Caiazza Comment on Hydrogen as a Zero-Carbon Firm Resource

Summary
This comment addresses the use of hydrogen in some form or other as the Draft Scoping Plan placeholder technology for the Zero-Carbon Firm Resource or Dispatchable Emissions-Free Resource (DEFR) generally accepted as a complementary requirement when intermittent resources like wind and solar make up a significant portion of the electric grid resource mix. Energy storage is required for intermittent resources but the cost for exclusive reliance on batteries is unacceptably high. These resources are included to maintain reliability when the wind does not blow and the sun does not shine for long periods. I conclude that the Final Scoping Plan has to do a much better job documenting the use of hydrogen for this resource to be considered credible.

My comments summarize background information in the Draft Scoping Plan and from the New York Independent System Operator (NYISO). I describe the Integration Analysis description of the Carbon-Free Electric Supply and the hydrogen costs provided in an Integration Analysis spreadsheet. I also describe the on-going NYISO update to their System and Resource Outlook that addresses DEFR. I used a relevant article, Hydrogen Is Unlikely Ever To Be A Viable Solution To The Energy Storage Conundrum, as the outline for these comments.

The 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 speculates without sufficient justification that the "zero-carbon firm resource" projections for the future can be met using hydrogen in one form or another. My concern is that the Plan does not provide enough reliable documentation to support the speculated use of hydrogen as the technology for this critical resource. The comments describe specific issues that need to be explicitly addressed in the Final Scoping Plan if the Climate Action Council is to make a compelling argument that this technology will keep the lights and heat on when needed most.

The Draft Scoping Plan calls for the use of so-called "green hydrogen" whereby hydrogen is produced by a carbon-free process of electrolysis from water. The first probem is that the costs for hydrogen produced using this technology are entirely speculative and by any reasonable basis of estimation will be extraordinaly high. Compared to the cost of production using natural gas natural gas to produce hydrogen, "green" hydrogen will be more than five times more expensive.

I used a Seeking Alpha analysis to estimate the hydrogen needed if it was combusted to make electricity or used to power fuel cells. For the NYISO and Integration Analysis scenarios I found that between 73 and 155 turbines sized at 288 MW would have to be dedicated for this resource application. At this time the world's largest hydrogen fuel cell is only 79 MW so between 266 and 566 fuels cells of that size would be required.

My analysis calculated the generation energy needed for electrolysis to support DEFR projections. Scenaro 2 requires 3,342 GWh of energy for DEFR and 12,812 GWh for electrolysis which is about half the projected imported wind total in 2040. The Integration Analysis emphasizes the use of solar over

wind and it appears that the electrolysis requirements are covered by the solar generation projections. Importantly, the NYISO draft Outlook Study projected DEFR requirements are an order of magnitude higher than the mitigation scenarios. As a result, the energy needed for the hydrogen to cover that need (130,353 GWh) is more than the projected total solar, land-based wind, and wind import energy (121,875 GWh) in 2040. The Climate Action Council must reconcile the differences between these two estimates because of the ramifications on the energy needed for DEFR using green hydrogen.

The difference in projections also exacerbates the problem associated with the critical winter-time wind lull DEFR condition problem. The mitigation scenarios call for much more solar capacity 43,432 MW than the combined land-based wind, imported wind, and offshore wind (26,606 MW) capacity. The Final Scoping Plan must ensure that an adequate amount of hydrogen is stored before the winter because the solar resource is so poor in the winter that it is unlikely that much if any replenishment during the winter can be expected. It is also critically important that the worst-case wind lull is defined correctly because it if is not then there will not be sufficient hydrogen available to cover the DEFR resources and blackouts will occur. The Climate Action Council must ensure the Final Scoping Plan addresses both of these issues to ensure a reliable electric system when it is needed the most.

There is a clear need for a feasibility analysis for the use of hydrogen as the DEFR. For example, where will all the combustion turbines, electrolyzers, pipelines, and fuel cells be located? I suspect that there will be significant permitting issues with all the resources needed. The capacity factors for this resource in the Draft Scoping Plan are 2% for all mitigation scenarios so there will be implentation issues. In the exisitng system the generating sources designed for peaking power for this reliability requirement used the cheapest technology available (simple-cycle gas turbines). Meeting this requirement in the future using the hydrogen DEFR resource will be using the most expensive generating technology available.

There are numerous technical concerns that were not addressed in the Draft Scoping Plan. It is not clear whether the Draft Scoping Plan addressed the complex and energy intesive process of compressing and liquifying hydrogen for storage and transport. That will require large amounts of additional energy which may be additional cost not yet figured into the calculations. I could not determine if the Draft Scoping Plan proposed to use the existing natural gas network in all or part. Metal embrittlement caused by exposure to hydrogen will no doubt require major modifications and replacements for the existing infrastructure. These costs must be clearly identified and included in the Draft Scoping Plan.

Zero-Carbon Firm Resource

In their presentation to the Power Generation Advisory Panel on September 16, 2020 E3 included a slide titled Electricity Supply – Firm Capacity. Consistent with the above the slide states: “The need for dispatchable resources is most pronounced during winter periods of high demand for electrified heating and transportation and lower wind and solar output”. The slide goes on to say: “As the share of intermittent resources like wind and solar grows substantially, some studies suggest that complementing with firm, zero emission resources, such as bioenergy, synthesized fuels such as hydrogen, hydropower, carbon capture and sequestration, and nuclear generation could provide a number of benefits”.

On September 10, 2020 the Analysis Group presented a discussion of draft recent observations as part of the New York Independent System Operator (NYISO) Climate Change Phase II Study. That discussion included a slide titled "Attributes of Generic Resource Required for Grid Reliability". In their analysis they included a generic resource they called the Dispatchable & Emissions-Free Resource, or "DE Resource". The DE Resources are "included to maintain reliability during the highest load hours of each modeling period" and they "provide the majority of energy on the peak winter hour during the CLCPA load scenario". They state "The DE Resources are included to maintain reliability during the highest load hours of each modeling period. DE Resources provide the majority of energy on the peak winter hour during the CLCPA load scenario."

The final Climate Change Impact and Resilience Study - Phase II report emphasized that "**The variability of meteorological conditions that govern the output from wind and solar resources presents a fundamental challenge to relying on those resources to meet electricity demand.**" Figure ES-2 from the report shows results for the CCP2-CLCPA Case in the winter, including an extended wind lull.

Figure ES-2: Hourly Load/Generation Balance, CCP2-CLCPA Winter Wind Lull Case

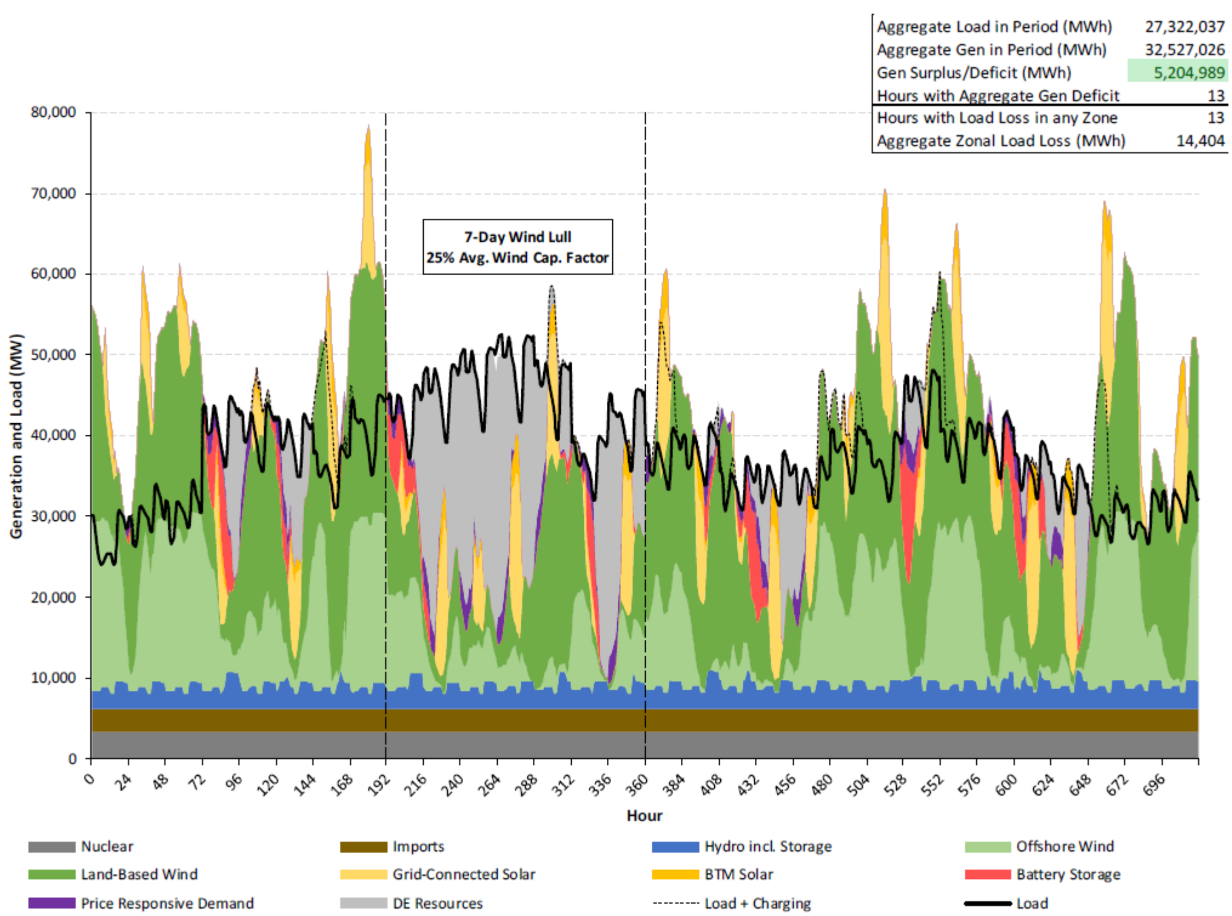


Table ES-2 from the report quantifies the total aggregated DEFR generation (MWh) needed for the extended wind lull. For a state-wide wind lull 6,988,838 MWh of energy is required to make up for the poor wind and solar performance. In my opinion this may not represent the worst-case scenario because the analysis only evaluated wind data from 2007 – 2013. I submitted a comment recommending that a longer period of data be considered. In particular an analysis using, meteorological reanalysis descriptive data generated by modern weather forecast models but using original data from decades ago can be used to evaluate wind lulls The ERA5 global reanalysis data base provides hourly estimates of a large number of atmospheric, land and oceanic climate variables from 1950 to the present. Until that data set is used, we won't know the worst-case wind lull.

Table ES-2: Case Result Summaries

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Summer Scenario - Grid in Transition Resource Set							
Baseline Summer	0	0	98	512	4,181,951	27,075	6,382
Heat Wave	0	0	98	523	4,404,209	27,075	6,382
Wind Lull - Upstate	0	0	98	516	4,501,251	28,807	7,643
Wind Lull - Off-Shore	0	0	226	543	4,983,818	28,360	6,450
Wind Lull - State-Wide	0	0	226	543	5,322,997	30,794	7,172
Hurricane/Coastal Wind Storm	25	20,488	240	559	4,832,633	27,075	6,380
Severe Wind Storm – Upstate	24	18,963	172	549	4,998,149	27,075	6,382
Severe Wind Storm – Offshore	0	0	171	556	5,126,163	27,460	6,380
Drought	0	0	102	520	4,616,646	28,720	8,162

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Winter Scenario - Grid in Transition Resource Set							
Baseline Winter	0	0	104	460	6,155,321	39,539	11,992
Cold Wave	0	0	104	466	6,272,961	39,539	11,992
Wind Lull - Upstate	8	7,090	110	469	6,309,711	39,539	12,408
Wind Lull - Off-Shore	6	1,378	168	487	6,836,558	39,539	11,627
Wind Lull - State-Wide	9	10,757	124	486	6,988,838	39,539	12,041
Severe Wind Storm – Upstate	51	57,457	110	551	6,707,765	38,284	11,461
Severe Wind Storm – Offshore	2	327	120	561	7,916,575	39,539	11,763
Icing Event	24	11,242	104	480	6,145,568	39,539	11,992

Appendix G Scenario Projected Zero-Carbon Firm Resource Capacity

The Integration Analysis description of the Carbon-Free Electric Supply in Appendix G starts at page 42 of Section I. I attached an annotated version of the Draft Scoping Plan description of the "Carbon-Free Electric Supply" in Appendix G Section I. The only annotation addition is an extracted copy of the actual data in the figures that list capacity (MW) and generation (GWh) in that section that are based on data in the IA-Tech Supplement Annex 2 Emissions Key Drivers spreadsheet.

Figure 30 lists the installed capacity (MW) in 2050 for all scenarios and Figure 31 lists the 2050 annual generation (GWh). The footnote explanation for zero-carbon free resources states:

> In Scenarios 1, 2, and 4, the "zero-carbon firm resource" represents a combination of existing and new combustion-based resources (i.e. combustion turbines and combined cycle gas turbines) that convert to utilizing hydrogen as a zero-carbon fuel. In Scenario 3, firm zero-carbon capacity represents a combustion-free resource, modeled as hydrogen fuel cells.

Figure 30. Installed Capacity in 2050, All Scenarios[31]

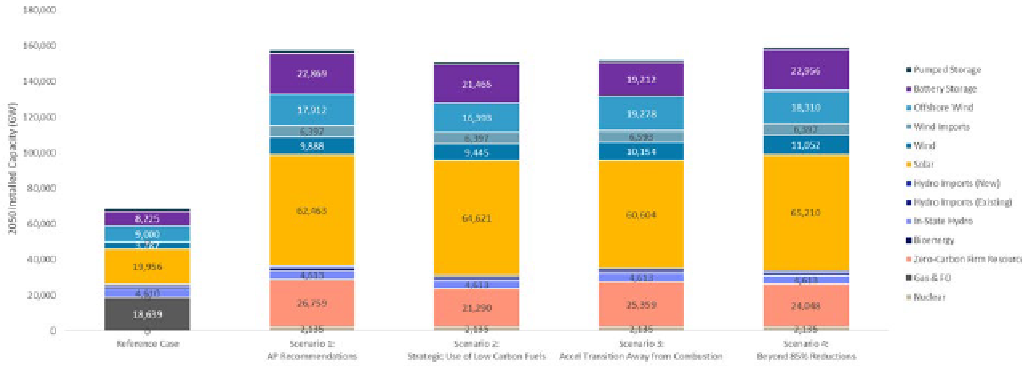
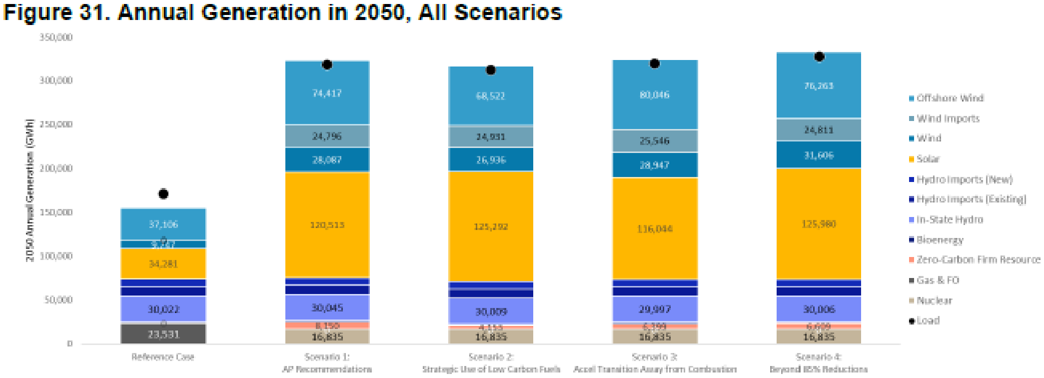


Figure 31. Annual Generation in 2050, All Scenarios



The first reference in the text to the zero-carbon firm resource is in the following:

> On the inter-day timescale, firm resources are needed to serve load and maintain system reliability during multi-day periods of low renewable output – periods in which the contributions of short-duration battery storage are limited. Our analysis identified a need for firm, zero-carbon capacity – in addition to the state's existing hydro and nuclear facilities – of between 21-27 GW to maintain system reliability while achieving a 100% zero-emissions grid.

To sum up, the Draft Scoping plan "zero-carbon firm resource" projections for the future rely on hydrogen in one form or another for "between 21-27 GW to maintain system reliability while achieving a 100% zero-emissions grid".

Hydrogen Costs in the Integration Analysis Spreadsheet

There is a tab titled "Hydrogen Costs" in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet that provides some documentation for hydrogen as a zero-carbon firm resource. The tab description states: This tab includes a summary of key cost metrics for hydrogen storage and total costs for all cost scenarios.

The documentation text states:

> Hydrogen is a strategic low-carbon fuel in Scenarios 1 and 2, meeting demands in transportation, industry, and electricity generation.

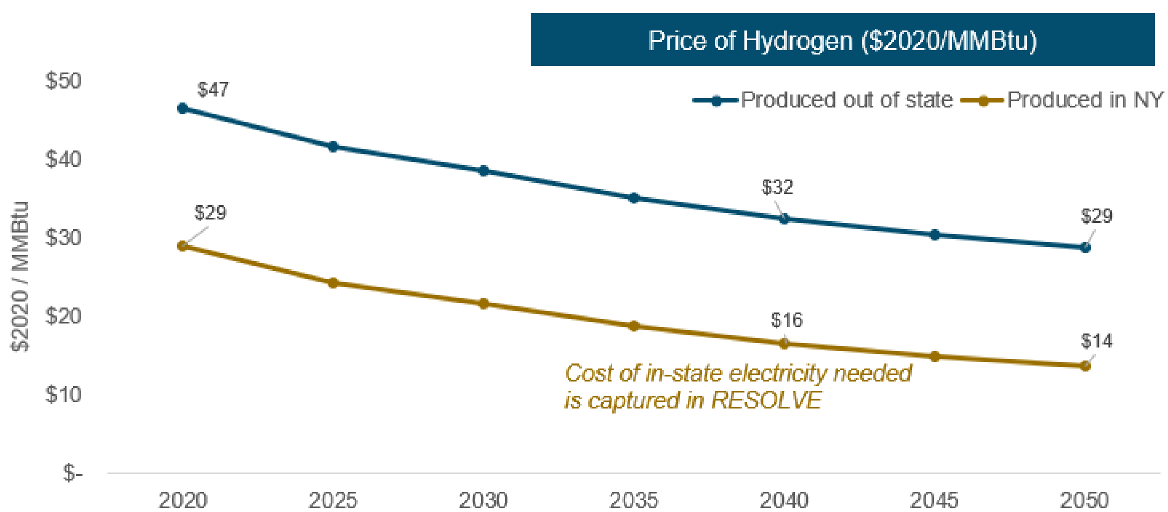
Under CLCPA accounting, hydrogen combustion achieves zero GHG emissions, although there are still local air pollutant implications to combustion (e.g., NOx emissions). Hydrogen can be produced through a variety of pathways, including steam methane reformation (SMR), SMR with carbon capture and sequestration (SMR+CCS), biomass to hydrogen with carbon capture and sequestration (BECCS H2), and electrolysis. In Integration Analysis scenarios, all hydrogen is assumed to be produced through electrolysis powered by electricity. Whether in-state or out-of-state, scenarios assume declining costs of electrolyzers and infrastructure over time

Electrolysis costs: Costs of electrolyzer and infrastructure: $22/mmBtu in 2030 declining to $14/mmBtu in 2050. All-in costs, including dedicated electricity production: $39/mmBtu in 2030 declining to $29/mmBtu in 2050.

Electrolyzer efficiency: Efficiency of electrolysis: 70-72% in 2030 increasing to 75-80% in 2050

In addition to cost for electrolyzers, infrastructure, and transportation Integration Analysis includes an additional cost to represent the cost for building long-term hydrogen storage systems in-state. This ranges from $0.36/kWh of hydrogen to $2.988/kWh of hydrogen. Range of costs for hydrogen storage sourced from Sandia National Lab, Economic Analysis of Large-Scale Hydrogen Storage for Renewable Utility Applications (2011).

There is a graph in the tab:



Tables listing the data used are also included in the tab:

Out of state cost of hydrogen		2020	2025	2030	2035	2040	2045	2050
Electricity Input Cost	2020 $/MMB	$ 16.31	$ 16.20	$ 16.09	$ 15.65	$ 15.33	$ 15.04	$ 14.75
Electrolyzer Capital Cost	2020 $/MMB	$ 22.50	$ 17.73	$ 14.82	$ 11.83	$ 9.56	$ 8.06	$ 6.79
Other Capital Costs (Pipeline Blending, Interconnection, etc)	2020 $/MMB	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.10	$ 0.10
Underground H2 Storage Cost	2020 $/MMB	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89
400-mile Pipeline Cost	2020 $/MMB	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40
Variable O&M Cost	2020 $/MMB	$ 4.36	$ 4.32	$ 4.30	$ 4.18	$ 4.09	$ 4.01	$ 3.94
Total Cost	2020 $/MMB	**$ 46.57**	**$ 41.66**	**$ 38.61**	**$ 35.05**	**$ 32.38**	**$ 30.51**	**$ 28.87**

In-state cost of hydrogen		2020	2025	2030	2035	2040	2045	2050
Electricity Input Cost	2020 $/MMB	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Electrolyzer Capital Cost	2020 $/MMB	$ 21.13	$ 16.65	$ 13.91	$ 11.10	$ 8.97	$ 7.57	$ 6.37
Other Capital Costs (Pipeline Blending, Interconnection, etc)	2020 $/MMB	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10
Underground H2 Storage Cost	2020 $/MMB	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.89
400-mile Pipeline Cost	2020 $/MMB	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.40
Variable O&M Cost	2020 $/MMB	$ 4.36	$ 4.32	$ 4.30	$ 4.18	$ 4.09	$ 4.01	$ 3.94
Subtotal	2020 $/MMB	**$ 28.88**	**$ 24.37**	**$ 21.61**	**$ 18.67**	**$ 16.46**	**$ 14.97**	**$ 13.70**

H2 cost estimates above represent an average of optimistic and conservative estimates. The electrolyzer assumptions used in each scenario are listed below. These a

Optimistic scenario		2020	2025	2030	2035	2040	2045	2050
Electrolyzer Cost	2020 $/kW	$ 1,169	$ 725	$ 546	$ 345	$ 243	$ 177	$ 138
Electrolyzer Efficiency (HHV)	%	70%	71%	72%	74%	76%	78%	80%

Conservative scenario		2020	2025	2030	2035	2040	2045	2050
Electrolyzer Cost	2020 $/kW	$ 1,172	$ 1,130	$ 1,011	$ 930	$ 804	$ 719	$ 628
Electrolyzer Efficiency (HHV)	%	70%	70%	70%	72%	73%	74%	75%

Finally, there are some relevant notes for these tables. The Out of State cost of hydrogen table includes the following notes:

- For electricity input cost: Assumes a dedicated solar resource with cap factor of 23.5%
- For underground H2 storage cost: Based on underground salt cavern storage
- For 400-mile pipeline cost: High pressure pipelines dedicated for H2. Cost estimates come from Argonne National Lab's Hydrogen Delivery Scenario Analysis Model (HDSAM)

The In-state cost of hydrogen tables includes the following notes:

- For electricity input cost: Cost of electricity is captured endogenously in RESOLVE
- Electrolyzer Capital Cost: Electrolyzer CAPEX is consistent with out-of-state. Difference can be attributed to 25% capacity factor assumed
- For underground H2 storage cost: Based on underground salt cavern storage
- High pressure pipelines dedicated for H2. Cost estimates come from Argonne National Lab's Hydrogen Delivery Scenario Analysis Model (HDSAM)
- Subtotal: Cost of electricity is captured endogenously in RESOLVE

There is an end note for these tables that states: "H2 cost estimates above represent an average of optimistic and conservative estimates. The electrolyzer assumptions used in each scenario are listed below. These assumptions are consistent in both in-state and out-of-state production. The electrolyzer costs are assumed to be for an alkaline electrolyzer."

Role of Hydrogen

There is a description of the Draft Scoping Plan uses for hydrogen in Appendix G Section I, Page 51 in the "Role of Hydrogen" section reproduced below.

Hydrogen is proposed for applications beyond "zero-carbon firm resource" requirements in this section:

> Hydrogen or bioenergy can play a critical role in decarbonizing sectors or applications that are difficult to electrify. By 2030, New York will likely need to spur initial market adoption of green hydrogen to help decarbonize medium and heavy-duty vehicles, as well as high-temperature

> industrial applications. In the longer term, low-carbon fuels may play critical roles in decarbonizing existing district heating and non-road transportation, including rail and aviation. Additionally, hydrogen-based resources can play a key role in the electric sector by providing firm capacity during extended periods of low renewable output, as discussed above.

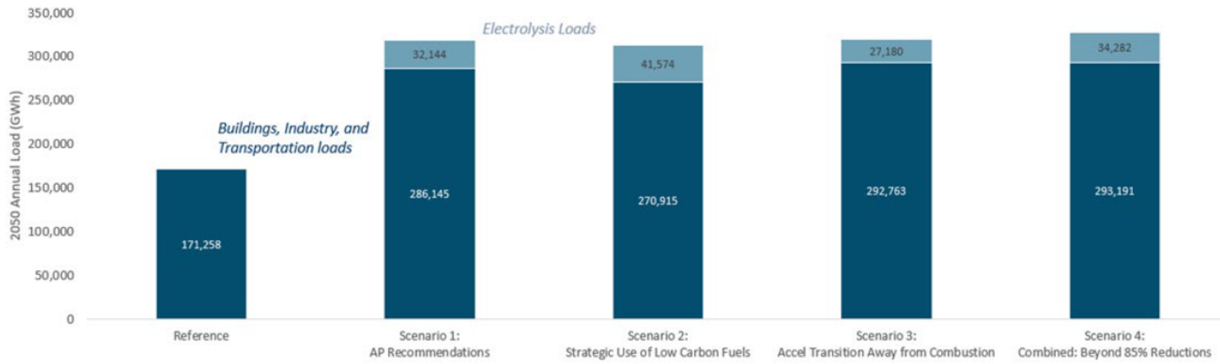
The description of the hydrogen assumptions makes it clear that the Draft Scoping Plan role for hydrogen description is just a presumptive framework. That does not mean that it will work. For example, "significant uncertainty in future transmission and storage costs based on production location and underground storage availability" indicates that there was no attempt to determine if there is sufficient underground storage available. If there isn't enough storage available then what is the cost for alternative storage? The following paragraph notes that the proxy for the hydrogen infrastructure does not represent an optimal configuration but I don't think it even represents what is feasible. At what point does the Climate Action Council plan to do a feasibility analysis to prove that this could work?

> Across all modeled pathways, New York's hydrogen demand is met with "green hydrogen," defined as hydrogen produced using electrolysis powered by renewable electricity. Hydrogen plays a strategic role across scenarios, with consumption ranging from 100-225 TBtu across modeled pathways in 2050. The production of large quantities of hydrogen can absorb excess renewable generation and prevent curtailment but will also require additional dedicated facilities to power electrolysis. In this analysis, our central assumption is that New York produces 50% of its hydrogen needs in-state and imports the remainder, with cost assumptions for that imported remainder consistent with the cost of "green hydrogen" produced in-state. Production costs for hydrogen were based on projections of electrolyzer capital costs and electricity prices, while transmission and storage costs were estimated assuming a 400-mile transmission pipeline and underground storage in salt caverns. Distribution costs for local hydrogen distribution via pipeline or freight truck were not included in this analysis, and it is important to note that there is significant uncertainty in future transmission and storage costs based on production location and underground storage availability. The hydrogen supply and infrastructure costs included in this study are a proxy for a future system that combines both in-state and imported production of hydrogen with a build out of transmission and storage infrastructure, but they are not meant to represent an optimal configuration of hydrogen production and transmission and storage infrastructure.

The text goes on to acknowledge that producing hydrogen via electrolysis requires a lot of energy:

> Producing half of New York's hydrogen demand with in-state electrolysis results in up to 42 TWh of additional electricity demand, as shown in Figure 37. An additional sensitivity examining an alternative assumption of 100% in-state hydrogen production is included in section 3.5.

Figure 37. Impacts of Electrolysis Loads on Total Electric Loads in 2050



> Electrolysis loads are highly flexible and can take advantage of excess renewables on a seasonal timescale, helping to balance and integrate renewables by serving as a form of long-duration storage that cannot be met with short-duration battery storage resources. However, although curtailed renewable electricity can contribute to a portion of hydrogen production needs, new renewable resources are also required to power electrolysis demand. These renewable resource needs are incorporated into the mitigation scenarios, and resource needs associated with 100% in-state hydrogen production are assessed in the sensitivity analysis included in section 3.5.

I interpret these last two paragraphs as a claim that the projected capacity and generation estimates include the power necessary to produce the hydrogen for all applications including the "zero-carbon firm resource" requirement. There is a problem however because it is not clear how they determined the load needed.

In-State Electrolysis Sensitivity Analysis Appendix G Section I — Page 78

Starting in Appendix G Section I, Page 78 the results of a sensitivity analysis of in-state electrolysis are presented. Of particular note in the section reproduced below are references to how much of the hydrogen is dedicated to DEFR.

> In each of the modeled pathways, New York is projected to rely on hydrogen usage as a key strategy to decarbonize sectors and applications that are difficult to electrify, in particular freight transportation, with consumption ranging between 100-225 TBtu across scenarios in 2050 (for more details, see the "Role of Hydrogen" section). All of New York's hydrogen demand is met with "green hydrogen," produced using electrolysis powered by renewable energy. For this analysis, the central assumption is that New York produces 50% of its hydrogen needs in-state and imports the remainder with cost assumptions for that imported remainder consistent with "green hydrogen" production. In addition, a sensitivity was performed on Scenario 2 to examine the impacts on the electric system resource mix of an alternative assumption of producing all (e.g., 100%) of New York's hydrogen demand in-state.

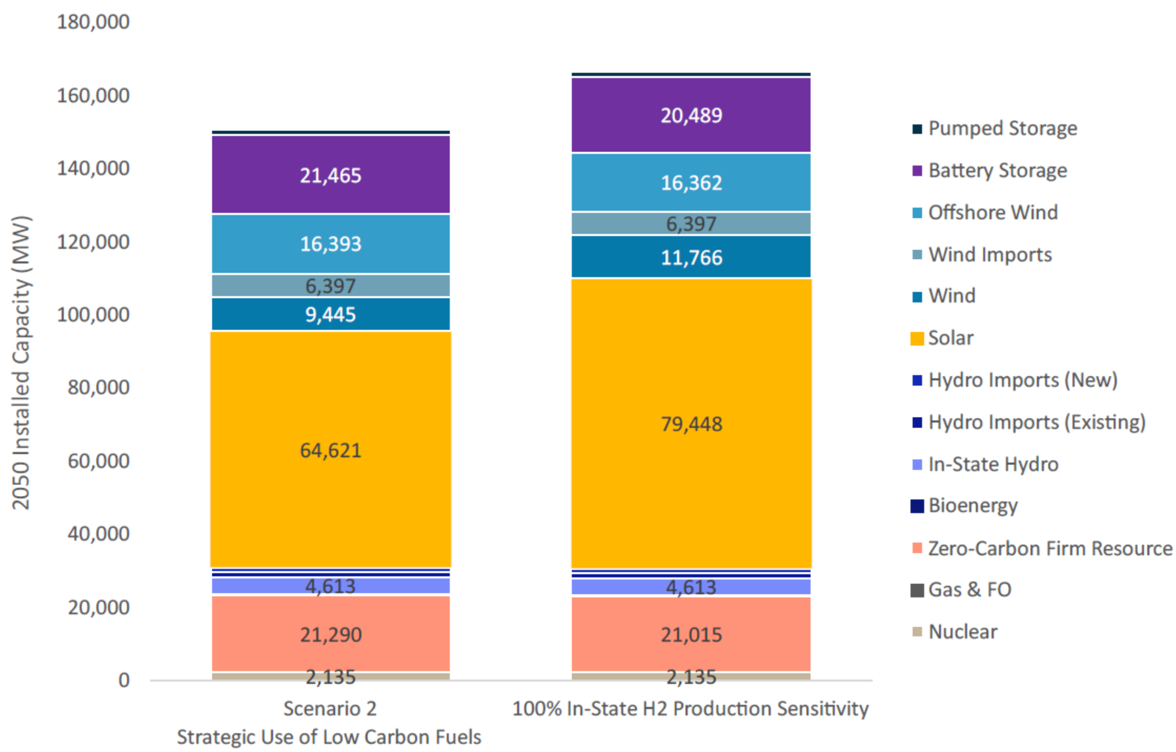
The rationale for out-of-state hydrogen production needs to be explained better. There is an unexplained tradeoff between greater in-state impacts and the presumption that a market will develop to provide New York with hydrogen. The Final Scoping Plan should clarify these issues.

In Scenario 2, which has the highest reliance on hydrogen of the four scenarios, increasing in-state electrolysis loads to meet all of New York's hydrogen demand results in total electricity demand of over 350,000 GWh by 2050, with over 80,000 GWh of electrolysis loads needed to produce hydrogen.

The additional electrolysis loads in turn require additional dedicated renewables, with 2,300 MW of new onshore wind resources and 14,600 MW of new utility-scale solar developed to power the electrolyzers. The total in-state wind and solar capacity in the sensitivity analysis reaches 11,800 MW and 79,400 MW, respectively. The 2050 resource mix of this sensitivity is provided in comparison to the Scenario 2 resource mix in Figure 59 below.

These two paragraphs present key numbers. Electrolysis will require 80,000 GWh of electricity, 2,300 MW of new onshore wind resources and 14,600 MW of new utility-scale solar development. There is a problem however. The critical DEFR condition is a winter-time wind lull and the proportion of wind to solar development is incompatible with a winter problem because the solar resource is so poor in the winter. As a result, just looking at a single worst-case period is insufficient. The hydrogen long-duration storage can be depleted by multiple periods of calm winds and solar dedicated to electrolysis won't be able to replenish the hydrogen stores as effectively as other times of the year. This is another feasibility issue that must be addressed by the Final Scoping Plan and reinforces the need for the long-period analysis of historical meteorological data.

Figure 59. 2050 Installed Capacity, Scenario 2 and 100% In-State Hydrogen Production Sensitivity



New York Independent System Operator Dispatchable Emissions-Free Resource

I previously submitted a comment describing the differences between the projections for future electricity generation by the New York Independent System Operator (NYISO) and those in the Draft Scoping Plan. The comments explain that NYISO is 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. The projection for future generation capacity and energy for the baseline case with a forecast for Climate Act is shown in the following table. In this table the DEFR rows are equivalent to the Draft Scoping Plan zero-carbon firm resource. Importantly note that NYISO projects 44,750 MW for 2040 in this category as opposed to 2040 estimates of 21,105 MW in Scenario 2, 23,522 MW in Scenario 3, and 23,676 MW in Scenario 4.

Table 1:

Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	21,232	21,234	-
DEFR - HcLo	-	-	-	-	3,812
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	7,053	40,938
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,086	12,612	19,087
OSW	-	1,826	5,036	9,000	9,000
UPV	32	4,676	4,676	4,676	4,676
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	5,793	11,450
Total	43,838	50,763	66,460	89,376	111,066

There is another nuance to the DEFR sources in the NYISO analysis. The report makes a distinction between three types of this kind of resource:

- High Capital, Low Operating (HcLo)
- Medium Capital, Medium Operating (McMo)
- Low Capital, High Operating (LcHo)

These are merely proxies for the characteristics of DEFRs that could address the requirement for long-duration, dispatchable, and emission-free resources necessary to maintain reliability and meet the objectives of the Climate Act. It does not mean that any specific technology will actually possess these characteristics.

The NYISO draft System Resource Outlook report states:

> Looking ahead to 2040, the policy for a zero-emissions electric system will also require the development of new technologies to maintain the supply demand balance. Substantial dispatchable emission-free resources (DEFR) will be required to fully replace fossil fuel-fired generation, which currently serves as the primary balancing resource. 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 (my highlight added*)**.

The statement that the "Resources with this combination of attributes are not commercially available at this time" is a primary driver of this comment. The Draft Scoping plan uses hydrogen as the placeholder for this technology presumably because the authors believe it is the most likely resource that will meet this critical requirement in the timeframe needed. The Climate Action Council must address whether that presumption is true.

Viability of Hydrogen as the Fuel for Zero-Carbon Firm Resources

I have been meaning to submit a comment on this topic for quite a while. I was going to use the material on my blog's Hydrogen Issue page as the basis for my comment. However, Francis Menton writing at the Manhattan Contrarian blog recently published a relevant article, Hydrogen Is Unlikely Ever To Be A Viable Solution To The Energy Storage Conundrum, that lays out the issues with hydrogen very well. He has given me permission to incorporate his work in this comment

As described above the the obvious but largely unrecognized problem is that electricity generated by intermittent renewables like wind and sun can't keep an electrical grid operating without some method of storing energy to meet customer demand in times of low production. These times of low production from wind and sun occur regularly — for example, calm nights — and can persist for as long as a week or more in the case of heavily overcast and calm periods in the winter. The zero-carbon firm resource is needed because the costs to meet this storage requirement using battery storage are excessivley high.

Menton has evaluated several competent calculations of the amount of storage needed for different jurisdictions to get through a full year with only wind and sun to generate the electricity. For the case of the entire United States, his post from January 2022 describes work of Ken Gregory, who calculates a storage requirement, based on the current level of electricity consumption, of approximately 250,000 GWH to get through a year. If you then assume as part of the decarbonization project the electrification of all currently non-electrified sectors of the economy (transportation, home heat, industry, agriculture, etc.), the storage requirement would approximately triple, to 750,000 GWH. If that storage requirement is to be met by batteries, and we price the amount of storage needed at the price of the best currently-available batteries (Tesla-type lithium ion batteries), we get an ***upfront capital cost in the range of hundreds of trillions of dollars.*** That cost alone would be a large multiple of the entire U.S. GDP, and obviously would render the entire decarbonization project impossible. In addition, lithium-ion type batteries (and all other currently-available batteries) do not have the ability to store power for months on end, as from the summer to the winter, without dissipation, and then discharge over the course of additional months. In other words, the fantasy of a fully wind/solar energy economy backed up only by batteries is doomed to quickly run into an impenetrable wall.

Earlier this year I adapted Gregory's analysis to New York. I pro-rated his nation-wide numbers to New York only numbers by assuming that the costs would be proportional to a similar analysis by Tanton for New York State costs. Gregory's total national capital cost of electrification is $433 trillion and New York's proportional share based on Tanton is $22.2 trillion.

Obviously relying exclusively on batteries is not going to be a viable approach to decarbonization. The only zero-emissions dispatchable resource that could be scaled up for use in New York is nuclear. In my opinion the single most obvious sign that the environmentalists who oppose all use of fossil fuels are not really serious about limiting GHG emissions or are just plain innumerate is their support for closing down 2.000 MW of nuclear power at Indian Point. Unfortunately I forsee no way that future nuclear development will be part of the Scoping Plan recommendations. Instead, the authors of the Integration Analysis and Draft Scoping Plan have decided that the most acceptable option would be to use hydrogen as the means of storage to balance the random swings of wind and solar electricity generation. The Climate Action Council has to address whether this is appropriate and if the Final Scoping Plan should include a provision for nuclear development in the future.

Menton writes:

> It's not like nobody has thought of this up to now. Indeed, to politicians and activists who can freely pontificate about theoretical solutions without having to worry about practical obstacles or costs, hydrogen seems like it couldn't be easier. With hydrogen, you can just completely cut carbon out of the energy cycle: make the hydrogen from water, store it until you need it, and then when the need arises burn it to produce energy with only water as the by-product.

Back in 2003, then-President George W. Bush proposed exactly such a system in his State of the Union address:

> In his 2003 State of the Union Address, President Bush launched his Hydrogen Fuel Initiative. The goal of this initiative is to work in partnership with the private sector to accelerate the research and development required for a hydrogen economy. The President's Hydrogen Fuel Initiative and the FreedomCAR Partnership are providing nearly $1.72 billion to develop hydrogen-powered fuel cells, hydrogen infrastructure technologies, and advanced automobile technologies. The President's Initiative will enable the commercialization of fuel cell vehicles in the 2020 timeframe.

The biggest failure for that initiative is fuel cell (that is, hydrogen-fueled) cars by 2020. There still are no commercially available fuel cells that I know about and there certainly isn't any large number of hydrogen-fueled cars on the roads here in 2022.

Zero-Carbon Firm Hydrogen Resource

The Draft Scoping plan states without justification that the "zero-carbon firm resource" projections for the future can be met using hydrogen in one form or another. The solution seems so terribly obvious, and yet nobody is doing it. What is wrong with everybody?

The Draft Scoping Plan must explain why the hydrogen placeholder for the zero-carbon firm resource can be considered a viable alternative by addressing the following. The summary of the problem is that hydrogen in the form of a free gas is much more expensive to produce than good old natural gas (aka methane or CH4), and once you have it, it is inferior in every respect to natural gas as a fuel for running the energy system. Hydrogen is far more difficult and costly than natural gas to transport, to store, and to handle. It is much more dangerous and subject to exploding. It is much less dense by volume, which makes it particularly less useful for transportation applications like cars and airplanes.

There are two other aspects of hydrogen use that have to be mentioned. The Draft Scoping Plan calls for so-called "green hydrogen" which produces the hydrogen by a carbon-free process of electrolysis from water. This hasn't been deployed at a large-scale yet much less implemented at the levels needed for the Climate Act transition. Secondly, mitigation scenario 3, Accelerated Transition from Combustion, adds another level of complexity specifying that electrcity has to be generated by fuel cells.

The Draft Scoping Plan does not even include a feasibility analysis that outlines how and where the hydrogen will be produced for the New York future grid. Obviously it is difficult to do an environmental assessment of the process and potential impacts to the environment. Below I describe a few of the issues that arise in consideration of hydrogen as the way to decarbonize that must be addressed in the Draft Scoping Plan in order to document that hydrogen might actually be a feasible zero-carbon firm resource.

Cost of "green" hydrogen versus natural gas.
In recent years, prior to the last few months, natural gas prices have ranged between about \$2 and \$6 per million BTUs in the U.S. The price spike of the past few months has taken the price of natural gas to about \$9/MMBTUs. Meanwhile, according to this December 2020 piece at Seeking Alpha, the price for "green" hydrogen produced by electrolysis of water is in the range of \$4 to \$6 per kg, which translates, according to Seeking Alpha, to \$32 to \$48 per MMBTU. In other words, even with the very dramatic recent rise in the price of natural gas, it is still 3 to 5 times cheaper to obtain than "green" hydrogen. There are some who predict dramatic future price declines for "green" hydrogen, and also continued price increases for natural gas. Maybe. But with prices where they are now, or anywhere close, nobody is going to make major purchases of "green" hydrogen as the backup fuel for intermittent renewables; and without buyers, nobody will produce large amounts of the stuff. This is particularly relevant because the cost analysis presumes that some unspecified fraction of the hydrogen needed will come from out of state.

New York Generator and Hydrolyzer Capacity Requirements
The Seeking Alpha piece has calculations of how much nameplate solar panel capacity it would take to produce enough "green" hydrogen to power just one small size (288 MW) GE turbine generator. The answer is, the solar nameplate capacity to do the job would be close to ten times the capacity of the plant that would use the hydrogen: "Consider the widely deployed GE 9F.04 gas turbine, which produces 288 MW of power. With 100% hydrogen fuel, GE states that this turbine would use about 9.3 million CF or 22,400 kg of hydrogen per hour. With an 80% efficient electrolysis energy cost of 49.3 kWh/kg, producing that one hour supply of hydrogen would require 1,104 MWh of power for electrolysis. To generate the hydrogen to run the turbine for 12 hours (~ dusk to dawn) would require 12 x 1,104 MWh, or 13.2 GWh. Given a typical 20% solar capacity factor, that would require about 2.6 GW of solar nameplate capacity dedicated to generating the hydrogen to fuel this 288 MW generator overnight."

The Seeking Alpha piece analysis contains background information that can be used to estimate how much hydrogen would be needed for the New York projections of the future dispatchable emissions-free resource (DEFR). Assuming that the more viable approach is to use hydrogen in proven utlity-scale combustion turbines, what if the projected DEFR resource was covered by using GE 9F.04 gas turbines burning hydrogen. That answer is the projected MW capacity of the DEFR needed divided by the turbine capacity. Table 2 shows that in 2040 this approach would require between 73 and 155 288 MW turbines dedicated for this resource application. At this time the world's largest hydrogen fuel cell is only 79 MW so between 266 and 566 fuels cells of that size would be required.

Table 2: Dispatchable Emissions-Free Resource GE 9F.04 Combustion Turbines Needed to Meet Integration Analysis Capacity Projections

	NYISO Baseline w/ CLCPA Case		Strategic Use of Low-Carbon Fuels		Accelerated Transition from Combustion		Beyond 85% Reduction	
Resource	2030	2040	2030	2040	2030	2040	2030	2040
DEFR (MW)	420	44,750	0	21,015	0	23,522	0	23,676
# Fuel Cell Systems	5	566	0	266	0	298	0	300
# Turbines	2	155	0	73	0	82	0	82

As noted above, Appendix G states that making hydrogen using electrolysis will require 80,000 GWh of electricity, 2,300 MW of new onshore wind resources and 14,600 MW of new utility-scale solar development. Table 3 lists the DEFR capacity (MW) and generation (GWh) for the NYISO draft outlook study projection and the Draft Scoping Plan mitigation scenarios. The Seeking Alpha piece analysis estimated that with an 80% efficient electrolysis energy cost of 49.3 kWh/kg, producing a one hour supply of hydrogen for one MW of a turbine would require 3.83 MWh of power for the electrolysis process. Multiplying that number by the energy projections gives the generation needed. As far as I can tell my estimates are consistent with the Appendix G projections.

Table 4 lists the annual energy fuel mix (GWh) for Scenario 2 from the Integration Analysis. Comparing those estimates relative to the generation needed for electrolysis gives an idea just how many renewable resources are needed to provide hydrogen for DEFR hydrogen is needed. Scenaro 2 requires 3,342 GWh of energy for DEFR and 12,812 GWh for electrolysis which is about half the projected imported wind total in 2040. Note that the NYISO draft Outlook study projected DEFR requirements are an order of magnitude higher. As a result, the energy needed for the hydrogen to cover that need (130,353 GWh) is more than the projected total solar, land-based wind, and wind import energy (121,875 GWh) in 2040. The Climate Action Council must reconcile the differences between these two estimates because of the ramifications on the energy needed for DEFR using green hydrogen.

This difference also exacerbates the problem associated with the critical winter-time wind lull DEFR condition problem. The mitigation scenarios call for much more solar capacity 43,432 MW than the combined land-based wind, imported wind, and offshore wind (26,606 MW) capacity. The Final Scoping Plan must ensure that an adequate amount of hydrogen is stored before the winter because the solar resource is so poor in the winter that it is unlikely that much if any replenishment during the winter can be expected. The organization and the experts responsible for electric system reliability have a significantly larger estimate for future DEFR which means that the hydrogen requirements are also much larger. The Climate Action Council must reconcile the different projections for the Final Scoping Plan.

Table 3: Energy Needed Energy Needed for DEFR Electrolysis

DEFR Installed Capacity (MW)	2020	2030	2040
NYISO Baseline w/ CLCPA Case	0	420	44,750
Reference Case	0	0	0
Scenaro 2: Strategic Use of Low-Carbon Fuels	0	0	21,015
Scenaro 3: Accelerated Transition from Combustion	0	0	23,522
Scenaro 4: Beyond 85% Reduction	0	0	23,676

DEFR Generation (GWhr)	2020	2030	2040
NYISO Baseline w/ CLCPA Case	0	0	34,005
Reference Case	0	0	0
Scenaro 2: Strategic Use of Low-Carbon Fuels	0	0	3,342
Scenaro 3: Accelerated Transition from Combustion	0	0	4,440
Scenaro 4: Beyond 85% Reduction	0	0	4,644

With an 80% efficient electrolysis energy cost of 49.3 kWh/kg, each MWh using hydrogen would require 3.83 MWh of power for electrolysis.

Generation Needed for Electrolysis (GWhr)	2020	2030	2040
NYISO Baseline w/ CLCPA Case	0	0	130,353
Reference Case	0	0	0
Scenaro 2: Strategic Use of Low-Carbon Fuels	0	0	12,812
Scenaro 3: Accelerated Transition from Combustion	0	0	17,018
Scenaro 4: Beyond 85% Reduction	0	0	17,800

Table 4 Scenario 2: Strategic Use of Low-Carbon Fuels Summary Annual Energy Fuel Mix (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 Resource	-	-	-	-	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)
Imports*	**4,694**	**3,827**	**2,309**	**4,573**	**13,545**	**14,266**	**14,818**
Exports	**(3,320)**	**(6,628)**	**(10,716)**	**(13,458)**	**(13,545)**	**(14,266)**	**(14,818)**
Load	**158,963**	**150,985**	**169,744**	**216,201**	**260,708**	**293,786**	**312,488**

The Draft Scoping Plan must address hydolysis issues in order to make the presumption that hydrogen is a viable technology for DEFR. It must document its methodology for the amount of energy necessary to produce the hydrogen projected to meet the DEFR projected energy and provide its estimates. The tab titled "Hydrogen Costs" in the IA-Tech-Supplement-Annex-1-Input-Assumptions spreadsheet makes presumptions without considering feasibility. The electricity input cost for in-state production notes that electricity cost is captured endogenously in RESOLVE. I think that the plan is for the electrolyzer facilities to use electricity produced by wind and solar from the grid rather than by co-locating them with the generating facilities. How does that square with the selling point for renewable resources that those resources would reduce transmission power losses?

The underground hydrogen storage cost is based on underground salt cavern storage. There are three concerns: that resource is only available in certain locations, is the amount of storage available consistent with the huge amounts of hydrogen that have to be stored, and an underground propane storage facility permit was denied because of community character concerns so how will this be different? The high-pressure pipelines dedicated for hydrogen transport are 400 miles long. How many will be needed and where will they be located. I believe that until a feasibility analysis is completed that addresses these questions that the Final Scoping Plan cannot presume that hydrogen is a viable DEFR. Does the Climate Action Council agree or disagree?

Green Hydrogen Production in New York

The Draft Scoping Plan Strategic Use of Low-Carbon Fuels Scenario projects that 21,015 MW of DEFR capacity and, I estimate , that 73 GE 9F.04 gas turbines will be needed by 2040. The unaddressed feasibility issue is where will they be located? If any of the electricity is generated using off-shore then I assume that the hydolysis facility will be located near the location where the power comes on-shore. I have my doubts that such a facility could be located without signficant local opposition in New York City or Long Island. On the other hand, there are transmission reliability constaints that require a certain fraction of power production in New York City. Presumably the electrolysis facility could be located elsewhere and the hydrogen piped to the City but you still have to generate power in the City because of reliability standards. There has been recent significant organized opposition to peaker power plants[1] so that will also draw local opposition.

There is another aspect of New York production. It is very likely that making enough "green" hydrogen to power the state means some fraction will require electrolyzing the ocean. The ocean is effectively infinite as a source of water, but fresh water supplies in the quantity needed could be limited. If you electrolyze salt water, you get large amounts of highly toxic chlorine. There are people working on solutions to this gigantic problem, but as of now it is all in the laboratory stage. Incremental costs of getting your "green" hydrogen from the ocean are a complete wild card.

[1] Although existing peaking power plants are alleged to be a primary driver of the environmental burden in neighboring environmental justice communities that is unlikely to be the case. The alleged problems are presumed to be caused by ozone and fine particulates but both are secondary pollutants that are not created until the pollutants have moved away from the neighborhood.

Green Hydrogen Generation
The capacity factor is the fraction of actual generation divided by the maximum possible generation. In the Draft Scoping Plan Strategic Use of Low-Carbon Fuels Scenario the 2040 dispatchable emission-free resource is projected to produce 3,342 GWh of energy using a capacity of 21,015 MW. That works out to a capacity factor of 2%. There are significant feasibility issues associated with that low number. At the top of the list is that paying for a resource that is used that infrequently is a difficult investment risk. The owners of those facilities are going to need financial guarantees to make the investments. Another way of looking at this problem is that in the exisitng system the generating sources designed for peaking power were the cheapest technology available (simple-cycle gas turbines). Meeting this requirement in the future using the hydrogen DEFR resource will be using the most expensive generating technology available. In addition, there currently is a large amount of capacity provided by residual-oil fired power plants that run rarely because of the high relative cost of oil but fulfill a key reliability requirement. Replacing them with a purpose built resource of any kind is going to be expensive and using hydrogen will exacerbate the problem significantly.

There is another aspect of "green" hydrogen that I haven't seen mentioned but warrants concern. The electrolyzer facilities will be running using intermittent power so the process itself will be intermittent. The best operating regime for any industrial process is steady-state. How will that be possible for this approach?

Hydrogen Density
Hydrogen is much less energy dense than gasoline by volume. For many purposes, and particularly for the purpose of transportation fuel, it is highly relevant that hydrogen is much less dense than gasoline by volume. Even liquid hydrogen has an energy density by volume that is only one-quarter that of gasoline (8 MJ/L versus 32 MJ/L), meaning a much larger a fuel tank; and liquid hydrogen needs to be kept at the ridiculously cold temperature of -253 deg C. Alternatively, you can compress the gas, but then you are talking more like a 10 times energy density disadvantage. Either compressing the gas or converting to liquid will require large amounts of additional energy, which is an additional cost that may not be figured into the calculations. The Council has to decide whether the Draft Scoping Plan address this issue adequately..

Metal Embrittlement
Hydrogen makes steel pipelines unacceptably brittle. Hydrogen is much more difficult than natural gas to transport and handle. Most existing gas pipelines are made of steel, and hydrogen has an effect on steel known as "embrittlement," that makes the pipes develop cracks and leaks over time. Cracks and leaks can lead to explosions. Also, because of the volumetric energy density issue, existing natural gas pipelines can carry far less energy if used to carry hydrogen. As a result, the existing natural gas network will have to be replaced or significantly upgraded in order to transport hydrogen. If these costs are not included in the Draft Scoping Plan, then they should be added to the Final Plan.

Conclusion
There are members of the Climate Action Council that believe "the word reliability is very intentionally presented as a way of expressing the improper idea that renewable energy will not be reliable." The worst-case renewable availability period is expected to occur in the winter because solar resource

availability is low because of the season, Great Lakes induced cloudiness, and the potential for snow on solar panels when there is a wind lull reducing that resource availability. This is the particular period when the zero-carbon firm resource will be needed most. The problem is exacerbated because those conditions are typically associated with the coldest weather of the year. When the state's heating and transportation systems convert to electricity the expectation is that maximum loads will occur during those periods. These comments describe many implementation issues associated with using hydrogen for the zero-carbon firm resource not the least of which is using mostly solar PV as a dedicated source of the electrolyzer power. I conclude that a feasibility analysis that address the questions raised is necessary. Even better would be a demonstration project at large scale to show how a hydrogen-based power system would work and how much it would cost after including all of the extras and current unknowns not just for producing it but also for transporting it and handling it safely.

I don't know how much extra our energy would cost if we forcibly got rid of all hydrocarbons and shifted to wind and solar backed up by "green" hydrogen — and neither does anybody else. An educated guess would be that the all-in cost of energy would get multiplied by something in the range of five to ten. Yes, that would probably be a big improvement over trying to accomplish the same thing with batteries. But it would still be an enormous impoverishment of the New Yorkers in the pointless quest to possibly shave a few hundredths of a degree off world average temperatures a hundred years from now.

Not so long ago the idea that natural gas could be used a bridge fuel until these aspirational dispatchable emission-free resources could be tested at the scale needed, perform like a natural gas fired generating unit, and provide power at a similar cost, was generally accepted as a rational approach. The analogy for skipping the need for a bridge fuel is that the Climate Action Council wants to jump out of a perfectly good airplane without a parachute because they assume that the concept of a parachute will be developed, proven technically and economically feasible, and then delivered in time to provide a soft landing. That cannot end well and this won't either.

I prepared this comment because I think this is a critical reliability issue and it has been essentially ignored by the Climate Action Council. How else could members of the Council claim that there are no reliability issues associated with renewable energy. 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.

Roger Caiazza
Pragmatic Environmentalist of New York
NYpragmaticenvironmentalist@gmail.com
Liverpool, NY