Caiazza Electric System Comments

Summary
These comments address a few Draft Scoping Plan electric system issues. The ultimate problem is that the Climate Act presumed that converting the electric grid from its current reliance on fossil fuels to provide reliable electricity when needed most was just a matter of political will. However, the New York Independent System Operator (NYISO) Power Trends 2022 report notes: "Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the objectives of the CLCPA. Resources with this combination of attributes are not commercially available at this time but will be critical to future grid reliability." The Draft Scoping Plan projects that the long-duration, dispatchable, and emission-free resource capacity requirement is about the same as the current fossil-fired generating capacity. This is an enormous challenge and the cavalier way it is addressed in the Draft does not inspire confidence that the Integration Analysis electric system projections are viable.

I estimated the costs for the projected generating capacity described in the Draft Scoping Plan Integration Analysis. My estimate of the overnight cost to develop the resources needed to transition to a zero-emissions electric system in 2040 are generally consistent with the Appendix G Figure 48 net present value of system expenditures. I estimate that the Reference Case capital costs are only $82.5 billion and that the mitigation scenarios range from $220 billion to $400 billion. There are variances relative to the Integration Analysis that I address to the extent possible.

The Draft Scoping Plan does not provide sufficient documentation to reconcile all the differences. My estimates only include the capital costs for the projected generating resources and do not include transmission ancillary services that must be included for a true estimate of the total costs to go to zero-emissions generation. In order to fully predict the costs of the Scoping Plan, the Climate Action Council should insist that the authors of the Integration Analysis provide more detailed explanations.

I submitted other comments that explained that the New York Independent System Operator (NYISO) is currently updating its System and Resource Outlook. I projected costs for their capacity projections and found that their cost numbers are 30% higher. I strongly recommend that the Climate Action Council reconcile the differences between the Draft Plan and the NYISO projections.

The Integration Analysis that provides the numbers used in the Draft Scoping Plan misleads readers with its definition of the Reference Case. Policy modeling like this compares projections for future mitigation scenarios against a business-as-usual case future projection. The definition used in the Integration Analysis "includes a business-as-usual forecast plus implemented policies". The Climate Act mandates "9 gigawatts (GW) of offshore wind electric generation by 2035". Incredibly, those resources are in the Reference Case. In my benefits are greater than costs comment I showed that the after correcting for other improperly categorized sectors from this mis-leading approach projects net-zero transition costs are between $295 billion and $316 greater than the benefits but the cost numbers in these comments show that the costs are increased to between $363 and $372 greater than the benefits. The Climate Action Council should insist that the Final Scoping Plan describe all the control measures, provide the

assumptions used for the strategies, the expected costs and expected emission reduction for each measure for the Reference Case, the Advisory Panel scenario and the three mitigation scenarios. Then the public would be able to decide for themselves which costs associated with "already implemented" programs are appropriate.

I quantified costs associated with some particular issues with the Integration Analysis cost projections. The Integration Analysis does not consider the effect of end-of-life retirements for wind, solar, and energy storage. I showed that in 2040 incorporating retirements would increase costs by at least 6%. However, costs jump considerably when costs to 2050 are considered. For example, my projected cost for Scenario 4 in 2040 is $399,530 million but the cost to replace all the equipment that ages out between 2020 and 2050 is $304,428 million. I also showed that the biomass and wind capacity factors are biased high. The observed statewide average wind capacity is trending down since 2015 and that effect is not addressed in the Draft Scoping Plan. The Climate Action Council should ensure that the Final Scoping Plan addresses these issues

I compared the capital costs (2020 $/kW) in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet Resource Costs tabs against the EIA Table 1: Cost of new central station electricity generating technologies. I show that with the exception of the capital costs for large hydro and a gas-fired combined cycle unit in Upstate New York all the other technology costs are lower and, in some cases, much lower in the Integration Analysis. If my comparison interpretation is correct then these numbers are outrageous. The capital costs for offshore wind are half of the EIA costs. While there may be some interpretation of the battery energy storage cost that can explain why EIA costs are five times higher, I don't think there is any interpretation issue with the hydrogen fuel cell technology that is five times higher in New York City and four times higher Upstate. The Climate Action Council must explain why the Draft Scoping Plan numbers are so high for these technologies.

Finally, I explain that the future reliability of the electric system is dependent upon a robust estimate of worst-case renewable resource availability. The percentage of weather dependent capacity is different for mitigation scenarios and the NYISO projections and I believe that is something that needs to be reconciled by the Climate Action Council. I also re-iterated my concern that all the estimates of future renewable resource availability need to use as long a period of historical meteorological data as possible. The Climate Action Council should insist that a more detailed evaluation of worst-cast wind and solar resource availability be completed as soon as possible.

Capacity Cost Calculations

Because the Draft Scoping Plan does not describe all the control measures, the assumptions used, the expected costs for those measures or the expected emission reductions, I was forced to calculate my own estimate of the cost for added capacity for the Reference Case, the Advisory Panel scenario and the three mitigation scenarios. These estimates do not cover all the costs in the electricity sector but evaluation of this component provides some important insights. My primary concern is the zero-emissions transition by 2040 so my analysis goes only to 2040.

I used three sources of data to calculate the capital costs for the generating capacity (MW) additions projected in the Draft Scoping Plan. The Integration Analysis lists projected installed capacity values for 2020 and for the Reference Case and Scenarios 1-4 for 2040 in the IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs spreadsheet. My primary source for cost information was U.S. Energy Information Administration (EIA) Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022. EIA does not provide costs for hydrogen electrolyzers so I used data in the "Hydrogen" tab in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet for electrolyzers, infrastructure, and transportation. The input data, calculations and results are included in the attached Caiazza Electric System Comment Spreadsheet and there is documentation for the methodology in Addendum 1: Capacity Cost Calculations.

My estimates for capacity costs include estimates for land-based wind, offshore wind, utility-scale solar, distributed solar, battery storage, in-state hydro, and the zero-carbon firm resource, also known as dispatchable, emission-free resource (DEFR). My estimates used the EIA overnight costs for everything, including fuel cells for DEFR, except the cost of producing hydrogen.

Due to time constraints, I did not evaluate the Integration Analysis methodology or values used in any detail. I attempted to replicate the social cost of carbon benefits analysis which is much more straight forward and ending up giving up in frustration because I could not match the numbers. In that case and this case, the Final Scoping Plan has to provide much more documentation in order to be considered adequate. My estimated costs only include capital costs and the Integration Analysis includes other costs for the electricity sector but I could not resolve what else was included.

However, I did compare the capital costs (2020 $/kW) in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet Resource Costs tabs against the EIA Table 1: Cost of new central station electricity generating technologies. Table A-3 in Addendum 1 shows that with the exception of the capital costs for large hydro and a gas-fired combined cycle unit in Upstate New York all the other technology costs are lower and, in some cases, much lower in the Integration Analysis. Table 1 lists the percentage differences. If my comparison interpretation is correct then these numbers are outrageous. The capital costs for offshore wind are half of the EIA costs. While there may be some interpretation of the battery energy storage cost that can explain why EIA costs are five times higher, I don't think there is any interpretation issue with the hydrogen fuel cell technology that is five times higher in New York City and four times higher Upstate. The Climate Action Council must explain why the Draft Scoping Plan numbers are so high for these technologies.

Table 1: Percentage Difference Between Integrated Analysis Base Capital Costs and EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022 Costs

Base Capital Costs by Technology (2020 $/kW)	Percent Difference between IA and EIA	
Technology	NYCW	NYUP
Wind		62%
Wind - Offshore	99%	141%
Solar - Tracking	36%	15%
Hydro - Large		-5%
Gas - CCGT	22%	-12%
Gas - CT - Frame	77%	34%
Hydrogen - Fuel Cell	515%	401%
Battery - Li ion	495%	482%

Transmission Ancillary Services Background

As far as I can tell there is a massive missing piece in the Integration Analysis cost estimates: transmission grid ancillary services. Due to the lack of comprehensive documentation, I could not determine how this necessary component was handled in the Draft Scoping Plan Integration Analysis. Importantly, I did not include any of these costs in my capacity capital cost projections.

This section describes transmission grid ancillary services as background. A reliable electric power system is very complex and must operate within narrow parameters while balancing loads and resources and supporting synchronism. New York's conventional rotating machinery such as oil, nuclear, and gas plants as well as hydro generation provide a lot of synchronous support to the system. This includes reactive power (vars), inertia, regulation of the system frequency and the capability to ramping up and down as the load varies. Wind and solar resources are asynchronous and cannot provide this necessary grid ancillary support.

Some, but not all of the disadvantages of solar and wind energy in this regard can be mitigated through electronic and mechanical means. When these renewable resources only make up a small percentage of the generation on the system, it is not a big deal. The system is strong enough that letting a small percentage of the resources that don't provide those services to lean on the system. But as the penetration of solar and wind energy increases the system robustness will degrade and reliability will be compromised without costly improvements. Obviously, the transition proposed in the Integration Analysis will need these improvements. A renewable system could be coupled with extensive batteries and other storage devices, large mechanical flywheels and condensers (basically an unpowered motor/generator that can spit out or consume reactive power). These devices could approximate the behaviors of our conventional power system.

My particular concern is that the Draft Scoping Plan has only considered the energy storage ancillary services needed to keep the system operating when intermittent wind and solar resources are not available. Importantly, the other grid support requirements needed so the electric grid can transmit the power from where it is produced to where it is needed are not adequately discussed in the Plan.

There are three references to “ancillary” in the text of the Draft Scoping Plan and Appendix G (Addendum 2). Note that Appendix A Power Generation Advisory Panel Recommendations (page A-74) explicitly addresses this problem as one of the components required for delivery:

> **Adapt current ancillary service market designs and look to add products that are needed to incent flexibility as needed to efficiently integrate renewables.** The NYISO supports markets for energy, ancillary services, and capacity. The fundamental relationship among these markets will likely need to evolve. For example, more revenue will likely shift to ancillary service markets over time as system needs are reevaluated in the context of integrating increasing quantities of renewable resources. Be proactive in developing new products needed, however they should be structured properly to only reflect current system needs to not cause unnecessary costs. A balancing act is needed between developing the products and services of the future while not implementing changes before they are needed.

The implementation lead is listed as the New York Independent System Operator (NYISO). To my knowledge the Climate Action Council has never addressed this issue or directed the analysts responsible for the Draft Scoping Plan and Integration Analysis to show how they have addressed this.

Unfortunately, it gets worse. On January 19, 2021 the New York State Department of Public Service (DPS) submitted the Initial Report on the Power Grid Study (“Power Grid Study”) prepared pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA). The AREGCBA legislation is intended to ensure that Climate Act generation is sited in a timely and cost-effective manner. In order for an electric energy grid powered primarily by renewable energy resources to maintain the same level of reliability as the existing system, somebody, somewhere has to provide transmission grid ancillary services. However, none of the four reports provided in the documentation address the problem.

The Climate Action Council has to ensure that transmission grid ancillary services are addressed in the Final Scoping Plan or there will be problems. I submitted another comment calling for reconciliation of the Integration Analysis and the latest NYISO capacity projections. This problem should be included in that process.

Overnight Capital Cost Results

Table 2 lists the overnight capital costs for the capacity additions for the Reference Case and Scenarios 1-4. Importantly these costs are not the total costs to integrate intermittent and diffuse renewable power into the system so they under-estimate the total costs. The EIA overnight costs are “levelized costs” that assume that production costs per unit of capacity over the life-cycle of the generator are comparable across all technologies. However, Paul Jaskow argues that:

> Levelized cost comparisons are a misleading metric for comparing intermittent and dispatchable generating technologies because they fail to take into account differences in the production profiles of intermittent and dispatchable generating technologies and the associated large variations in the market value of the electricity they supply. Levelized cost comparisons overvalue intermittent generating technologies compared to dispatchable base load generating technologies.

Ancillary services are one of the factors that have to be taken into account.

According to my analysis, the Reference Case capital costs are only $82.5 billion. The mitigation scenarios range from $220 billion to $400 billion. The lower Scenario 2 value is because hydrogen is burned in a combustion turbine rather than used in a fuel cell for the DEFR. Figure 48 in Appendix J lists the net present value of system expenditures in reference case and scenarios 2-4 (2020-2050) in the electricity sector: Reference Case $424 billion and for the mitigation scenarios between $514 and $536 billion. The mitigation scenarios are similar and the extra costs are at least partly due to my analysis getting cut off in 2040. However, there is a substantial unexplained difference between the Reference Case values. It is impossible to determine the cause of the difference because the Draft Scoping Plan does not provide any cost breakdown of electric sector costs. Note that the Reference Case does not include DEFR so that is surely a primary reason for the difference.

Table 2: Estimated Capacity Additions and Overnight Capital Costs for Integration Analysis

	Integration Analysis Scenario Capacity Added (MW)				
Resource	Reference	Scenaro 1	Scenaro 2	Scenaro 3	Scenaro 4
Wind	1,870	4,268	3,929	4,209	4,366
Wind Imports	0	6,104	6,397	6,397	6,397
Wind_Offshore	9,000	14,529	14,364	16,756	15,875
Solar	6,803	24,271	27,359	25,348	25,551
Distributed Solar	5,266	13,481	13,481	13,481	13,481
Battery Storage	4,122	9,514	9,963	11,457	10,826
Pumped Storage	0	0	0	0	0
Hydro Imports (New)	1,250	2,550	2,550	2,550	2,550
Hydro Imports (Existing)	0	0	0	0	0
In-State Hydro	341	344	344	344	344
Nuclear	(3,573)	(1,505)	(1,505)	(1,505)	(1,505)
Gas & FO	(10,069)	(26,388)	(26,388)	(26,388)	(26,388)
Zero-Carbon Firm Resource	0	22,521	21,015	23,522	23,676
Hydrogen Production	0	22,521	21,015	23,522	23,676
Biomass	0	0	0	0	0

	Integration Analysis Scenario Costs ($ million 2021)				
Resource	Reference	Scenaro 1	Scenaro 2	Scenaro 3	Scenaro 4
Wind	$ 4,265	$ 9,735	$ 8,961	$ 9,601	$ 9,958
Wind Imports	$ -	$ -	$ -	$ -	$ -
Wind_Offshore	$ 54,711	$ 88,320	$ 87,317	$ 101,863	$ 96,502
Solar	$ 9,232	$ 33,055	$ 37,247	$ 34,517	$ 34,792
Distributed Solar	$ 7,387	$ 19,246	$ 19,246	$ 19,246	$ 19,246
Battery Storage	$ 5,531	$ 12,676	$ 13,267	$ 15,287	$ 14,424
Pumped Storage	$ -	$ -	$ -	$ -	$ -
Hydro Imports (New)	$ -	$ -	$ -	$ -	$ -
Hydro Imports (Existing)	$ -	$ -	$ -	$ -	$ -
In-State Hydro	$ 1,413	$ 1,427	$ 1,427	$ 1,427	$ 1,427
Nuclear	$ -	$ -	$ -	$ -	$ -
Gas & FO	$ -	$ -	$ -	$ -	$ -
Zero-Carbon Firm Resource	$ -	$ 186,030	$ 30,759	$ 193,279	$ 195,186
Hydrogen Production	$ -	$ 23,276	$ 21,720	$ 24,310	$ 24,470
Biomass	$ -	$ -	$ -	$ -	$ -
Total	**$ 82,538**	**$ 373,766**	**$ 219,944**	**$ 399,530**	**$ 396,006**

NYISO Outlook Study

In my NYISO reconciliation comments I explained that the New York Independent System Operator (NYISO) is currently (June 6, 2022) updating its System and Resource Outlook. The last Outlook Study

Status presentation (April 26, 2022) noted that the draft report will be issued in June 2022. One of the supporting documents for this study is the Capacity Expansion Zonal Results Analysis spreadsheet. The projected new generating resources in the preliminary modeling results are different than the capacity additions in the Draft Scoping Plan Integration Analysis.

That comment documented the differences between the current preliminary draft NYISO capacity projections and the Draft Scoping Plan Integration Analysis. Importantly, even though the total generation capacity is pretty close between the analyses, the Climate Action Council and the NYISO have to reconcile four significant differences in the projections. The NYISO analysis projects dispatchable emissions-free resources capacity on the order twice as much as the three Integration Analysis mitigation scenarios. The NYISO analysis projects land-based wind capacity development about three times larger than the three Integration Analysis mitigation scenarios. The NYISO analysis projects off-shore wind capacity about 50% less than the three Integration Analysis mitigation scenarios. The NYISO analysis projects that solar will provide about one tenth the projected capacity of the three Integration Analysis mitigation scenarios. Clearly the Climate Action Council has to ensure that the differences are reconciled.

I calculated the costs for the preliminary draft NYISO capacity projections using the same methodology and added them to the other Integration Analysis results in Table 3. The costs are 30% higher than the most expensive mitigation scenario. I believe this is because the NYISO analysis projects dispatchable emissions-free resources capacity on the order twice as much as the three Integration Analysis mitigation scenarios.

Table 3: Estimated Capacity Additions and Overnight Capital Costs for Integration Analysis and NYISO Draft Capacity Projections

Resource	Integration Analysis Scenario Capacity Added (MW)					NYISO Draft Outlook Added MW
	Reference	Scenaro 1	Scenaro 2	Scenaro 3	Scenaro 4	
Wind	1,870	4,268	3,929	4,209	4,366	17,102
Wind Imports	0	6,104	6,397	6,397	6,397	
Wind_Offshore	9,000	14,529	14,364	16,756	15,875	9,000
Solar	6,803	24,271	27,359	25,348	25,551	4,644
Distributed Solar	5,266	13,481	13,481	13,481	13,481	9,082
Battery Storage	4,122	9,514	9,963	11,457	10,826	10,045
Pumped Storage	0	0	0	0	0	0
Hydro Imports (New)	1,250	2,550	2,550	2,550	2,550	
Hydro Imports (Existing)	0	0	0	0	0	
In-State Hydro	341	344	344	344	344	1,209
Nuclear	(3,573)	(1,505)	(1,505)	(1,505)	(1,505)	
Gas & FO	(10,069)	(26,388)	(26,388)	(26,388)	(26,388)	
Zero-Carbon Firm Resource	0	22,521	21,015	23,522	23,676	44,750
Hydrogen Production	0	22,521	21,015	23,522	23,676	44,750
Biomass	0	0	0	0	0	

Resource	Integration Analysis Scenario Costs ($ million 2021)					NYISO Draft Outlook ($ million 2021)
	Reference	Scenaro 1	Scenaro 2	Scenaro 3	Scenaro 4	
Wind	$ 4,265	$ 9,735	$ 8,961	$ 9,601	$ 9,958	$ 39,010
Wind Imports	$ -	$ -	$ -	$ -	$ -	
Wind_Offshore	$ 54,711	$ 88,320	$ 87,317	$ 101,863	$ 96,502	$ 66,330
Solar	$ 9,232	$ 33,055	$ 37,247	$ 34,517	$ 34,792	$ 6,302
Distributed Solar	$ 7,387	$ 19,246	$ 19,246	$ 19,246	$ 19,246	$ 12,324
Battery Storage	$ 5,531	$ 12,676	$ 13,267	$ 15,287	$ 14,424	$ 13,269
Pumped Storage	$ -	$ -	$ -	$ -	$ -	
Hydro Imports (New)	$ -	$ -	$ -	$ -	$ -	
Hydro Imports (Existing)	$ -	$ -	$ -	$ -	$ -	
In-State Hydro	$ 1,413	$ 1,427	$ 1,427	$ 1,427	$ 1,427	$ 5,010
Nuclear	$ -	$ -	$ -	$ -	$ -	
Gas & FO	$ -	$ -	$ -	$ -	$ -	
Zero-Carbon Firm Resource	$ -	$ 186,030	$ 30,759	$ 193,279	$ 195,186	$ 335,536
Hydrogen Production	$ -	$ 23,276	$ 21,720	$ 24,310	$ 24,470	$ 46,251
Biomass	$ -	$ -	$ -	$ -	$ -	
Total	**$ 82,538**	**$ 373,766**	**$ 219,944**	**$ 399,530**	**$ 396,006**	$ 524,032

Reference Case

The Draft Scoping Plan claims that “The cost of inaction exceeds the cost of action by more than $90 billion”. However, the caveat that this statement is “relative to the Reference Case” is often neglected and makes all the difference. Policy modeling like this compares projections for future mitigation scenarios against a business-as-usual case future projection. As I showed in my benefits are greater than costs comment, the Appendix G: Integration Analysis Technical Supplement states:

> The Reference Case is used for evaluating incremental societal costs and benefits of GHG emissions mitigation. The Reference Case includes a business as usual forecast plus implemented policies, including but not limited to federal appliance standards, energy efficiency

achieved by funded programs (Housing and Community Renewal, New York Power Authority, Department of Public Service, Long Island Power Authority, NYSERDA Clean Energy Fund), funded building electrification, national Corporate Average Fuel Economy standards, a statewide Zero-emission vehicle mandate, and a statewide Clean Energy Standard including technology carveouts.

The Integration Analysis that provides the numbers used in the Draft Scoping Plan misleads readers with this definition of the Reference Case because there are already "implemented" programs included in the Reference Case that would not exist were it not for the Climate Leadership and Community Protection Act (Climate Act). The Climate Act includes requirements to develop:

- 9 gigawatts (GW) of offshore wind electric generation by 2035;
- 6 GW of distributed photovoltaic solar generation by 2025; and
- 3 GW of energy storage capacity by 2030.

The most glaring abuse of the already "implemented" condition in the Reference Case is the 9 GW of offshore wind that is included for that case as shown in Table 3. Using these numbers, the Integration Analysis claims that the costs of offshore wind is between $32.6 billion and $47.2 billion for the mitigation scenarios relative to the Reference Case. In reality, the Reference Case should exclude all the off-shore wind costs so the mitigation scenario costs range between $87.3 and $101.9 billion. Similarly, the explicit references to distributed solar and energy storage capacities in the Climate Act mean that no costs should be included in the Reference case. In my other comments I showed that the net-zero transition costs are between $295 billion and $316 greater than the benefits but these numbers show that the costs are between $363 and $372 greater than the benefits. In my opinion, the appropriate business-as-usual case to compare costs for the mitigation scenarios would exclude all the renewable energy category costs which would further reduce the benefit to cost ratio.

Retirement Costs Not Included in Draft Scoping Plan

I submitted retirement assumption comments that pointed out that the Integration Analysis assumes that the expected lifetimes of those technologies is indefinite. As a result, units are assumed to remain online throughout the study period and no costs for replacements between now and 2050 are included. I did not attempt to calculate the additional costs for this inappropriate assumption in those comments. I address that issue in Table 4 that lists the additional costs to replace land-based wind, solar and battery storage through 2040. Costs are increased by at least 6%. Note, however, that the costs to replace retired units sharply increases between 2040 and 2050 when the big buildouts of renewables age out. For example, my projected cost for Scenario 4 in 2040 is $399,530 million but the cost to replace all the equipment that ages out between 2020 and 2050 is $304,428 million. The previously submitted retirement comments concluded that the Climate Action Council needs to explain why reasonable retirement dates should not be included in the Final Scoping Plan. it would also be appropriate for the Scoping Plan numbers to include their own estimates of the costs to replace retired equipment.

Table 4: Cost for Additional Capacity Installed for Replacement at Expected Lifetime

	Replacement Capacity (MW)					Total Cost	Replacement Cost
Scenario 2	2025	2030	2035	2040	Total	(2021$/kW)	($ million)
Zero-Carbon Firm Resource	-	-	-	-	-		$ -
Wind				1,917	1,917	$ 2,281	$ 4,372
Wind_Offshore				-	-		$ -
Solar				14,438	14,438	$ 1,357	$ 19,592
Battery Storage		750	750	1,500	3,000	$ 1,321	$ 3,963
						Total	$ 27,928

	Replacement Capacity (MW)					Total Cost	Replacement Cost
Scenario 3	2025	2030	2035	2040	Total	(2021$/kW)	($ million)
Zero-Carbon Firm Resource	-	-	-	-	-		$ -
Wind				1,917	1,917	$ 2,281	$ 4,372
Wind_Offshore				-	-		$ -
Solar				12,795	12,795	$ 1,357	$ 17,363
Battery Storage		750	750	1,500	3,000	$ 1,321	$ 3,963
						Total	$ 25,698

	Replacement Capacity (MW)					Total Cost	Replacement Cost
Scenario 4	2025	2030	2035	2040	Total	(2021$/kW)	($ million)
Zero-Carbon Firm Resource	-	-	-	-	-		$ -
Wind				1,917	1,917	$ 2,281	$ 4,372
Wind_Offshore				-	-		$ -
Solar				11,782	11,782	$ 1,357	$ 15,988
Battery Storage		750	750	1,500	3,000	$ 1,321	$ 3,963
						Total	$ 24,324

	Replacement Capacity (MW)					Total Cost	Replacement Cost
Reference Case	2025	2030	2035	2040	Total	(2021$/kW)	($ million)
Zero-Carbon Firm Resource	-	-	-	-	-		$ -
Wind				1,917	1,917	$ 2,281	$ 4,372
Wind_Offshore				-	-		$ -
Solar				274	274	$ 1,357	$ 371
Battery Storage		750	750	1,500	3,000	$ 1,321	$ 3,963
						Total	$ 8,707

Integrated Assessment Capacity Factors

The capacity factor is the fraction of actual generation divided by the maximum possible generation. Tables 5-7 list the Integration Analysis fuel mix capacity, energy, and capacity factors for the three mitigation scenarios. There are some issues that need to be highlighted with these data. It appears that the 2020 capacity factors were picked arbitrarily rather than based on observed data. For example, the biomass generating sector at 95% is higher than nuclear and that is improbable. Wind and solar have particular problems.

The solar capacity factor of 17.2% is consistent with the only utility-scale solar facility in New York. However, note that the capacity factor increases over time. That is only appropriate if the solar panels use tracking technology. Three new Central New York solar facilities, 280 MW Excelsior disturbing 1,635 acres, 80 MW Trelina 474 disturbed acres, and the 200 MW Garnet with 1,054 disturbed acres all propose to use fixed panels. As a result, their costs will be higher than the costs projected in the Integration Analysis. The Climate Action Council should insist on a requirement for tracking solar panels to be consistent with the Integration Analysis projections.

Table 5: Scenario 2 Integration Analysis Fuel Mix Capacity, Energy, and Capacity Factors

Mitigation Scenarios Summary Fuel Mix Capacity (MW)

Scenario 2	2020	2025	2030	2035	2040	2045	2050
Nuclear	4,860	3,355	3,355	3,355	3,355	3,355	2,135
Gas & FO	26,388	25,775	21,579	18,078	-	-	-
Zero-Carbon Firm Resour	-	-	-	-	21,015	21,576	21,290
Biomass	327	327	327	327	327	275	178
In-State Hydro	4,269	4,269	4,610	4,610	4,613	4,613	4,613
Hydro Imports (Existing)	1,485	1,485	1,485	1,485	1,485	1,485	1,485
Hydro Imports (New)	-	-	1,250	1,250	1,250	1,250	1,250
Wind	1,917	3,292	3,814	4,263	5,845	7,781	9,445
Wind Imports	-	-	1,760	5,796	6,397	6,397	6,397
Wind_Offshore	-	1,826	6,200	9,906	14,364	16,393	16,393
Solar	2,592	8,201	18,852	28,994	43,432	53,089	64,621
Battery Storage	750	1,500	3,000	5,791	10,713	17,046	21,465
Pumped Storage	1,435	1,435	1,435	1,435	1,435	1,435	1,435

Mitigation Scenarios Summary Annual Fuel Mix Energy (GWh)

Scenario 2	2020	2025	2030	2035	2040	2045	2050
Nuclear	38,318	26,452	26,452	26,452	26,452	26,452	16,835
Gas & FO	70,449	58,305	24,562	19,651	-	-	-
Zero-Carbon Firm Resour	-	-	-	-	3,342	3,675	4,153
Biomass	2,721	2,721	2,721	2,721	2,721	2,288	1,480
In-State Hydro	27,121	27,011	30,857	30,963	30,045	30,021	30,009
Hydro Imports (Existing)	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Hydro Imports (New)	-	-	8,760	8,760	8,760	8,760	8,760
Wind	4,796	8,238	9,873	11,229	16,035	21,854	26,936
Wind Imports	-	-	6,944	22,810	25,130	24,916	24,931
Wind_Offshore	-	7,611	25,657	41,016	59,778	68,287	68,522
Solar	3,908	13,087	32,965	52,781	80,620	100,948	125,292
Battery Storage	(16)	47	(774)	(1,543)	(2,196)	(3,406)	(4,319)
Pumped Storage	(74)	(50)	(233)	(123)	(348)	(380)	(476)

Mitigation Scenarios Summary Annual Capacity Factors (%)

Scenario 2	2020	2025	2030	2035	2040	2045	2050
Nuclear	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Gas & FO	30.5%	25.8%	13.0%	12.4%			
Zero-Carbon Firm Resour					1.8%	1.9%	2.2%
Biomass	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
In-State Hydro	72.5%	72.2%	76.4%	76.7%	74.3%	74.3%	74.3%
Hydro Imports (Existing)	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%
Hydro Imports (New)			80.0%	80.0%	80.0%	80.0%	80.0%
Wind	28.6%	28.6%	29.6%	30.1%	31.3%	32.1%	32.6%
Wind Imports			45.0%	44.9%	44.8%	44.5%	44.5%
Wind_Offshore		47.6%	47.2%	47.3%	47.5%	47.6%	47.7%
Solar	17.2%	18.2%	20.0%	20.8%	21.2%	21.7%	22.1%
Battery Storage	-0.2%	0.4%	-2.9%	-3.0%	-2.3%	-2.3%	-2.3%
Pumped Storage	-0.6%	-0.4%	-1.9%	-1.0%	-2.8%	-3.0%	-3.8%

Table 6: Scenario 3 Integration Analysis Fuel Mix Capacity, Energy, and Capacity Factors

Mitigation Scenarios Summary Fuel Mix Capacity (MW)

Scenario 3	2020	2025	2030	2035	2040	2045	2050
Nuclear	4,860	3,355	3,355	3,355	3,355	3,355	2,135
Gas & FO	26,388	25,775	22,398	14,292	-	-	-
Zero-Carbon Firm Resour	-	-	-	5,489	23,522	25,230	25,359
Biomass	327	327	327	327	327	275	178
In-State Hydro	4,269	4,269	4,610	4,613	4,613	4,613	4,613
Hydro Imports (Existing)	1,485	1,485	1,485	1,485	1,485	1,485	1,485
Hydro Imports (New)	-	-	1,250	1,250	1,250	1,250	1,250
Wind	1,917	3,292	4,600	5,220	6,126	8,250	10,154
Wind Imports	-	-	2,421	5,448	6,397	6,593	6,593
Wind_Offshore	-	1,826	6,600	10,423	16,756	19,278	19,278
Solar	2,592	8,201	16,762	28,625	41,420	49,042	60,604
Battery Storage	750	1,500	3,000	8,090	12,207	16,383	19,212
Pumped Storage	1,435	1,435	1,435	1,435	1,435	1,435	1,435

Mitigation Scenarios Summary Annual Fuel Mix Energy (GWh)

Scenario 3	2020	2025	2030	2035	2040	2045	2050
Nuclear	38,318	26,452	26,452	26,452	26,452	26,452	16,835
Gas & FO	70,461	57,869	25,668	21,231	-	-	-
Zero-Carbon Firm Resour	-	-	-	-	4,440	5,419	6,399
Biomass	2,721	2,721	2,721	2,721	2,721	2,288	1,480
In-State Hydro	27,121	26,995	30,870	30,993	29,982	29,996	29,997
Hydro Imports (Existing)	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Hydro Imports (New)	-	-	8,760	8,760	8,760	8,760	8,760
Wind	4,796	8,238	12,296	14,130	16,799	23,200	28,947
Wind Imports	-	-	9,544	21,389	25,002	25,563	25,546
Wind_Offshore	-	7,611	27,293	43,153	69,388	79,540	80,046
Solar	3,908	13,087	28,596	51,328	75,966	92,094	116,044
Battery Storage	(16)	66	(822)	(1,875)	(2,443)	(3,249)	(4,081)
Pumped Storage	(74)	(64)	(223)	(115)	(288)	(310)	(395)

Mitigation Scenarios Summary Annual Capacity Factors (%)

Scenario 3	2020	2025	2030	2035	2040	2045	2050
Nuclear	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Gas & FO	30.5%	25.6%	13.1%	17.0%			
Zero-Carbon Firm Resour				0.0%	2.2%	2.5%	2.9%
Biomass	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
In-State Hydro	72.5%	72.2%	76.4%	76.7%	74.2%	74.2%	74.2%
Hydro Imports (Existing)	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%
Hydro Imports (New)			80.0%	80.0%	80.0%	80.0%	80.0%
Wind	28.6%	28.6%	30.5%	30.9%	31.3%	32.1%	32.5%
Wind Imports			45.0%	44.8%	44.6%	44.3%	44.2%
Wind_Offshore		47.6%	47.2%	47.3%	47.3%	47.1%	47.4%
Solar	17.2%	18.2%	19.5%	20.5%	20.9%	21.4%	21.9%
Battery Storage	-0.2%	0.5%	-3.1%	-2.6%	-2.3%	-2.3%	-2.4%
Pumped Storage	-0.6%	-0.5%	-1.8%	-0.9%	-2.3%	-2.5%	-3.1%

Table 7: Scenario 4 Integration Analysis Fuel Mix Capacity, Energy, and Capacity Factors

Mitigation Scenarios Summary Fuel Mix Capacity (MW)

Scenario 4	2020	2025	2030	2035	2040	2045	2050
Nuclear	4,860	3,355	3,355	3,355	3,355	3,355	2,135
Gas & FO	26,388	25,775	21,579	20,326	-	-	-
Zero-Carbon Firm Resour	-	-	-	-	23,676	24,333	24,048
Biomass	327	327	327	327	327	275	178
In-State Hydro	4,269	4,269	4,610	4,613	4,613	4,613	4,613
Hydro Imports (Existing)	1,485	1,485	1,485	1,485	1,485	1,485	1,485
Hydro Imports (New)	-	-	1,250	1,250	1,250	1,250	1,250
Wind	1,917	3,292	3,859	4,491	6,282	8,305	11,052
Wind Imports	-	-	2,649	5,970	6,397	6,397	6,397
Wind_Offshore	-	1,826	6,600	9,967	15,875	18,066	18,310
Solar	2,592	8,201	18,060	29,841	41,623	53,450	65,210
Battery Storage	750	1,500	3,000	6,311	11,576	18,973	22,956
Pumped Storage	1,435	1,435	1,435	1,435	1,435	1,435	1,435

Mitigation Scenarios Summary Annual Fuel Mix Energy (GWh)

Scenario 4	2020	2025	2030	2035	2040	2045	2050
Nuclear	38,318	26,452	26,452	26,452	26,452	26,452	16,835
Gas & FO	70,459	58,124	25,587	20,850	-	-	-
Zero-Carbon Firm Resour	-	-	-	-	4,644	5,614	6,609
Biomass	2,721	2,721	2,721	2,721	2,721	2,288	1,480
In-State Hydro	27,121	27,000	30,867	30,994	30,023	30,008	30,006
Hydro Imports (Existing)	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Hydro Imports (New)	-	-	8,760	8,760	8,760	8,760	8,760
Wind	4,796	8,238	9,966	11,856	17,274	23,376	31,606
Wind Imports	-	-	10,449	23,455	25,035	24,849	24,811
Wind_Offshore	-	7,611	27,293	41,237	65,700	74,600	76,263
Solar	3,908	13,087	31,293	53,921	76,465	101,267	125,980
Battery Storage	(16)	61	(812)	(1,781)	(2,381)	(3,844)	(4,823)
Pumped Storage	(74)	(59)	(220)	(163)	(345)	(306)	(426)

Mitigation Scenarios Summary Annual Capacity Factors (%)

Scenario 4	2020	2025	2030	2035	2040	2045	2050
Nuclear	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Gas & FO	30.5%	25.7%	13.5%	11.7%			
Zero-Carbon Firm Resour					2.2%	2.6%	3.1%
Biomass	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
In-State Hydro	72.5%	72.2%	76.4%	76.7%	74.3%	74.3%	74.3%
Hydro Imports (Existing)	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%	79.6%
Hydro Imports (New)			80.0%	80.0%	80.0%	80.0%	80.0%
Wind	28.6%	28.6%	29.5%	30.1%	31.4%	32.1%	32.6%
Wind Imports			45.0%	44.8%	44.7%	44.3%	44.3%
Wind_Offshore		47.6%	47.2%	47.2%	47.2%	47.1%	47.5%
Solar	17.2%	18.2%	19.8%	20.6%	21.0%	21.6%	22.1%
Battery Storage	-0.2%	0.5%	-3.1%	-3.2%	-2.3%	-2.3%	-2.4%
Pumped Storage	-0.6%	-0.5%	-1.7%	-1.3%	-2.7%	-2.4%	-3.4%

2021 Wind Resources

The 2020 wind capacity factor is 28.6% in Tables 5-7. This is inconsistent with observed New York data. The NYISO Gold Book summarizes New York load & capacity data. It includes a table that lists pertinent information for every generating unit in New York. I have been extracting wind facility information so that I could calculate capacity factors for many years as shown in Table 8. The only years that were close to the 28.6% with 2014 and 2015. In 2021 the statewide wind capacity factor was only 22.3%.

This trend could be the result of natural variability but there are a couple of other possibilities. It is possible that it reflects facilities built since then have worse wind resources dragging statewide average down. I suspect it is more likely system degradation over time. In order to confirm that specific data for wind turbine facilities would be needed comparable to the summer and winter Dependable Maximum Net Capability (DMNC) tests that NYISO requires for most units in the New York market.

The Climate Action Council should resolve the Draft Scoping Plan wind issues. The Final Scoping Plan projections for the amount of wind capacity must use a more realistic capacity factor. If there is in fact an observed degradation of wind generation over time then that too should be incorporated in the Final Scoping Plan. If these issues are not resolved then the projected capacity will be too low and the costs under-estimated.

Table 8: New York State Wind Facility Capacity Factors Based on NYISO "Gold Book" Load & Capacity Data Reports Table III-1

Station	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Altona_Wind_Power			1.0%	17.4%	22.0%	20.9%	20.2%	19.0%	21.8%	19.9%	19.9%	20.6%	19.7%	20.1%	21.6%	19.0%
Arkwright_Summit_Wind_Farm														37.4%	37.2%	34.0%
Bliss_Wind_Power			16.8%	22.0%	21.3%	21.7%	23.3%	23.2%	23.5%	23.3%	23.2%	23.9%	35.7%	37.4%	37.2%	19.9%
Canandaigua_Wind_Power			5.5%	19.9%	23.6%	22.1%	22.6%	22.0%	23.7%	23.8%	23.6%	24.2%	21.9%	19.3%	22.3%	14.8%
Cassadaga_Wind																15.3%
Chateaugay_Wind_Power			10.3%	18.4%	20.6%	21.6%	20.6%	20.2%	21.5%	22.7%	22.5%	22.3%	22.4%	19.0%	6.0%	18.8%
Clinton_Wind_Power			11.4%	20.2%	19.7%	19.8%	19.0%	20.0%	21.1%	19.9%	19.9%	19.4%	20.5%	21.1%	22.2%	17.2%
Copenhagen_Wind_Farm														35.2%	20.0%	34.3%
Ellenburg_Wind_Power			12.9%	22.8%	22.2%	23.7%	22.2%	23.2%	24.9%	24.5%	23.8%	24.4%	16.7%	19.3%	20.0%	20.4%
Erie_Wind							25.3%	31.5%	29.9%	28.9%	29.0%	28.0%	13.8%	35.2%	39.2%	19.9%
Fenner_Wind_Power	29.4%	36.0%	27.0%	26.1%	9.9%	25.1%	22.5%	26.0%	25.4%	25.6%	23.7%	16.9%	20.3%	22.3%	23.6%	27.9%
Hardscrabble_Wind						22.8%	26.5%	27.9%	28.4%	28.3%	28.1%	27.4%	19.9%	14.1%	7.2%	24.5%
High Sheldon Wind Farm				22.3%	24.5%	26.5%	25.8%	27.1%	27.5%	26.2%	27.2%	27.2%	20.7%	27.6%	12.6%	21.5%
Howard_Wind							23.7%	26.7%	26.5%	25.6%	26.6%	26.6%	27.3%	28.4%	10.6%	22.5%
Jericho_Rise_Wind											27.0%	36.2%	25.1%	24.8%	25.0%	29.5%
Madison_Wind_Power	19.9%	20.9%	18.8%	19.4%	17.7%	21.4%	18.7%	20.2%	20.7%	19.4%	19.7%	20.5%	24.9%	26.6%	26.0%	10.1%
Maple_Ridge_Wind_1	20.1%	25.9%	26.6%	26.1%	24.4%	26.2%	25.9%	26.9%	29.0%	28.1%	27.4%	28.2%	33.2%	33.4%	33.2%	22.4%
Maple_Ridge_Wind_2			26.8%	25.6%	24.3%	25.4%	25.3%	26.3%	28.4%	27.3%	26.7%	27.5%	18.4%	18.5%	16.8%	21.2%
Marble_River_Wind							18.0%	27.2%	28.6%	28.8%	27.7%	28.7%	26.5%	26.5%	26.6%	23.7%
Marsh Hill Wind Farm										47.6%	38.8%	34.4%	25.6%	25.3%	25.4%	34.4%
Munnsville_Wind_Power			29.5%	29.4%	28.0%	29.0%	28.7%	29.6%	31.8%	30.2%	31.1%	32.0%	25.9%	27.6%	25.9%	26.4%
Orangeville_Wind_Farm								11.9%	33.3%	34.9%	32.2%	34.0%	32.7%	35.5%	13.4%	29.9%
Roaring_Brook_Wind																12.4%
Steel_Wind		5.9%	21.3%	24.1%	27.6%	21.9%	27.7%	11.9%	33.3%	34.9%	31.8%	29.6%	19.3%	11.2%	29.5%	19.4%
Western_NY_Wind_Power	25.0%	26.9%	19.7%	23.7%	23.0%	23.2%	20.8%	30.5%	26.6%	28.9%	21.6%	12.3%	35.2%	33.5%	34.2%	2.9%
Wethersfield_Wind_Power				20.0%	23.1%	23.2%	22.6%	16.6%	16.1%	23.5%	24.0%	24.7%	26.8%	15.5%	6.2%	20.6%
State Wide Totals	21.2%	26.3%	20.9%	18.9%	18.8%	20.9%	23.2%	23.9%	24.3%	23.9%	25.7%	26.4%	24.5%	25.3%	23.9%	22.3%
State Wide Net Energy GWh	518	800	1,282	1,960	2,216	2,472	3,060	3,541	3,985	3,984	3,943	4,219	3,985	4,400	4,162	4,111
State Wide Annual Capacity GWh	2,446	3,045	6,126	10,362	11,808	11,808	13,217	14,154	14,224	14,344	15,352	15,975	16,264	17,390	17,390	18,456

State Average Capacity Factor	21.2%	26.3%	20.9%	18.9%	18.8%	20.9%	23.2%	25.0%	28.0%	27.8%	25.7%	26.4%	24.5%	25.3%	23.9%	22.3%

I found another NYISO resource dated March 31, 2021 that provides the 2021 wind production including the 2021 wind curtailment. The data sets list the hourly total wind production and curtailments for the entire New York Control Area (NYCA). I have summarized the data in Table 9. Curtailments are those hours when the system load is small enough that wind production is greater than what is needed so the wind power is curtailed, i.e., not used.

Table 9: NYISO Hourly Wind Production at the Aggregated NYCA-Wide Level

Statistic	Production (MW)	Curtailments (MW)	Production % of Total	Curtailment % of Total
Maximum	1,889.9	494.8	86%	25%
99%	1,648.8	198.3	78%	10%
95%	1,329.3	57.5	63%	3%
90%	1,089.4	16.9	52%	1%
85%	930.1	5.9	44%	0%
80%	805.5	1.7	38%	0%
75%	695.6	0.2	33%	0%
70%	601.7	0.0	29%	0%
65%	523.5	0.0	25%	0%
60%	460.0	0.0	22%	0%
55%	401.7	0.0	19%	0%
50%	345.4	0.0	16%	0%
45%	299.3	0.0	14%	0%
40%	257.6	0.0	12%	0%
35%	223.3	0.0	11%	0%
30%	185.7	0.0	9%	0%
25%	151.6	0.0	7%	0%
20%	116.3	0.0	5%	0%
15%	83.6	0.0	4%	0%
10%	51.9	0.0	2%	0%
5%	19.2	0.0	1%	0%
Mean	469.2	9.6	22%	0%

To this point the comment emphasis has been on annual projections but these data illustrate the importance of considering the effect of shorter periods. The percentiles are shown in the first column and the data indicate that wind power is greater than 78% of the total capacity only 87 hours (99th percentile) in 2021. Three quarters of the time the production is less than 696 MW which is equivalent to one third of the total capacity. If you assume that production less than 10% is the threshold for no wind support value then wind won't be producing appreciable power 30% of the time. In order for the future electric grid to provide reliable power all the time the distribution of weather dependent resources has to be considered in projections of future capacity requirements.

For example, the existing wind facilities are spread across Upstate. NYISO cannot provide individual unit generation so I cannot definitively say that those facilities are highly correlated. However, given that half the time the total generation capacity is only 16% of the total I am sure that is the case. As a result, improving energy production at the lower levels requires a lot more generation capacity. For example, at the 25th percentile the total capacity is 151.6 MW. If planners predict we need wind generation capacity to equal 1,000 MW 75% of the time. then, based on 2021 data, the state land-based wind capacity would have to increase to 13,900 MW, over six times greater than current capacity.

Of course, there are tradeoffs between overbuilding and developing battery storage or the dispatchable emissions free resource. Table 10 compares the Reference Case and mitigation scenarios for five categories of resources. The existing dispatchable resource category includes nuclear, gas & fuel oil, biomass, in-state hydro, and new hydro imports. The dispatchable emissions free resource, battery storage and pumped storage categories only cover one sector in the fuel mix categories of the Integration Analysis fuel mix tables. The weather-dependent resource category includes wind, wind imports, offshore wind, solar and new hydro imports. I expect that the worst-case wind conditions will occur in a large high-pressure system that covers the entire state land mass, the state's off-shore wind resource territory, and neighboring areas where we could expect to import wind energy. The new hydro imports capacity refers to the Champlain Hudson Power Express (CHPE) project to import power from Hydro Quebec. The high-pressure system that brings the large area of calm winds also is associated with very cold weather in the winter and both Quebec and New York will have simultaneous high loads. The contract with CHPE is for their surplus energy and at peak loads there is no surplus available for export.

Table 10: 2040 Percentage of Weather Dependent Capacity

Resource Percentage	Reference Case	Scenario 2	Scenario 3	Scenario 4	NYISO Outlook
Existing Dispatchable	21.0%	8.6%	8.6%	8.6%	
Dispatchable Emissions-Free	0.0%	18.4%	20.6%	20.7%	28.7%
Battery Storage	4.3%	9.4%	10.7%	10.1%	7.3%
Pumped Storage	1.3%	1.3%	1.3%	1.3%	
Weather-Dependent	25.1%	62.4%	63.0%	62.5%	28.2%

Resource Capacity (MW)	Reference Case	Scenario 2	Scenario 3	Scenario 4	NYISO Outlook
Existing Dispatchable	24,028	9,780	9,780	9,780	
Dispatchable Emissions-Free	0	21,015	23,522	23,676	44,750
Battery Storage	4,872	10,713	12,207	11,576	11,450
Pumped Storage	1,435	1,435	1,435	1,435	
Weather-Dependent	28,697	71,288	71,949	71,427	43,961
Total	59,033	114,232	118,894	117,896	155,815

As noted elsewhere there are differences between the resource capacity allocations between the NYISO resource outlook and the Integration Analysis mitigation scenarios. Note that in Table 10 at least 62.4% of the mitigation scenario capacity is weather dependent and DEFR is on the order of 20%. However, the NYISO projection projects that DEFR and the weather dependent resources are about the same percentage by increasing DEFR and reducing weather-dependent resources. This is a significant difference of opinion about how to handle this situation. It is important that the Climate Action Council insist that these results be reconciled.

It is imperative that the State conduct a detailed evaluation of renewable energy resource availability to determine the generation and energy storage requirements of the future New York electrical system. As these results show, the annual wind resources capabilities can be very low for long periods. I submitted renewable resource comments in March that explain that in order to ensure electric system reliability for an energy system that depends on weather-dependent resources, the resources available during periods of low wind and solar energy production must be known. If the worst-case conditions are not known, then the energy storage and DEFR capacity may not be sufficient to keep the lights on. To date, many studies do not consider the importance of worst-case conditions on reliability planning and I believe that the Draft Scoping Plan also fails to address this issue. My comments explained that there is a viable approach that could robustly quantify the worst-case renewable energy resources and provide the information necessary for adequate planning.

I prepared this comment because the Integrated Analysis electric system analysis is biased low and my evaluation shows this clearly. I have written extensively on implementation of the Climate Act because I believe the ambitions for a zero-emissions economy outstrip available renewable technology such that it will adversely affect reliability and affordability, risk safety, affect lifestyles, will have worse impacts on the environment than the purported effects of climate change in New York, and cannot measurably affect global warming when implemented. The opinions expressed in this document do not reflect the position of any of my previous employers or any other company I have been associated with, these comments are mine alone.

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Addendum 1: Capacity Cost Calculations

Because the Draft Scoping Plan does not describe all the control measures, the assumptions used, the expected costs for those measures or the expected emission reductions, I was forced to calculate my own estimate of the cost for added capacity for the Reference Case, the Advisory Panel scenario and the three mitigation scenarios. These estimates do not cover all the costs in the electricity sector but evaluation of this component provides some important insights. My primary concern is the zero-emissions transition by 2040 so my analysis goes only to 2040.

I got the overnight cost (2021$/kW) for different technologies from the U.S. Energy Information Administration (EIA) [Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022]() as shown in Table A-1 The summary notes:

> The tables presented below are also published in the Electricity Market Module chapter of the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2022 (AEO2022) Assumptions document. Table 1 represents our assessment of the cost to develop and install various generating technologies used in the electric power sector. Generating technologies typically found in end-use applications, such as combined heat and power or roof-top solar photovoltaics (PV), will be described elsewhere in the Assumptions document. The costs shown in Table 1, except as noted below, are the costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency to underestimate the full engineering and development costs for new technologies during technology research and development.

The EIA narrative notes:

> All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind and solar PV, in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To reflect this difference, we report a weighted average cost for both wind and solar PV, based on the regional cost factors assumed for these technologies in AEO2022 and the actual regional distribution of the builds that occurred in 2020 (Table 1).

EIA Annual Energy Outlook 2022 Table A-1: Cost and performance characteristics of new central station electricity generating technologies

https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Technology	First Available Year (a)	Size (MW)	Lead Time (years)	Base overnight cost (b) (2021$/kW)	Technological optimism factor (c)	Total overnight cost (d) (e) (2021$/kW)	Variable O&M (f) (2021$/MWh)	Fixed O&M (2021$/kW-y)	Heat rate ((g) (Bty/kWh)
Ultra-supercritical coal (USC)	2025	650	4	$4,074	1	$4,074	$4.71	$42.49	8,638
USC with 30% carbon capture and sequestration (CCS)	2025	650	4	$5,045	1.01	$5,096	$7.41	$56.84	9,751
USC with 90% CCS	2025	650	4	$6,495	1.02	$6,625	$11.49	$62.34	12,507
Combined-cycle—single-shaft	2024	418	3	$1,201	1	$1,201	$2.67	$14.76	6,431
Combined-cycle—multi-shaft	2024	1,083	3	$1,062	1	$1,062	$1.96	$12.77	6,370
Combined-cycle with 90% CCS	2024	377	3	$2,736	1.04	$2,845	$6.11	$28.89	7,124
Internal combustion engine	2023	21	2	$2,018	1	$2,018	$5.96	$36.81	8,295
Combustion turbine— aeroderivativeh	2023	105	2	$1,294	1	$1,294	$4.92	$17.06	9,124
Combustion turbine—industrial frame	2023	237	2	$785	1	$785	$4.71	$7.33	9,905
Fuel cells	2024	10	3	$6,639	1.09	$7,224	$0.62	$32.23	6,469
Nuclear—light water reactor	2027	2,156	6	$6,695	1.05	$7,030	$2.48	$127.35	10,443
Nuclear—small modular reactor	2028	600	6	$6,861	1.1	$7,547	$3.14	$99.46	10,443
Distributed generation—base	2024	2	3	$1,731	1	$1,731	$9.01	$20.27	8,923
Distributed generation—peak	2023	1	2	$2,079	1	$2,079	$9.01	$20.27	9,907
Battery storage	2022	50	1	$1,316	1	$1,316	$0.00	$25.96	NA
Biomass	2025	50	4	$4,524	1	$4,525	$5.06	$131.62	13,500
Geothermal (i) (j)	2025	50	4	$3,076	1	$3,076	$1.21	$143.22	8,813
Conventional hydropower (j)	2025	100	4	$3,083	1	$3,083	$1.46	$43.78	NA
Wind (e)	2024	200	3	$1,718	1	$1,718	$0.00	$27.57	NA
Wind offshore (i)	2025	400	4	$4,833	1.25	$6,041	$0.00	$115.16	NA
Solar thermal (i)	2024	115	3	$7,895	1	$7,895	$0.00	$89.39	NA
Solar photovoltaic (PV) with tracking (e), (i), (k)	2023	150	2	$1,327	1	$1,327	$0.00	$15.97	NA
Solar PV with storage (i),(k)	2023	150	2	$1,748	1	$1,748	$0.00	$33.67	NA

Notes

(a) The first year that a new unit could become operational.

(b) Base cost includes project contingency costs.

(c) We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

(d) Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2022.

(e) Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2020 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2022 was $1,411 per kilowatt (kW), and for solar PV with tracking, it was $1,323/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

(f) O&M = Operations and maintenance.

(g) The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, Annual Electric Generator Report. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion, and no set British thermal unit conversion factors exist. The module calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.

(h) Combustion turbine aeroderivative units can be built by the module before 2023, if necessary, to meet a region's reserve margin.

(i) Capital costs are shown before investment tax credits are applied.

(j) Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.

(k) Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

In order to account for differences by region the EIA analysis provides information by region. Unfortunately, the Integration Analysis does not provide New York Control Area information using the same breakdown. For my analysis I assumed that the EIA NYCW region covers NYISO control area zones J, New York City and K, Long Island.

> Table A-2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and our modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. We represent this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

I incorporated EIA Table 1 and Table 2 data into the attached Caiazza Electric System Comment Spreadsheet. The spreadsheet tab “EIA” combines the EIA data.

The spreadsheet tab “Costs” sums the Integration Analysis lists projected installed capacity values for 2020 and for the Reference Case and Scenarios 1-4 for 2040 in columns A-L. The capacity values were extracted from the IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs spreadsheet. I assumed that the Climate Act capacity additions (MW) from today to 2040 equal the 2040 total capacity minus the 2020 capacity for each generator type.

In column N I list the EIA costs for each generating sector that increased capacity. In order to account for differences by region the EIA analysis provides information by region. Unfortunately, the Integration Analysis does not provide New York Control Area information using the same breakdown. For my analysis I assumed that the EIA NYCW region covers NYISO control area zones J, New York City and K, Long Island. Everything else is in EIA NYUP.

To get the cost per scenario generator type listed in columns P-T, I multiplied the overnight cost (2021$/kW) times the capacity addition (MW) times 1000 kW/MW. A couple of notes on assumptions. I used the Solar photovoltaic (PV) with tracking because I could not find a cost without tracking for distributed solar. EIA did not include a cost for NYCW for wind so I used the NYUP value.

Table A-2: Total overnight capital costs of new electricity generating technologies by region
https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Technology	Total Overnight Cost (2021$/kW)	
	NYCW	NYUP
Ultra-supercritical coal (USC)	NA	$4,614
USC with 30% carbon capture and sequestration (CCS)	NA	$5,729
USC with 90% CCS	NA	$7,303
Combined-cycle—single-shaft	$1,912	$1,445
Combined-cycle—multi-shaft	$1,725	$1,238
Combined-cycle with 90% CCS	$3,422	$2,953
Internal combustion engine	$2,769	$2,125
Combustion turbine— aero derivative	$1,864	$1,405
Combustion turbine—industrial frame	$1,144	$854
Fuel cells	$9,201	$7,498
Nuclear—light water reactor	NA	$7,430
Nuclear—small modular reactor	NA	$8,040
Distributed generation—base	$2,754	$2,081
Distributed generation—peak	$2,994	$2,257
Battery storage	$1,351	$1,321
Biomass	$7,292	$5,389
Geothermal	NA	NA
Conventional hydropower	NA	$4,144
Wind	NA	$2,281
Wind offshore	$6,079	$7,370
Solar thermal	NA	NA
Solar photovoltaic (PV) with tracking	$1,612	$1,357
Solar PV with storage	$2,078	$1,796

The assumptions for the costs for the zero-carbon firm resource estimates were more involved. As a first order approximation I assumed that hydrogen would be used for this resource and included two cost components. I assumed electricity production comes from fuel cells and EIA has a cost for the fuel cells. On the other hand, EIA does not provide a cost for the electrolysis process itself. In another set of comments on hydrogen for DEFR, I described how the Integration Analysis handled hydrogen for DEFR. The "Hydrogen" tab in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet lists costs for electrolyzers, infrastructure, and transportation. I did not add costs to build hydrogen storage assuming that salt caverns could store all the necessary hydrogen. The additional cost for building long-term hydrogen storage systems ranges from $0.36/kWh of hydrogen to $2.988/kWh of hydrogen. Because I believe that the Integration Analysis includes sufficient wind and solar capacity to power the electrolyzers I did not add any capacity costs for that requirement. I calculated the total combined costs for electrolyzers, infrastructure, and transportation. I converted the listed values in $/mmBtu to $/MW using data from the "Hydrogen" tab. The DEFR capacity is installed between 2035 and 2040 so I used the 2035 value of $1,034.

I compared the capital costs (2020 $/kW) in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet Resource Costs tabs against the EIA Table 1: Cost of new central station electricity generating technologies. Table A-3 shows that with the exception of the capital costs for large hydro and a gas-fired combined cycle unit in Upstate New York the Integration Analysis all the other technology costs are lower and, in some cases, much lower in the Integration Analysis. If my comparison interpretation is correct then these numbers are outrageous. The capital costs for offshore wind are half of the EIA costs. While there may be some interpretation of the battery energy storage cost that can explain why EIA costs are five times higher, I don't think there is any interpretation issue with the hydrogen fuel cell technology that is five times higher in New York City and four times higher Upstate. The Climate Action Council must explain why the Draft Scoping Plan numbers are so high for these technologies.

Table A-3: Compare IA-Tech-Supplement-Annex-1-Input-Assumptions Spreadsheet to EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022

IA-Tech-Supplement-Annex-1-Input-Assumptions Resource Costs Tables			EIA Table 1: Cost of new central station electricity generating technologies				EIA Table 2		Percent Difference between IA and EIA	
Base Capital Costs by Technology (2020 $/kW)	Resource Costs - Mid	Resource Costs - Low		Base overnight cost	Technological optimism factor	Total overnight cost	Total Overnight Cost (2021$/kW)			
Technology	2020	2020	Technology	(2021$/kW)		(2021$/kW)	NYCW	NYUP	NYCW	NYUP
Wind	$ 1,412	$ 1,412	Wind	$1,718	1	$1,718	NA	$2,281		62%
Wind - Offshore	$ 3,055	$ 3,055	Wind offshore	$4,833	1.25	$6,041	$6,079	$7,370	99%	141%
Solar - Tracking	$ 1,183	$ 1,183	Solar photovoltaic (PV) with tracking	$1,327	1	$1,327	$1,612	$1,357	36%	15%
Solar - Dist Comm	$ 1,948	$ 1,948								
Solar - Dist Res	$ 3,959	$ 3,959								
Hydro - Non-Powered Dam	$ 2,829	$ 2,829								
Hydro - Large	$ 4,364	$ 4,364	Conventional hydropower	$3,083	1	$3,083	NA	$4,144		-5%
Gas - CCGT	$ 1,411	$ 1,411	Combined-cycle—multi-shaft	$1,062	1	$1,062	$1,725	$1,238	22%	-12%
Gas - CT - Frame	$ 1,052	$ 1,052	Combustion turbine— aeroderivative	$1,294	1	$1,294	$1,864	$1,405	77%	34%
Hydrogen - Fuel Cell	$ 1,496	$ 1,496	Fuel cells	$6,639	1.09	$7,224	$9,201	$7,498	515%	401%
Pumped Storage [Energy, $/kWh]	$ 136	$ 136								
Battery - Li [Energy, $/kWh]	$ 227	$ 227	Battery storage	$1,316	1	$1,316	$1,351	$1,321	495%	482%

Addendum 2: References to Ancillary in the Draft Scoping Plan

Chapter 13, Electricity page 172:

- **Wholesale Market Improvements:** The State should continue assessing opportunities to improve accuracy and granularity of wholesale market energy price signals, including shortage pricing, congestion relief, and peak/off-peak pricing. This should include the evaluation of the inclusion and valuation of ancillary market services in the context of integrating increasing quantities of renewable resources and other products.
- **Support Flexible Resources:** The State should adapt current ancillary service market designs and look to add products that are needed to incent flexibility as needed to efficiently integrate renewables. The NYISO supports markets for energy, ancillary services, and capacity. The fundamental relationship among these markets will likely need to evolve. For example, more revenue will likely shift to ancillary service markets over time as system needs are reevaluated in the context of integrating increasing quantities of renewable resources. This should include proactive development of new products needed; however, they should be structured properly to only reflect current system needs to not cause unnecessary costs. A balancing act is needed between developing the products and services of the future while not implementing changes before they are needed.

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> **Co-optimization of energy & ancillary services:** RESOLVE includes reserve requirements in its generator dispatch, which is co-optimized to meet load while simultaneously reserving flexible capacity within NYISO to meet the contingency and flexibility reserve needs across the New York zones.[70]

[70] Ancillary services, such as contingency and flexibility reserves, are services necessary to maintain electric system reliability that are provided outside of day-ahead and real-time energy markets.

Enabling initiative – Initiative #9: Components of the strategy

Components required for delivery	Implementation lead	Time to implement	Other key stakeholders
Expand wholesale market eligibility participation rules for new policy resources. The NYISO is in the process of implementing the first part of a Hybrid Storage Model, where hybrid resources will be allowed to participate as two separate resources located at the same site. The current expectation is for a second potentially more versatile "Aggregated" model market design in 2021. The NYISO is also working on a Distributed Energy Resources (DER) Participation Model. The NYISO is working toward but has not yet implemented a full wholesale DER market design. The NYISO should make changes consistent with FERC Order 2222 requirements.	NYISO	Ongoing	PSC, NYSERDA, Utilities, Suppliers
Continue assessing opportunities to improve accuracy and granularity of wholesale market energy price signals, including shortage pricing, congestion relief, and peak/off-peak pricing. Inclusion, and valuation, of ancillary market services will need to be evaluated in the context of integrating increasing quantities of renewable resources and other products.	NYISO	Ongoing	
Adapt current ancillary service market designs and look to add products that are needed to incent flexibility as needed to efficiently integrate renewables. The NYISO supports markets for energy, ancillary services, and capacity. The fundamental relationship among these markets will likely need to evolve. For example, more revenue will likely shift to ancillary service markets over time as system needs are reevaluated in the context of integrating increasing quantities of renewable resources. Be proactive in developing new products needed, however they should be structured properly to only reflect current system needs to not cause unnecessary costs. A balancing act is needed between developing the products and services of the future while not implementing changes before they are needed.	NYISO	Ongoing	

This page is included because of a quirk of Microsoft Word. My apologies for any confusion.