.

### 6.3 ANNUALIZED ENERGY BALANCE BY SCENARIO

The sum of all generation must equal load. However, for 100% carbon-free systems (year 2040, Figs 6.3-1 B, C) the total load is larger than customer demand by the amount of energy (MWh) needed to charge traditional storage devices and/or PtG technologies (e.g., year 2040, Fig 6.3-1D). Minimum GWh requirements, particularly for the final year of the horizon, occurred for the Cost-Optimal case (Fig 6.3-1A). In the PtG Scenario "Thermal" units are running, using renewable gas, but their use is limited (Figure 6.3-1D) in terms of GWh and confined to four power plants: The two existing Combined Cycles (415 MW of capacity) and the new-build Reciprocating engine plant (166 MW) and 374 MW of new-build peaking GTs. The remaining (existing) thermal capacity was not used at all in the final year of the horizon.

More details, including over-generation from wind and solar, are shown in Fig 6.3-2. Overgeneration is minimized in the Cost-Optimal and PtG cases, and maximized for the 100% Carbon Free scenarios. For the Carbon-Free 100% scenarios extensive over-build of wind, solar and battery storage is needed to cover the low-wind months in the summer, which means in the rest of the year there is too much renewable capacity. For this modeling study wind was given a slightly larger VOM charge, which in turn led to higher levels of wind over-generation than solar (Fig 6.3-2 B, C in particular).

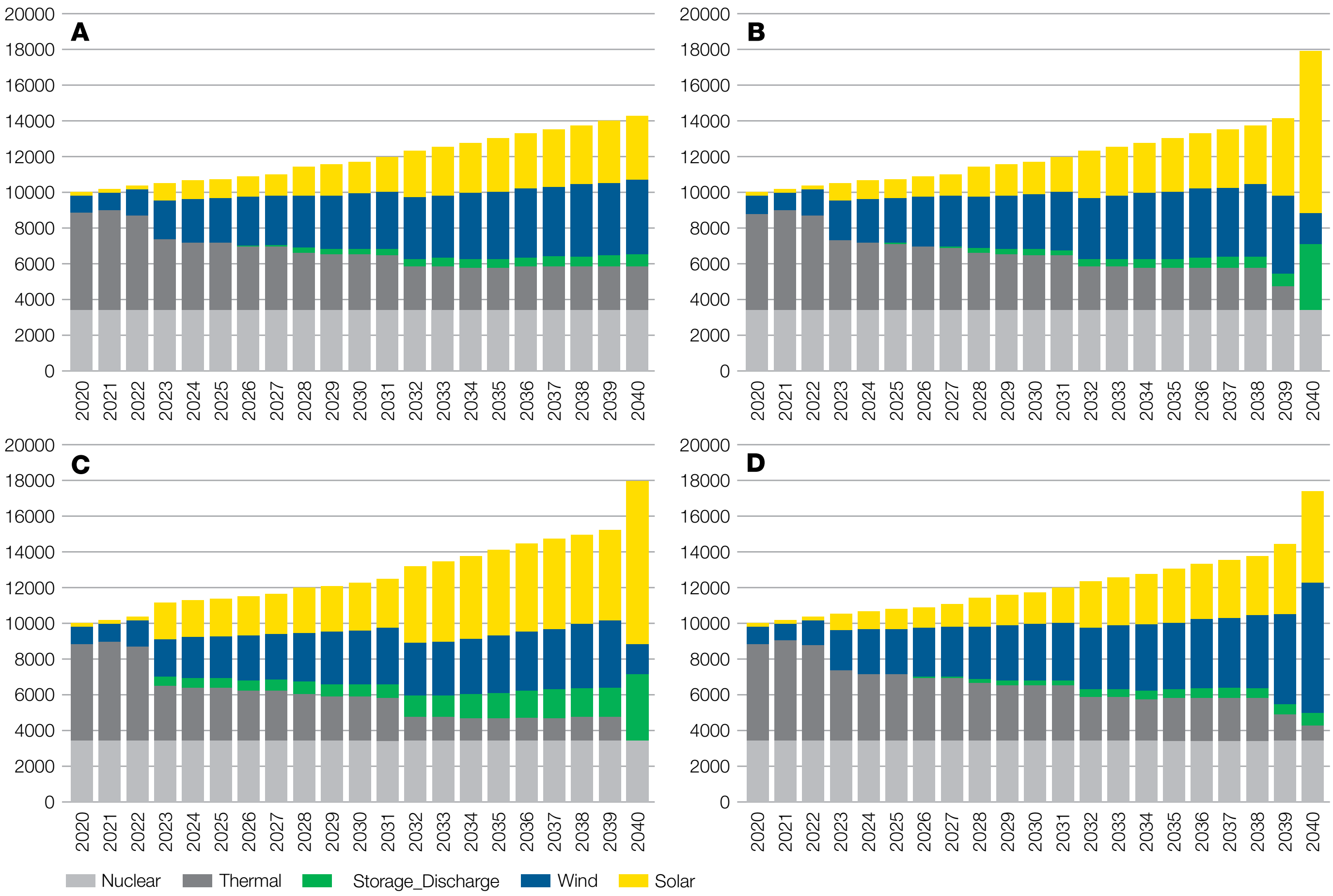


**Figure 6.3-1.** Energy Balance (annual GWh) indicating load serving contribution from nuclear, thermal, storage-discharge, wind and solar. Cost-Optimal (A), 100% Carbon Free (B), 100% Carbon Free, no new thermal (C), 100% Carbon Neutral, with PtG (D)

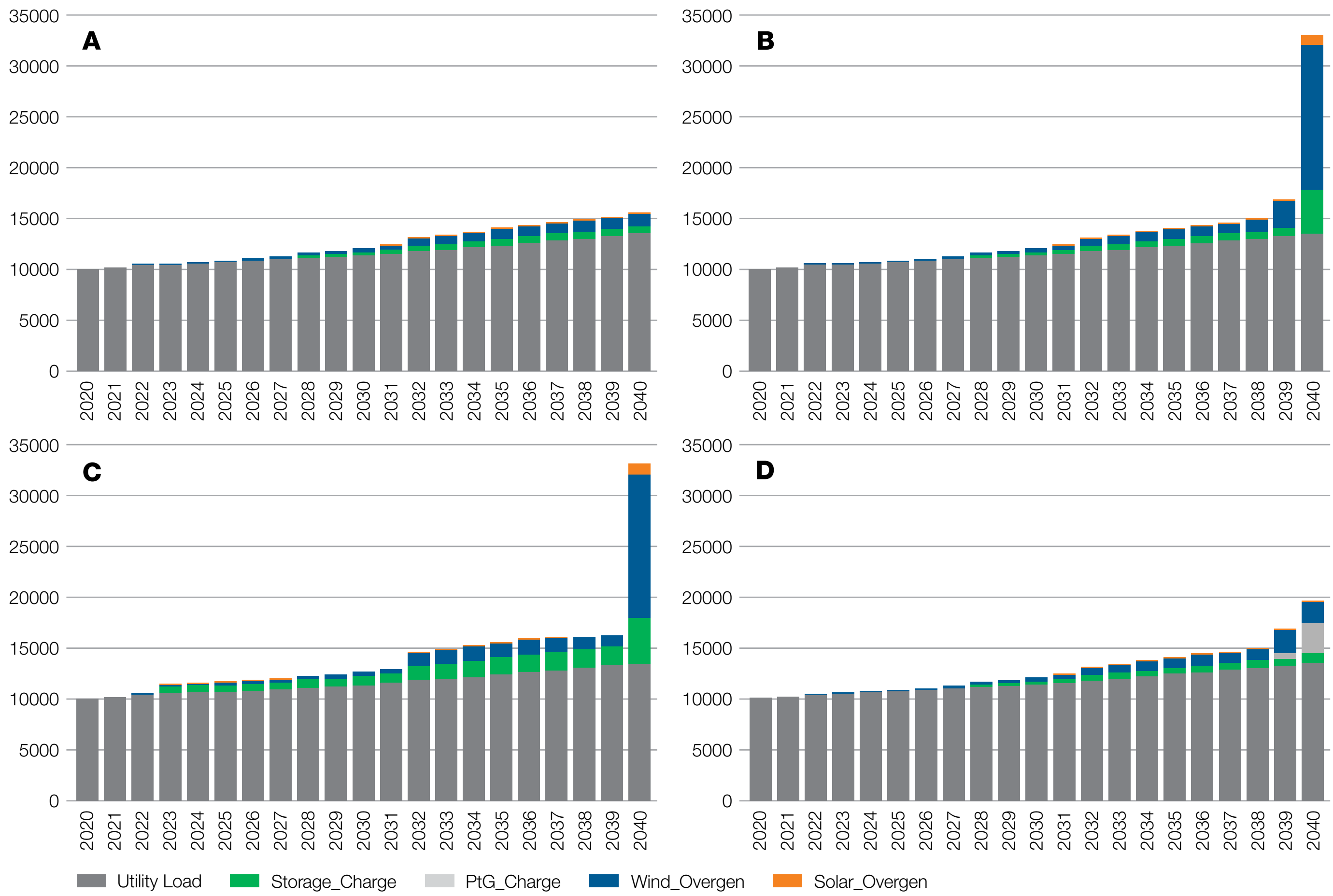


**Figure 6.3-2.** Energy Balance (GWh) indicating allocation of all energy generated or potentially generated (overgeneration, which could also equate to curtailment). The Utility Load plus Storage Charging and PtG Charging is the sum of all load generation must satisfy and equals the generation totals in Figure 6.3-1. Also indicated are Wind_Overgen and Solar_Overgen, which represent the excess generation capabilities of each resource, which must be dumped or curtailed in some manner, and represents an inefficiency in the system. Cost-Optimal (A), 100% Carbon Free (B), 100% Carbon Free, no new thermal (C), 100% Carbon Neutral, with PtG (D).

### 6.4 POWER-TO-GAS CHARACTERISTICS, CHARGING, DISCHARGING, USE BY EXISTING THERMAL

The dynamics of the portfolio in the PtG scenario producing synthetic methane was a bit different than the prior scenarios in that the purpose of PtG is to generate and store renewable fuel for long-term use in existing thermal facilities, a mechanism not available to the 100% carbon free scenarios. The installation/use of PtG technology was not exhibited until the final years of the planning horizon (2039, 2040), and came into use for energy balancing in 2040, when the system was expected to be 100% carbon-neutral (e.g. Fig 6.2-1 D).

Renewable gas production and use was in-phase with wind profiles (Fig. 6.4-1). Production occurred in months 1-5 and again in months 9-12, while the net bank of fuel GWh was drawn down from months 6-8. The drawdown of synthetic methane occurred during the summer months of falling wind capacity factor, where renewable gas was converted to MWh in existing thermal power plants. But not all facilities were used. In 2040 only four power plants were dispatched with renewable gas: The two CCGTs (415 MW), the new-build Recip plant (166 MW) and the new-build peaking GT Plant (374 MW).

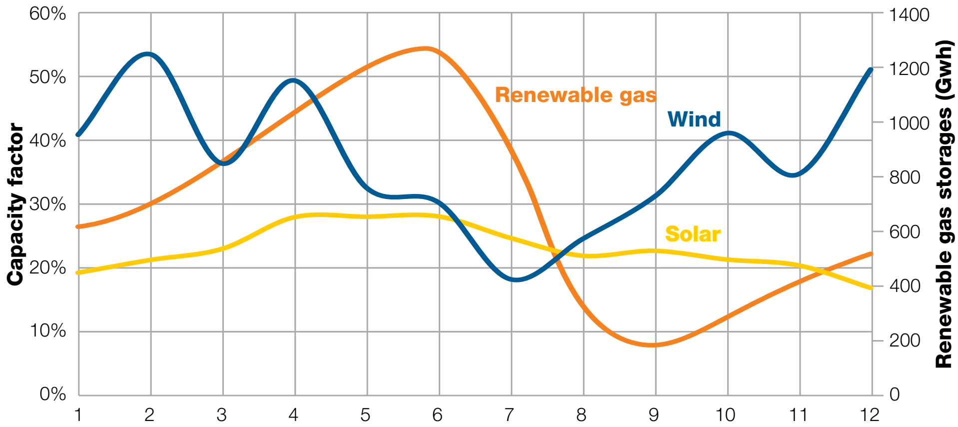


**Figure 6.4-1** Monthly solar and wind capacity factors, and average monthly renewable gas storage and use by existing thermal facilities.

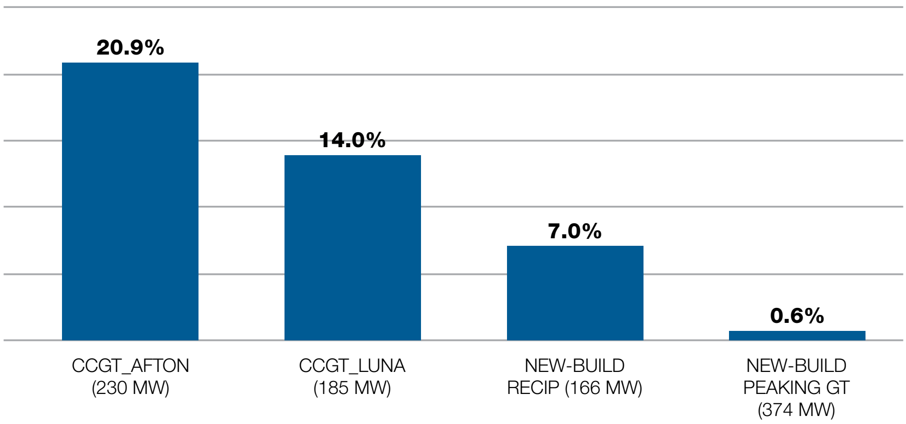


**Figure 6.4-2.** Capacity factor of thermal assets in 2040 for 100% Carbon-Neutral scenario using PtG technology for production of renewable gas.

Given the amount of thermal capacity used by the system in 2040 (Fig 6.4-2), their heat rates (efficiency expressed as MBtu or MWh of fuel consumed to generate 1 MWh of electricity), and the peak volume of renewable-gas generated (Fig 6.4-1), **the combination of thermal capacity and renewable gas is the equivalent of a 955 MW "battery" with a duration of 554 hours (23 days).**

### 6.5 ANNUALIZED PORTFOLIO COSTS BY SCENARIO

The Cost-Optimal scenario has steadily increasing costs across the horizon as the portfolio adjusts to modest load growth and seeks to capitalize on ever-falling costs for energy storage, wind and solar (Fig. 6.5 A). Even so, in the 2023 time frame the lowest cost replacement of coal retirement is a mix of wind, solar, flexible Reciprocating engines and peaking GTs, which is true also for the 100% carbon-free and carbon-neutral with PtG Scenarios. For the "no new thermal" Scenario (Fig 6.5 C) higher costs occur during the coal-retirement time frames as the blend of wind, solar and storage to replace, especially in 2023 time frame, is more expensive than thermal. In both 100% carbon free cases (Fig 6.5 B, C) significant capital expenditures occur at the end of the horizon as ALL thermal capacity (for reliability and energy provision) must be replaced entirely with a blend of wind, solar and massive amounts of energy storage. For the PtG

Scenario (Fig 6.5 D) natural gas as a fuel is discarded entirely at the end of the horizon, and an alternate form of energy storage (PtG) is installed to leverage the existing thermal capacity, resulting in far lower "last year" annual costs relative to the 100% wind + solar + traditional energy storage approaches.

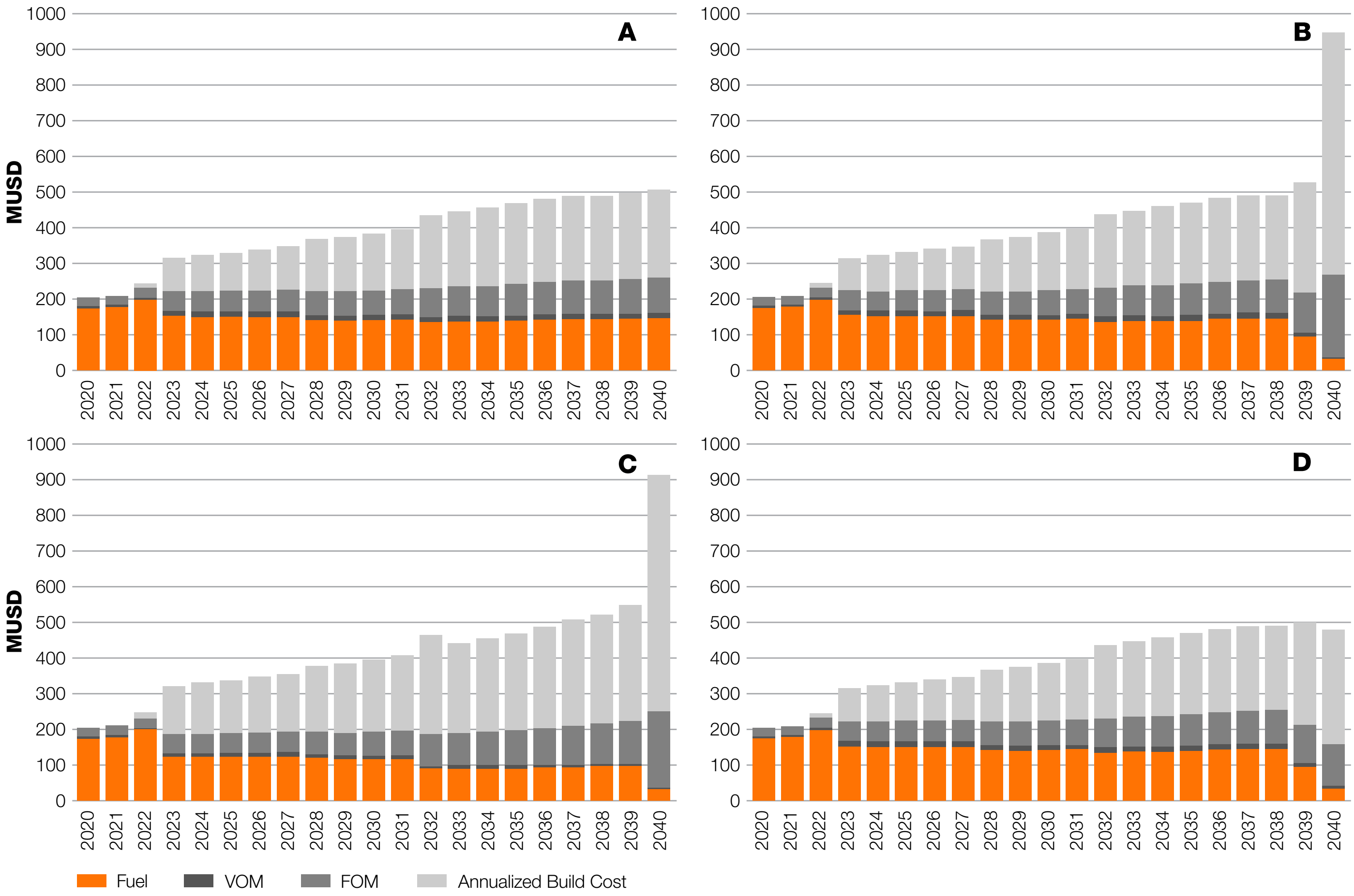


**Figure 6.5.** Annualized portfolio costs by Scenario. Cost-Optimal (A), 100% Carbon Free (B), 100% Carbon Free, no new thermal (C), 100% Carbon Neutral with PtG (D)

### 6.6 NPV AND $/MWH COSTS BY SCENARIO- CARBON-NEUTRAL WITH PTG THE LEAST EXPENSIVE, CARBON-FREE THE MOST EXPENSIVE

The 20-year net present value (NPV) was calculated for the four scenarios (Fig. 6.6-1), showing the following and accounting for "end effects" (e.g., [27,28]):

- To get to 100% carbon-free, the all-in cost (NPV basis) is 37% higher than the cost-optimal case. That is, the cost of moving from 80% carbon reduction to 100% carbon-free requires a 37% cost premium.
  - The reason for the significant cost-adder is the large magnitudes of wind, solar and Li-Ion battery capacity needed to serve load in the absence of any thermal generation at all, specifically in low-wind and low-solar months.
  - This NPV values (6.6-1) are the cost of traveling the "path to 100%" and, even with end-effect accounting, heavily discount the huge wind, solar and battery storage in the last year(s) of the 20-year horizon.
- The lowest cost option of those evaluated is the 100% carbon-neutral scenario with PtG.

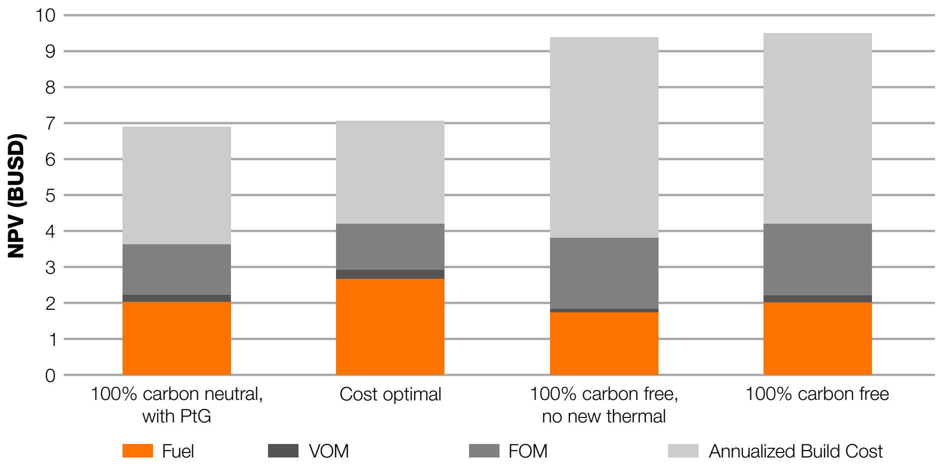


**Figure 6.6-1.** Net Present Value (NPV) of scenarios ranked by cost, from lowest (left) to highest (right).

When looking at the final year of the horizon (the first year the system is actually carbon-free or carbon-neutral for all but the cost-optimal scenario), the costs for carbon-free scenarios is significantly higher (Fig. 6.5). The majority of the costs are annualized and recurring capital expenditures similar to a mortgage payment on a house. These payments represent the ongoing cost of maintaining a carbon-free system where the majority of capacity has little to no variable cost but high capital cost. Under such a framework, taking the annual cost (year 2040, Fig. 6.5) and dividing by annual utility load (MWh) we arrive at Figure 6.6-2.

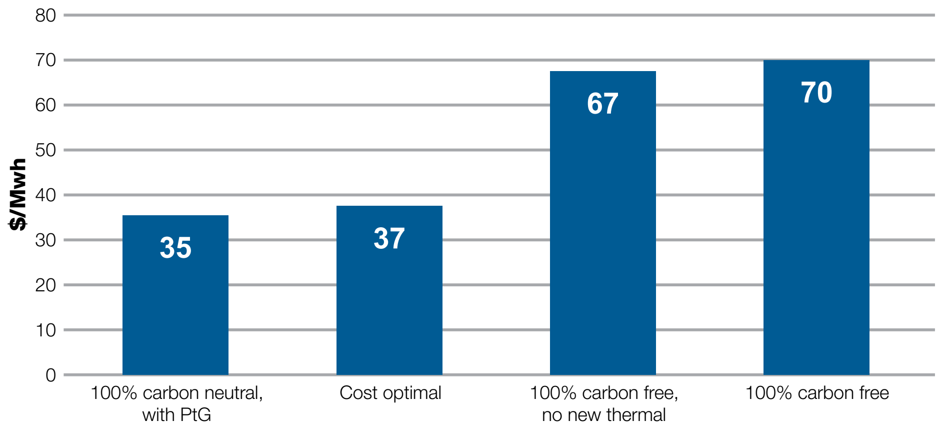


**Figure 6.6-2.** Cost of energy ($/MWh) for 2040 and beyond.

These results indicate that a 100% carbon-free power system will result in ratepayer costs double that of a carbon-neutral system. And that a carbon-neutral system using power-to-gas (methane) is equivalent to or less expensive than a system with 80% carbon-free energy but still allowing for the use of fossil fuels.

# 7. Discussion

**7.1 ECONOMICS ALONE CAN GET US FAR ALONG THE PATH TO 100%**

In the absence of any mandated $CO_2$ reductions, renewable portfolio standards, subsidies or carbon taxes, the results here show that a typical US electric utility can achieve significant carbon reductions just based on economic considerations alone. In the case of PNM the bulk annual $CO_2$ emissions in 2040 were 80% less than in 2020, even though load was higher in 2040 than 2020. The implications are that electric utilities can reasonably expect to achieve high renewable penetrations and dramatic $CO_2$ reductions independent of policy, driven mainly by the falling price curves of wind, solar and battery storage. In this type of scenario tremendous volumes of wind and solar capacity are installed along with battery storage, but the underlying thermal fleet is retained for reliability purposes and for arbitrage, balancing the cost of renewables plus storage against gas generation. When renewable electrons are scarce and batteries coping with charge/discharge cycles, gas generation fills the gaps. But these gaps represent only about 20% of the utility load annually.

**7.2 THE PATH TO 100% CARBON FREE IS THE MOST EXPENSIVE OPTION**

**The path to a 100% carbon-free portfolio that disallows combustion of renewable fuels is the most expensive option.** If a utility must be 100% carbon-free, reliant on nuclear and hydro, VREs such as wind and solar, and storage alternatives (like batteries) which are almost universally sub 12-hour duration, a necessary consequence is overbuild. Wind and solar capacity must be installed in large enough quantities to meet demand even when wind is sporadic or not blowing at all, and/or when solar is minimized due to day length or cloud cover. Energy storage is required in large volumes to account for missing renewable energy. In this work the 100% carbon-free scenarios required more than 3X the combined capacity of wind and solar, and more than 6X the amount of storage energy (MWh) than the Cost-Optimal scenario.

Any renewable mandate that disallows combustion of renewable fuels will necessitate the retirement and decommissioning of every thermal asset and the entirety of the fuel infrastructure. Capturing the full cost of this process is complex and beyond the scope of this work, but the costs are non-trivial (e.g., see [29,30]). In addition, any system that places heavy reliance on Li-Ion batteries will need to account for degradation and performance loss, which in effect requires complete or partial replacement of the battery modules every ten years or so.

In terms of inefficiencies, for the year 2040 when the 100% target is reached, in the carbon-free scenarios approximately 50% of renewable energy (GWh on an annual basis) from wind and solar is in excess of what the system can absorb, resulting in curtailment. This means wind and solar capacity is by no means delivering energy at the expected $/kWh because the capacity factors are reduced considerably relative to what they could produce if left "free" to generate. This implies ratepayers are paying for renewable capacity that is not used to its full potential. It also means that independent power producers (IPPs) under contract to deliver renewable MWh are at risk of being paid for substantially less MWh than their assets actually generate.

**7.3 THE PATH TO 100% CARBON-NEUTRAL (WITH RENEWABLE PTG) IS THE LEAST EXPENSIVE OPTION**

**The path to 100% carbon neutral is the least expensive pathway that satisfies IPCC requirements for net zero $CO_2$ emissions by 2050.** Power-to-Gas (methane) technology can provide weeks to months of fuel volumes for use in existing thermal capacity. For the utility analyzed here, combining the stored fuel potential with thermal capacity yields what is, in effect, a massive long-duration energy storage system (955 MW by 554 hour duration). To attend to seasonal variations in wind, solar and hydro resources, as well as atypical but not unexpected periods of low renewable generation, electric utility systems need storage systems with durations in excess of 10-12 hours, and PtG technology allows for this provision in a cost optimal way relative to battery storage technology. This does not mean PtG would supplant the need for batteries, rather that PtG would supplement the use of more traditional storage technologies for cost-optimal outcomes and to assure reliability. Our findings reflect recent publications that reach similar conclusions, that PtG is most effective for high renewable systems (approaching 100%) [31], and that a combination of storage technologies (including PtG) yields a lower cost system than one that relies entirely on battery storage [23]

The use of renewable, carbon-neutral fuels is not new to the utility industry and has a long history in the form of biofuels. For example, Hawaii Electric Company (HECO) is subject to a 100% renewable mandate and envisions use of existing thermal assets burning biofuels to achieve this goal [32]. Investment in flexible, high efficiency simple cycle capacity, such as Reciprocating Engines, combined with renewable fuels, allows for a complement to battery storage systems [33] similar to what was illustrated with the PtG Scenario in this work. The choice of thermal plus biofuels provides firm capacity with hundreds of hours of duration acting in effect as a giant battery, offsetting the much higher cost of providing the same energy via massive overbuilds of wind, solar and traditional energy storage mechanisms such as batteries.

Biofuels, while considered renewable (and carbon-neutral, or in effect carbon-free), have limitations related to costs and availability. Expansion of plant-based biofuels requires use of arable land for crop production that competes with the same for food production. Other biofuels, such as methane recovery from livestock production and wastewater treatment plants, offer a renewable source of biofuels, but have a finite limit on production not commensurate with the full needs of a large electric utility. Biofuels can and will play a part in decarbonization schemes but will need to be supplemented with power-to-gas approaches, which can be installed anywhere and need only access to air and water.

### 7.4 PATHWAYS TO 100% REQUIRE ADDITIONAL FLEXIBLE GAS CAPACITY

**Flexible gas capacity is part of the preferred pathway for a cost-optimal completion of the path to 100%.** Many utilities across the world are retiring slower, inflexible and inefficient baseload units as they phase in greater amounts of wind and solar. The retirements are less related to generation cost ($/MWh) and more a function of the impact renewables have on dispatch decisions grid operators must make. Hour to hour (and minute to minute) dispatch of assets across a portfolio to meet load is typically based on a dispatch stack with lowest variable cost units dispatched first, and the most expensive units dispatched last (variable cost = fuel + variable operations & maintenance, or VOM). Renewables have very low variable cost, so their MWh are taken first. The next units to be dispatched based on fuel + VOM would typically be large baseload coal or large combined cycle gas turbines. These large thermal units generally have the lowest $/MWh operations cost. *However, baseload thermal units such as boilers and gas-turbine combined cycles are not designed for cyclic operation, and have operational constraints such as;*

- **Long start times:** Once the dispatch order is given, the units can take at least one hour, if not several hours, to come to full load.
- **Minimum run time:** Once the units are started, they must run 2, 4, 6 or more hours. This is necessary to avoid thermal stresses that can lead to forced outages.
- **Minimum down time:** Once the units are shut down, they must stay down for multi-hour periods. This allows cooling of thermal components in a way that alleviates stress (and maintains reliability).
- **Start Cost:** Many baseload type units were designed to start infrequently (several times a year). If they are subjected to more frequent starts, the consequence is higher maintenance costs. While the actual maintenance costs may be spread over multiple years, for cost recovery the most common approach is to define a maintenance-based start cost, $/Start. For large coal or combined cycle plants these costs can be in the range of 5,000 to 10,000 $/start for every 100 MW of capacity.

As wind and solar output rapidly change throughout the day, the resultant net load becomes ever more volatile. Periods occur where the baseload units would be dispatched based on cost but cannot be dispatched due to their operational constraints. If power is only needed for 20 or 30 minutes, large coal or combined cycles can't get to full load before they are no longer needed. If power is needed for 1-2 hours, even if the units can start fast enough, their min run times may require them to stay on (and burn fuel) beyond the time their MWh are needed. Even if a baseload plant is started to meet load for a multi-hour period, there may be several more hours they are needed later in the day, with time periods in between shorter than the min down time, meaning the units would either have to run (and lose money) to meet load in both time periods, or shut down after the first and not be available for the second. And finally, greater renewable penetration generally reduces variable cost of energy, which means inflexible boiler or CCGT plants may be able to dispatch without violating operational constraints, yet not make enough revenue to cover their start costs. For all the reasons above, as renewable penetrations increase, large baseload units become uneconomic and infeasible as primary energy sources. This is evidenced in the market today in places like California, where market price volatility with a modest 30% renewable penetration (on an annual GWh basis) is forcing combined cycles to retire decades before the end of their technical or commercial life [34].

The types of thermal units that make the most sense in a high renewable, low-carbon energy system are flexible simple cycle assets. These can come in two forms;

1. Flexible, high efficiency Reciprocating engines.
2. Low cost peaking units

Reciprocating engines can come to full load in 5-minutes or less, have efficiencies rivaling some combined cycles, no min up time constraints, have wide operating ranges (10% min load), and very fast ramp rates (min to full load in seconds). Operationally they are the closest thermal option to battery storage in terms of flexibility. The fast-start capabilities of reciprocating engines allow them to jump in and out of real-time energy markets which are typically run on 5-minute increments, supplying energy on an as-needed basis in real-time. Flexible recip capacity is needed in high-renewable systems, greater than 15-20% of annual GWh, to balance minute to minute and hour to hour net load volatility (net load = utility load - renewable MW).

Low cost peaking units, such as Frame or Industrial GTs, also fit into low-carbon systems as they are literally not intended to run much, if at all. Their purpose is to provide the lowest cost option for satisfying capacity reserve margins and to attend to occasional peak loads (hence the term peaking units). Peaking units are not meant for real-time balancing as they have long start times (15 minutes), often have min run times of 1 or more hours, and high maintenance-based start costs.

# 8. Conclusions

Exciting new paradigms are emerging that lead electric utilities to explore pathways towards 100% decarbonization. This work demonstrates that utilities moving towards 100% carbon-free over multi-decade planning horizons will see flexible capacity and peaking assets as part of the cost-optimal new-build capacity mix as the system moves from low to high renewable penetration. The exact mix of capacity types and amounts will be dependent on the utility. However, for a truly 100% carbon-free system all the thermal assets will need to be retired and decommissioned once the target date for zero-carbon intensity approaches. This causes utility executives and the public to question the necessity of adding any new thermal at all if it's only going to be retired ahead of its useful life (leading to stranded asset problems). One approach is to disallow any new thermal at all, which (as shown in this analysis) leads to cost outcomes similar to just allowing thermal in the first place, but still at very high cost to ratepayers (as a result of having to over-install VRE and storage capacity to attend to seasonal fluctuations in wind, solar, hydro production).

An alternative pathway is to define "100%" in alignment with IPCC requirements of net-zero carbon emissions by 2050, which is the same as carbon-neutral. From a climate change perspective, the goal is not to eliminate all forms of $CO_2$, but rather to assure no net increase in atmospheric $CO_2$ concentration. Power-to-Gas uses carbon-free energy to produce renewable methane, $CH_4$. All the carbon in renewable $CH_4$ is taken from $CO_2$ extracted from air and simply recycled back into the atmosphere when combusted in a thermal power plant. The carbon balance is neutral and in agreement with IPCC net-zero requirements. This work shows that;

- A PtG pathway to 100% carbon-neutral outcomes is 37% less expensive than carbon-free (across a 20-year planning horizon) and
- A carbon-neutral system with PtG will cost ratepayers half that of a carbon-free system (on a $/MWh basis)

The net-zero concept is important to understand, as it achieves the goal of no net increase in $CO_2$, but it does not manifest itself in the form of mandatory requirements as defined in many Renewable Portfolio Standards, or in systems declaring they will only obtain 100% renewable energy (which many believe necessitates provision of MWh only from wind, solar, hydro, geothermal or maybe biofuels). As shown here, power systems designed for "100% carbon-free" are significantly more expensive than the net-zero (carbon-neutral) approach. What's more, net-zero allows for a wider diversity of technology choices utilities can consider as they move towards carbon-neutral, including whatever thermal assets are considered necessary, as these units will be an integral part of the 100% carbon-neutral system. It is vitally important for policy makers, utility executives and others in the energy space to convey this information to the public so that the average person concerned about climate change is not immediately opposed to any new thermal generation. New thermal generation will continue to play a decreasing role in provision of MWh, with ever-more being provided by renewable sources, but is still a critical piece of the net-zero, carbon-neutral paradigm.

Power-to-Gas ($CH_4$) is an integral component of net-zero pathways, providing a mechanism for seasonal energy shifting to complement the shorter-term storage technologies, and reduces over-generation by optimizing utilization of renewable resources. Unlike Hydrogen as a renewable fuel, renewable methane can directly interface with all existing natural gas storage and distribution systems and be used to power natural gas capacity utilities own, assuring flexible thermal assets installed today will never become stranded assets.

# Bibliography


[1] 100% Commitment in Cities, Counties and States. Sierra Club., (n.d.). https://www.sierraclub.org/ready-for-100/commitments (accessed April 19, 2015).

[2] M. Coren, Two US electric utilities have promised to go 100% carbon-free—and admit it's cheaper, Quartz. (2018). https://qz.com/1490832/two-utilities-promised-to-go-100-carbon-free-last-week/.

[3] S. Ptacek, S, Carter, More Utilities Make Big Commitments to Climate Action. Natural Resources Defense Council., (2019). https://www.nrdc.org/experts/sophia-ptacek/more-utilities-make-big-commitments-climate-action (accessed June 19, 2011).

[4] M. Fraende, Denmark aims for 100 percent renewable energy in 2050, Reuters. (2011). https://www.reuters.com/article/us-denmark-energy/denmark-aims-for-100-percent-renewable-energy-in-2050-idUSTRE7AO15120111125.

[5] T. Love, Scotland Will Run on 100% Renewable Energy by 2020, GreenMatters.Com. (2019). https://www.greenmatters.com/renewables/2017/11/08/Z2rjgAy/scotland-2020-solar.

[6] Summary for Policymakers of IPCC Special Report on Global Warming of 1.5°C approved by governments. Intergovernmental Panel on Climate Change., 2018. https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/.

[7] Sources of Greenhouse Gas Emissions. U.S. Environmental Protection Agency., (2019). https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions (accessed March 19, 2019).

[8] Electricity Data. U.S. Energy Information Agency., (2019). https://www.eia.gov/electricity/data.php#gencapacity (accessed February 19, 2004).

[9] Public Service of New Mexico. Electric Integrated Resource Plan, 2011-2030, 2011. https://www.pnm.com/documents/396023/396193/2011_IRP_final/af9ea6f6-59e2-4a29-aca9-26bde3cd4b03.

[10] Public Service of New Mexico. Integrated Resource Plan, 2014-2033., 2014. https://www.pnm.com/documents/396023/396193/PNM+2014+IRP/bdccdd52-b0bc-480b-b1d6-cf76c408fdfc.

[11] Public Service of New Mexico. Integrated Resource Plan, 2017-2036, 2017. https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed.

[12] G. Bade, New Mexico regulators approve PNM plan to phase out coal by 2031, Util. Dive. (2018). https://www.utilitydive.com/news/new-mexico-regulators-approve-pnm-plan-to-phase-out-coal-by-2031/544859/.

[13] PNM makes historical announcement about New Mexico's energy future. Public Service of New Mexico., (2019). https://www.pnm.com/042219-pathto100.

[14] Bloomberg NEF, LCOE Analysis, 2019.

[15] Wind Prospector, U.S. National Renewable Energy Laboratory., 2019. (n.d.). https://maps.nrel.gov/wind-prospector/ (accessed 19.01.23).

[16] Solar Power Data for Integration Studies. U.S. National Renewable Energy Laboratory., (2019). https://www.nrel.gov/grid/solar-power-data.html (accessed 19.01.27).

[17] Electric Power Monthly. U.S. Energy Information Agency., (n.d.). https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

[18] Wind generation seasonal patterns vary across the United States. U.S. Energy Information Agency. 15.02.25., n.d. https://www.eia.gov/todayinenergy/detail.php?id=20112#.

[19] P. Gleick, Impacts of California's Ongoing Drought: Hydroelectricity Generation 2015 Update, 2016. https://pacinst.org/wp-content/uploads/2016/02/Impacts-Californias-Ongoing-Drought-Hydroelectricity-Generation-2015-Update.pdf.

[20] W. Zambon, Renato, Barros, Mario, Yeh, Impacts of the 2012–2015 Drought on the Brazilian Hydropower System, in: World Environ. Water Resour. Congr. 2016, 2016. **https://ascelibrary.org/doi/10.1061/9780784479858.010**.

[21] R. Morison, Britain has gone nine days without wind power. Bloomberg., Bloom. News. (2018). **bloomberg.com/news/articles/2018-06-07/u-k-wind-drought-heads-into-9th-day-with-no-relief-for-weeks**.

[22] Solar Power in New England: Concentration and Impact. ISO New England., (2019). **https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact**.

[23] A. Breyer, C, Fasihi, M, Aghahosseini, Carbon dioxide direct air capture for effective climate change mitigation based on renewable electricity: a new type of energy system sector coupling., Mitig. Adapt. Strateg. Glob. Chang. (2019). **https://link.springer.com/article/10.1007/s11027-019-9847-y**.

[24] S. MacKinnan, MA, Brouwer, J, Samuelsen, The role of natural gas and its infrastructure in mitigating greenhouse gas emissions, improving regional air quality, and renewable resource integration, Prog. Energy Combust. Sci. 64 (2018) 62–92.

[25] Technical Correspondence between Wartsila (Helsinki) and Lappeenranta University of Technology, Finland, (2019).

[26] M. Thema, M, Bauer, F, Sterner, Power-to-Gas: Electrolysis and methanation status review, Renew. Sustain. Energy Rev. 112 (2019) 775–787.

[27] B. Wilson, R, Biewald, Best Practices in Electric Utility Integrated Resource Planning: Examples of state regulations and recent utility plans. Synapse Energy Economics, Inc., 2013. **https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf**.

[28] Y. Hadley, SW, You, S, Shankar, M, Liu, Electric Grid Expansion Planning with High Levels of Variable Generation. Oak Ridge National Laboratory report # ORNL/TM-2015/515., 2016. **https://info.ornl.gov/sites/publications/Files/Pub59037.pdf**.

[29] D. Raimi, Decommissioning U.S. Power Plants; decisions, costs and key issues. Resources for the Future (RFF) Report., 2017. **https://media.rff.org/documents/RFF20Rpt20Decommissioning20Power20Plants.pdf**.

[30] C. Roselund, Rush to gas risks hundreds of billions in stranded assets, PV Mag. (2018). **https://pv-magazine-usa.com/2018/05/22/rush-to-gas-risks-hundreds-of-billions-in-stranded-assets/**.

[31] A. Blanco, H, Faaij, A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage, Renew. Sustain. Energy Rev. 81 (2018) 1049–1086.

[32] Hawaiian Electric Renewable Energy Sources, Biofuels., (2019). **https://www.hawaiianelectric.com/clean-energy-hawaii/clean-energy-facts/renewable-energy-sources/biofuels** (accessed July 19, 2019).

[33] K. Mcinerney, Schofield Generating Station Highlights Value of Reciprocating Engines, Power Eng. (2017). **https://www.power-eng.com/articles/print/volume-121/issue-8/features/schofield-generating-station-highlights-value-of-reciprocating-engines.html**.

[34] A. Scott, General Electric to scrap California power plant 20 years early, Reuters Bus. News. (2019). **https://www.reuters.com/article/us-ge-power/general-electric-to-scrap-california-power-plant-20-years-early-idUSKCN1TM2MV**

**For questions of comments, please contact**

Joseph Ferrari
General Manager, Utility Market Development
Wartsila North America, Inc.
**Joseph.ferrari@wartsila.com**

**WÄRTSILÄ ENERGY**
**BUSINESS IN BRIEF**

Wärtsilä Energy leads the transition towards a 100% renewable energy future. We help our customers unlock the value of the energy transition by optimising their energy systems and future-proofing their assets. Our offering comprises flexible power plants, energy management systems, and storage, as well as lifecycle services that enable increased efficiency and guaranteed performance. Wärtsilä has 72 GW of installed power plant capacity in 180 countries around the world.

01.2020

wartsila.com/energy



WÄRTSILÄ