December 11, 2022

Options for a Zero Carbon PJM

The design of a zero carbon PJM system begins with architecture, basic structure, the relationship between wind, PV, nuclear and storage. A simple hourly dispatch spreadsheet model quantifies options for reliable Zero Carbon PJM systems. Given historical metered load, the objective is to compare concepts based on system generation cost ($/MWh). Clarity is achieved by minimizing assumptions and unessential detail to focus on structural relationships. At this concept stage, consistency and relative cost/performance are critical, absolute accuracy is not. Assumptions are minimized by scaling wind & PV profiles, using a NREL database for consistent current unit costs, all new construction, no legacy constraints, no learning curves, no load projections, perfect transmission (no loss, no cost), and a closed PJM system. Salient conclusions are:

Any Zero Carbon PJM system is likely to double current generation cost.
Nuclear power is the low-cost zero carbon technology.
The cost of managing intermittency on cleaner systems limits the value of wind and solar.

1.0 NUCLEAR POWER IS THE WORKHORSE

The objective is to clarify the destination. Given what is known today, and enough time and money, what are the cost-optimal proportions of wind, PV, nuclear and storage for a Zero Carbon PJM. 100% clean electric power is a prerequisite for decarbonizing other energy sectors via electrification. Focusing on Zero Carbon with a concept model reduces confusion and ambiguity simplifying the high-level decision-making process.

1.1 CLEAN SYSTEMS DOUBLE THE COST

The zero carbon PJM dilemma is illustrated in Fig 1.1. Imagine todays PJM electric power system approximated as powered by 100% Combined Cycle natural gas (CC). That's this study's reference system, the red square. It's cost of generating electricity is about 5 ¢/kWh, approximates. PJM's market clear price for energy + capacity today.

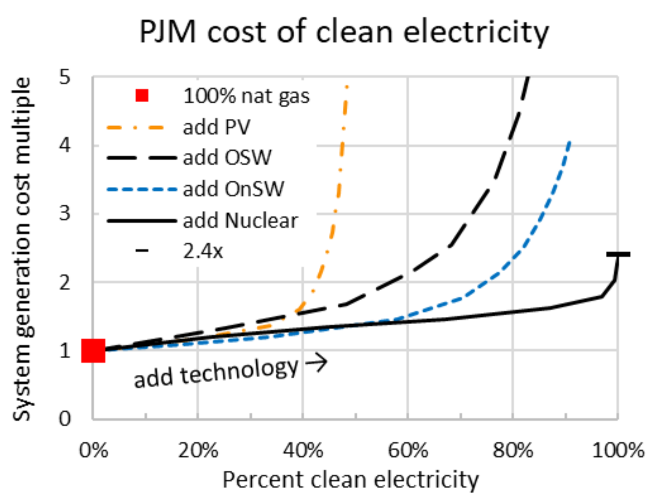

Figure 1.1

Next, add utility scale PV to create a system configuration consisting of CC natural gas + PV. The more PV, the cleaner the system, up to a point. The modeled orange dot-dash cost curve tracks system generation cost. PV alone cannot get past 50% because the sun shines only half the time. Next remove the PV and add Offshore Wind (OSW). System cost is modeled as the long dash cost curve. Then onshore wind (OnSW), then nuclear. The model shows that nuclear is the only single technology that can achieve 100% clean though the cost is high, 2.4x the current cost.

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Fig. 1.1 shows that at low percentages, below 40% clean, it does not matter much what technology is chosen to reduce emissions. In this range any of the chosen technologies displaces natural gas and cleans up the system a little. With the baseline assumptions (§2.1), everything is more costly than natural gas, but not by much. The key question and the focus of this study is the system configuration options for 100% clean. Understanding cost effective zero-carbon options now helps avoid substantial commitments to technologies that have no place on a zero carbon PJM.

1.2 STORAGE HELPS, BUT NOT ENOUGH

Fig 1.2 summarizes concept model results for 100% clean using one and two generator technology systems with Li battery storage. All the system configurations in Fig 1.2 are 100% clean. Relative cost is multiples of the reference cost (the red square in fig 1.1.

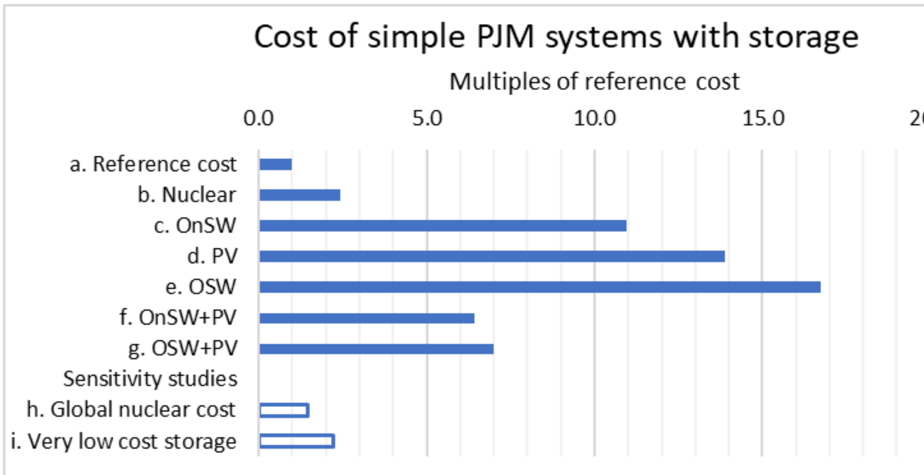

Figure 1.2

a. The reference cost (§3.1) is 5 ¢/kWh.
b. As noted in §1.1, a nuclear-no-storage system configuration (100% peak load nuclear) has a cost of 2.4x using the baseline assumptions §2.1. Adding Li battery (§3.3.1) reduces the blip near 100% clean in Fig 1.1 resulting in a system cost of 2.2x (bar b in Fig 1.2). This technology configuration has the lowest system cost of any investigated with the baseline assumptions §2.1.
c. Technically, overbuilding onshore wind (OnSW) with enough storage (§3.4) would satisfy load but at enormous cost, 11.0x. The essential difficulty is that without cheap natural gas or hydro there is no cost-effective, clean method for managing intermittency.
d. At 13.9x, utility scale PV + Li battery (§3.5) is more costly than OnSW, largely because of a resource deficiency during winter solstice months. This same winter solstice PV problem is evident in PV data published by IESO (Ontario), ERCOT (Texas) and CAISO (California).
e. OffShore (OSW, §3.4) + Li storage is the highest-cost single technology at 16.7x.
f. At 6.4x, the cost-optimal combination of OnSW+PV, with a specific nameplate ratio (§3.6) is lower cost than PV or OnSW alone but still very expensive.
g. Likewise, the cost-optimal combining OSW + PV (§3.7) also reduces cost below OSW & P alone, but it is still very high and impractical at 7x. The cost optimal system is mainly PV with a little OSW.
h. NREL cost data for nuclear power, used for all baseline comparisons herein, is inconsistent with global historical cost data (§4.2). Global experience suggests a nuclear configuration cost potential of 1.4x.
i. Speculative very low-cost storage (unit energy storage cost 8x below Li) makes intermittent generation competitive with but not lower cost than nuclear (§4.2).

1.3 BASELOAD NUCLEAR SIMPLIFIES THE SYSTEM, REDUCING COST

§3.8 extends the optimization analysis to three generator components (wind + PV + nuclear. Fig. 1.3 is a simplified version of Fig 3.9. The horizontal axis is nuclear nameplate as a percentage of peak load. As in Fig. 1.1, the independent variable is relative cost.

With the baseline assumptions, the lowest cost generator is nuclear + LI battery storage, with nuclear sized to 80% of peak load (green diamond). The dashed blue curve in Fig 1.3 shows that below 80%, a nuclear only system becomes expensive because storage requirements become seasonal. Since the system has a 60% load factor (peak/average), nuclear only generators cannot provide the system with enough energy below 60% nameplate.

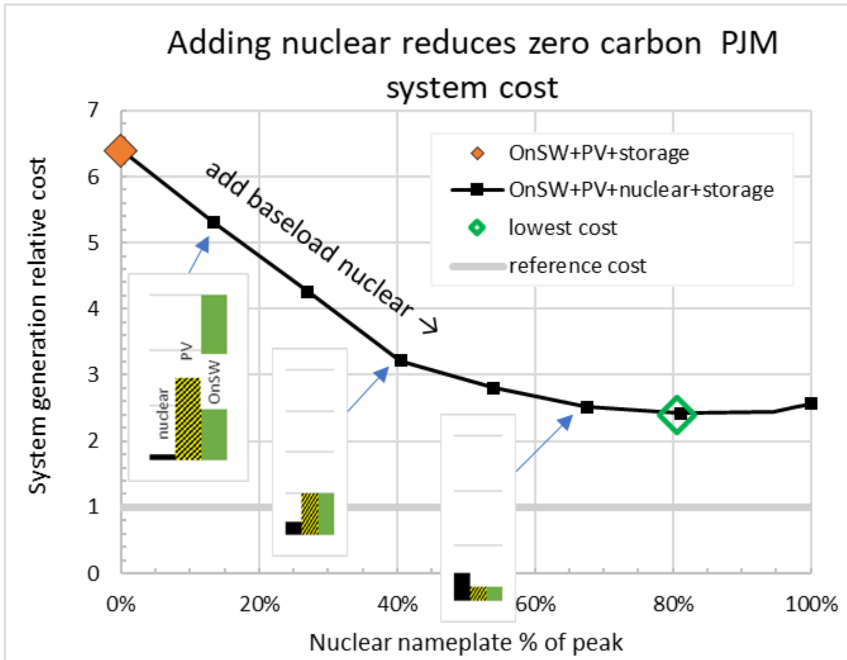

Figure 1.3

The addition of OnSW & PV allows the system to operate with less than 60% nuclear although system costs are always higher than all nuclear. Modest amounts of intermittent generation (<20% of system energy, the purple line between 60-80% nuclear nameplate) have modest impact on system cost. As nuclear nameplate approaches zero and the orange dash curve approaches the vertical axis, OnSW and PV generators dominate, curtailment and storage costs become huge, and system generation cost approaches 6.4x, the same number on bar f of Fig 1.2. 6.4x is the cheapest non-nuclear 100% clean solution.

The three main conclusions of this study:

1. Any 100% clean PJM system is likely to double current generation cost.
2. While storage helps, the cost of managing intermittency on cleaner systems without hydro limits the value of intermittent generators.
3. Nuclear power is the low-cost zero carbon technology.

2.0 METHOD

Minimize assumptions and keep it simple

The method is "Concept Modeling," few components, minimal assumptions, and few variables for the purpose of rapid optimization and highlighting structural relationships. All system configurations are sized to satisfy a historical hourly load profile with no unserved load. This classical engineering development method starts simple and gradually add complexity in stages to build up a full system. This is the first stage. After the destination is identified, then it is rational to develop a roadmap and figure out how to get there from here.

The analysis employs a simple hourly dispatch model coded in an EXCEL spreadsheet. It is available for download with descriptive notes here. The intention is that anyone who understands EXCEL logical IF statements can download the workbook, change the input variables, or modify its functionality. An understanding of higher order computer languages is not necessary. The code is simple and transparent for the user. The main requirement for applying the model to a power grid is hourly profiles for load, wind and PV. Different grids with different renewable resources and the availability of dispatchable hydro would result in different system configurations.

2.1 BASELINE ASSUMPTIONS SIMPLIFY THE MODELING

This concept model uses simple spreadsheet hourly dispatch (§2) to compare the system costs of different technology combinations for a Zero Carbon PJM. The requirement is to satisfy historical load profiles, with no unserved load.

- The requirement is Zero Carbon, no fossil fuel, fully decarbonized electric power.
- Historical hourly load profiles.
- Scaled PJM historical profiles for wind, and PV production for 2021. All comparisons scale the same profiles.
- Assumed PJM RTO capacity factors: OnSW=30%, utility scale PV 17%, OSW=45%.
- No unserved load, no reserves.
- The value metric is the system generation cost (generators + storage) required to satisfy historical conditions. This is comparable to PJM's annual average clearing price for energy plus capacity.
- All new construction, no legacy system constraints, no markets, policy free.
- Unit costs are obtained from the National Renewable Energy Laboratory Advanced Technology Database (NREL/ATB.v1), R&D case (no tax credits or incentives), moderate estimates. Assumptions are minimized by using Real 2020$
- No learning curves or load projections.
- A closed PJM system, no imports/exports.
- Perfect transmission, no cost, no loss.
- Lithium ion (Li) battery storage is assumed for most clean system configurations (note that utility scale application of Li storage is yet to be proven).

2.2 RESOURCE DATA SOURCE

For this paper, all systems were sized for the PJM Regional Transmission Organization (RTO) load for the calendar year 2021. Concurrent hourly wind and utility scale PV production are downloaded and normalized using an estimated capacity factor (CF). The only assumption is CF, everything else is metered production, no modeling of wind and PV from National Weather Service (NWS) data.. An exception to this is offshore wind where no data exists. The model empirically scales concurrent metered data for the mid-Atlantic states as a proxy.

2.3 MODELING LOGIC

Primary inputs are peak load and nameplate values for nuclear, wind, and PV, no fossil fuel. The model uses these inputs to scale hourly profiles for load, wind, and PV. For each hour, available energy production is compared with load. If available energy exceeds load the model charges storage. If available energy is insufficient, the model discharges storage. Nuclear is dispatched first, followed by wind and solar. Since wind and solar have no variable cost, it does not matter which is dispatched before the other. At the end of the run (this study uses one year, 8760 hours) the energy storage profile defines maximum energy storage requirements as well as storage power requirements, and curtailment for that nameplate combination. If the storage level does equal or exceed the level at the beginning of the year, there was insufficient energy and the system was not viable.

NREL/ATB provides unit fixed and variable cost as well as capital recovery factors for each of the technologies. CAPEX is annualized using the capital recovery factor. Total annual cost is divided by total annual production to produce and energy cost $/MWh (dollars per million watt-hours) or cts/kWh.

More detail is provided in the EXCEL workbook notes.

3.0 CONCEPT MODELING RESULTS

All analysis in this section is compliant with the Baseline Assumptions of §2.1. The culmination of the baseline analysis is §3.8, the cost-optimal combinations of onshore wind, utility scale PV and nuclear.

3.1 REFERENCE PJM SYSTEM GENERATION COST - $50/MWh

The reference cost provides a consistent comparison of current costs with the cost of generating 100% clean electricity by optional system configurations. PJM presents the average wholesale clearing price for both energy and capacity markets on the PJM system for 2020 and 2021 in Table 8 of the 2021 PJM som. This price is consistent with the Concept Model as it excludes Transmission, Ancillary Services, Administration and Uplift (reserves). The numbers are summarized in Table 3.1. Note that the wholesale price expressed as $50/MWh (million watt-hour) is equal to 5 cts/kWh (thousand watt-hour). For comparison Maryland's average retail price for 2021 was about 13 cts/kWh.

Reference PJM system cost		
2021 PJM wholesale price*	$50.74	$/MWh
2020 PJM wholesale price*	$31.22	$/MWh
100% combined cycle**	$53.78	$/MWh
Reference cost	$50.00	$/MWh
*https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf		
**Based on a natural gas price of $5/million BTU		

Table 3.1

Note the PJM wholesale electricity price increase between the years 2020 and 2021. This corresponds to a doubling of electric power natural gas prices from 2020 to 2021, which the EIA, World Bank and others regard as transient. The planet has >50 years of proven reserves at current prices and demand.

The 100% combined cycle number is the modeled cost of satisfying the PJM2021 load profile using combined cycle natural gas generators with $5/million BTU and NREL/ATB cost numbers for combined cycle generators. The cost of a new entry combined cycle generator is roughly competitive in the PJM marketplace.

3.2 PJM2021 METERED LOAD

The calendar year 2021 was chosen for analysis. The hourly load profile is presented in Fig. 3.1. Notable details are that the peak load was 149 GW and the average load is 89 GW. If storage were free, the system would require a minimum of 783 TWh of energy generation during the year. But storage is not free, and

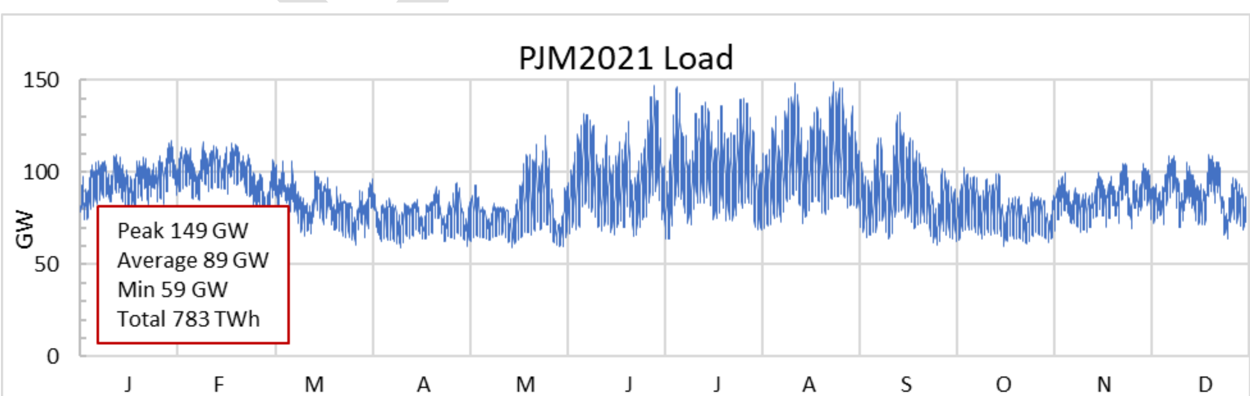

Figure 3.1

it is often cheaper to discard (curtail) the power rather than store it. The analysis in the following sections amounts to finding the cost optimal balance of wind, PV nuclear and storage for PJM2021.

3.3 100% NUCLEAR + LI STORAGE ONLY

100% nuclear means that all the energy is produced by nuclear generators. One system configuration option is to size the nuclear nameplate to equal peak load (no storage). Fig. 3.1 shows that for this configuration, the nuclear capacity factor is only 60%, 40% of the energy that could have been used is discarded ((149-89)/149). Based on the installed capacity of 148 MW, an annual generation of 783 TWh, and NREL/ATB estimates for nuclear, generation system cost is $128/MWh (2.6 x reference). Fig. 3.2 shows that the impact of battery storage is to reduce peak capacity requirements. If the storage is cheaper than the reduction in nuclear capacity, systems with storage would have lower system generation cost.

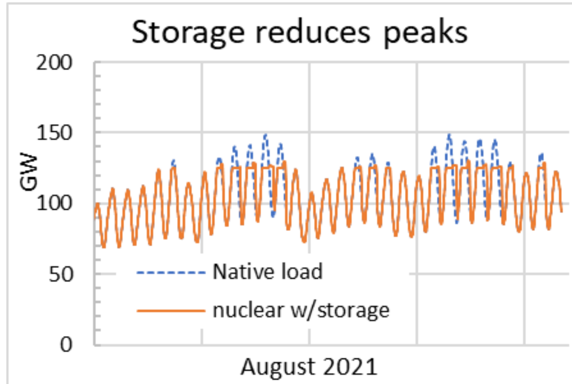

Figure 3.2

Running the model multiple times, calculating storage requirements and system generation cost for each nuclear nameplate, produces the curve presented in Fig. 3.3. Storage does reduce cost but, using NREL/ATB unit cost numbers, only a little, from 2.6x the reference cost to a minimum of 2.4x at a nameplate of 84% of peak. Below this nameplate level, system costs start escalating because the storage is not used efficiently because it is no longer cycled daily.

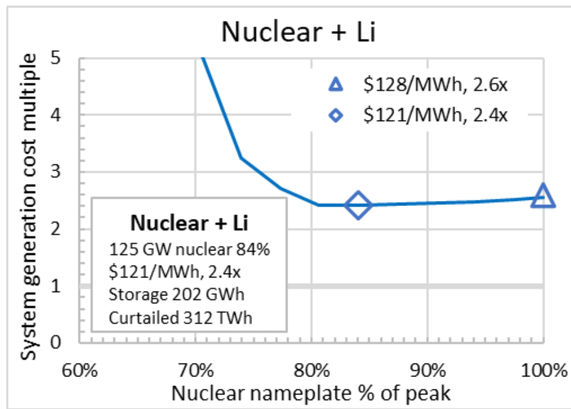

Figure 3.3

Fig. 3.1 shows that the average load for 2021 was 89 GW, 60% of peak. If nuclear nameplate dropped below 60% the system would not have enough energy to satisfy load and the model fails. Also, as nuclear nameplate approaches 60% of peak, storage is seasonal.

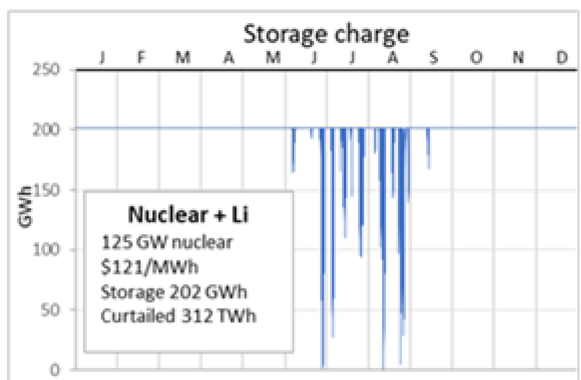

Figure 3.4

At 84% of peak (125 GW nuclear nameplate) hourly storage charge is shown in Fig. 3.4. The model shows that a minimum of 202 GWh storage would be required for 2021. This storage size, 202 GWh, is modest for PJM, ~1.4 hours at full peak power. Cycling is daily.

3.4 100% WIND + LI STORAGE ONLY

By overbuilding PJM wind, and with enough storage, a system that derives 100% of its electricity from wind is technically feasible. Fig. 3.5 shows the model results with baseline assumptions showing that offshore wind (OSW = $837/MWh, 16.7x the reference cost) is 50% more costly than onshore wind (OnSW = $548/MWh, 11.0x the reference cost). Neither of these systems are practical. The cost is too high, mainly the result of an enormous over build, 4.0x the load peak for OSW, and 6.7x for OnSW. Fig. 3.6 shows that storage requirement is enormous, seasonal and curtailment is high.

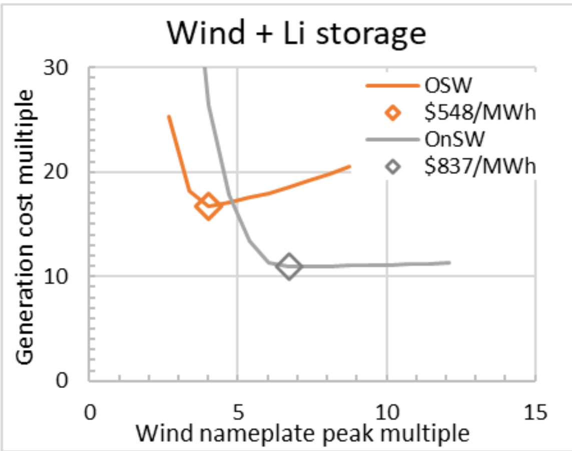

Figure 3.5

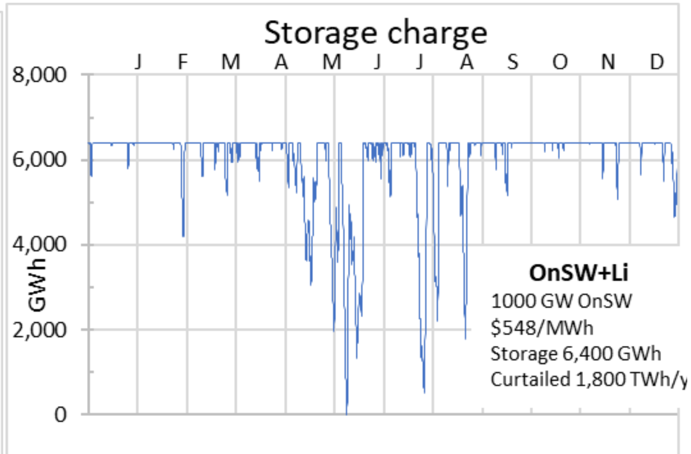

Figure 3.6

3.5 100% PV + LI STORAGE ONLY

By overbuilding PJM PV, and with enough storage, a system that derive 100% of its electricity from PV is technically feasible. The model (Fig. 3.7) suggests the combination of 1,300 GW PV plus 10,000 GWh storage satisfies load. The system cost is $695/MWh, 14x the reference cost of $50/MWh and midway between OnSW and OSW. The dashed line in Fig. 3.7 indicates that it is not clear that there is a viable

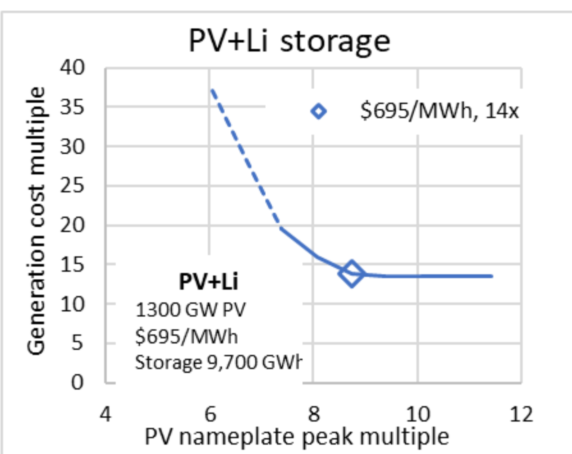

Figure 3.7

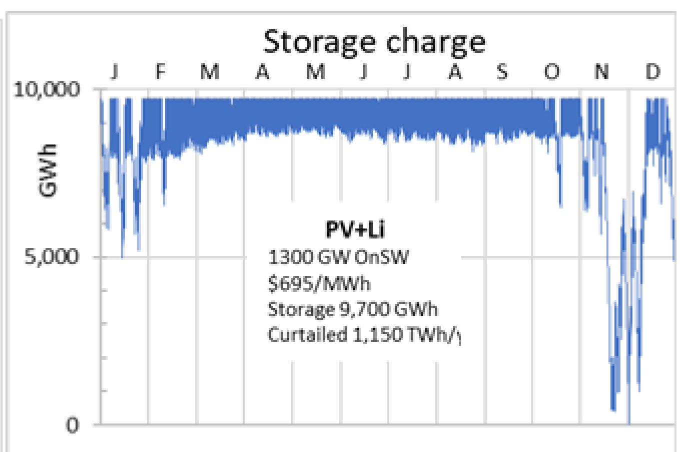

Figure 3.8

system for these parameters. It would be clearer with multiple years of data and starting/stopping at the equinox rather than the solstice.

Fig. 3.8 shows that at the system level the single technology PV storage requirement is seasonal. The demand for storage, the combination of moderately high load and low resource is severe for Nov-Dec-Jan winter solstice. We have seen his effect not only for PJM, but also for IESO (Ontario), ERCOT and CAISO. This winter solstice deficiency is fatal to the usefulness of PV as a system resource. It might be ameliorated by positioning the PV collectors at a tilt angle greater than latitude, increasing winter solstice production at the expense of summer production and total production. But such speculations are beyond the scope of this study.

3.6 ONSHORE WIND (OnSW) + PV + Li

Onshore wind + PV + Li battery storage only for PJM is technically feasible but not a credible system. It does however provide a useful data point.

The optimal combination of OnSW + PV is found by setting nuclear and Off Shore Wind (OSW) to zero as Concept Model inputs, then cycling through all combinations of OnSW and PV. This produces the map presented in Table 3.3. White cells are not viable system configurations.

	PV nameplate (GW)										
OnSW\PV	0	100	200	300	400	500	600	700	800	900	1000
0											28.2
100									11.0	9.7	9.3
200						9.7	8.7	8.4	8.3	8.2	8.2
300				0	8.0	7.9	7.9	7.9	7.9	7.9	7.9
400			9.2	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
500			8.5	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
600		10.4	8.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.1
700	17.8	9.6	7.6	6.7	6.7	6.7	6.7	6.7	6.9	7.2	7.5
800	13.4	9.0	7.3	6.6	6.4	6.5	6.7	7.0	7.3	7.6	7.9
900	11.3	8.8	7.3	6.7	6.5	6.8	7.1	7.4	7.7	8.0	8.3
1000	11.0	8.6	7.4	6.9	6.9	7.2	7.5	7.8	8.1		
1100	11.0	8.6	7.5	7.2	7.3	7.6	7.9	8.2			
1200	10.0	8.7	7.8	7.5	7.7	8.0	8.3				

OnSW nameplate (GW)

OnSW + PV + Li
400 GW PV
800 GW OnSW
$321/MWh, 6.4x
Storage 1,460 GWh
Curtailed 1,900 TWh

reference cost multiple

Table 3.3

Note that the row where OnSW=0 is the PV only curve presented in Fig. 3.7 and the column PV=0 is the OnSW only curve presented in Fig. 3.5.

The main conclusion is that the combination of 800 GW OnSW and 400 GW PV produces a cost-optimal system of $321/MWh or 6.4 times the reference cost. This combination is a substantial improvement from PV only ($695/MWh) and OnSW only ($548/MWh) indicating that OnSW and PV complement each other. However, it $321/MWh is still 6.4x legacy system cost indicating that OnSW + PV is an impractical system.

The yellow cells indicate a rather broad range of OnSW/PV combinations that are within 10% of the minimum. It is noteworthy that the system exhibits a single simple optimum point, and the optimization is well behaved

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3.7 OFFSHORE WIND (OSW) + PV + Li

Table 3.4 shows the result of a similar exercise for OSW + PV. It reveals a low-cost optimum of $349/MWh, 6.98x, that is heavily weighted to PV (1,000 MW PV and 100 MW OSW). While standalone PV is less costly than standalone OSW, a little OSW reduces systems cost. However, the OSW + PV system configuration is 7x more costly than the reference cost.

	PV nameplate (GW)														
OSW\PV	0	100	200	300	400	500	600	700	800	900	1000	1100	1200	1300	1400
0													16	13.4	13.4
100					11.3	8.2	7.94	7.7	7.46	7.22	6.98	7.04	7.18	7.54	7.54
200		72.8	26.1	12.1	8.2	7.36	7.28	7.22	7.18	7.34	7.52	7.68	7.86	8.42	8.42
300	60.8	25	13.8	9.96	8.7	7.98	7.92	7.88	7.98	8.16	8.34	8.58	8.9	0	0
400	25.3	15.9	12	10.5	9.28	8.72	8.66	8.74	8.92						
500	18.2	14.1	12.5	11.1	9.86	9.52	9.54	9.7							
600	16.7	14.6	13.1	11.7	10.5	10.4	10.5								
700	17.1	15.2	13.7	12.3	11.2	11.3									
800	17.5	15.8	14.3	12.9	12.2										
900	18	16.4	14.9	12.9											

OSW nameplate (GW)

OSW + PV + Li
1000 GW PV
1009 GW OSW
$349/MWh
Storage 2,560 GWh
Curtailed 1,100 TWh

Refereence cost multiple

Table 3.4

3.8 THREE-WAY OPTIMIZATION: OnSW + PV + NUCLEAR with Li storage

Fig 3.9 presents the results of a three-way PJM optimization of Onshore wind, utility scale PV and nuclear for a zero carbon PJM system Fig 3.9 is the same as Fig.1.1.

The orange diamond on the vertical axis of Fig. 3.9 is the 100% OnSW + PV scenario found by the map shown in Table 3.3. 100% OnSW + PV + Li storage is technically feasible but costly. The low-cost optimum was $321/MWh, 6.4x the reference cost of

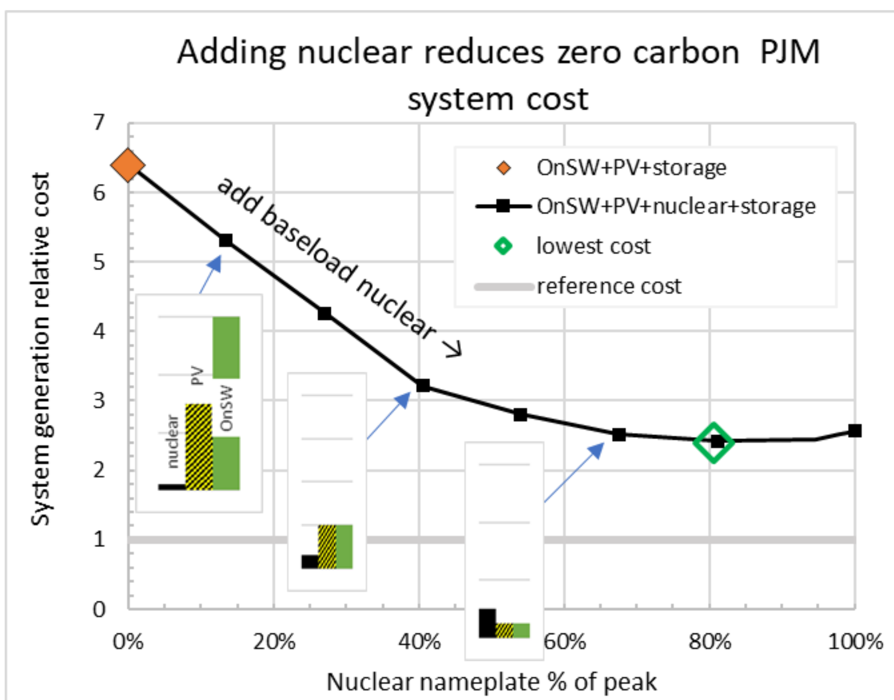

Figure 3.9

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$50/MWh, with 400 GW PV and 800 GW OnSW. Note the enormous overbuild, peak load was 149 GW.

20 GW nuclear (13.3% of peak load) is added to the model, then the OnSW/PV mapping like that in Table 3.3 is repeated to find the new low cost optimum which was 300 GW PV and 600 GW OnSW. The magnitude of the generators, 20 GW nuclear, 300 GW PV, and 600 GW On SW are presented as three bars and associated with the first data point at 13.3% of peak load.

The process is they repeated to fill in the cost-optimal curve in Fig 3.9. The three bar charts all have the same vertical scale and show how the proportions of nuclear/PV/OnSW change as nuclear is added to the system. As nuclear increases to 2/3 of peak load the curve flattens out and the proportions of PV/OnSW become modest.

The lowest system cost is 2.4x, the same number that was observed in Fig. 3.3 with nuclear + Li storage only. Although with three factor optimization there may be components of PV/OnSW in this region of the curve. The flat region of the curve between 2/3 and full peak load needs a more refined analysis.

3.9 OPTIMAL COMBINATIONS OF OnSW & PV

Fig. 3.10 plots out the cost optimal combinations of OnSW & PV nameplate. For the baseline assumptions, there is an optimal relationship between on shore wind nameplates and utility scale PV nameplates of about 1.7/1 (OnSW/PV). That is, 1 GW of PV nameplate wants to see 1.7 GW of OnSW nameplate for minimum system cost. Other combinations of wind and PV nameplates would increase system cost. This is apparent from the map in Table 3.3.

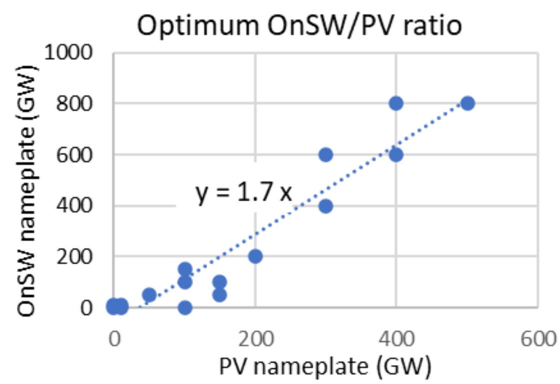

Figure 3.10

4.0 SENSITIVITY STUDIES

The §3 results are focused on zero carbon PJM system options, constrained by the baseline assumptions presented in §2.1. This §4.0 presents three sensitivity studies that step outside of those assumptions:

4.1 WHAT IS THE COST OF CLEAN ELECTRIC POWER

The physical relationships shown in in Fig. 4.1 (duplicate of Fig. 1.1 constrain the options for transitioning to zero carbon PJM. This study begins with what exists today. Imagine a PJM electric power system that is powered 100% by Combined Cycle natural gas. That is the study reference system, the big red square. It's cost of generating electricity is about 5 ¢/kWh, approximating today's cost of generating electric power. 100% CC is considered to be 0% clean.

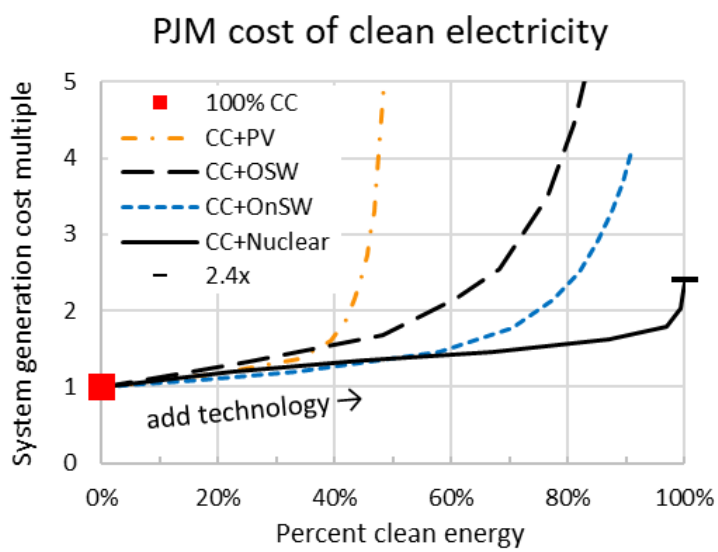

Figure 4.1

Next, add utility scale PV only to the system. PV displaces natural gas, so the more PV added to the system, the cleaner it gets. As PV is added, the system cost tracks the orange dot-dash curve. The system needs to retain the annualized capital cost of all the CC generators to provide power when there is no sun so the value of PV is the cost of fossil fuel saved. Since natural gas is cheaper than the annualized capital cost of PV, PV always adds cost and the orange dot-dash curve always slopes up to the right. PV only cannot get past 50% because the sun shines only half the time.

Next remove the PV and begin adding Offshore Wind (OSW). This produces the long dash cost curve. Then remove the OSW and add the onshore wind (OnSW). The system cost tracks the short dash blue curve. Neither PV, OSW of OnSW can get to 100% clean by themselves because there are hours when PJM wind and solar produce little to no power and it does not matter how many PV panels or wind turbines are deployed, no wind no sun no power. This leads to the requirement for storage which is analyzed in §3.

Lastly nuclear is added to the system producing the solid black cost curve. Nuclear can get to 100% clean but the last 5% is problematic. Methods for better managing diurnal load variations need to be explored.

With the baseline assumptions, adding wind or PV always increases system cost. Ratepayers will rebel at high prices long before full net-zero PJM is reached, and become stuck with an expensive dirty system.

4.2 NREL/ATB UNIT COST ESTIMATES FOR NUCLEAR POWER ARE TOO CONSERVATIVE

The Baseline uses Real 2020$ unit costs from NREL/ATB.v1, R&D case (no tax credits or incentives), moderate estimates. For the most part, the NREL/ATB moderate estimates seem modestly optimistic. It does however seem to seriously overstate nuclear power plant construction cost with the result that the §3 results are inconsistently conservative when it comes to nuclear power.

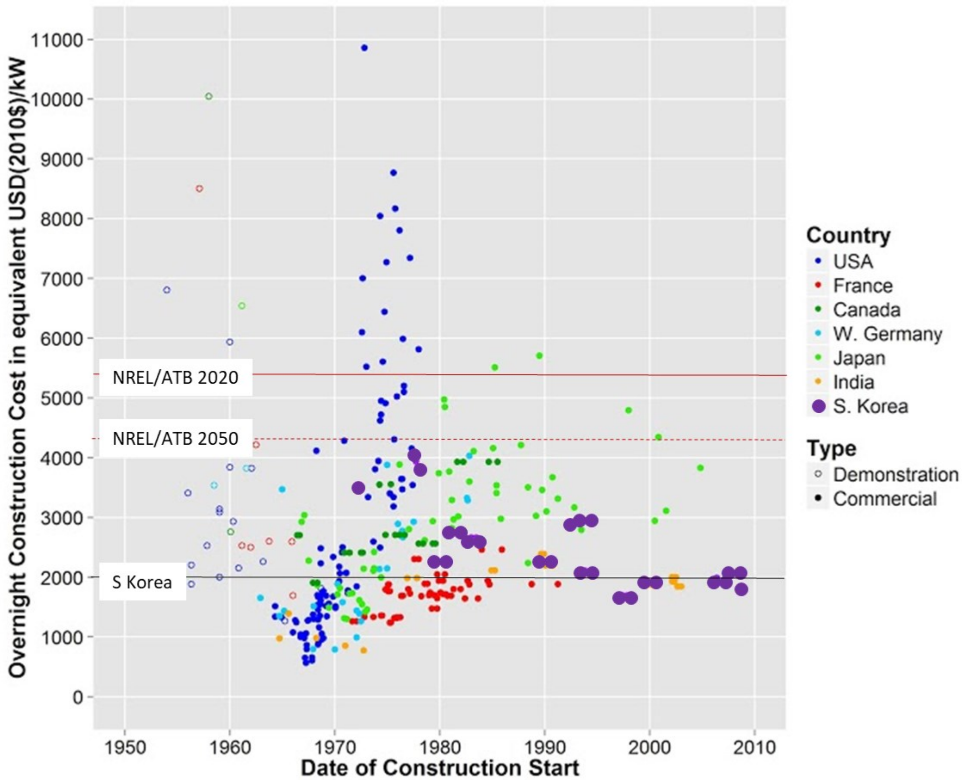

Figure 4.2

Fig 4.2 from the [Breakthrough Institute](#) shows Overnight Construction cost worldwide excluding China. (These numbers are reconciled with 2020$CAPEX used for the Concept Model in the workbook global nuclear tab.) The South Korea data is emphasized. Also added is the equivalent of NREL/ATB 2020 number used for §3 analysis as well a NREL/ATB learning curve expectations for 2050. Both these NRLE/ATB numbers are more than double current South Korean cost, triple China current cost (not shown).

Figure 4.3 compares the impact that lower nuclear power plant construction costs might have on system generation cost. The system configuration is nuclear + storage only. Such a system has no solution below 60% because that is the PJM load factor. At 70% nameplate seasonal storage costs dominate. As nuclear nameplate is added beyond 70% system costs come down to 2.4x using NREL/ATB baseline costs, 1.4x using South Korea costs. Also, the

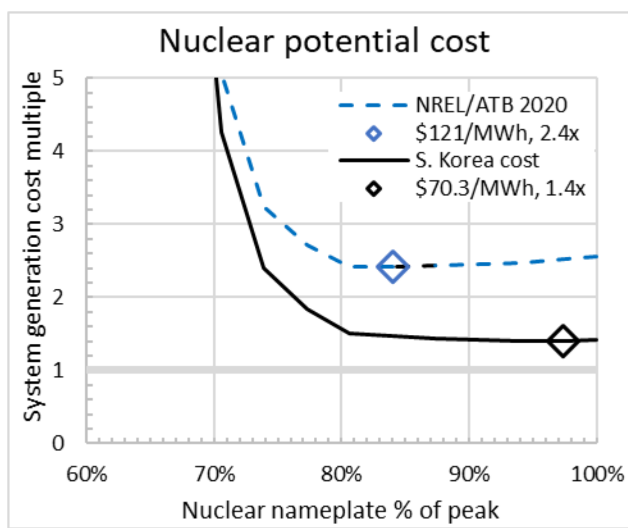

Figure 4.3

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role of storage has changed. Using S Korea CAPEX, minimum cost is at 97% of peal capacity and Li storage is only marginally useful.

America's nuclear construction costs are high because every nuclear plant is custom designed, awarded to the low bidder, and when project management stumbles, regulators halt construction while costs accrue, companies sue and go bankrupt. S. Korea achieves its low costs with a single company that designs builds, owns, and operates standardized design nuclear power plants. Substantially lower costs can be achieved if America figures out a new paradigm for how it builds nuclear plants.

4.3 DOES VERY LOW-COST STORAGE MAKE A DIFFERENCE?

Without fossil fuel or hydro, PJM's main technology option for managing variability is low-cost storage. The baseline assumption is Li battery storage which is a proven technology but unproven application at utility scale. There is no data yet on technology life, reliability, and operational characteristics.

Aside from hydro, the only proven low-cost utility scale storage technology is thermal. France uses oversized domestic hot water heaters under utility control to effectively manage diurnal variations. DoE is researching high temperature thermal storage, charged by solar concentrators, to power steam turbines. MIT has a variation on this theme, a CRUSH concept that uses nuclear reactors to thermally charge very large piles of crushed rock and generate steam to power steam turbines.

Table 4.2 compares utility scale Li battery storage with NREL/ATB costs with CRUSH. The power cost Is the cost of the turbine generators set. The NREL/ATB number of $922/kW for combustion turbines was used. Far less certain is the energy storage cost. The $43/kWh was derived from a bottom-up estimate, details available here.

Storage CAPEX		
	$/kW	$/kWh
Li battery	$249	$369
CRUSH thermal	$922	$43

Table 4.2

Fig. 4.3 compares two wind + PV + nuclear systems where the storage cost varies by a factor of 8. Very low-cost storage lowers the system cost but not by much, from 2.4x to 2.2x. The real impact of low-cost storage is that it allows intermittent generation to be competitive of a wider range of system penetration

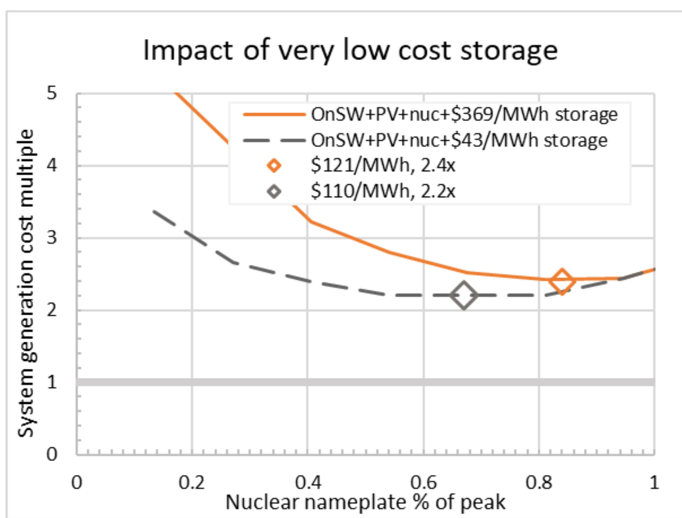

Figure 4.3

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5.0 CONCLUSIONS

The key to "concept modeling" is to keep it simple and basic, to minimize the assumptions, unessential detail, and to focus on structure, the relationship between components, on architecture. The main objective is consistent relative comparison, not absolute accuracy. The Baseline modeling assumptions were presented in §1.2.

Table 5.1 summarizes the concept modeling results. The reference cost of 5 ¢/kWh is approximately the PJM wholesale cost of generating electricity today; the average PM market clearing price for energy plus capacity, as well as the system cost of powering PJM with 100% combined cycle natural gas. This number does not include out of market costs such as transmission, distribution, social costs, all of which increase the retail price of electricity in Maryland to ~ 13 ¢/kWh. All the system configuration estimates in Table 5.1 employ various amounts of storage with a cost corresponding to Li battery storage. Note that Li batteries have not yet been proven at scale for utility scale storage.

Baseline system generation cost			
System Configurations with Li storage	Relative cost	Absolute ¢/kWh	Curtailment load factor
a. Reference cost	1.0	5	0.0
b. Nuclear	2.4	12	0.4
c. OnSW	11.0	55	2.0
d. PV	13.9	70	1.5
e. OSW	16.7	84	2.0
f. OnSW+PV	6.4	32	2.4
g. OSW+PV	7.0	35	1.4

Table 5.1

The absolute cost column is the model result for each system configuration. The relative cost is the ratio of that configuration cost to the reference cost. The curtailment load factor cost is the amount of energy that is discarded by the system configuration divided by the annual load. The nuclear +Li storage configuration has a curtailment load factor of 0.4 which means it generates 40% more power than is delivered to load less down time for maintenance, repair and refueling.

To put these results in context, all eight large clean power grids around the world employ some combination of nuclear plus hydro, these are the only proven technologies for Zero Carbon power systems. Unfortunately, PJM has little hydro which creates challenges.

5.1 CORE CONCLUSIONS

- All the baseline Zero Carbon PJM configurations more than double the generation cost of a legacy natural gas system. Since the planet has proven natural gas reserves for over 50 years at current prices and demand, it is likely that electricity from natural gas will remain flat and low for the next couple of decades. The fact the Zero Carbon configurations cannot compete with natural gas generation presents a fundamental political obstacle to decarbonization.
- 100% nuclear power has the lowest clean system cost. The relative cost of 2.4 includes Li storage. Peak load 100% nuclear without Li storage has a relative cost of 2.6.
- Intermittent generation always increases the cost of nuclear PJM systems (Fig 1.1 & 4.1). This increase is modest if intermittent penetration is less than about 20% by energy. This is not true on other grids with better renewable resources like CAIOS and ERCOT where the is a modest "sweet spot."

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- The system cost of managing intermittency (curtailment and storage) is what drives the huge cost of net-zero carbon intermittent generator options. Additional transmission and stability management, not included in Concept Modeling, will drive intermittency management costs even higher. High penetration of intermittent generation is technically feasible but wholly impractical.
- There is a cost-optimal balance (on PJM) of OnSW and utility scale PV with a nameplate ratio of about 1.7:1 (Fig. 3.10). While the optimum balance will reduce the cost of either wind or PV alone, the relative cost is still high at 6.4 (Table 3.3).
- The cost-optimal balance of offshore win (OSW) + PV is quite different (Table 3.4). Low-cost PV drives OSW to low levels but the lowest cost combination always has a small amount of OSW.

5.2 SENSITIVITY STUDY CONCLUSIONS

- The NREL/ATB nuclear cost estimates are unreasonably high, inconsistent with the mild optimism behind the wind and PV estimates. Global construction cost data suggests the potential is to reduce nuclear system costs to 1.4x from 2.2x.. This is still 40% higher than the reference cost.
- South Korean management practices suggest that construction costs could be substantially reduced if America improves the way it manages the construction, regulation and operation of nuclear plants.
- Nuclear simplifies the system and the role of storage changes to become less essential to controlling system costs and reliability.
- Unproven very low-cost storage (energy cost 8x below Li) would make intermittent generation cost competitive with nuclear over energy penetration range of up to 70%. It does not notably reduce system cost but makes intermittent generation more cost competitive.
- §4.1 illustrates the risk of simply adding wind to a fossil fuel system. System costs increase gradually, up to 60% penetration by energy, then the cost of managing intermittency drives system costs rapidly higher. At 60%, system generation cost has approximately doubled and there is no way to net-zero without decommissioning the wind.

5.3 THE COST DILEMMA

With the baseline assumptions, the low-cost nuclear option is 2.2x the reference cost. The inconvenient fact is that natural gas is very cheap and it likely to remain so for decades. There are options outside of the baseline for managing costs.

- Centralized management of nuclear power plant selection, construction and operation offers a 2x potential cost improvement (§4.1).
- PJM has a 60% load factor. Assuming 10% outage for maintenance and refueling, a nuclear system generates 30% more power than used for electricity. Finding other markets such as EVs, district heating or H_2 production could provide a 25% cost improvement.
- Existing PJM nuclear plants have a peak load availability of 0.994. This means that a reliable system does not need an overbuilt generation and transmission infrastructure required for the existing PJM system (peak load availability of 0.93) or for intermittent generation (OSW 0.45, OnSW 0.3, PV 0.15). Semi-autonomous distribution systems are feasible. Cost impact is currently unclear.

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6.0 NEXT STEPS

Classic system engineering development starts with simple concept modeling to characterize architecture, then gradually adds complexity in stages to reach a system design. Its conclusions are quite robust, and effort should proceed to a more detailed analysis of the more complex aspects not included in the concept model study.

6.1 REFINING & UPGRADING THE PJM CONCEPT MODEL

6.1.1 EXTEND THE HISTORICAL TIME SERIES - PJM publishes hourly solar data for 3 years, back to 2019. Extending the time series from one year to 3-4 years would improve accuracy. It would be necessary to adjust the profiles for growth.

6.1.2 EQUINOX TO EQUINOX - Running the model equinox to equinox would eliminate winter solstice ambiguities in weather dependent data.

6.1.3 REFINE OSW PROFILES – There is no mid Atlantic OSW data. This model created a proxy by scaling PJM OnSW data for coastal States and empirically adjusting it to get a 45% capacity factor observed by the Block Island wind farm. This should be compared with an alternative approach that uses National Weather Service along with wind turbine models to develop a time series.

6.1.4 PV SYSTEM OPTIMIZATION – Latitude tilt is a rule-of-thumb for maximizing annual production from PV collectors. The result is higher PV production during the summer, lower PV production during the winter. Poor performance during winter solstice limits the usefulness of PV in a system. What deployment strategy (like tilt at an angle greater than latitude) maximizes PV value in a system?

6.2 HOW ROBUST ARE THE CONCLUSIONS?

While the conclusions appear to be quite robust, there are a wide variety of scenarios and technology developments that need to be monitored.

6.2.1 VALUE OF MINIMAL TRANSMISSION ARCHITECTURES – One baseline assumption was perfect transmission which biases the results in favor of intermittent generators. Transmission realities will increase the cost spread between intermittent and base load generation but by how much? Transmission has two functional requirements: distribution from generator to load and interconnection for reliability. If one generator fails, robust transmission allows others take up the load, so the SYSTEM delivers reliable power. Distribution costs are minimized by locating generators near load. Interconnection can be minimized by generators with high peak load availability (capacity). Generators with low capacity (wind and solar) benefit from lots of interconnections driving the system architecture to a national grid with national blackout vulnerabilities. Dependable generators (nuclear) need little interconnection driving the system architecture to semi-autonomous distribution systems with only local interties. The system cost of these architectural options will likely be dramatic and needs to be better quantified.

6.2.2 LOAD PROFILES – Explore a range of profiles, including flat profiles, to see how they affect the 3 main conclusions. While load growth changes the magnitude of required generation, different load profiles may change the fundamental conclusions about the relationship between different generation technology types. What about a flat profile? The impact of unplanned growth will likely result in decreasing load factors (average to peak loads) driving up system costs.

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6.2.3 VERY LOW-COST STORAGE CONCEPTS (§4.2) – The main impact of an 8x reduction is energy storage cost appears to be to not lower system cost but to extend the range over which intermittent generation is competitive with nuclear generators. The system impact of very low-cost storage needs to be examined more thoroughly. What are requirements?

6.2.4 ELECTRIFICATION IMPACT – Energy transition via wires or pipes, the jury is still out. The result is contingent on the economics of generation and transmission systems.

6.2.5 LEARNING CURVES (§4.1) – Aside from nuclear power, is there anything in the learning curves that might change the relationship between technologies and the baseline conclusions?

6.2.6 SECONDARY TECHNOLOGIES – There are a host of secondary generation technologies (carbon sequestration, biofuels, tides …) and cost sensitivities that need to be tracked to assess and score the potential for system changing breakthroughs or hidden problems.

6.2.7 FOSSIL FUEL PRICE – The conclusion "*double the cost of legacy systems"* conclusion is contingent on natural gas prices staying flat and low. How realistic is that?

6.3 **IDENTIFY AND PRIORTIZE DEVELOPMENT NEEDS**

6.3.1 TOTAL SYSTEM DEVELOPMENT – Electric power is only 1/3 of America's total primary energy consumption. While there are sound arguments that electric power architecture needs to be resolved first, all the pieces need to fit together as a single complex system. This is mammoth undertaking that has not begun yet.

6.3.2 NUCLEAR CONSTRUCTION MANAGEMENT – Conduct a review of nuclear power plant construction around the world and of large-scale construction projects in the US. What sort of management structure (like a States owned nuclear power plant authority) would minimize cost and risk of reconstructing a nuclear power plant industry?

6.3.3 MANAGING DIURNAL LOAD VARIATION – There is need of a disciplined engineering characterization of several available options. France uses oversized domestic hot water heaters under control of the electric utility. This study assumes Li storage technology though it is unproven at scale. Load following nuclear is another approach. Green gas fired combustion turbines is another. What is the system effectiveness of PV concurrence? Combustion turbines and a little bit of fossil fuel may also be an option

6.3.4 NUCLEAR RELAIBILITY REUIREMENTS – Nuclear plants on the PJM system currently have a peak load availability of 0.994. Is there any merit to specifying a higher requirement?

6.3.5 WHAT DO ZERO CARBON MARKETS LOOK LIKE? – The existing PJM market has evolved to minimize cost for legacy generators. Ideally, fair markets align price with cost and the concept model show that the cost base is changing dramatically, from high variable cost to high fixed cost. Ignoring legacy constraints, what would a fair market look like with the cost base characterized by the concept models?

6.3.6 What are alternative system architectures? – District heating cogeneration subsystems. How does this fit together.

6.4 THE ROADMAP, HOW TO GET THERE FROM HERE

6.4.1 HOW MUCH INTERMITTENT GENERATION CAN BE TOLERATED ABD WHAT IS THE MIX? - Fig. 3.9 suggests that a modest amount of OnSW and utility scale PV can be tolerated without substantially increasing system cost. A more refined analysis using the upgraded concept model is needed to identify how much exactly? What are the correct proportions of wind and PV? What is the role of OSW and residential PV?

6.4.2 MARKETS AND COST – Fair markets align price with cost and the cost structure of clean systems with high fixed cost is dramatically different from fossil fuel systems with high variable cost. Users will pay more for peak capacity, less for energy. Ignoring legacy market design, what is the optimal fair market design, wholesale and retail, for a Zero Carbon PJM.

6.5 WHAT CAN BE SAID ABOUT POLICY

6.5.1 COST – A fundamental conclusion is that a clean PJM will more than double the cost of legacy fossil fuel systems and that cost spread is likely to persist for decades. How is that managed? One option is to subsidize the preferred technology but for how long.

6.5.2 OPTIMUM WIND/PV RATIO – Fig. 3.10 suggests that something like 1.7 is an optimum ration of wind and PV nameplates. This suggestion needs to be refined.

6.5.3 MARYLAND AS A STAND-ALONE SYSTEM - OSW imposes peak load capacity requirements on the rest of the system. In theory these costs are recovered through the capacity market. However, the costs required to maintain system reliability at high penetration of intermittent renewables is poorly understood. These currently out-of-market costs include transmission, spinning reserves to maintain stability, storage, and curtailment. We can develop a sense of the magnitude of these cost by modeling Maryland as a stand-alone system.

6.5.4 MARKET BASED DEVELOPMENT IS A FLAWED POLICY - Does residential PV add value to a Zero Carbon PJM? Relying on markets for design guidance assumes that market fairly align with cost. This is not true today. Current markets do not fairly reflect the value of clean firm capacity. The low-risk sequence is to first design the system, then the market.