Attachment G

System Reliability Impact Study and Class Year Study

System Reliability Impact Study

POWERGEM

Power Grid Engineering & Markets

Final Report

System Reliability Impact Study: AP Dutchess Project (Q310)

Prepared for

Advanced Power Services (NA) Inc.

Prepared by

Manos Obessis
Johnny Willis
Scott Gass

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EXECUTIVE SUMMARY

PowerGEM, LLC has conducted a study to evaluate the impact of the proposed 1002 MW AP Dutchess project ("AP Dutchess" or "Project") on the reliability of the NYISO bulk power system and the local network. This System Reliability Impact Study (SRIS) was performed in accordance with the NYISO SRIS criteria and procedures.

The AP Dutchess project is a three train combined cycle power plant, with each train consisting of two electric generators: a combustion turbine generator (CTG) and a steam turbine generator (STG). The project is proposed to be connected to the Consolidated Edison Company of New York, Inc. (ConEdison) network. The proposed Point of Interconnection (POI) will be along the Pleasant Valley – Long Mountain 345 kV transmission line (circuit #398), approximately 14.5 miles east of the Pleasant Valley substation and 3.25 miles west of the New York – Connecticut border. The Project will be located in Dutchess County, New York and is expected to have a maximum potential summer generating capacity of 1002 MW and winter generating capacity of 1115 MW. AP Dutchess is in position # 310 ("Q310") in the NYISO interconnection queue and has an expected in-service date of December 2014.

The study included steady state analysis (thermal and voltage), stability analysis, extreme contingency analysis, short circuit analysis, and interface transfer analysis. NPCC criteria A-10 testing, an interconnection cost estimate and schedule, and studies by Con Edison were also included. Analysis was performed without the Project, as well as with the Project at full output, in order to evaluate its impact on the bulk and local power network. Further Project analysis may be undertaken in future studies, if and as deemed necessary.

Based on the analysis summarized in this report, the following conclusions have been reached for each of the requirements in the scope of work.

<u>Power flow analysis</u>

Analysis results show that the Project does not introduce any new thermal overloads under normal or contingency conditions. The impact of the Project on pre-existing overloads is small. Contingency analysis under summer conditions with the Project online indicates that the Ramapo 500 kV voltage drops below 1.0 p.u; allowing voltage controlling devices to regulate mitigates the issue. The Project does not introduce any other new voltage violations under normal or contingency conditions and its impact on system voltages is in most instances small.

The inclusion of the AP Dutchess project does not impair the ability to maintain the ABC/JK wheel under summer or winter conditions.

Sensitivity analysis indicates that operation of the Project does not restrict the operating flexibility of the CHG&E 115/69 kV system. Further, AP Dutchess does not restrict the ability of the system to accommodate the concurrent operation of the Athens and Besicorp projects at full output.

<u>Stability analysis</u>

Stability testing was conducted for summer peak and light load conditions, with and without the AP Dutchess project (four scenarios). A total of 135 contingencies were tested for each scenario. The Project and system were stable for all contingencies and scenarios.

The critical clearing time (CCT) for a three-phase fault at the Project's interconnecting 345 kV bus was 16.5 cycles. The Project had a minor positive impact (0.5 cycles) on the CCT at the Pleasant Valley 345 kV bus.

Extreme contingency analysis

The Project had no detrimental impact on thermal or voltage performance under extreme contingency conditions. All New York and New England extreme contingencies simulated in stability analysis were stable both pre-Project and post-Project.

Transfer limit analysis

AP Dutchess exhibited a relatively small impact on the transfer limits of NYCA interfaces. Upon further examination, it was determined that the impact was primarily due to the dispatch pattern used in the study. The Project reduces the transfer limits of the NY-NE and NE-NY interfaces. In the case of the NE-NY interface, the Project effectively replaces other imports from New England generating resources. AP Dutchess has a positive effect on the thermal transfer limits of New England interfaces.

NPCC A-10 criteria testing

Testing was undertaken to identify any existing or new stations that could be classified as bulk power system elements, based on NPCC criteria. Testing was conducted for the new AP Dutchess 345 kV bus and the existing Pleasant Valley 115 kV bus. Neither bus needs to be classified as bulk power.

Short circuit analysis

The Project increased short circuit currents at 32 buses in the study area by more than 0.1 kA. However, the increase in fault current at these buses as a result of the Project remained small, and currents were below the interrupting ratings of the existing circuit breakers. No replacement of circuit breakers is required.

System Upgrade Facilities

The Project will connect to the network via a six breaker ring bus arrangement. A non-binding good faith cost estimate to complete the required facilities is $22 Million. This estimate includes the cost to construct the Attachment Facilities as well as the cost for System Upgrade Facilities associated with the new Attachment Facilities. The estimated time to engineer, construct, and commission the required facilities is 22 to 26 months. The above estimates do not account for the development of any facilities under the Developer's responsibility.

Based on the analysis performed for this SRIS, the AP Dutchess project does not degrade system reliability or adversely impact the operation of the power system.

1. INTRODUCTION

Advanced Power Services (NA) Inc. ("Developer") has proposed the development of a 1002 MW combined cycle project ("AP Dutchess" or "Project") to be connected to the Consolidated Edison Company of New York, Inc. (ConEdison) network. The proposed Point of Interconnection ("POI") will be along the Pleasant Valley – Long Mountain 345 kV transmission line (circuit #398), approximately 14.5 miles east of the Pleasant Valley substation and 3.25 miles west of the New York – Connecticut border. The Project will be located in Dutchess County, New York and is expected to have a maximum potential summer generating capacity of 1002 MW and winter generating capacity of 1115 MW. The Project is in position # 310 in the NYISO interconnection queue and has an expected in-service date of December 2014.

This report presents the analysis results for the Project's System Reliability Impact Study ("SRIS"). The objectives of the analysis were to assess the impact of the Project on

- the reliability of the NYISO bulk power system, including potentially Affected Systems,
- the reliability of the local network,
- transmission interface transfer limits.

The study was performed in accordance with applicable NERC, NYSRC, NPCC, and ConEdison reliability and design standards, and in accordance with applicable NYISO and ConEdison study guidelines, procedures and practices. In addition, applicable reliability standards, guidelines and study practices of ISONE and Northeast Utilities System, that are comparable with NYISO's reliability standards, guidelines and study practices, were applied to evaluate the incremental impact of the Project on the ISONE system.

The study included steady state (thermal and voltage), stability, extreme contingency, and short circuit analysis. It also included testing of the NPCC A-10 criteria. This SRIS report also includes a list of the required facilities to physically interconnect the Project to the power network, as well as a non-binding good faith cost estimate to construct those facilities. Analysis was performed on models without and with the Project in order to evaluate the Project's impact on the bulk and local power network, and on bulk power system transmission interfaces.

A work scope for the study has been provided by the NYISO and is included as Appendix 1-A.

Upon completion of the SRIS, and in accordance with the NYISO interconnection process, the Project may participate in the Facilities Study (a.k.a., Class Year Study), which performs a final evaluation and identification of the interconnection facilities required for the Project, and develops the final cost estimates and cost allocation of the identified system upgrade facilities and system deliverability upgrades.

2. PROJECT DESCRIPTION

The AP Dutchess project is a three train combined cycle power plant, with each train consisting of two electric generators: a combustion turbine generator (CTG) and a steam turbine generator (STG). The CTGs are General Electric Model 7FA.05 units and the STGs are General Electric Model A14 units. The three steam units will operate at a nominal voltage of 18 kV, each with a summer net output of 140.5 MW, which will be stepped up to 345 kV through individual 175 MVA transformers. The three gas turbines will operate at a nominal voltage of 18 kV, each with a summer net output of 193.6 MW, which will be stepped up to 345 kV through individual 260 MVA transformers. All six generator step up transformers are connected wye-grounded on the high side and delta connected on the low side. The Project is expected to have a maximum potential summer generating capacity of 1002 MW and a maximum potential winter generating capacity of 1115 MW.

The proposed interconnection point for the Project is a new six breaker ring bus on the existing Pleasant Valley – Long Mountain 345 kV line (circuit #398), located approximately 14.5 miles east of the Pleasant Valley substation and 3.25 miles from the NY-CT border. A simplified diagram of the proposed interconnection is shown in Figure 2-1. A more detailed interconnection diagram is included in Appendix 2-A.

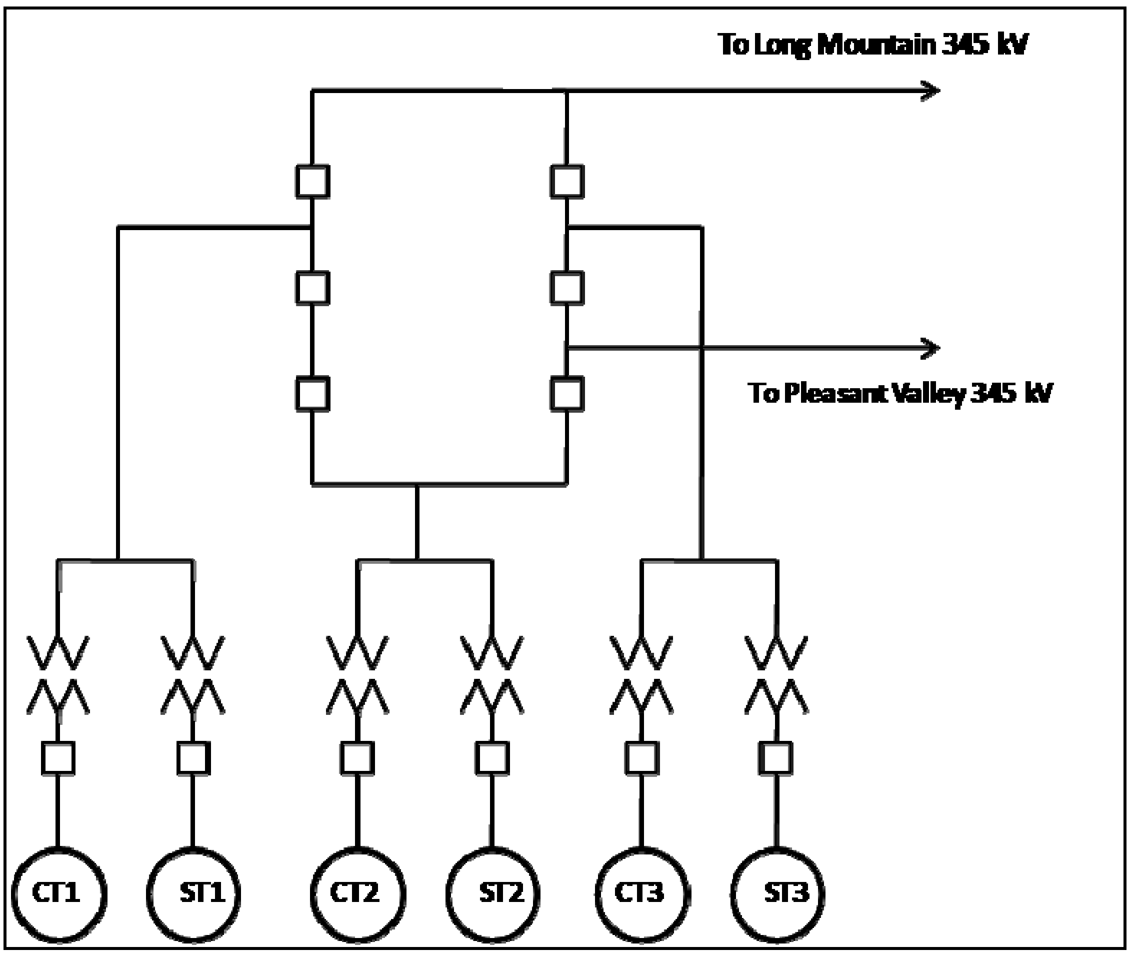

Figure 2-1. One line diagram of the proposed AP Dutchess interconnection

3. STUDY METHODOLOGY & ASSUMPTIONS

The analysis in this study proceeded in accordance with the methodology and subject to the assumptions and study parameters outlined in this section. The analysis was performed using PowerGEM TARA, Aspen OneLiner, Siemens PTI PSS/E, and Powertech Labs DSATools software.

3.1 Study Area

In accordance with the approved study scope, the AP Dutchess SRIS analysis focused on the impact of the Project on the bulk power system in the Hudson Valley (Zone G), Millwood (Zone H), Dunwoodie (Zone I), southern portion of Capital (Zone F), and southern portion of Mohawk Valley (Zone E) areas. The study also focused on the western portion of Connecticut, excluding southwestern Connecticut (SWCT), adjacent to the NYISO Hudson Valley (Zone G) region. It further included the underlying 138 kV, 115 kV, and 69 kV network elements in Hudson Valley and Millwood areas and the western portion of Connecticut, excluding SWCT, adjacent to the NYISO Hudson Valley, which would most likely be affected by the Project. All of these areas are collectively referred to as the “Study Area” in the remainder of this report.

3.2 Study Database

The NYISO provided a set of study data, including load flow cases and accompanying files, representing projected loading and system conditions for the year 2013. Two cases were considered in the study:

Case 1 – Base case without the Project. The case included the baseline system and the proposed projects listed in Appendix A of the SRIS Scope (Appendix 1-A). The Short Circuit base case models all projects as in-service. The Power Flow base case typically models all projects in-service at full output, but may model some projects as out-of-service or at less than full output as necessary to establish a feasible base dispatch. All generation was dispatched in accordance with the NYISO Minimum Interconnection Standard.

Case 2 – Case 1 with the Project modeled. The Project was modeled as in-service at full output. Unit and facility reactive resources for the Project were represented. Generation was re-dispatched in the Power Flow case as necessary and in accordance with the NYISO Minimum Interconnection Standard.

Summer peak, winter peak, and light load models were provided for each one of the above cases. Table 3-1 provides a list of the load flow cases used in the study. The table also lists the names used in this report to denote each case.

Table 3-1: List of study cases

Description	Used in	Name
Summer peak, without Project	Steady state, stability, and interface transfer analysis	SPOFF
Summer peak, with Project	Steady state, stability, and interface transfer analysis	SPON
Winter peak, without Project	Steady state analysis	WPOFF
Winter peak, with Project	Steady state analysis	WPON
Light load, without Project	Stability analysis	LLOFF
Light load, with Project	Stability analysis	LLON

Upon examination of the study database as provided by the NYISO, and in cooperation with the NYISO and the Developer, the following changes were made to accurately represent the Project in the base cases in accordance with the Interconnection Request submitted by the Developer:

Short Circuit Data – The machine MVA base, in the case with the Project on, were modified as follows:

The MVA base for the GT models was changed to 282.6 MVA (from 257.3 MVA)
The MVA base for the ST models was changed to 244 MVA (from 164.4 MVA)

Stability Data – The following GT data were modified in order to match the LFIP Interconnection Request:

GENROU CON (J+11) leakage reactance revised to 0.172 (from 0.154)
GGOV ICON(M+1) fuel flag revised to 1 (from 0)

Load Flow Data – The following changes were made to the load flow data that was used in both steady state and stability analysis:

- MVA Base for GT units changed to 282.6 MVA for summer, winter, and light load
- MVA Base for ST units changed to 244 MVA for summer, winter, and light load
- Reactive power (Q) limits were changed as follows (include netting of station load):

GT (summer):	Qmax=122.3	Qmin= -67.7
ST (summer):	Qmax=88	Qmin= -47
GT (winter):	Qmax=137.6	Qmin= -77.4
ST (winter):	Qmax=91.5	Qmin= -49.5

Table 3-2 summarizes generation changes in the summer and winter cases to accommodate the Project, as well as base transfer levels for key NYCA interfaces. Table 3-3 presents detailed flow information for all ties between NYISO and ISONE, in accordance with the study work scope[1]. Corresponding information for the light load cases is in Tables 3-4 and 3-5.

Table 3-2. Case generation changes and interface transfers (MW) *

Plant or unit	SPOFF	SPON	Difference	WPOFF	WPON	Difference
Roseton 2	560	258	-302	457	157	-300
AK 3	457	257	-200	276	0 (off)	-276
Bowline 1	500	0 (off)	-500	474	0 (off)	-474
Rav 1	370	370	0	258	225	-33
Rav 2	370	370	0	257	225	-32
AP Dutchess	0	1002	1002	0	1115	1115
Central East	2458	2418	-40	1426	1384	-42
Total East	5534	5532	-2	2921	2924	3
UPNY-SENY (op)	4912	4911	-1	2679	2682	3
UPNY-ConEd (op)	3595	3801	206	2117	2461	344
Dunwoodie South (op)	3485	3688	203	2307	2649	342
NY-NE	-257	-257	0	-249	-249	0

* There were also small generation changes, not shown, at NYCA slack buses

[1] The summer and winter cases as originally provided by the NYISO, had the Project dispatched against Bowline and AK3 only. The cases were redispatched as shown in Table 3-2 in order to improve voltages in the SENY region, as allowed under the NYISO Minimum Interconnection Standard.

Table 3-3. Flow information on NY-NE ties (MW)

Tie line	SPOFF	SPON	Delta	WPOFF	WPON	Delta
Plattsburgh-Gr. Island 115	115	115	0	113	113	0
Hoosick-Bennington 115	-16	-23	-7	-3	-10	-7
Whitehall-BlissPAR 115	0	0	0	0	0	0
Rotterdam-Bear Swamp 230	-52	-71	-19	-46	-68	-22
Alps-MA/NY 345	13	-86	-99	169	60	-109
AP Dutchess-CT/NY 345	113	238	125	-53	85	138
Northport-Nor. Harbor 138	-100	-100	0	-100	-100	0
Smithfield-Salisbury 69	*line open*	*line open*	N/A	*line open*	*line open*	N/A
Cross Sound Cable DC	-330	-330	0	-330	-330	0

Table 3-4. Case generation changes and interface transfers (MW) *

Plant or unit	LLOFF	LLON	Difference
Roseton 1	543	0	-543
AK 3	516	316	-200
Rav 1	357	150	-207
Rav 2	314	150	-164
AP Dutchess	0	1114	1114
Central East	1826	1790	-36
Total East	4650	4654	4
UPNY-SENY (op)	3161	3169	8
UPNY-ConEd (op)	1710	2280	570
Dunwoodie South (op)	1584	2150	566
NY-NE	-253	-257	-4

* There were also small generation changes, not shown, at NYCA slack buses

Table 3-5. Flow information on NY-NE ties (MW)

Tie line	LLOFF	LLON	Difference
Plattsburgh-Gr. Island 115	113	113	0
Hoosick-Bennington 115	31	23	-8
Whitehall-BlissPAR 115	0	0	0
Rotterdam-Bear Swamp 230	86	65	-20
Alps-MA/NY 345	-80	-188	-108
AP Dutchess-CT/NY 345	24	156	132
Northport-Nor. Harbor 138	-98	-98	0
Smithfield-Salisbury 69	*line open*	*line open*	N/A
Cross Sound Cable DC	-330	-330	0

The Athens SPS was not modeled in the base cases used in this SRIS. In steady state analysis, discussed in Section 4, post contingency flows on the Leeds – Pleasant Valley 345 kV lines were compared against their LTE ratings listed in Table 3-6.

Table 3-6. Leeds – Pleasant Valley 345 kV line ratings

	summer conditions			winter conditions		
	normal	LTE	STE	normal	LTE	STE
Leeds - Pleasant Valley 345	1331	1538	1725	1624	1783	1912
Leeds - Athens 345	1331	1538	1725	1624	1783	1946
Athens - Pleasant Valley 345	1331	1538	1725	1624	1783	1946

3.3 Modeling Assumptions

In accordance with standard NYISO analysis practices, phase angle regulators (“PARs”), switched shunts, and LTC transformers were allowed to regulate in pre-contingency conditions; they were locked (non-regulating) in post-contingency conditions. SVC and FACTS devices in NYCA were set to zero reactive power output pre-contingency, but were allowed to regulate up to their full output post-contingency. HVDC taps were controlling pre-contingency and fixed post contingency.

In order to determine interface transfer limits, the study simulated generation transfers, in various sending and receiving subsystems, as used in NYISO planning and operating studies.

3.4 Study Methodology

The following analyses were performed as part of this SRIS and results are presented in subsequent sections of this report:

- Steady state (thermal and voltage) analysis, to assess the impact of the Project on branch loadings and bus voltages in the Study Area. Power flow analysis was also conducted to evaluate PAR performance and the flow and balance on the A, B, C, J, and K lines.
- Stability analysis, to determine the impact of the Project on system performance within the Study Area. Stability analysis was used to calculate critical clearing times at the Project’s interconnection point and an adjacent 345 kV bus.
- Short circuit analysis, to evaluate the impact of the Project on system protection and adequacy of existing circuit breakers.
- Extreme contingency analysis, to evaluate representative extreme contingencies within the Study Area.
- Interface transfer analysis, to determine the incremental impact of the Project on normal and emergency transfer limits of the Central East, Total East, UPNY-SENY, UPNY-ConEd, Dunwoodie-South, NY-NE and NE-NY interfaces. Additionally, the Connecticut Import (CT_Imp), Connecticut East-West (CT E-W) and Southwest Connecticut (SWCT) interfaces of the New England transmission system were evaluated.
- NPCC A-10 criteria testing, to determine if there are any changes in the classification of existing and proposed stations with regard to Bulk Power status, as a result of the Project.

4. STEADY STATE ANALYSIS

Power flow analysis was conducted with and without the AP Dutchess project, for summer and winter peak loading conditions, to evaluate the impact of the Project on the local and bulk power system. The analysis was performed using PowerGEM's TARA software.

Power flow analysis focused on the study area discussed in Section 3.1. All transmission elements in the study area rated at 230 kV or higher, as well as transmission elements in zones G (Hudson Valley) and H (Millwood) rated at 69 kV or higher, were checked for thermal overloads against their Rate A/normal (pre-contingency conditions), or Rate B/LTE (design and local contingency conditions) ratings. All elements in the New England part of the study area, rated at 69 kV and above, were also monitored for thermal overloads. All system buses in the study area rated at 230 kV or higher, buses in zones G and H, as well as buses in the NE portion of the study area rated at 69 kV and higher, were monitored for voltage violations. Pre- and post-contingency voltage limits of 0.95 to 1.05 p.u. were used to identify voltage violations. Specific pre- and post-contingency voltage limits were observed for several bulk power system buses in the study area, as specified in Attachment A.2 of the NYISO Transmission & Dispatching Operations Manual.

The analysis considered normal or pre-contingency (all lines in) conditions, as well as post-contingency conditions. The list of contingencies used in the study comprised of a) NYISO design contingencies covering the NYCA study area, b) local contingencies covering the network in the vicinity of the POI, c) standard contingencies covering the New England study area, and d) single element contingencies covering the entire study area, for all transmission elements at 230 kV or higher. Definitions for the NY design contingencies were provided by the NYISO. Definitions for the NE standard contingencies were provided by the ISONE. Some contingencies were modified for consistency with the study cases. As specified in the study scope, phase shifters, switched shunts, and LTC transformers were allowed to regulate pre-contingency, but were locked/fixed post-contingency. SVC and FACTS devices were set to approximately zero reactive power output pre-contingency, per standard NYISO practice, and were allowed to operate at full range post-contingency.

The contingency, monitored element, and subsystem files (i.e., 'con', 'mon', and 'sub' files) used in the study are included in Appendix 4-F.

The following subsections present the results of the power flow analysis. Based on the analysis results, it is concluded that the project does not cause any adverse thermal overloads or voltage violations on the local and bulk power network. The Project meets all applicable NERC, NPCC, and NYSRC design standards.

4.1 Thermal Analysis

Summer peak and winter peak loading conditions were compared for the cases with and without the project, to evaluate the impact of AP Dutchess on the thermal behavior of the network.

4.1.1 Normal (pre-contingency) conditions

Table 4-1 lists transmission elements overloaded under summer normal (all lines in) conditions. There were no violations under winter normal conditions. The overload reported in Table 4-1 is clearly dependent on import levels into NYC and system dispatch patterns, and is not directly associated with the Project. No action was taken to mitigate this overload in order to maintain import levels into NYC as originally set.

Table 4-1. Pre-contingency line overloads (MVA)

	summer			
	Rate A	SPOFF	SPON	Diff
W73 tap – Dunwoodie S. 345/115	341	346	348	2

Comparison of pre-contingency line flows, with and without the Project, indicates that the most significant line flow changes occurred in the vicinity of the Project's POI. A sample of line flows are shown in Table 4-2. A list of pre-contingency flows, for summer and winter conditions, is included in Appendix 4-A to assess the incremental impact of the Project under normal conditions.

Table 4-2. Pre-contingency local network line flows (MVA)

	summer				winter			
	Rate A	SPOFF	SPON	Diff	Rate A	WPOFF	WPON	Diff
Hurley-Roseton 345	1395	411	482	72	1712	264	339	75
RTavern-CCorners 345	1554	598	630	33	1793	331	367	36
BuchananN-Eastview 345	1811	961	908	-52	1918	569	527	-42
AP Dutchess-PV 345	1195	124	746	622	1195	105	995	890
Millwood 345/115 #1	228	64	67	3	261	49	54	5

Figures 4-1 and 4-2 show line flows (MW and MVar) in the vicinity of the proposed interconnection for the cases without and with the Project. Arrows indicate direction of flow.

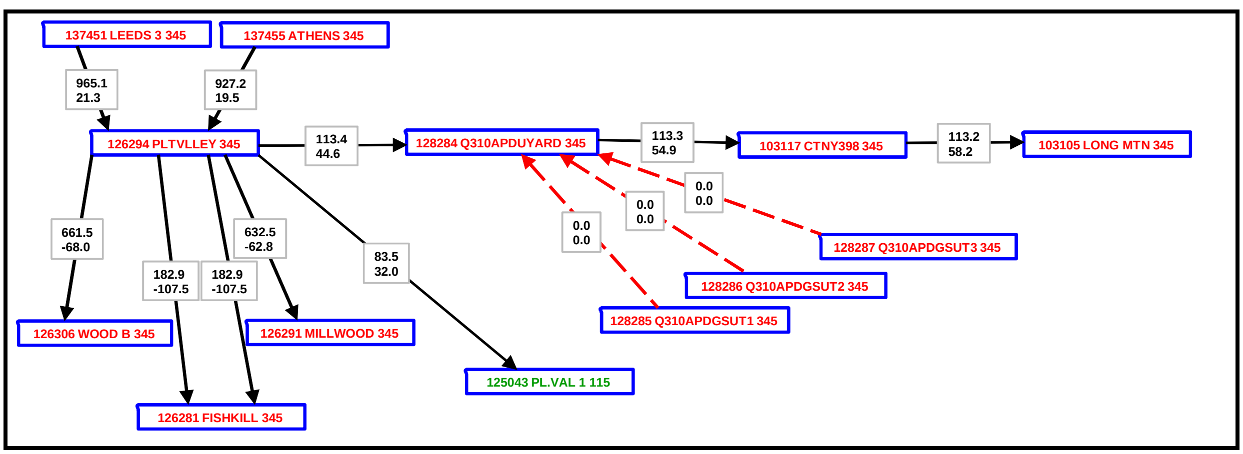

Figure 4-1. Line flows in vicinity of Project interconnection (case SPOFF)

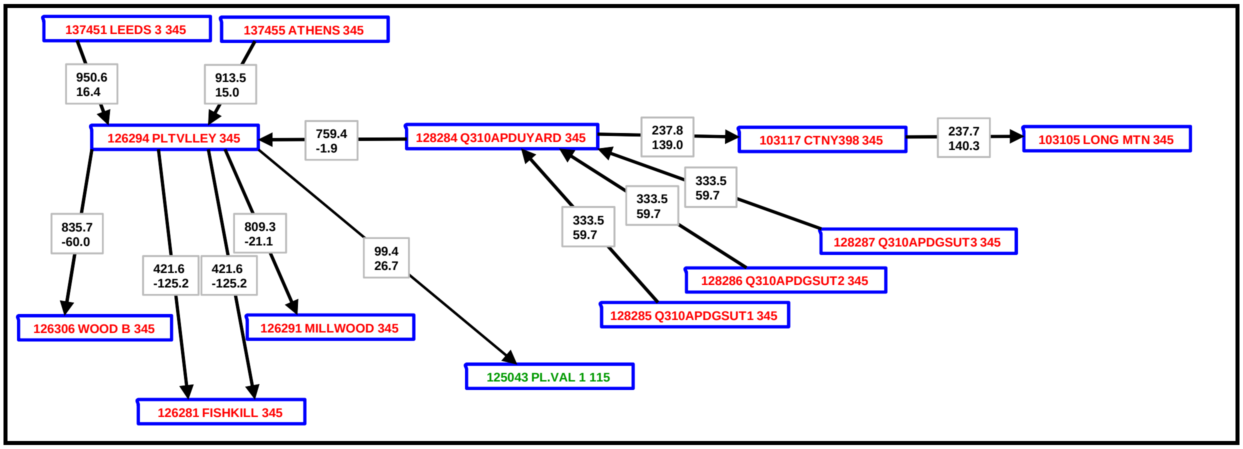

Figure 4-2. Line flows in vicinity of Project interconnection (case SPON)

4.1.2 Contingency conditions

Design and local contingencies were evaluated using AC (non linear) contingency analysis. Using the summer and winter cases described in Section 3.2, contingency analysis results show that in most instances the Project has a very small impact on pre-existing overloads. Table 4-3 shows those instances where the Project increases overloads by more than 1 MVA for summer peak loading conditions. Table 4-4 presents similar information for winter conditions.

Table 4-3. Post-contingency line overloads, summer conditions

		Flow (MVA)				Loading (%)		
Transmission Element	**Contingency**	**Rate B**	**SPOFF**	**SPON**	**Diff**	**SPOFF**	**SPON**	**Diff**
GALEVILE 69.0–KERHNKMK 69.0	TWR:34&42	44	62	64	2	140.6	144.8	4.2
GALEVILE 69.0–MODENA 6 69.0	TWR:34&42	44	58	60	2	132.6	136.7	4.1
HONK FLS 69.0–KERHNKMK 69.0	TWR:34&42	41	63	65	2	154.5	159.1	4.6
MODENA 6 69.0–MODENA 1 115	TWR:34&42	41	60	62	2	147.1	150.8	3.7
W.WDBR69 69.0–W.WDB115 115	TWR:34&42	48.3	83	86	3	171.0	178.0	6.9
RAMP138 138–SGRLF138 138	TWR:34&42	300	393	397	4	130.9	132.2	1.3
BURNS138 138–MONSEY 138	TWR:67&68&BW	501	718	728	10	143.3	145.3	2.0
MONSEY 138–TALLMAN 138	TWR:67&68&BW	501	758	766	9	151.2	153.0	1.8
RAMP138 138–TALLMAN 138	TWR:67&68&BW	501	824	831	7	164.4	165.8	1.4
RAMP138 138–SGRLF138 138	SB:ROCK_345_3456	300	392	394	1	130.7	131.2	0.5
ROTRDM.2 230–RTRDM1 115	SB:ROTT_230_R84	355	350	357	7	98.6	100.7	2.0
ROTRDM.2 230–RTRDM1 115	SB:ROTT_230_R84JOR	355	350	357	7	98.6	100.7	2.1

Table 4-4. Post-contingency line overloads, winter conditions

		Flow (MVA)				Loading (%)		
Transmission Element	**Rate B**	**Rate B**	**SPOFF**	**SPON**	**Diff**	**SPOFF**	**SPON**	**Diff**
RAMP138 138--TALLMAN 138	TWR:67&68&BW	531	564	565	1	106.2	106.4	0.3

The results in Table 4-3 indicate that the Project introduces two very small new overloads on the Rotterdam 230/115 #2 transformer. Modifying the set point of the switched shunts at Rotterdam or allowing the shunts to regulate post-contingency mitigates these overloads. In every other instance, the impact of the Project is very small compared to the pre-existing overloads. It is expected that several of these overloads are likely addressed currently by operating guidelines.

Post-contingency line flows on transmission network elements in the vicinity of the Project changed after including the Project in the load flow model. Table 4-5 lists sample post-contingency line flows, without and with the Project, on selected transmission elements for selected contingencies. These flows are below their respective LTE ratings and are presented in order to demonstrate the incremental impact of the Project on the network.

Table 4-5. Design contingencies: Post-contingency line flows (MVA)

	summer				winter			
	Rate B	**SPOFF**	**SPON**	**Delta**	**Rate B**	**WPOFF**	**WPON**	**Delta**
	SB:MILL_345_4							
Hurley-Roseton 345	1623	429	506	76	1885	278	358	81
RTavern-CCorners 345	1733	605	640	35	1793	335	374	39
BuchananN-Eastview 345	1990	1049	1002	-47	2115	623	587	-37
AP Dutchess-PV 345	1386	160	695	535	1386	82	955	873
Millwood 345/138 #1	330	67	68	2	339	50	54	4
	L/O AP Dutchess – Long Mountain (line #398)							
Hurley-Roseton 345	1623	402	464	63	1885	267	334	67
RTavern-CCorners 345	1733	593	621	28	1793	333	363	30
BuchananN-Eastview 345	1990	962	912	-50	2115	569	528	-40
AP Dutchess-PV 345	1386	0	977	977	1386	0	1071	1071
Millwood 345/138 #1	330	64	67	3	339	49	54	6
	TWR:F30&F31							
Hurley-Roseton 345	1623	461	547	87	1885	301	394	92
RTavern-CCorners 345	1733	623	662	39	1793	347	391	44
BuchananN-Eastview 345	1990	999	960	-39	2115	595	564	-31
AP Dutchess-PV 345	1386	222	611	390	1386	68	888	820
Millwood 345/138 #1	330	53	51	-1	339	41	43	2
	TWR:W89&W90							
Hurley-Roseton 345	1623	356	422	66	1885	231	296	66
RTavern-CCorners 345	1733	594	626	32	1793	326	362	36
BuchananN-Eastview 345	1990	1149	1123	-26	2115	684	674	-10
AP Dutchess-PV 345	1386	237	616	379	1386	77	885	808
Millwood 345/138 #1	330	64	68	4	339	50	55	5

The full set of post-contingency thermal overload results is included in Appendix 4-B. The Appendix includes all instances where line loading exceeds 90% of applicable rating, without or with the Project. The Appendix results for winter conditions indicate a number of overloads on the S. Mahwah-Waldwick 345 kV lines (lines J&K). The Project has a positive impact on those overloads, in that it reduces post-contingency flows. The overloads possibly reflect incorrect winter ratings (winter ratings are lower than summer ratings). Further, PSEG also uses 30-minute ratings on those circuits under contingency conditions.

In response to comments received during the review of the report, Appendix 4-E includes supplemental post contingency results. The Appendix includes all post-contingency flows within 2 buses from the Pleasant Valley 345 kV for a number of bulk system contingencies.

4.2 Voltage Analysis

Voltage analysis was conducted with and without the Project, to evaluate its impact on network voltage profiles. The analysis was performed using PowerGEM's TARA software.

Voltage analysis used pre-contingency and post-contingency voltage limits of 0.95 to 1.05 pu to identify voltage violations. Specific pre-contingency and post-contingency limits were observed for a number of bulk power system buses in the study area; limits for these buses were as specified in Attachment A.2 of the NYISO Transmission & Dispatching Operations Manual.

The following subsections present the results of the voltage analysis. Based on the analysis results, the Project does not introduce any new voltage violations. Its impact on system bus voltages is relatively small.

4.2.1 Normal (pre-contingency) conditions

Comparing pre-contingency voltage levels, with and without the Project, the Project has a small impact on bus voltages. There were no pre-contingency voltage violations on the bulk or local transmission network. Sample bus voltages are shown in Table 4-6. A comprehensive list of pre-contingency voltage levels, without and with the Project, is included in Appendix 4-A to assess the impact of the Project under normal transmission conditions.

Table 4-6. Pre-contingency bus voltages (pu)

	summer			winter		
	SPOFF	**SPON**	**Delta**	**WPOFF**	**WPON**	**Delta**
Rock Tavern 345	1.0229	1.0252	0.0023	1.0434	1.0401	-0.0033
Pleasant Valley 115	1.0031	1.0059	0.0028	1.0118	1.0102	-0.0016
Buchanan N. 345	1.0405	1.0403	-0.0002	1.0436	1.0428	-0.0008
Dunwoodie 345	1.0267	1.0233	-0.0034	1.0476	1.0462	-0.0014
Millwood 345	1.0276	1.0235	-0.0041	1.0446	1.0430	-0.0016

4.2.2 Contingency conditions

Post contingency results indicate a number of voltage violations without or with the Project, particularly at the 115 kV and 69 kV networks. Analysis results indicate that in most instances, the Project has a small effect on bus voltages under contingency conditions and pre-existing low-voltage violations did not exhibit sensitivity to the Project (i.e., voltage impact was less than 0.005 pu). For several contingencies, the Project had an impact on a number of 69 kV, 115 kV and 138 kV bus voltages; in all instances, voltages were maintained above 0.90 pu. Table 4.7 lists bulk power system (i.e., 230 kV and above) voltage violations for summer conditions. All but one 345 kV violations do not indicate significant sensitivity to AP Dutchess. Allowing voltage controlling devices to regulate post-contingency eliminates all violations involving Ramapo 500 kV and its bus voltage is maintained above 1.0 pu post-contingency. Except from the instances listed in Table 4-7, the Project did not introduce any new voltage violations. Voltage limit checks for all contingencies are included in Appendix 4-B.

Table 4-7. Bulk power system voltage violations, summer conditions (pu))

Bus	Contingency	SPOFF	SPON	Diff
WOODA345	BUS:WOODA_345	0.9219	0.9188	-0.0031
WOODA345	SB:E_FI_345_6	0.9095	0.9039	-0.0056
WOODA345	SB:E_FI_345_4	0.9206	0.9172	-0.0034
MDTN TAP	SB:ROCK_345_3456	0.9390	0.9375	-0.0015
RAMAPO 5	GEN:IND PT 2	1.0031	0.9912	-0.0119
RAMAPO 5	GEN:IND PT 3	1.0076	0.9983	-0.0093
RAMAPO 5	GEN:RAVNWD 3	1.0101	0.9997	-0.0104
RAMAPO 5	SB:BUCH_345_N_7	1.0071	0.9946	-0.0125
RAMAPO 5	SB:BUCH_345_N_9	1.0060	0.9935	-0.0125
RAMAPO 5	SB:BUCH_345_N_11	1.0063	0.9938	-0.0125
RAMAPO 5	SIN:250	1.0059	0.9984	-0.0075
RAMAPO 5	BUCHANAN N--IP2 345	1.0020	0.9900	-0.0120
RAMAPO 5	BUCHANAN S--IP3 345	1.0067	0.9975	-0.0092

The following observations apply for voltage analysis and results:

1) Although a low voltage limit of 0.95 pu was observed in the study, a post-contingency low limit of 0.90 p.u. is applicable throughout the NYCA study area for buses at 138 kV and below. For buses rated at 138 kV and below, only voltages below 0.90 pu may be characterized as voltage violations. Results in Appendix 4-B list all instances where voltages drop below 0.95 pu, pre- or post-contingency.
2) In order to consider voltage as being impacted by the Project, a minimum threshold of 0.005 pu was applied on voltage difference (without and with the Project), per NYISO criteria.
3) A small number of buses exhibited persistent low-voltage violations following almost all contingencies (as well as pre-contingency), with or without the Project (for example, Falls V., N. Canaan, Salisbury). For winter conditions, several bulk power buses exhibited consistent high-voltage violations, with or without the Project. The Project's impact on these voltages was negligible or minimal. These violations are not included in appendix material, for ease of presentation of results.
4) Several switched shunts were modeled in the summer cases, at the 138 kV and 69 kV networks. The shunts provided little or no reactive support under base case conditions and were locked under contingency conditions. Most voltage violations in lower voltage networks can be mitigated by allowing these switched shunts to regulate post-contingency.

Table 4-8 lists a sample of post contingency voltages, with and without the Project, for selected system buses for selected contingencies. None of the voltages in Table 4-8 are voltage violations; they are presented to demonstrate the incremental impact of the Project on the network.

Table 4-8. Post contingency network bus voltages (in p.u.)

	summer			winter		
	SPOFF	**SPON**	**Delta**	**WPOFF**	**WPON**	**Delta**
	SB:MILL_345_4					
Rock Tavern 345	1.0218	1.0232	0.0014	1.0412	1.0368	-0.0044
Pleasant Valley 115	1.0017	1.0045	0.0028	1.0109	1.0090	-0.0019
Buchanan N. 345	1.0405	1.0403	-0.0002	1.0420	1.0408	-0.0012
Dunwoodie 345	1.0249	1.0208	-0.0041	1.0460	1.0440	-0.0020
Millwood 345	1.0272	1.0218	-0.0054	1.0426	1.0408	-0.0018
	L/O AP Dutchess – Long Mountain (line #398)					
Rock Tavern 345	1.0232	1.0257	0.0025	1.0446	1.0407	-0.0039
Pleasant Valley 115	1.0047	1.0077	0.0030	1.0130	1.0109	-0.0021
Buchanan N. 345	1.0405	1.0403	-0.0002	1.0444	1.0431	-0.0013
Dunwoodie 345	1.0269	1.0231	-0.0038	1.0489	1.0464	-0.0025
Millwood 345	1.0280	1.0235	-0.0045	1.0461	1.0434	-0.0027
	TWR:F30&F31					
Rock Tavern 345	1.0151	1.0164	0.0013	1.0382	1.0307	-0.0075
Pleasant Valley 115	0.9929	0.9975	0.0046	1.0094	1.0046	-0.0048
Buchanan N. 345	1.0405	1.0403	-0.0002	1.0420	1.0399	-0.0021
Dunwoodie 345	1.0249	1.0199	-0.0050	1.0458	1.0428	-0.0030
Millwood 345	1.0304	1.0245	-0.0059	1.0449	1.0430	-0.0019
	TWR:W89&W90					
Rock Tavern 345	1.0193	1.0165	-0.0028	1.0369	1.0319	-0.0050
Pleasant Valley 115	1.0008	1.0021	0.0013	1.0093	1.0075	-0.0018
Buchanan N. 345	1.0402	1.0277	-0.0125	1.0377	1.0358	-0.0019
Dunwoodie 345	1.0175	1.0065	-0.0110	1.0397	1.0373	-0.0024
Millwood 345	1.0171	1.0040	-0.0131	1.0361	1.0328	-0.0033

4.3 PAR and Wheel Analysis

The study work scope specifies that the impact of the AP Dutchess project on the ABC/JK PAR schedule (the "Wheel") be assessed. This analysis was performed for summer and winter peak load conditions, using the cases described in Section 3.2. Table 4-9 shows the impact of the Project on PAR angle ranges for summer conditions. Table 4-10 shows similar information for winter conditions. Finally, Table 4-11 shows PAR flows without and with the Project.

Table 4-9. ABC/JK PAR performance, summer conditions (angle, in degrees)

PAR	min	max	SPOFF	SPON
Ramapo #1	-40	40	-10.9	-8.4
Ramapo #2	-40	40	-10.9	-8.4
Waldwick-Fairlawn	-32	32	6.5	4.2
Waldwick-Hawthorne	-30	30	7.1	4.8
Waldwick-Hillsdale	-32	32	9.3	7.1
Goethals	-37.8	37.8	-5.6	-8.4
Farragut #1	-30	30	-5.4	-2.5
Farragut #2	-30	30	-6.1	-3.3

Table 4-10. ABC/JK PAR performance, winter conditions (angle, in degrees)

PAR	min	max	WPOFF	WPON
Ramapo #1	-40	40	6.0	8.4
Ramapo #2	-40	40	6.0	8.4
Waldwick-Fairlawn	-32	32	3.6	1.1
Waldwick-Hawthorne	-30	30	4.0	1.4
Waldwick-Hillsdale	-32	32	7.2	4.6
Goethals	-37.8	37.8	3.4	-1.5
Farragut #1	-30	30	-16.4	-14.0
Farragut #2'	-30	30	-17.3	-14.8

Table 4-11. ABC/JK wheel flows (MW)

	Summer		Winter	
	SPOFF	SPON	WPOFF	WPON
Hudson - Farragut 345 #1	333	333	333	333
Linden - Goethals 230	333	333	333	333
Hudson - Farragut 345 #2	333	333	333	333
Waldwick - S Mahwah 345 #1	-456	-457	-470	-470
Waldwick - S Mahwah 345 #2	-544	-544	-531	-531
Wheel Balance	-1	-2	-2	-2

The inclusion of the AP Dutchess project does not impair the ability to maintain the ABC/JK wheel under any system conditions tested.

4.4 Sensitivity Analysis

As specified in the scope, sensitivity steady state analysis was performed under summer conditions to determine the impact of the Project on transmission system conditions for varying levels of Danskammer output. The purpose of this sensitivity analysis was to determine whether the Project restricts the operating flexibility of the CHG&E 115/69 kV system. Further, sensitivity analysis was performed to evaluate the impact on system conditions resulting from the concurrent operation of the Athens, Besicorp and AP Dutchess projects at full output.

4.4.1 Sensitivity to Danskammer output

For the purposes of this sensitivity analysis, four sets of cases, with and without the Project, were developed, with varying levels of Danskammer output. In all cases with the Project on, AP Dutchess was dispatched as described in Section 3.2, i.e., against Roseton, Bowline, and AK 3. Danskammer output variations were adjusted by a mix of 50/50 generation in upstate New York / New York City & Long Island regions. Table 4-12 shows the generation dispatch used to adjust for Danskammer output. Values shown are with reference to generation output in the SPOFF case (pre-Project). Similar values were used to develop the post-Project cases.

Table 4-12. Generation adjustments to accommodate Danskammer varying output (MW)

	SPOFF	Case A	Case C	Case E	Case G
Danskammer output	379	0	250	354	494
	Delta from SPOFF				
Danskammer	0	-379	-129	-25	+115
Kintigh (AES Somerset)	0	50	40		
Sithe	0	40			
Oswego	0	0	30	10	-65
Weathersfield	0	60			
Flat Rock	0	40			
Northport	0	30			
SCS	0	80			
Rav 3	0	0	20	15	-50
York GT	0	40			
East River GT	0	40	40		

Sensitivity post-contingency steady state results for all four sets of cases are included in Appendix 4-C. Thermal as well as voltage results are qualitatively similar to the results discussed in Sections 4.1 and 4.2. The Project does not introduce any new thermal or voltage violations. Voltage violations on lower voltage networks can be mitigated by allowing switched shunts to regulate post contingency. The Project reduces post-contingency overloads in the immediate vicinity of the Danskammer plant. Based on the sensitivities conducted in the study, the Project does not have any adverse impact on the operational flexibility of the CHG&E 115/69 kV system.

4.4.2 Sensitivity to concurrent operation of Athens & Besicorp projects

For the purposes of this sensitivity, summer peak load cases were developed with Athens and Besicorp at full output, an increase of 1120 MW from the SPOFF/SPON cases. Generation in areas 1, 3, and 4 was reduced by 320 MW, 570 MW and 230 MW respectively to accommodate the increased output in area 6. Except from the increased output from Athens and Besicorp, the dispatch of the remaining generating units in area 6 did not change from the SPOFF/SPON cases. The generation changes resulted in an increase of power flowing through the Leeds-

Athens-Pleasant Valley 345 kV transmission corridor. In all cases with the Project on, AP Dutchess was dispatched as described in Section 3.2, i.e., against Roseton, Bowline, and AK 3. Table 4.13 shows the output of the largest generating plants in the Capital region (area 6) as modeled in these sensitivities. The dispatch of these units is the same in the cases with or without the Project.

Table 4.13. Generation output of largest plants in Capital region

Power plant	Output (MW)
Gilboa	920
Athens	1080
Besicorp	619
Bethlehem	272
JMC	94
IP Corinth	63
Indeck-C	53
CETI	70
EJW+STWB	50

Sensitivity thermal as well as voltage results are for the most part qualitatively similar to the results discussed in Sections 4.1 and 4.2. The Project has a small impact on preexisting thermal overloads and voltage violations. One notable exception is that the Project has a 2.5% contribution on a preexisting overload in Reynolds Rd. 345/115 kV transformer, under normal conditions, as shown in Table 4-14. The Project also introduces a new 1.4% overload on the same transmission element, following two contingencies in the New Scotland bus (contingencies ‘BUS:N.S._77’ & ‘SB:NSCT_345_R2>R14>R62>R93’). The Project has negligible impact on a few other overloads in the Reynolds Rd. / Alps area. The full set of sensitivity post-contingency steady state results is included in Appendix 4-D.

Table 4-14. Pre-contingency line overloads in Athens/Besicorp sensitivity (MVA)

	summer			
	Rate A	sens-OFF	sens-ON	Diff
Reynolds Rd. 345/115	459	479	492	13

5. STABILITY ANALYSIS

Simulations and analysis were conducted to observe the impact of the AP Dutchess project on system stability for summer peak and light load conditions.

5.1 Stability Modeling

Stability simulations were performed on pre-Project and post-Project models, for summer peak and light load conditions. Simulations took into account system modeling changes discussed in Section 3. Light load simulations used the cases provided in the NYISO database. Simulations were performed with the Powertech Labs DSATools software (version 10). The model names used are in Table 5.1 and are the same as provided by the NYISO. The detailed stability data for these models is contained in Appendix 5-A.

Table 5.1 Stability model names

	Generator	**Excitation**	**Stabilizer**	**Governor**
Combustion turbines	GENROU	ESST4B	PSS2A	GGOV1
Steam Turbines	GENROU	ESST4B	PSS2A	none

5.2 Contingencies

Design contingencies were tested for the summer peak and light load cases, for both NYISO and ISONE. For NYISO, these included standard contingencies for the UPNY-ConEd, Total East, and Central East interfaces, as well as several contingencies involving the AP Dutchess interconnecting circuits to Pleasant Valley 345 kV bus (NYISO) and Long Mountain 345 kV bus (ISONE). For ISONE, the list included design contingencies at the 345 kV buses in the New England portion of the study area. The contingencies are listed in Tables 5-2 through 5-6.

Table 5-2. List of UPNY-ConEd design contingences

ID	UPNY-ConEd Design Contingency Description
UC03	UC03 3PH@SPRAIN BK-LO TOWER(2-1956)MILLWOOD-SPRAIN BROOK
UC04	UC04 SLG-STK @ BUCHANAN NORTH IP#2 STK BKR 9
UC05	UC05 3PH-STK @ BUCHANAN SOUTH W97*MILLWOOD STK BKR 6
UC06	UC06 SLG-STK @ DUNWOODIE - PVLE W90 STK#8 CLR RAINEY#72
UC07	UC07 SLG-STK @ FISHKILL-PL.VAL F36 STK#11 CLR BANK#1
UC08	UC08 SLG-STK @ LADENTOWN-RAMAPO W72 STK#1-56-2 CLR W67
UC09	UC09 SLG-STK@MILLWOOD-EASTVIEW-SPRAIN BROOK STK#16 CLR W98
UC10	UC10 SLG-STK@RAMAPO-ROCK TAVERN STK T-77-94-2 CLR Y94
UC11	UC11 SLG-STK@SPRAINBROOK-TREMONT STK RNS6 CLEAR W93&W79
UC12	UC12 SLG-STK@RAMAPO-JEFFERSON STK T-1500-W72-2 CLR W72
UC13	UC13 SLG-STK@LEEDS-N.SCOTLAND STK R94301 CLR#303*HURLEY
UC14	UC14 SLG STK@LEEDS-GILBOA STK R391 CLR#91 PL.VALLEY
UC15	UC15 SLG-STK@LEEDS-PLEASANT VALLEY STK R9293 CLR#93 NS
UC16	UC16 SLG-STK @ ROSETON ROSETON-ROCK TAVERN#311 STK 31151
UC18	UC18 3PH@LADENTOWN-LO TOWER Y88&Y94 BUCHANAN RIVER CROSSING
UC19	UC19 3PH@MILLWOOD-LO TOWER (2-1961) MILLWOOD-SPRAINBROOK
UC20	UC20 3PH@DUNWOODIE-LO TOWER(2-1938)PLEASANTVILLE*DUNWD
UC21W	UC21W 3PH@PL.VALLEY-LO TOWER(2-1961)PV-MILLWOOD DBL CKT
UC22	UC22 SLG-STK@LADENTOWN-BUCHANAN Y88 STK#3-56-2 CLR W67&BP#1
UC23	UC23 SLG-STK@RAMAPO-BUCHANAN STK T-77-94-2 CLR#377 ROCK TAV
UC24	UC24 SLG-STK@ROCK TAVERN-ROSETON CLR COOPERS-ROCK TAV
UC25	UC25 3PH @ RAVENSWOOD#3 - TRIP GEN.@ 4.5~
UC26	UC26 LLG LO TOWER LADENTOWN-W.HAVERSTRAW REJ BOWLINE
UC27	UC27 SLG-STK@ROCK TAVERN-COOPERS CLR ROCK TAVN-RAMAPO
UC29	UC29 SLG-STK@LADENTOWN-BUCHANAN Y88 STK#6-56-2 CLR W68&BP#2
UC30	UC30 LLG@ROCK TAVN-COOPERS CORNERS-ROCK TAVERN DBL CKT
UC30AR	UC30AR LLG@ROCK TAVN-COOPERS CORNERS-ROCK TAVERN DBL CKT
UC32	UC32 SLG-STK@COOPERS CCRT-42 BACKUP CLR UCC-2 41@MARCY

Table 5-3. List of Total East design contingences

ID	Total East Design Contingency Description
TE02W	TE02W 3PH@FISHKILL-LO TOWER(2-1938)FISHKILL-PLEASANTVILLE
TE03	TE03 3PH@SPRAIN BK-LO TOWER(2-1956) MILLWOOD-SPRAIN BROOK
TE05	TE05 3PH-STK @ BUCHANAN SOUTH W97*MILLWOOD STK BKR 6
TE10	TE10 SLG-STK@RAMAPO-ROCK TAVERN STK T-77-94-2 CLR Y94
TE12	TE12 SLG-STK@RAMAPO-JEFFERSON STK T-1500-W72-2 CLR W72
TE14	TE14 SLG-STK@LEEDS-GILBOA STK R391 CLR#91 PL.VALLEY
TE15	TE15 SLG-STK@LEEDS-PLEASANT VALLEY STK R9293-CLR#93 NS
TE16	TE16 SLG-STK @ ROSETON ROSETON-ROCK TAVERN#311-STK 31151
TE18	TE18 3PH@LADENTOWN-LO TOWER Y88&Y94 BUCHANAN RIVER CROSSING
TE20	TE20 3PH@DUNWOODIE-LO TOWER(2-1938)PLEASANTVILLE-DUNWD
TE21	TE21 3PH@PL.VALLEY-LO TOWER(2-1961)PV-MILLWOOD DBL CKT
TE27	TE27 SLG-STK@ROCK TAVERN-COOPERS CLR ROCK TAVN-RAMAPO
TE29	TE29 3PH@N.SCOT N.SCOT-LEEDS#93 W-HS RCL
TE30	TE30 3PH@LEEDS GILBOA - LEEDS GL-3
TE31	TE31 3PH@GILBOA GILBOA - NEW SCOTLAND GNS-1
TE32	TE32 3PH@NEW SCOTLAND - 77 BUS
TE33	TE33 3PH@NEW SCOTLAND - 99 BUS
TE34	TE34 SLG-STK@GILBOA GILBOA-NSCOT STUCK 3308
TE35	TE35 3PH@LEEDS LEEDS-ATHENS#91 W-HS RCL
TE36	TE36 3PH @ LEEDS LEEDS - HURLEY AVENUE
TE37	TE37 3PH@80%FROM ROSETON ROSETON-HURLEY AV#303 CLR ZONE2@ROS
TE38	TE38 3PH-NC @ ROCK TAVERN ROSETON - ROCK TAVERN #311
TE39	TE39 LLG@LADENTOWN - STORM WATCH - Y88+Y94+69-J3410
TE40	TE40 3PH@RAMAPO-2 RAMAPO-WALDWICK 69-J3410+70-K3411
TE41	TE41 SLG-STK@GILBOA GILBOA - LEEDS GL-3 STK 3208
TE42	TE42 3PH@RAMAPO 500KV JEFFERSON-RAMAPO#5018 N.C.
TE43	TE43 3PH@LEEDS LEEDS-PLEASANT VALLEY#92 W-HS RCL

Table 5-4. List of Central East design contingences

ID	Central East Design Contingency Description
CE01	CE01 3PH AT EDIC 345KV EDIC-NEW SCOTLAND #14 NORMALLY CLEARED
CE01_AR	CE01_AR 3PH AT EDIC 345KV EDIC-NEW SCOTLAND #14 NORMALLY CLEARED
CE02	CE02 3PH AT MARCY 345KV MARCY-N.SCOTLAND 18 NORMALLY CLEARED
CE03	CE03 SLG-STK@EDIC345KV EDIC-N.SCOT #14 BKUP CLR@FITZ 345
CE04	CE04 SLG-NC@EDIC EDIC-NEW SCOTLAND #14 W-HS&AUTO RCL
CE05	CE05 3PH @ EDIC 345KV EDIC-MARCY UE1-7 NORM.CLR
CE06	CE06 3PH @MARCY 345KV EDIC-MARCY UE1-7 NORM.CLR
CE07	CE07 LLG @MARCY-EDIC ON MARCY-COOPERS & EDIC-FRASER DBL CCT
CE07AR	CE07AR LLG @MARCY-EDIC ON MARCY-COOPER & EDIC-FRASER DBL CKT
CE08	CE08 LLG @COOPERS ON MARCY-COOPER FRASER-COOPERS
CE08AR	CE08AR LLG @COOPERS ON MARCY-COOPER FRASER-COOPERS
CE09	CE09 SLG-STK@EDIC345KV FITZ-EDIC #FE-1 BKUP CLR@N.SCOT345
CE10	CE10 SLG-STK@MARCY345 MARCY-N.SCOT UNS18 STK@MARCY 345
CE11	CE11 SLG-STK @FRASER 345 ON FRASER-GILBOA
CE12	CE12 3PH-NC@NSCOT345 EDIC-N.SCOT #14 W-HIGH SPEED RCL
CE13	CE13 3PH@VOLNEY 345KV VOLNEY-MARCY VU-19 NORM.CLR.
CE14	CE14 3PH@ MARCY 345KV VOLNEY-MARCY VU-19 NORM.CLR.
CE15	CE15 SLG-STK@MARCY345 VOLNEY-MARCY VU-19 STK@MARCY 345
CE16	CE16 SLG-STK @EDIC 345 ON EDIC-FRASER
CE17	CE17 SLG-STK @MARCY ON MARCY-COOPERS
CE18	CE18 LLG@ROCK TAVN COOPERS CORNERS-ROCK TAVERN DBL CKT
CE19	CE19 LLG COOPERS ON COOPERS CORNERS-ROCK TAVERN DBL CKT
CE19AR	CE19AR LLG LO TOWER@COOPERS CORNERS-ROCK TAVERN DBL CKT W-RCL
CE20	CE20 SLG-STK@EDIC345 EDIC-MARCY UE1-7 CLR PORTER 230&115#4
CE21	CE21 SLG-STK @FRASER FRASER-COOPERS 33 CLR#32@OAKDALE
CE22	CE22 3PH-NC@EDIC 345 EDIC-FRASER EF-24-40
CE22AR	CE22AR 3PH-NC@EDIC 345 EDIC-FRASER EF-24-40 W-RCL@FRASER
CE23	CE23 LLG@FRASER ON MARCY-COOPERS EDIC-FRASER DBL CKT
CE24	CE24 3PH-NC@FRASER ON FRASER - COOPERS CORNERS FCC-33
CE24AR	CE24AR 3PH-NC@FRASER FRASER-COOPERS CORNERS FCC-33 W-RCL
CE25	CE25 3PH-NC@COOPERS FRASER-COOPERS CORNERS FCC-33
CE25AR	CE25AR 3PH-NC@COOPERS FRASER-COOPERS FCC-33 W-RCL
CE26	CE26 3PH-NC@COOPERS MARCY-COOPERS CORNERS UCC-2 41
CE26AR	CE26AR 3PH-NC@COOPERS MARCY-COOPERS UCC-2 41 W-RCL
CE27	CE27 3PH-NC@COOPERS COOPERS CORNERS-ROCK TAVERN CCRT-34
CE27AR	CE27AR 3PH-NC@COOPERS COOPERS - ROCK TAVERN CCRT-34 W-RCL
CE28	CE28 3PH-NC@COOPERS COOPERS CORNERS-ROCK TAVERN CCRT-42
CE28AR	CE28AR 3PH-NC@COOPERS COOPERS - ROCK TAVERN CCRT-42 W-RCL
CE32	CE32 3PH-NC@FRASER ON EDIC - FRASER EF-24-40
CE32AR	CE32AR 3PH-NC@FRASER ON EDIC - FRASER EF-24-40
CE33	CE33 3PH-NC@FITZ ON EDIC - FITZPATRICK FE-1
CE99	CE99 SLG-STK@SCRIBA345 SCRIBA-VOLNEY 21 FITZ-SCRIBA #10

Table 5-5. List of local design contingences

ID	Local Design Contingency Description
LC01	LC01 3PH AT Q310 345KV TRIP Q310-PLTVALLEY AT 4.5~
LC02	LC02 3PH AT Q310 345KV TRIP Q310-LONGMTN AT 4.5~
LC03	LC03 NO FAULT OF LOSS Q310 GENERATION
LC04	LC04 SLG@Q310 STUCK BKR 52-4 TRIP Q310-PLVALLEY 4.5~ & GT2+ST2 10.0~
LC05	LC05 SLG@Q310 STUCK BKR 52-1 TRIP Q310-LONGMTN 4.5~ & GT1+ST1 10.0~

Table 5-6. List of ISONE design contingences

ID	Type	ISO New England Design Contingency Description
FB345NC01	3 phase	3PH NC FLT at Frost Bridge on 3208 to N.Bloomfield
FB345NC02	3 phase	3PH NC FLT at Frost Bridge on 352 Line to Long Mountain
FB345NC03	3 phase	3PH NC FLT at Frost Bridge on 329 Line to Southington
FB345NC04	1 phase	1-phase fault at Frost Bridge on 3208 to North Bloomfield, 6T breaker failure, bus trips
FB345NC05	1 phase	1-phase fault at Frost Bridge on autotransformer #2, 9T breaker failure, bus trips
FB345NC06	1 phase	1-phase fault at Frost Bridge on 352 2T breaker failure, 329 trips
FB345NC07	1 phase	1-phase fault at Frost Bridge on 1X 5T breaker failure, 3208 trips
LMT01	3 phase	Long Mountain on the 321
LMT02	3 phase	Long Mountain on the 398
LMT03	3 phase	Long Mountain on the 352
LMT04	1 phase	1 PH FAULT Long MT B Bus w-stk 6T
LMT05	1 phase	1 PH FAULT Long MT B Bus w-stk 9T
PLUM01	3 phase	Plumtree on the 321
PLUM02	3 phase	Plumtree on the 3403
PLUM03	3 phase	Plumtree on the 345-kV side of the 1X auto
PLUM21	1 phase	321 w/stk 2T breaker
PLUM22	1 phase	Plumtree on the 345-kV side of the 1X auto w/stk 2T breaker
PLUM24	1 phase	Plumtree 345-kV "A" Bus w/stk 29T breaker
SEABRKG1	none	Trip Seabrook generator
SGTN01	3 phase	Southington on the 3754
SGTN02	3 phase	Southington on the 329
SGTN03	3 phase	Southington on the 3041
SGTN05	1 phase	3041 w/stk 4T breaker
SGTN06	1 phase	345-kV side of the Southington 2X xfmr. w/stk 1T breaker
SGTN10	1 phase	3041 w/stk 3T breaker
SGTN11	1 phase	329 w/stk 4T breaker
SGTN12	1 phase	329 w/stk 5T breaker
SGTN13	1 phase	3754 w/stk 1T breaker
SGTN14	1 phase	3754 w/stk 7T breaker
SGTN15	1 phase	345-kV side of the Southington 1X xfmr. w/stk 7T breaker
SGTN16	1 phase	345-kV side of the Southington 2X xfmr. w/stk 3T breaker
SGTN17	1 phase	345-kV side of the Southington 3X xfmr. w/stk 5T breaker

5.3 Stability Results

The contingencies in Tables 5-2 through 5-6 were simulated for summer peak load and light load conditions, without and with the Project. The contingency was applied at 0.5 seconds, and simulations were terminated at 15.0 seconds and results from the simulations were examined. The Project and the system were stable for all simulations.

Plots of the response of key variables are provided in the Appendices as outlined in Table 5-7.

Table 5-7. Organization of stability results contingencies

	Appendices for Design Contingency Stability Plots			
	Summer Peak		Light Load	
Contingencies	SPOFF Appendix 5-B	SPON Appendix 5-C	LLOFF Appendix 5-C	LLON Appendix 5-D
UPNY-ConEd	5-B1	5-C1	5-D1	5-E1
Total East	5-B2	5-C2	5-D2	5-E2
Central East	5-B3	5-C3	5-D3	5-E3
Local	5-B4	5-C4	5-D4	5-E4
ISONE	5-B5	5-C5	5-D5	5-E5

The plots indicate the status of the Project, the load level, and the contingency description and/or ID. Plots show the response of various generator rotor angles, bus voltages, and other variables of interest in the study area.

With the Project off, the plots are organized as follows:

- Page 1 – rotor angles
- Page 2 – rotor angles
- Page 3 – bus voltages
- Page 4 – bus voltages
- Page 5 – Interface MW flows, and Leeds/Fraser/Marcy reactive power

With the Project on, the plots are organized as follows:

- Page 1 – rotor angles
- Page 2 – rotor angles
- Page 3 – Q310 (i.e., AP Dutchess) active and reactive power
- Page 4 – Q310 field voltage and power system stabilizer (PSS) output
- Page 5 – Q310 generator speed and turbine mechanical torque
- Page 6 – bus voltages
- Page 7 – bus voltages
- Page 8 – interface MW flows, and Leeds/Fraser/Marcy reactive power

Due to the large number of contingencies simulated, the appendices are quite large. To assist in navigating the appendices, each appendix subsection begins with a cover page. Further, to examine results for a particular contingency, the reader may apply the search function available in the Acrobat Reader software by searching on the contingency ID.

5.4 Critical Clearing Time

Critical clearing time (CCT) analysis was conducted for summer peak conditions. Specifically, CCT was evaluated for the AP Dutchess 345 kV bus and the Pleasant Valley 345 kV. The results of the analysis are summarized in Table 5-8.

Table 5-8. Critical clearing time results

Impact on Critical Clearing Time		
Contingency	Pre-Project	Post-Project
3LG @ AP Dutchess 345 kV, trip Q310-Pleasant Valley (CCT-LC01)	Not applicable	17.5 cycles (1)
3LG @ AP Dutchess 345 kV, trip Q310-Long Mountain (CCT-LC02)	Not applicable	16.5 cycles (1)
3LG @ Pleasant Valley 345 kV, trip PV-Millwood #t 1 (CCT-PV01)	21.0 cycles (2)	21.5 cycles (2)

1) Limited by transient stability of AP Dutchess combustion turbines.
2) Limited by transient stability of Roseton generation.

For the AP Dutchess 345 kV bus, a three-phase fault must be cleared within 16.5 cycles to avoid transient instability of the Project's combustion turbines. For the Pleasant Valley 345 kV bus, the CCT is slightly improved from 21.0 to 21.5 cycles when the Project is on-line.

Plots for the CCT simulations are provided in Appendix 5-F. Simulations of both the critical clearing time, and an additional 0.5 cycle increment are included to show both stable and unstable response.

5.5 Impact on Special Protection Systems

The nearest SPS to the AP Dutchess project is designed to run back the Athens generation to avoid overload of one of the Athens/Leeds to Pleasant Valley 345 kV circuits for loss of a parallel circuit. This SPS is not required for stability performance and is expected to operate within two minutes should an overload occur. The Athens SPS was not considered in the modeling of the AP Dutchess project and thus it was not examined to the 15 second system stability simulations conducted for this portion of the analysis.

6. SHORT CIRCUIT ANALYSIS

The short circuit analysis was conducted with the Aspen One-Liner software using a database provided by the NYISO. The database included cases with and without the Project. As mentioned in Section 3.2, the machine MVA base of the Project's units had to be revised, in the case with the Project on. The MVA base for the GT models was changed to 282.6 MVA (from 257.3 MVA) and the MVA base for the ST models was changed to 244 MVA from (164.4 MVA).

This analysis was performed in accordance with the NYISO Guideline for Fault Current Assessment. Three-phase-to-ground, two-phase-to-ground, and one-phase-to-ground faults were applied to buses included in the Study Area as defined in the scope of work. An Aspen one-line of the Project interconnection is provided in Appendix 6-A.

Table 6-1 lists all buses for which the Project increases short circuit levels by at least 0.1 kA. The lowest breaker rating at each of those buses is also shown, as provided by the NYISO.

Table 6-1. Project short circuit impacts of at least 0.1 kA

AP Dutchess System Reliability Impact Study - Short Circuit Results											
Total Fault Current (kA)											
			AP Dutchess Off			AP Dutchess On					
KV	BUS	Lowest Bkr	3LG	2LG	1LG	3LG	2LG	1LG	Max-off	Max-on	Change
345	Q310APDGSUT1		na	na	na	28.528	28.317	26.905	na	28.528	na
345	Q310APDGSUT2		na	na	na	28.528	28.317	26.905	na	28.528	na
345	Q310APDGSUT3		na	na	na	28.528	28.317	26.905	na	28.528	na
345	Q310APDUYARD		na	na	na	28.539	28.326	26.913	na	28.539	na
345	ATHENS	43.8	33.877	32.806	29.973	34.241	33.131	30.194	33.877	34.241	0.364
345	ATHENS 61	N/A	33.818	32.740	29.890	34.180	33.063	30.110	33.818	34.180	0.362
345	ATHENS 62	N/A	33.818	32.740	29.890	34.180	33.063	30.110	33.818	34.180	0.362
345	ATHENS 63	N/A	33.818	32.740	29.890	34.180	33.063	30.110	33.818	34.180	0.362
345	BUCHAN S	40	39.139	38.225	34.830	39.441	38.484	34.982	39.139	39.441	0.302
345	DUNWOODIE	63	51.477	50.799	43.632	51.991	51.245	43.858	51.477	51.991	0.514
345	DVNPT NK	N/A	36.527	36.595	30.575	36.745	36.779	30.658	36.595	36.779	0.185
345	E FISHKILL	50	39.680	37.891	29.483	41.028	39.216	30.614	39.680	41.028	1.348
345	EV 56-1	N/A	31.452	30.052	24.912	31.593	30.172	24.961	31.452	31.593	0.141
345	EV 56-2	N/A	34.822	33.382	27.133	35.086	33.612	27.233	34.822	35.086	0.264
345	EV 61-1	N/A	34.085	32.826	26.899	34.336	33.046	26.997	34.085	34.336	0.252
345	EV61-2	N/A	34.085	32.668	26.421	34.336	32.887	26.515	34.085	34.336	0.252
345	IP-3	N/A	37.766	36.869	33.938	38.042	37.104	34.077	37.766	38.042	0.276
345	LADENTOWN	63	39.399	39.214	35.235	39.569	39.356	35.309	39.399	39.569	0.170
345	LEEDS	38.1	34.539	33.484	30.524	34.915	33.821	30.755	34.539	34.915	0.376
345	MILLWOOD	63	45.288	43.287	33.669	45.869	43.808	33.915	45.288	45.869	0.581
345	NSCOT 77B	52.5	31.630	30.174	24.259	31.743	30.265	24.290	31.630	31.743	0.113
345	NSCOT 99B	56.4	31.623	30.170	24.260	31.736	30.262	24.291	31.623	31.736	0.113
115	PLEASANT VAL	N/A	27.644	26.854	25.036	27.698	26.898	25.177	27.644	27.698	0.054
345	PLEASANT VAL	63	41.220	38.831	26.899	43.900	41.566	29.972	41.220	43.900	2.680
345	PVILLE-1	63	21.948	20.608	15.594	22.096	20.738	15.638	21.948	22.096	0.148
345	PVILLE-2	63	22.153	20.907	16.208	22.303	21.038	16.254	22.153	22.303	0.151
345	RAMAPO	63	43.559	43.458	39.164	43.741	43.610	39.246	43.559	43.741	0.182
345	ROCK TAVERN	38	26.923	25.685	20.817	27.070	25.812	20.872	26.923	27.070	0.147
345	Roseton	63	35.085	34.139	30.873	35.659	34.686	31.285	35.085	35.659	0.574
345	SPBY49SR	63	52.808	52.191	45.003	53.344	52.657	45.244	52.808	53.344	0.535
345	SPRN BRK	63	52.813	52.196	45.007	53.348	52.662	45.247	52.813	53.348	0.535
345	WD-A DUM	N/A	21.341	20.082	15.389	21.572	20.295	15.510	21.341	21.572	0.231
345	WD-B DUM	N/A	24.684	23.416	18.226	24.987	23.702	18.413	24.684	24.987	0.303
345	WOOD ST A	N/A	22.021	21.011	16.923	22.267	21.239	17.061	22.021	22.267	0.246
345	WOOD ST B	N/A	25.309	24.029	18.970	25.628	24.331	19.172	25.309	25.628	0.320
345	LONG MTN 13J	N/A	20.840	19.994	14.945	24.068	23.424	19.089	20.840	24.068	3.228
N/A - Not Available and/or Not Applicable											
Only buses for which impact is at least 0.1 kA are shown											

The results show that all circuit breaker ratings are above the maximum short circuit current. Thus, no circuit breaker upgrades or replacements are required as a result of the Project.

Additional information on the short circuit modeling and detailed results of the analysis are provided in Appendix 6-B.

7. EXTREME CONTINGENCY ANALYSIS

Representative extreme contingencies were evaluated for summer peak conditions to assess the impact of the Project. Per NPCC Basic Criteria, the objective of the extreme contingency analysis is "... to obtain an indication of system strength, or to determine the extent of a widespread system disturbance, even though extreme contingencies do have low probabilities of occurrence". System performance requirements are thus less stringent for extreme contingencies. Widespread cascading outages, infeasible voltage patterns, or system separations are not acceptable grid responses to these events. Any violations revealed by extreme contingency analysis with or without the addition of the AP Dutchess project are reported, but are not required to be resolved by system upgrades.

7.1 Steady State Analysis

Six extreme contingencies were tested, with and without the AP Dutchess project. Contingency descriptions are listed in Table 7-1. All extreme contingency testing used the peak load summer conditions described in Section 3.2.

Table 7-1. List of extreme contingencies

EC#	Description
17	LOSS OF R.O.W. WEST OF ROTTERDAM
18	LOSS OF NEW SCOTLAND SUBSTATION
19	LOSS OF LEEDS SUBSTATION
20	LOSS OF FISHKILL SUBSTATION
21	LOSS OF ROSETON SUBSTATION AND GENERATION
25	LOSS OF MILLWOOD SUBSTATION

All extreme contingencies tested solved. Overloads without and with the Project occurred on the N. Catskill-Airco 115 kV line following contingency EC19, and on the Fraser-Edic 345 kV line following contingency EC17. Voltage violations without and with the Project, occurred at Fraser and Coopers Corners 345 kV stations following contingency EC17, and at Jordanville and Porter 230 kV stations following contingency EC18. A small number of 115 kV and 69 kV bus voltages dropping below 0.95 pu, without or with the Project, also occurred. Complete results are provided in Appendix 7-A.

In almost all instances, the addition of the AP Dutchess project did not have any adverse impact on thermal or voltage performance under extreme contingency steady state conditions. The only exception is following contingency EC20, when the Project impacts some local 115 kV and 69 kV voltages. In all instances, the addition of the Project does not introduce any new steady state violations under extreme contingency conditions.

7.2 Stability Analysis

Extreme contingency stability analysis was conducted on the summer peak loading cases described in Section 3.2. Table 7-2 lists the NYISO extreme contingencies and Table 7-3 lists the ISONE extreme contingencies simulated in this analysis.

Table 7-2. List of NYISO extreme contingencies

ID	Extreme Contingency Description
EC12	EC12 3PH-STK@MARCY345 VOLNEY-MARCY VU-19 STK@MARCY 345
EC13	EC13 LOSS OF EDIC SUBSTATION
EC14	EC14 LOSS OF R.O.W. SOUTH OF UTICA
EC15	EC15 LOSS OF R.O.W. EAST OF UTICA
EC16	EC16 LOSS OF FRASER SUBSTATION
EC17	EC17 LOSS OF R.O.W. WEST OF ROTTERDAM
EC18	EC18 LOSS OF NEW SCOTLAND SUBSTATION
EC19	EC19 LOSS OF LEEDS SUBSTATION
EC20	EC20 LOSS OF FISHKILL SUBSTATION
EC21	EC21 LOSS OF ROSETON SUBSTATION AND GENERATION
EC22	EC22 LOSS OF RAMAPO SUBSTATION
EC23	EC23 LOSS OF BUCHANAN SUBSTATION
EC24	EC24 LOSS OF R.O.W. WEST OF BUCHANAN
EC25	EC25 LOSS OF MILLWOOD SUBSTATION
EC26	EC26 LOSS OF R.O.W. SOUTH OF MILLWOOD
EC31	EC31 3PH-STK @EDIC 345 ON EDIC-FRASER
EC32	EC32 3PH@EDIC(STK) 345KV EDIC-NEW SCOTLAND #14
EC35	EC35 3PH-STK@EDIC345KV FITZ-EDIC #FE-1 BKUP CLR@N.SCOT345
EC36	EC36 3PH-STK@RAMAPO-ROCK TAVERN STK T-77-94-2 CLR Y94

Table 7-3. List of ISONE extreme contingencies

ID	Fault Type	Extreme Contingency Description
FB345EC04	3 phase	3-phase fault (IPT) at Frost Bridge on 3208 to North Bloomfield, 6T breaker failure, bus trips
FB345EC05	3 phase	3-phase fault (ipt) at Frost Bridge on autotransformer #2, 9T breaker failure, bus trips
FB345EC06	3 phase	3-phase fault at Frost Bridge on 352 2T breaker failure, 329 trips
FB345EC07	3 phase	3-phase fault at Frost Bridge on 1X 5T breaker failure, 3208 trips
LMT06	3 phase	Long Mountain 345 kV "B" bus w/stk 6T breaker (IPT)
LMT07	3 phase	Long Mountain 345 kV "B" bus w/stk 9T breaker (IPT)
PLUM05	3 phase	Plumtree 1X autotransformer w/stk 2T breaker (IPT)
PLUM20	3 phase	321 w/stk 2T breaker (IPT)
PLUM23	3 phase	Plumtree 'A' Bus w/stk 29T breaker (IPT)

The system was stable for all contingencies, without and with the AP Dutchess project. Plots for the NYISO extreme contingencies are provided in Appendix 7-B, while those for the ISONE extreme contingencies are in Appendix 7-C.

8. INTERFACE TRANSFER LIMIT ANALYSIS

Interface transfer limit analysis was performed to evaluate the impact of the AP Dutchess project on the normal and emergency transfer limits of the following interfaces:

- Central East (CE) / Total East (TE)
- UPNY-SENY (US) – open & closed
- UPNY-ConEd (UC) – open & closed
- Dunwoodie South – DS (open & closed)
- NYISO-ISONE (NYNE)
- ISONE-NYISO (NENY)

As specified in the study scope of work, transfer limit analysis was also conducted for the following interfaces in the New England transmission system:

- Southwest Connecticut (SWCT)
- Connecticut Import (CT_Imp)
- Connecticut East-West (CT_E-W)

Interface definitions were provided by the NYISO and ISONE. Those definitions were updated as necessary, for consistency with the underlying power flow models. As specified in the scope of work, transfer limit analysis was performed for summer peak load conditions.

8.1 Thermal Analysis

Thermal transfer limit analysis is based on DC (linear) power flow, which assumes that voltages, reactive flows, or losses do not change with increased transfer levels. Power transfers were simulated between sending and receiving subsystems, appropriately selected for each interface. Power apportionment within each sending/receiving system was in accordance to standard proportions, as used in NYISO planning and operating studies. ISONE provided guidance on subsystem definition for the analysis of the NE interfaces.

Normal and emergency transfer limits were calculated for each interface. A normal interface transfer limit is the transfer level where a) a branch flow reaches its normal rating, under pre-contingency conditions, or b) a branch flow reaches its long term emergency (LTE) rating following any design contingency. An emergency interface transfer limit is the transfer level where a) a branch flow reaches its normal rating, under pre-contingency conditions, or b) a branch flow reaches its short term emergency (STE) rating following a single line, multi-element, or generator outage. The Dunwoodie South normal limits are based on cable STE ratings when post-contingency flows are limiting.

Normal and emergency thermal transfer limits are presented in Table 8-1. Detailed output results for the thermal transfer analysis are included in Appendix 8-A.

A review of the results in Table 8-1 indicates that the Project has a negligible impact on Dunwoodie South, a small positive impact on UPNY-SENY and UPNY-ConEd and a small negative impact on Central East and Total East. The Project also has a positive impact on the thermal limits of the interfaces in New England.

The addition of the AP Dutchess project has a negative impact on the NY-NE and NE-NY thermal transfer limits. With regard to the NE-NY transfers, due to its position on one of the major tie lines, the new project effectively replaces incremental power transfers from New England into New York. With regard to the NY-NE transfers, it should be noted that the current

LTE rating on the Pleasant Valley-AP Dutchess-CT/NY segment is lower than the LTE rating on the CT/NY-Long Mountain portion of the same line.

The Project's impact on the NE-NY and NY-NE interfaces may be further assessed, if and as deemed necessary, during the "Other Interfaces No Harms" test of the Deliverability Study, conducted by the NYISO as part of their Class Year assessment (i.e., Facilities Study).

Table 8-1. Thermal normal and emergency transfer limits (MW)

	Normal limits			Emergency limits		
	SPOFF	SPON	Difference	SPOFF	SPON	Difference
CE	3237 (a)	3136 (b)	-101	3564 (c)	3458 (c)	-106
TE	7104 (a)	6978 (b)	-126	7762 (c)	7625 (c)	-137
US (op)	5505 (d)	5576 (d)	71	6169 (e)	6240 (e)	71
US (cl)	6435 (d)	6507 (d)	72	7099 (e)	7171 (e)	72
UC (op)	5863(f)	5882 (g)	19	6391 (h)	7810 (i)	1419
UC (cl)	8254 (f)	8274 (g)	20	8783 (h)	10202 (i)	1419
DS (op)	4742 (j)	4745 (j)	3	4742 (j)	4745 (j)	3
DS (cl)	7067 (j)	7070 (j)	3	7067 (j)	7070 (j)	3
NE-NY	2112 (k)	499 (k)	-1613	2120 (l)	958 (m)	-1162
NY-NE	815 (n)	586 (o)	-229	1587 (p)	1363 (q)	-224
SWCT	3676 (r)	3772 (r)	96	4238 (s)	4365 (s)	127
CT_Imp	5015 (t)	5065 (t)	50	5113 (u)	5164 (u)	51
CT_E-W	4248 (v)	4298 (v)	50	5035 (w)	5112 (w)	77

(a) Marcy-New Scotland 345 (LTE: 1650 MW) for SB:Edic_345_R140 (L/O N. Scotland-Edic 345, Edic-Porter 345/230, & Edic-Porter 345/115)
(b) New Scotland77-Leeds 345 (LTE: 1538 MW) for L/O New Scotland99-Leeds 345
(c) New Scotland77-Leeds 345 (STE: 1724 MW) for L/O New Scotland99-Leeds 345
(d) Leeds-Pleasant Valley 345 (LTE: 1535 MW) for L/O Pleasant Valley-Athens 345
(e) Leeds-Pleasant Valley 345 (STE: 1725 MW) for L/O Pleasant Valley-Athens 345
(f) Ramapo-Rock Tavern 345 (LTE: 1990 MW) for SB:E_FI_345_5 (L/O E. Fishkill-Roseton 345, & E. Fishkill 345/115)
(g) Ramapo-Rock Tavern 345 (LTE: 1990 MW) for TWR:F38&F39 (L/O E. Fishkill-Wood-Pleasantville E. 345, E. Fishkill-Wood-Pleasantville W. 345, Wood 345/115)
(h) Roseton-Fishkill 345 (normal: 1935 MW)
(i) Ramapo-Rock Tavern 345 (normal: 1811 MW)
(j) Dunwoodie-Reactor71 (normal: 783 MW)
(k) Norwalk Harbor 138/115 (LTE: 450 MW) for SB:PV_345_RNS3 (L/O Pleasant Valley-E. Fishkill 345, & Pleasant Valley-AP Dutchess 345)
(l) Norwalk Harbor 138/115 (LTE: 450 MW) for L/O Long Mountain-CT/NY 345
(m) AP Dutchess – Pleasant Valley 345 (normal: 1135 MW)
(n) Pleasant Valley-CT/NY 345 (LTE: 1317 MW) for SBK:MILLST 3:14T (L/O Beseck-Haddam auto-Millstone 345, & Millstone #3)
(o) AP Dutchess-CT/NY 345 (LTE: 1317 MW) for SBK:MILLST 3:14T (L/O Beseck-Haddam auto-Millstone 345, & Millstone #3)
(p) Pleasant Valley-CT/NY 345 (normal: 1135 MW)
(q) AP Dutchess-CT/NY 345 (normal: 1135 MW)
(r) East Devon-DevSinger 345 (STE: 1128 MW) for DEVONSTK1 (L/O E.Devon-Devon 345, & Devon-Singer 345)
(s) East Devon-DevSinger 345 (STE: 1128 MW) for L/O E. Devon-Singer #2 345
(t) Northfield-Ludlow 345 (LTE: 1649 MW) for 312LINE (L/O Berkshire-Northfield 345)
(u) Northfield-Ludlow 345 (STE: 1673 MW) for 312LINE (L/O Berkshire-Northfield 345)
(v) Millstone-Montville 345 (LTE: 1793 MW) for 310-348WDC2 (L/O Card-Millstone 345, Haddam 345/115, & Millstone-Haddam auto-Beseck 345)
(w) Millstone-Montville 345 (normal: 1488 MW)

8.2 Voltage Analysis

Voltage transfer limit analysis was performed for the intra-NYCA interfaces for summer peak load conditions. A series of power flow cases were created modeling increasing transfers, using generation shifts similar to those used in the thermal analysis (i.e., from Ontario/upstate New York region to NYC/LI area).

Selected contingencies, listed in Table 8-2, were applied at each transfer level to determine voltage stability. As the transfer across an interface is increased, the voltage-constrained limit is determined to be the lesser of a) the pre-contingency interface flow where the post-contingency voltage falls below the OP-1 post-contingency limit, or b) 95% of the pre-contingency interface flow at the "nose" of the post-contingency PV curve. Since the ‘nose’ of the curve cannot be pinpointed exactly, the 95% rule is applied to the last transfer level where the case seems to reach a stable solution.

Table 8-2: List of contingencies for voltage transfer limit analysis

Description	code	Description	code	Description	code
L/O DBL Marcy-NS	ce02d	L/O Roseton-Fishkill	te38	L/O Y88/Y94	uc18
L/O Marcy-South N.	ce07	L/O Leeds-PV #2	te43	L/O TWR W89/W90	uc20
L/O Marcy-South S.	ce08	L/O Indian Pt #2	log03	L/O TWR 30/31	uc21
L/O CC-RockTav	ce27	L/O Millstone #3	log04	L/O SBK RockTav	uc27
L/O DBL Marcy-CC	ce29d	L/O Ravenswood #3	log09	L/O TWR 34/42 S.	uc30
L/O NS Bus-ALPS	te32	L/O Y86/Y87	uc02	L/O TWR 34/42 N.	uc31
L/O NS Bus-GILB	te33	L/O SBK Buchanan	uc04	L/O TWR W97/W98	uc33

Voltage transfer limits are shown in Table 8-3. The table only shows one set of limits; since limits in all instances were defined by the 95% of voltage collapse criterion, normal and emergency limits were the same. Additional details in the form of P-V curves for selected contingencies and buses are included in Appendix 8-B.

Table 8-3: Voltage transfer limits (MW)

Interface	SPOFF	SPON	Difference
Central East	2789 (a)	2698 (a)	-91
Total East	6209 (a)	6081 (a)	-128
UPNY - SENY (op)	5621 (a)	5489 (a)	-132
UPNY - SENY (cl)	6506 (a)	6374 (a)	-132
UPNY - ConEd (op)	4374 (a)	4430 (a)	56
UPNY - ConEd (cl)	6646 (a)	6702 (a)	56
Dunwoodie South (op)	4212 (a)	4258 (a)	46
Dunwoodie South (cl)	6422 (a)	6468 (a)	46

(a) 95% of voltage collapse following L/O Rav#3 (log09)

A review of the results in Table 8-3 indicates that the Project has a small positive impact on UPNY-ConEd and Dunwoodie South and a small negative impact on Central East, Total East and UPNY-SENY. Given that the voltage transfer limits in Table 8-3 are controlling over the thermal limits in Table 8-2, additional analysis was undertaken in order to better understand the impact of the Project on NYCA interfaces. A new series of cases was developed in which the

Project was dispatched against Roseton and Bowline; imports into NYC were restored as in the pre-Project case. Voltage analysis was repeated and the impact of the AP Dutchess project on voltage transfer limits is less than 50 MW in all instances. It can therefore be concluded that the impact shown in Table 8-3 is dependent on the specific dispatch assumptions used in the study.

8.3 Stability Analysis

NYISO Transmission Planning Guideline #3-0 requires that stability analysis be conducted to insure that the system is stable at 111% (or more) of the controlling transfer limits (thermal or voltage).

Cases were developed without and with the Project to meet this requirement. As is standard practice for evaluating the intra-state interfaces required for this SRIS, generation was increased in upstate New York and decreased in the New York City area to achieve the required transfer levels. Because of low base case voltages at some buses in the pre-contingency system for these very high transfer levels, additional capacitors were added at the Millwood 345 kV bus. (This is a practice also sometimes used in NYISO system evaluations).

Summer peak cases were developed with 111% or higher transfer levels than those found in the thermal and voltage analysis, as shown in Table 8-4. In these cases, the NE-NY interface flow was 257 MW with the Project off and 257 MW with the Project on. Further Project analysis may be undertaken in future studies, if and as deemed necessary.

Table 8-4. Transfer limit stability cases

	Steady-state controlling (voltage) limit		Stability case steady-state transfer and % of controlling (voltage) limit	
Interface	Project Off	Project On	Project Off Stability Case	Project On Stability Case
Central East	2789	2698	3219 115.4%	3137 116.3%
Total East	6209	6081	6975 112.3%	6869 113.0%
UPNY–SENY (op)	5621	5489	6255 111.3%	6160 112.2%
UPNY–SENY (cl)	6506	6374	7183 110.4%	7083 111.1%
UPNY–ConEd (op)	4374	4430	4914 112.3%	5021 113.3%
UPNY–ConEd (cl)	6646	6702	7304 110.0%	7406 110.5%
Dunwoodie-S (op)	4212	4258	4790 113.7%	4894 114.9%
Dunwoodie_S (cl)	6422	6468	7114 110.8%	7214 111.5%

Contingencies tested for the transfer limit analysis were selected from those simulated in Section 5, based on their severity and location. (The DSATools software computes a stability index to assist in comparing the impact of contingencies on system stability). The contingencies tested are listed in Table 8-5.

Table 8-5. Stability contingencies for transfer analysis

ID	Interface	Design Contingency Description
UC05	UPNY-ConEd	UC05 3PH-STK @ BUCHANAN SOUTH W97*MILLWOOD STK BKR 6
CE01	Central East	CE01 3PH AT EDIC 345KV EDIC-NEW SCOTLAND #14 NORMALLY CLEARED
CE33	Central East	CE33 3PH-NC@FITZ ON EDIC - FITZPATRICK FE-1
CE99	Central East	CE99 SLG-STK@SCRIBA345 SCRIBA-VOLNEY 21 FITZ-SCRIBA #10
UC19	UPNY-ConEd	UC19 3PH@MILLWOOD-LO TOWER (2-1961) MILLWOOD-SPRAINBROOK
LC01	Local (Q310)	LC01 3PH AT Q310 345KV TRIP Q310-PLTVALLEY
UC21W	UPNY-ConEd	UC21W 3PH@PL.VALLEY-LO TOWER(2-1961)PV-MILLWOOD DBL CKT
TE43	Total East	TE43 3PH@LEEDS LEEDS-PLEASANT VALLEY#92 W-HS RCL
UC20	UPNY-ConEd	UC20 3PH@DUNWOODIE-LO TOWER(2-1938)PLEASANTVILLE*DUNWD
UC03	UPNY-ConEd	UC03 3PH@SPRAIN BK-LO TOWER(2-1956)MILLWOOD-SPRAIN BROOK
UC18	UPNY-ConEd	UC18 3PH@LADENTOWN-LO TOWER Y88&Y94 BUCHANAN RIVER CROSSING
UC25	UPNY-ConEd	UC25 3PH @ RAVENSWOOD#3 - TRIP GEN.@ 4.5~
UC04	UPNY-ConEd	UC04 SLG-STK @ BUCHANAN NORTH IP#2 STK BKR 9
LC02	Local (Q310)	LC02 3PH AT Q310 345KV TRIP Q310-LONGMTN
CE07AR	Central East	CE07AR LLG @MARCY-EDIC ON MARCY-COOPER & EDIC-FRASER DBL CKT
CE08AR	Central East	CE08AR LLG @COOPERS ON MARCY-COOPER FRASER-COOPERS
UC30AR	UPNY-ConEd	UC30AR LLG@ROCK TAVN-COOPERS CORNERS-ROCK TAVERN DBL CKT

The Project and the system were stable for all contingencies. Therefore, stability response did not limit transfers. Plots for the stability simulations are provided in Appendix 8-C.

8.4 Summary of Transfer Limits

A summary of the impact of the AP Dutchess project on interface transfer limits, for summer peak conditions, based on the analyses reported in this section, is provided in Table 8-6.

Table 8-6. Summary of AP Dutchess impact on interface transfer limits (MW)

	Normal limits			Emergency limits		
	SPOFF	SPON	Difference	SPOFF	SPON	Difference
CE	2789 (V)	2698 (V)	-91	2789 (V)	2698 (V)	-91
TE	6209 (V)	6081 (V)	-128	6209 (V)	6081 (V)	-128
US (op)	5505 (T)	5489 (V)	-16	5621 (V)	5489 (V)	-132
US (cl)	6435 (T)	6374 (V)	-61	6506 (V)	6374 (V)	-132
UC (op)	4374 (V)	4430 (V)	56	4374 (V)	4430 (V)	56
UC (cl)	6646 (V)	6702 (V)	56	6646 (V)	6702 (V)	56
DS (op)	4212 (V)	4258 (V)	46	4212 (V)	4258 (V)	46
DS (cl)	6422 (V)	6468 (V)	46	6422 (V)	6468 (V)	46
NE-NY*	2112 (T)	499 (T)	-1613	2120 (T)	958 (T)	-1162
NY-NE*	815 (T)	586 (T)	-229	1587 (T)	1363 (T)	-224
SWCT*	3676 (T)	3772 (T)	96	4238 (T)	4365 (T)	127
CT_Imp*	5015 (T)	5065 (T)	50	5458 (T)	5754 (T)	296
CT_E-W*	4248 (T)	4298 (T)	50	5035 (T)	5112 (T)	77

* thermal analysis only (V) voltage limit (T) thermal limit

In summary, the Project exhibited a relatively small impact on the transfer limits of NYCA interfaces. The Project reduces the transfer limits of the NY-NE and NE-NY interfaces. In the case of the NE-NY interface, the Project seems to effectively replace other imports from New England generating resources. On the New England system, AP Dutchess has a positive effect on the thermal transfer limits of ISONE interfaces.

Note that the purpose of this SRIS analysis was to assess the incremental impact of the project on the voltage transfer limits of the interfaces concerned, rather than to calculate precise transfer limiting levels. In this analysis, no efforts were made to optimize transfer levels in order to maximize thermal or voltage transfer limits. As with all SRIS analysis, these results are based on the studied system conditions and assumptions. The results in the tables presented in Section 8 reflect the particular assumptions used in this study.

9. NPCC A-10 CRITERIA TESTING

The NPCC A-10 criteria for the "Classification of Bulk Power System Elements" outline the methodology to identify the Bulk Power System (BPS) elements, or parts thereof, of the interconnected NPCC Region. The methodology consists of a transient stability test and a steady state test; a transmission element is classified as part of the bulk power system if either of the two tests classifies the element as BPS. In accordance with the work scope, testing was undertaken to identify any existing or new stations that should be classified as bulk power system elements, based on the NPCC criteria and the NYISO test procedure.

Testing was conducted for the new AP Dutchess 345 kV bus and the existing Pleasant Valley 115 kV bus.

9.1 Transient Stability Test

For transient stability testing, the NPCC A-10 criteria requires that the fault is uncleared at the bus of interest, and instead is cleared at remote substations with delayed clearing time. Clearing time should be based on existing relaying information, or if not available, a clearing time of 30 cycles should be used. To test the new AP Dutchess 345 kV bus and the existing Pleasant Valley 115 kV bus, two contingencies were simulated for summer peak load conditions, both pre-Project and post-Project.

- A three-phase fault at the AP Dutchess 345 kV bus, clearing the fault at 11.0 cycles, and tripping (1) all AP Dutchess generation is on-line, (2) the AP Dutchess – Pleasant Valley 345 kV line, and (3) the AP Dutchess – Long Mountain 345 kV line. (The 11.0 cycle clearing time at Pleasant Valley 345 kV was based on information provided by Con Edison).
- A three-phase fault at the Pleasant Valley 115 kV bus, clearing the fault at 30.0 cycles, and tripping all connections to the bus.

Stability simulations showed that the system is stable for both contingencies. Neither bus needs to be classified as BPS based on the NPCC A-10 transient stability test. Stability plots are included in Appendix 9-A.

9.2 Steady State Test

In the steady state test, each bus is "removed" and post contingency results are analyzed for significant adverse impacts outside the local area. Loss of the AP Dutchess 345 kV bus does not result in any overloads or voltage violations. Loss of the Pleasant Valley 115 kV bus results in some overloads and voltage violations, limited to the local area. System conditions following the loss of the Pleasant Valley 115 kV bus are very similar with the corresponding post-contingency results for the pre-Project case. Neither bus need be classified as BPS based on the steady state test. Steady state post contingency results are included in Appendix 9-B.

Based on the analysis conducted for this study, neither the Pleasant Valley 115 kV bus nor the AP Dutchess 345 kV bus needs to be classified as BPS.

10. INTERCONNECTION PRELIMINARY COST AND SCHEDULE ESTIMATE

The following information was provided by the Developer.

A good faith, non binding cost estimate for the new 345 kV substation is approximately $22,000,000, for a 6-breaker ring configuration. This cost estimate includes the cost of development of the 345 kV GIS Substation and the transmission line/tower loop through into the existing ConEdison lines (including engineering/procurement/construction/commissioning). The estimate does not include any cost for fixing the ConEdison line splices on existing feeders (as stated in the ConEdison studies, discussed in Section 11).

The estimated construction time is 22-26 months.

11. STUDIES BY CON EDISON

Con Edison, the interconnecting transmission owner, conducted two studies related to the proposed AP Dutchess project.

- Physical Feasibility Report: This report addresses items such as space required for the substation at the POI, permits, and environmental impacts. The complete ConEdison report is contained in Appendix 11-A.
- Bus Flow Analysis: This report analyzes whether there is a need to upgrade existing substation equipment at the Pleasant Valley 345 kV substation, as well as requirements for the proposed AP Dutchess 345 kV substation. The complete ConEdison report is contained in Appendix 11-B.

12. CONCLUSIONS

Based on the analysis summarized in this report, the following conclusions have been reached for each of the requirements in the scope of work.

Power flow analysis

- Analysis results show that the Project does not introduce any new thermal overloads under normal or contingency conditions. The impact of the Project on pre-existing overloads is small. Contingency analysis under summer conditions with the Project online indicates that the Ramapo 500 kV voltage drops below 1.0 p.u; allowing voltage controlling devices to regulate mitigates this issue. The Project does not introduce any other new voltage violations under normal or contingency conditions and its impact on system voltages is in most instances small.
- The inclusion of the AP Dutchess project does not impair the ability to maintain the ABC/JK wheel under summer or winter conditions.
- Sensitivity analysis indicates that operation of the Project does not restrict the operating flexibility of the CHG&E 115/69 kV system. Further, AP Dutchess does not restrict the ability of the system to accommodate the concurrent operation of the Athens and Besicorp projects at full output.

Stability analysis

- Stability testing was conducted for summer peak and light load conditions, with and without the AP Dutchess project (four scenarios). A total of 135 contingencies were tested for each scenario. The Project and system were stable for all contingencies and scenarios.
- The critical clearing time for a three-phase fault at the AP Dutchess new 345 kV bus was 16.5 cycles. The Project had a minor positive impact (0.5 cycles) on the CCT at the Pleasant Valley 345 kV bus.

Extreme contingency analysis

- The Project had no detrimental impact on thermal or voltage performance under extreme contingency conditions. All New York and New England extreme contingencies simulated in stability analysis were stable both pre-Project and post-Project.

Transfer limit analysis

- The Project exhibited a relatively small impact on the transfer limits of NYCA interfaces. Upon further examination, it was determined that the impact was primarily due to the dispatch pattern used in the study. The Project reduces the transfer limits of the NY-NE and NE-NY interfaces. In the case of NE-NY, the Project effectively replaces other imports from New England generating resources. AP Dutchess has a positive effect on the thermal transfer limits of New England interfaces.

NPCC A-10 criteria testing

- Testing was undertaken to identify any existing or new stations that could be classified as bulk power system elements, based on NPCC criteria. Testing was conducted for the new AP Dutchess 345 kV bus and the existing Pleasant Valley 115 kV bus. Neither bus needs to be classified as bulk power.

Short circuit analysis

- The Project increased short circuit currents at 32 buses in the study area by more than 0.1 kA. However, the increase in fault current at these buses as a result of the Project remained small, and currents were below the interrupting ratings of the existing circuit breakers. No replacement of circuit breakers is required.

System Upgrade Facilities

- The Project will connect to the network via a six breaker ring bus arrangement. A non-binding good faith cost estimate to complete the required facilities is $22 Million. This estimate includes the cost to construct the Attachment Facilities as well as the cost for System Upgrade Facilities associated with the new Attachment Facilities. The estimated time to construct the required facilities is 22 to 26 months. The above estimates do not account for the development of any facilities under the Developer's responsibility.

Further Project analysis may be undertaken in future studies, if and as deemed necessary.

Based on the analysis performed for this SRIS, the AP Dutchess project does not degrade system reliability or adversely impact the operation of the power system.

Class Year Study

Initial Round

Class Year 2011 Facilities Studies System Upgrade Facilities (SUF)

A report from the New York Independent System Operator

Rev. 3

July 9, 2013
(for July 16 TPAS / CY11 IPFS WG and July 18 OC)

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Appendices:

Executive Summary

This Class Year 2011 (**CY11, or Class 2011**) Interconnection Facilities Study[1](Facilities Study or Class Year Study) was performed in accordance with the applicable rules and requirements set forth under Attachments S, X and Z of the NYISO Open Access Transmission Tariff (OATT). Draft results will be presented to the Interconnection Projects Facilities Study Working Group (IPFS WG[2]), the Transmission Planning Advisory Subcommittee (TPAS) and the Operating Committee (OC) through meetings and group status reports.

In the NYISO Interconnection Process, the Facilities Study is the last and most comprehensive study in the interconnection study process. Attachment X of the OATT calls for three successive Interconnection Studies of each proposed project. These studies analyze proposed projects in varying levels of detail. First is the Interconnection Feasibility Study, which is a high level evaluation of the configuration and local system impacts. The second study is the Interconnection System Reliability Impact Study, an intermediate level study that evaluates the project's impact on transfer capability and system reliability. The final study in the interconnection process is the Facilities Study – a detailed study that evaluates the cumulative impact of a group of projects that have completed similar milestones – a "Class Year" of projects.[3] The Facilities Study identifies the upgrade facilities needed to reliably interconnect all the projects in a Class Year. For the group of Class Year projects requesting Capacity Resource Interconnection Service ("CRIS"), the Facilities Study includes a Deliverability test to determine the extent to which each project is deliverable at the requested CRIS MW level ("Class Year Deliverability Study"). The Facilities Study then allocates the cost of System Upgrade Facilities and System Deliverability Upgrades identified in the study among the projects in the Class Year in accordance with the cost allocation methodologies set forth in Attachment S of the OATT.

The purposes of the Facilities Study are:

● To identify the interconnection facilities (*i.e.,* the System Upgrade Facilities (**SUFs)** the Connecting Transmission Owner Attachment Facilities (**CTOAFs),** and certain Developer Attachment Facilities (DAFs), that would be required for the reliable interconnection of a group of projects referred to as a

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[1] Capitalized terms not otherwise defined in this report have the meaning set forth in Attachments S and X of the OATT.

[2] To enhance the participation of Market Participants in the study process, at the beginning of each Class Year the NYISO assembles a working group of all interested parties, including Transmission Owners, Project Developers and their Subject Matter Experts, NYISO staff, etc. The working group is called the Interconnection Projects Facilities Study (CYxx IPFS) working group (WG).

[3] All Large Facilities (studied in the NYISO interconnection process under Attachment X) are subject to the Class Year Study procedures. Certain Small Generating Facilities are also required to participate in the Class Year Study and all Small Generating Facilities may elect to participate in a Class Year Study. As described in Section 32.3.5.3 of Attachment Z, if any Interconnection Study determines that a Small Generating Facility requires a non-Local System Upgrade Facility to interconnect, then that Small Generating Facility is placed in the next Class Year Study, and cost responsibility is allocated to the Small Generating Facility in accordance with the procedures and methodologies in Attachment S.

Class Year[4] (*e.g.,* Class Year 2011, or CY11, in this report), under the Minimum Interconnection Standard (**MIS**). The MIS is designed to ensure reliable access by the proposed project to the New York State Transmission System (NYSTS), and does not subject the proposed project to any deliverability test or deliverability requirement. The Class Year projects must meet the MIS in order to interconnect to the NYSTS and to become qualified to provide Energy Resource Interconnection Service (ERIS).

● To identify any System Deliverability Upgrades (**SDUs**) that may be required for the Class Year projects under the NYISO Deliverability Interconnection Standard (**DIS**). The DIS is applied only to those projects electing Capacity Resource Interconnection Service (CRIS), while MIS is applied to all Class Year projects. The DIS is designed to ensure that the proposed project is deliverable throughout the New York Capacity Region where the project will interconnect, and also that the Developer of the project restores the transfer capability of any Other Interfaces degraded by its interconnection.

Due to the complexity and extent of the assessments, the Class Year Facilities Study was divided by the NYISO into two parts, based on two significantly different aspects of the Class Year Study:

Part 1 Studies are individually performed for each project, to address the CTOAFs required for each project, and also the Local SUFs (i.e., the SUFs at each Point of Interconnection, and also the related metering, protection and telecommunication facilities). The Connecting Transmission Owner (CTO) standards, design requirements and practices are applied for the Part 1 Studies; therefore NYISO offers each CTO the choice to lead this part (the CTO has the option to hire a Consultant for all or part of these studies), as a first and recommended choice. If the CTO declines, then the NYISO will hire a consultant and facilitate this part as well, with main support and detailed involvement of the respective CTO.

> At the end of the process, **each project** will have a **"Part 1 Study" report** and supporting appendices, identifying Local SUFs (*i.e*., POI connection design/engineering, and protection/communication at POI and remote ends), CTOAFs, and certain DAFs.

Part 2 Studies identify the remainder of the SUFs (under the MIS), and also the SDUs (under the DIS), required for the Class Year of projects in aggregate, by performing steady state, transient stability, short circuit and resource adequacy type of assessments.

> For the "Part 2 Studies", there will be two separate reports, one for SUFs (**"the SUF Report"**), and one for the Deliverability Study and SDUs (**"the Deliverability Report"**). Also, the SUF Report will summarize the Local SUFs identified via the Part 1 Studies, for a complete SUFs Project Cost Allocation. These two reports and the supporting appendices will go through the TPAS and Operating Committee (OC) review and approval process.

[4] A proposed project became part of Class Year 2011 if on or before March 1, 2011 (i) the Operating Committee has approved the Interconnection System Reliability Impact Study (SRIS) for the project, and (ii) a regulatory milestone has been satisfied in accordance with Attachment S of the OATT.

The Part 2 of the Facilities Study consists of various assessments (*e.g.,* thermal, voltage, stability, short circuit, resource adequacy, special studies, *etc.*) performed on two system representation models, as described in Attachment S of the NYISO OATT: the Annual Transmission Baseline Assessment (**ATBA**) system (the baseline system) and the Annual Transmission Reliability Assessment (**ATRA**) system. The "ATRA system" is the baseline system plus the Class Year projects addition and the respective redispatch. Together and under MIS, these studies result in the identification and cost allocation of the "but for" SUFs required for the subject Class Year projects to reliably interconnect to the system, and also in the determination of any Electrical or Functional Headroom reimbursements from the current CY to the prior CY projects. Under DIS, ATBA-Deliverability (ATBA-D) and ATRA-Deliverability (ATRA-D) studies are performed, to identify whether or not a project that requested CRIS evaluation is deliverable, and if not, what SDUs are necessary to make it deliverable.

The results and conclusions of the CY11 Facilities Study, as related with the MIS and SUFs, are summarized in this report (*i.e.,* "the SUF Report").

Class Year 2011 started with seven generation projects, which would add approximately 2125 MW (nameplate or summer peak net output, as applicable) to the New York grid, and also one 15 MW uprate on an existing merchant transmission project (i.e., Q351 Linden VFT Uprate). After the membership for Class Year 2011 was determined, Q169 Alabama Ledge was withdrawn from the queue by the Developer. Also, Q351 Linden VFT Uprate was removed from the Interconnection process pursuant to an order by the Federal Energy Regulatory Commission (FERC) in Docket No. EL12-64-000.

Table E-1 shows the list of CY11 projects, their interconnection points, etc. Also, **Figure E-1** shows the CY11 projects on the New York State County/TO Districts map.

There are four Connecting Transmission Owners (CTO) involved in this CY11:

- Consolidated Edison Company of New York, Inc. (Con Edison) is a CTO for three combined cycle natural gas (CCNG[5]) generation projects: 200 MW Berrians GT (Q201), its 50 MW uprate, Berrians II (Q224), the 1020 MW Cricket Valley Energy Center (Q310).
- Niagara Mohawk Power Corporation d/b/a National Grid (National Grid) is a CTO for one wind generation project: the 79.8 MW Arkwright Summit (Q198);
- New York Power Authority (NYPA) is a CTO for one CCNG project: the 678 MW[5] CPV Valley (Q251); and
- Central Hudson Gas & Electric (CHGE) is a CTO for one solid waste project: the 19 MW[5] Taylor Biomass (Q349).

[5] For temperature sensitive output projects, the MW value represents the Maximum Summer Peak Net Output which can be achieved between 85 and 95 F.

Summary of Study Results:

SUF Cost Allocation: As reflected in this report, and summarized in **Table 12.1.R1**, the CY11 Project Developers will be responsible for SUF cost[6] of **$308,460,001** to interconnect their projects into the New York grid.

Time to construct: The detailed schedules are reflected in the Part 1 Studies for each project, and also summarized in this report, under **Section 11. SUFs and Cost Allocation.** The schedules will be further refined during the Interconnection Agreement (IA) phase.

Headroom reimbursement:

The following projects impact the "electrical Headroom holder buses":

- Q201 Berrians GT impacts Queensbridge 138 kV; the Developer will reimburse CY01 **$36,720;**
- Q251 CPV Valley impacts Sprainbrook 345 kV; the Developer will reimburse CY01 **$203,632**; and
- Q310 Cricket Valley impacts Sprainbrook 345 kV, Rainey 345 kV and Sherman Creek 138 kV; the Developer will reimburse CY01 **$842,010**.

There is no functional Headroom identified as needed/used by any CY11 project.

Thermal, Voltage, Stability Base Case (Local) and Transfer Analysis for NY Internal Interfaces: Any limits violations and reductions in transfer limits for NY internal interfaces identified by this study were observed under specific system conditions, study assumptions, and dispatch patterns modeled in the respective study cases, and can be managed through the normal operating procedures of the NYISO and/or TOs; therefore, they are not considered a degradation of the system reliability or non-compliance with NERC, NPCC or NYSRC reliability standards. Consequently, under the NYISO MIS requirements, no SUFs are required to address them.

Thermal Transfer Analysis for NY to NE / NE to NY External Interface: The analysis showed reductions in the transfer limits of the NY-NE external interface in both directions, as a result of the Q310 Cricket Valley project. In this case, NYISO concluded that, because the Cricket Valley project is interconnecting directly to an inter-ISO tie, the resultant degradation of transfer limits could not be managed through the normal operating procedures of the NYISO and/or CTO. Therefore, the Cricket Valley project was determined to have adverse reliability impacts under the MIS and system upgrades will

[6] Any difference between a Project Cost Allocation and the actual cost of the Developer's share of required System Upgrade Facilities will be addressed in accordance with applicable provisions of Attachment S and Attachment X of the OATT, including Section 25.8.6 of Attachment S.

be required to mitigate such impacts, in the form of a second Pleasant Valley to Cricket Valley 345 kV line (PV to CV line), and reconductoring of the Cricket Valley to New England border to Long Mountain 345 kV segment of Line 398 (CV to NE to LM, or CV to LM).

Short Circuit Assessment: Among the CY11 monitoring buses, the lowest breaker interrupting rating was exceeded by the total bus fault at Astoria West 138 kV, in both ATBA and ATRA. The Individual Breaker Analysis (IBA) determined that the two breakers are not overdutied under the ATBA system assumptions; however become overdutied under ATRA due to NRG's Berrians GT project. The cost to replace the two breakers owned by US PowerGen is estimated at **$3,450,000**. The two breakers do not fall within the definition of New York State Transmission System. Therefore, their replacement is not categorized as SUFs for the purpose of this study. These breakers must nonetheless be replaced in order to accommodate the interconnection of the Q201 Berrians GT project.

ATBA Resource Reliability: There would be no capacity shortages for the ATBA system. Also, the ATBA future system was found to be well within (below) the LOLE criteria of 0.1 days/year for all years studied.

Electromagnetic transients (EMT) study: There is no additional SUF identified via this study. The results are detailed in the report titled "Q310 Cricket Valley Energy Center Electromagnetic Transients Analysis", performed by Mitsubishi Electric Power Products, Inc. (MEPPI) for the NYISO.

ISO-NE studies: ISO-NE's thermal transfer studies performed on NY to NE interfaces (both directions) concluded that the Q310 Cricket Valley project, as proposed to interconnect on the Pleasant Valley to Long Mountain 345 kV tie (i.e., Line #398), has an adverse impact on both NE-NY import and exports capabilities, and also on the operability of the system. The second Pleasant Valley to Cricket Valley 345 kV line solution, along with the reconductoring of Cricket Valley to Long Mountain 345 segment proposed package addresses ISO-NE's concerns.

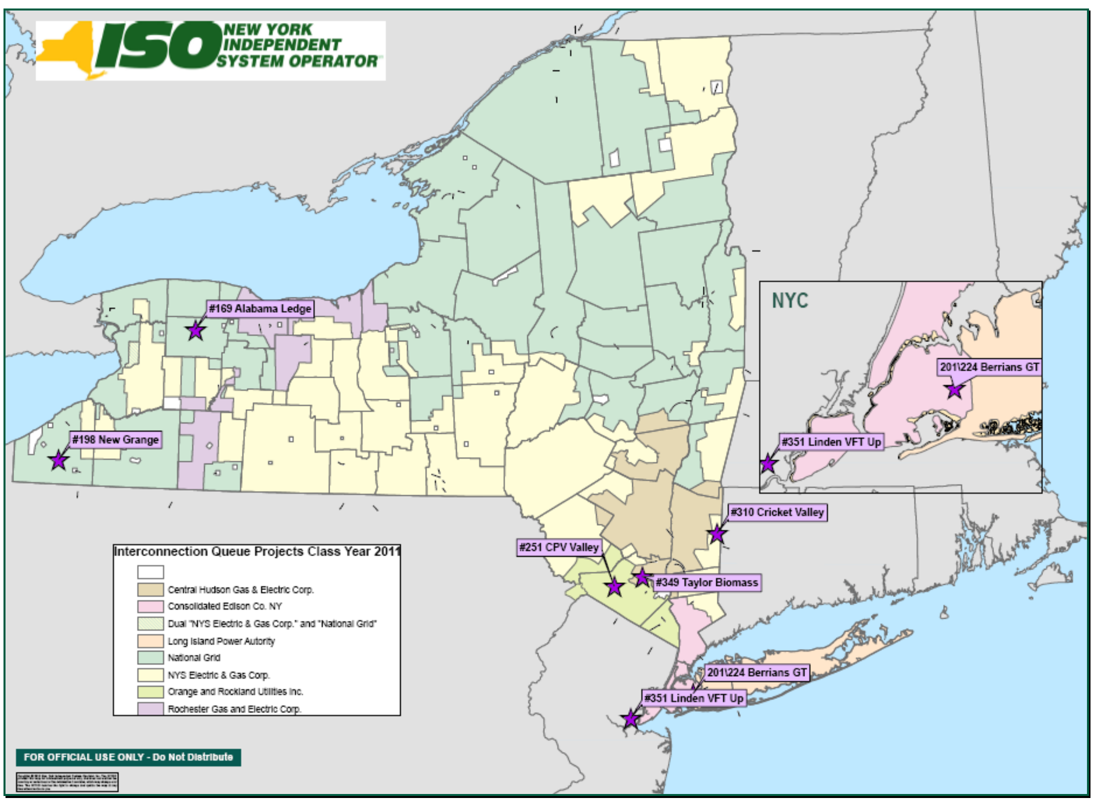
Table E-1: Class 2011 Proposed Projects

Class Year 2011 (CY11) list									
Queue#	**Developer**	**Project Name**	**Summer Peak Rating (MW)**	**CRIS Request (MW)**	**Fuel**	**Point of Interconnection**	**CTO**	**Zone**	**COD*****
~~**169***~~	~~Alabama Ledge Wind Farm, LLC~~	~~**Alabama Ledge Wind Farm**~~	~~80~~	~~79.8~~	~~W~~	~~Oakfield - Lockport 115 kV~~	~~NM-NG~~	~~B~~	~~2013~~
198	Arkwright Summit Wind Farm, LLC	**Arkwright Summit Wind Farm**	80	79.8	W	Dunkirk - Falconer 115 kV	NM-NG	A	2013
201	NRG Energy	**Berrians GT**	200	155	CC-NG	Astoria West Substation 138 kV	ConEd	J	2014
224	NRG Energy, Inc.	**Berrians GT II**	50	0	CC-NG	Astoria West Substation 138 kV	ConEd	J	2014
251	CPV Valley, LLC	**CPV Valley**	678	680	CC-NG	CoopersCorners – Rock Tavern 345 kV	NYPA	G	2016
310	Cricket Valley Energy Center, LLC	**Cricket Valley Energy Center**	1020	1,002	CC-NG	Pleasant Valley - Long Mt. 345 kV	ConEd	G	2015
349	Taylor Biomass Energy, LLC	**Taylor Biomass**	19	19	SW	Maybrook - Montgomery 69 kV	CHGE	G	2012
~~**351****~~	~~Linden VFT, LLC~~	~~**Linden VFT Uprate**~~	~~15~~	~~15~~	~~AC~~	~~Goethals 345 kV~~	~~ConEd~~	~~J~~	

Notes:

* Q169 project was withdrawn from the queue by the Developer during the CY11 process (as of June 1, 2012).
**Q351 project was removed from the Interconnection Process based on a FERC Order in Docket No. EL12-64-000.
***The updated schedule is detailed in the Part 1 Studies for each project, and also summarized under "SUF identified via Part 1 Studies" section of this report. The schedule will be further refined during the Interconnection Agreement phase.

Figure E-1: CY11 Projects on County and TO Districts Map (approximate locations)



See notes * and ** above. Also, Q198 New Grange is now named "Arkwright Summit Wind Farm".

1. Introduction

1.1. Background

As described in the Executive Summary, the purpose of the Facilities Study is to identify the interconnection facilities (*i.e.,* the Attachment Facilities and the SUFs), that would be required for the interconnection of a group of projects referred to as a Class Year (*e.g.,* Class Year 2011, or Class 2011, or CY11, in this study report). The Facilities Study also includes a Deliverability Study to identify any SDUs that may be required for the Class Year projects to be deliverable under the DIS.

CY01 was the first Class Year study performed under Attachment S of the NYISO OATT.

CY06 was the first Class Year to undergo the full scope of the Facilities Study under the NYISO's Standard Large Facilities Interconnection Procedures (LFIP/Attachment X of the NYISO OATT). Studies prior to CY06 addressed SUFs only, and, although Attachment Facilities were modeled, the studies did not address identification or cost of Attachment Facilities or protection -related SUFs.

CY07 was the first Class Year to include a Deliverability Study.

A unique aspect of the Class 2009 and Class 2010 is that NYISO proposed a one-time process applicable to both classes. Attachment S was amended to implement this one time process, which mainly allowed NYISO to proceed with the two classes together for schedule purposes, while preserving each class identity for cost allocation purposes.

This CY11 study formally commenced on March 1, 2011 in accordance with Attachment S of the OATT. Part 1 Studies for the CY11 projects were initiated in spring 2011. However, the Part 2 Studies were not able to begin in earnest until CY09 and CY10 were completed on November 30, 2011. The Part 2 Studies were initiated in December 2011 and preliminary results were presented to the CY11 IPFSWG on June 18, 2012. The remainder of the CY11 study focused primarily on the Cricket Valley project (Q310). Because that project is a proposed interconnection to a New York (NY)-New England (NE) tie-line, additional studies and coordination with ISO-NE and the affected NE transmission owners were required to evaluate and address the reliability impacts of the Cricket Valley project on the NE as well as NY systems. This report addresses the CY11 studies pertaining to the identification and cost allocation of the SUFs required for the CY11 projects.

1.2. Study Process Description

As described in the Executive Summary, the Class Year Facilities Study was divided by the NYISO into two parts, based on two significantly different aspects of the Class Year Study: Part 1 Studies (*i.e.,* design engineering type of studies) and Part 2 Studies (*i.e.,* system simulation type of studies, under both MIS and DIS).

Each project will have a "Part 1 Study" report and supporting appendices identifying Local SUFs (*i.e.*, POI connection design/engineering, and protection/communication at POI and remote ends), CTOAFs, and certain DAFs.

For the "Part 2 Studies," there will be two separate reports, one for SUFs ("the SUF Report"), and one for the Deliverability Study and SDUs ("the Deliverability Report"). Also, the SUF Report will summarize the Local SUFs identified via the Part 1 Studies, for a complete SUFs cost allocation.

The Part 2 Studies consist of various assessments performed on two system representation models, as described in Attachment S of the OATT: the Annual Transmission Baseline Assessment (ATBA) and the Annual Transmission Reliability Assessment (ATRA). The "ATRA system" is the "ATBA system" plus the Class Year projects addition and the respective redispatch. Together and under MIS, these studies result in the identification and cost allocation of the "but for" SUFs required for the subject Class Year projects to reliably interconnect to the system, and also in the determination of any Electrical or Functional Headroom reimbursements from the current CY to the prior CY projects. Under DIS, ATBA-Deliverability (ATBA-D) and ATRA-Deliverability (ATRA-D) studies are performed, to identify whether or not a project that requested CRIS evaluation is deliverable, and if not, what SDUs are necessary to make it deliverable.

The ATBA and ATRA cases (power flow, stability, short-circuit) are the foundations of the Part 2 Studies. It is the difference between these two cases (ATBA and ATRA) that establishes a snapshot of the incremental collective[7] impact on the system caused by the studied Class Year projects (and the corresponding dispatch). If any SUF is identified as needed, assessments will be re-performed, as applicable in order to either define system impacts of the newly-identified system elements, or to identify cost estimates and time to construct; the cost is allocated based on a pro-rata impact of each project on the respective SUF if the impact can be measured in discrete electrical units (*e.g.,* Amperes, MW, etc.), or by the number of projects needing the respective SUFs, if the impact cannot be measured in discrete electrical units (*e.g.,* a new ring bus shared by more than one project).

[7] Note: individual impact was extensively studied during each project's System Reliability Impact Study, SRIS.

The studies were conducted in cooperation with the Market Participants (MPs), by creating a working group (WG) at the beginning of each Class Year process. The WG is created by the NYISO by TPAS/OC invitations asking all interested parties to join an open study WG, named the Interconnection Projects Facilities Study Working Group, IPFSWG (see **Appendix A** for details). The WG members met several times, and also received information via group email. The WG members were encouraged to submit comments anytime during the study period. There was also a focused, NYISO coordinated 3 - party (combination of CTO, Developer, NYISO) communication process to review the Part 1 Studies for each of the Class Year projects.

The Facilities Study process also involves the review and compilation, as applicable, of a number of previously performed studies, in order to identify what needs to be re-evaluated specifically for the scope of the Facilities Study (defined in the Study Plan (Appendix B), circulated among the IPFSWG members for comments), and what can be relied upon with no further assessment.

1.3. Study Approval, Decision Rounds, and Settlement Processes

The SUF Report, the Deliverability Report and the supporting materials (appendices) will be presented for TPAS and OC for approval. After OC approval of the SUF and the Deliverability Reports (the Initial Round Reports), the process enters a 30 calendar-day decision period during which the CY Developers are given the choice to accept or reject their respective Project Cost Allocation for SUFs and SDUs as summarized in the Initial Round Reports.

If any Developers reject their Project Cost Allocation for SUFs, the associated projects are removed from the Class. Any Developers who accept their Project Cost Allocation for SUFs, but reject their Project Cost Allocation for SDUs, remain in the Class, but will only be eligible for partial CRIS up to the amount of the proposed capacity of their project determined to be deliverable, if any.

NYISO re-evaluates the SUFs, and SDUs as applicable, for the remaining Class Year projects, makes any necessary adjustments, and issues revised SUF and Deliverability Reports (the Second Round Reports) in 14 calendar days. Then, the remaining Developers have 7 calendar days to decide if they accept/reject the new Project Cost Allocation, and so on.

The Class Year settles after all remaining Developers accept their Project Cost Allocations for SUFs, and SDUs as applicable, and post their respective Security with the applicable TO(s), for the full amount of their respective SUF/SDU Project Cost Allocation. The Security must be posted with the identified Transmission Owners in five business days after NYISO issues a Notice of Acceptance of Project Cost

Allocation. Developers also must make any applicable Headroom payments to prior Class Year Developers in the same timeframe.

1.4. ATBA and ATRA Systems Description

The ATBA and ATRA cases (*i.e.,* system representations) are the foundations of these studies. The ATBA case is a five-year look-ahead of the New York Control Area (NYCA) system and represents a 2016 summer peak (coincident peak) 50/50 load forecast and system representation. The starting point of the ATBA case is the NYISO FERC 715 2016 summer case ("the FERC Case") as an external input into the Class Year interconnection studies, and also into other planning and interconnection studies. The FERC case went through a separate (*i.e.,* external to the class process) and major base case development process, during which each Transmission Owner (TO) participated, and reflects the 2011 Gold Book [7] reported data (*e.g.,* all generation and transmission facilities identified in the Gold Book 2011 as existing as of January 1, 2011, 5-year ahead planned retirements and re-ratings, 5-year ahead TO firm plans reported in the Gold Book, load forecast, etc.).

The FERC Case also included the latest available neighboring system representations at the time the Class Year started, and the respective ties schedules (received through NPCC and MMWG base case development processes). This model also included an updated 5-year-ahead representation as received from the ISO-NE.

The aforementioned FERC case was further customized as part of the Facilities Study to meet specific Attachment S requirements for the baseline system: *e.g.,* to model Class 2001, Class 2002, Catch-up Class 2003-2005, Class 2006, 2007, 2008, 2009 and 2010 proposed projects that accepted their cost allocation, (see **Table 1.4.2** below); to reflect the scheduled generation retirements, (see **Table 1.4.1** below), etc. This baseline system case does not include the Class 2011 projects which are the subject of this cost allocation.

The CY11 ATRA case consists of the same system representation as the ATBA case with the addition of the CY11 projects at full output and associated system changes and dispatch patterns (CY11ATRA=ATBA+CY11 projects). It is the difference between these two cases (ATBA and ATRA) that establishes an incremental impact on the system, collectively caused by new projects and the respective re-dispatch.

Below are the additions, retirements, and the TO firm plans tables modeled in both the ATBA and ATRA systems (source: 2011 Gold Book).

Table 1.4.1: Proposed Retirements Modeled in ATBA/ATRA:

Owner/Operator	Project Name	Zone	Summer MW capab
Units retired since 2010			
Erie Blvd. Hydro - Lower Hudson	Johnsonville 2	F	0.0
Energy Systems North East LLC	Energy Systems North East	A	79.4
Project Orange Associates	Project Orange 1	C	40.0
Project Orange Associates	Project Orange 2	C	0.0
AES Eastern Energy, LP	Greenidge 4 *	C	106.1
AES Eastern Energy, LP	Westover 8 *	C	81.2
Scheduled Retirements			
National Grid Generation LLC	Far Rockaway 4	K	100.0
National Grid Generation LLC	Glenwood 4 and 5	K	100.0
National Grid Generation LLC	Barrett 7	K	18
"Mothball" Notices			
TC Ravenswood, LLC	GT Unit 3-4	J	35.8
Power City Partners	Sithe Massena at Alcoa	D	80.7
Standard Binghamton, LLC	Standard Binghamton	C	47.7
RG&E	Unit 13 CT at Beebee St. Rochester	B	18
Black River Generation LLC	Fort Drum	E	56

Table 1.4.2: Prior Class Year Proposed Additions Modeled in ATBA and ATRA System Representation

Queue	Developer	Project Name	POI	CTO	Zone	Summer Output (MW) (Full values shown for wind and solar)	CRIS (MW)	UNIT TYPE
		Completed Class Year Facilities Study - CY11 ATBA list closed as of Nov 30, 2011 with CY09-10 full settlement						
119	ECOGEN, LLC	Prattsburgh Wind Farm	Eelpot Rd-Flat St. 115kV	NYSEG	C	78.2	78.2	Wind Turbines
127A	Airtricity Munnsville Wind Farm, LLC	Munnsville	OriskanyTap-MorrisvilleTap 46k	NYSEG	E	40.5	40.0	Wind Turbines
147	NY Windpower, LLC	West Hill Windfarm	Oneida-Fenner 115kV	NM-NG	C	31.5	31.5	Wind Turbines
161	Marble River, LLC	Marble River Wind Farm	Willis-Plattsburgh WP-1 230kV	NYPA	D	84.0	84.0	Wind Turbines
166	AES-Acciona Energy NY, LLC	St. Lawrence Wind Farm	Lyme Substation 115kV	NM-NG	E	79.5	79.5	Wind Turbines
171	Marble River, LLC	Marble River II Wind Farm	Willis-Plattsburgh WP-2 230kV	NYPA	D	132.3	132.3	Wind Turbines
182	Howard Wind, LLC	Howard Wind	Bennett-Bath 115kV	NYSEG	C	57.4	57.4	Wind Turbines
206	Hudson Transmission Partners	Hudson Transmission	West 49th Street 345kV (Berge	ConEd	J	660.0	660.0	DC/AC
197	PPM Roaring Brook, LLC/PPM	Roaring Brook Wind	Boonville-Lowville 115kV	NM-NG	E	78.0	0.0	Wind Turbines
207	BP Alternative Energy NA, Inc.	Cape Vincent	Rockledge Substation 115kV	NM-NG	E	210.0	0.0	Wind Turbines
213	Noble Environmental Power, LLC	Ellenburg II Windfield	Willis-Plattsburgh WP-2 230kV	NYPA	D	21.0	21.0	Wind Turbines
216	Nine Mile Point Nuclear, LLC	Nine Mile Point 2 Uprate	Scriba Station 345kV	NM-NG	C	168.0	96.3	Nuclear Uprate
231	Seneca Energy II, LLC	Seneca	Goulds Substation 34.5kV	NYSEG	C	6.4	0.0	Methane
234	Steel Winds, LLC	Steel Winds II	Substation 11A 115kV	NM-NG	A	15.0	0.0	Wind Turbines
222	DEGS Wind I, LLC \; Ball Hill Windpark LLC	Ball Hill Windpark	Dunkirk-Gardenville 230kV	NM-NG	A	90.0	90.0	Wind Turbines
232	Bayonne Energy Center, LLC	Bayonne Energy Center	Gowanus 345kV	ConEd	J	500.0	512.0	Dual Fuel
245	Innovative Energy Systems Inc.	Fulton County Landfill	Ephratah – Amsterdam 69kV	NM-NG	F	3.2	0.0	Methane
237	Allegany Wind, LLC	Allegany Wind	Homer Hill – Dugan Rd. 115kV	NM-NG	A	72.5	0.0	Wind Turbines
260	Beacon Power Corporation	Stephentown	Greenbush - Stephentown 115k	NYSEG	F	20.0	0.0	Flywheel
263	Stony Creek Wind Farm, LLC	Stony Creek Wind Farm	Stolle Rd - Meyer 230kV	NYSEG	C	88.5	88.5	Wind Turbines
308	Astoria Energy II, LLC	Astoria Energy II	Astoria Annex 345kV	NYPA	J	575.9	576.0	Combined Cycle
330	Long Island Solar Farm LLC	Upton Solar Farms	Brookhaven 8ER 69kV	LIPA	K	31.5	31.5	Solar
		Other Non-Class Generators						
	Riverbay Corporation	Co-op City			J	24.0		Combined Cycle
180A	Green Power	Cody Road	Fenner - Cortland 115kV	NM-NG	C	10.0	10.0	Wind Turbines
204A	Duer's Patent Project, LLC	Beekmantown Windfarm	Kent Falls-Sciota 115 kV	NYSEG	D	19.5	19.5	Wind Turbines
284	Broome Energy Resources, LLC	Nanticoke Landfill		NYSEG	C	1.6	0.0	Methane
250	Seneca Energy II, LLC	Ontario	Haley Rd. - Hall 34.5kV	NYSEG	B	5.6	0.0	Methane

Table 1.4.3: GB2011: TO Firm Plans (5-year-ahead Plans in the ATBA and ATRA Summer Peak)

Transmission Owner	Terminals		Line Length miles (1)	Service Date/Yr Prior to (2)	Year	Nominal Voltage in kV Operating	Design	# of ckts
Firm Plans (included in 2016 Master Case)								
CHGE	E. Fishkill	E. Fishkill	xfmr #2	S	2012	345/115	345/115	1
CHGE (4)	Pleasant Valley	Todd Hill	5.60	W	2015	115	115	1
CHGE (4)	Todd Hill	Fishkill Plains	5.23	W	2015	115	115	1
CHGE	Hurley Ave	Saugerties	11.11	S	2018	115	115	1
CHGE	Saugerties	North Catskill	12.25	S	2018	115	115	1
ConEd (3)	Vernon	Vernon	Phase Shifter	S	2010	138	138	1
ConEd	Farragut	East 13th Street	1.98	S	2011	345	345	1
ConEd	Farragut	East 13th Street	1.98	S	2011	345	345	1
LIPA	Shore Road	Lake Success	8.72	S	2012	138	138	2
LIPA	Riverhead	Canal	16.40	S	2013	138	138	1
NYPA	Willis	Duley	-24.38	S	2012	230	230	1
NYPA (5)	Willis	Patnode	9.11	S	2012	230	230	1
NYPA (5)	Patnode	Duley	15.27	S	2012	230	230	1
NYPA	Niagara	Rochester	-70.20	W	2013	345	345	1
NYPA (5)	Niagara	BPS Station	66.40	W	2013	345	345	1
NYPA	Dysinger Tap	Rochester	-44.00	W	2013	345	345	1
NYPA (5)	Dysinger Tap	BPS Station	40.20	W	2013	345	345	1
NYPA (5)	BPS Station	Rochester	3.80	W	2013	345	345	1
NYPA (11)	Pannell	Clay	-61.60	W	2016	345	345	1
NYPA (5) (11)	Pannell	Auburn New 345/115 kV Sub	21.00	W	2016	345	345	1
NYPA (5) (11)	Auburn New 345/115 kV Sub	Clay	40.60	W	2016	345	345	1
NYSEG (3)	Clarks Corners	Clarks Corners	xfmr	W	2010	345/115	345/115	1
NYSEG (3)	Clarks Corners	Clarks Corners	xfmr	W	2010	345/115	345/115	1
NYSEG	Avoca	Stony Ridge	20.10	S	2011	230	230	1
NYSEG	Stony Ridge	Hillside	26.70	S	2011	230	230	1
NYSEG	Stony Ridge	Stony Ridge	xfmr	S	2011	230/115	230/115	1
NYSEG	Stony Ridge	Sullivan Park	6.20	S	2011	115	115	1
NYSEG	Sullivan Park	West Erie	3.20	S	2011	115	115	1
NYSEG	Meyer	Meyer	Cap Bank	S	2011	115	115	1
NYSEG (6)	Wood Street	Carmel	1.34	S	2012	115	115	1
NYSEG (6)	Wood Street	Katonah	11.70	S	2012	115	115	1
NYSEG	Klinekill Tap	Klinekill	<10	S	2012	115	115	1
NYSEG	Wethersfield	Meyer	-31.50	S	2013	230	230	1
NYSEG (5)	Wethersfield	South Perry	11.50	S	2013	230	230	1
NYSEG (5)	South Perry	Meyer	20.00	S	2013	230	230	1
NYSEG	South Perry	South Perry	xfmr	S	2013	230/115	230/115	1
NYSEG	Watercure Road	Watercure Road	xfmr	S	2013	345/230	345/230	1
NYSEG (5)	BPS Station	Rochester	3.80	W	2013	345	345	1
NYSEG	Auburn New 345/115 kV Sub	Auburn New 345/115 kV Sub	xfmr	W	2016	345/115	345/115	1
NYSEG	Auburn New 345/115 kV Sub	State Street	15.00	W	2016	115	115	1
NGRID	Greenbush	Hudson	-26.43	S	2012	115	115	1
NGRID (5)	Greenbush	Klinekill Tap	20.30	S	2012	115	115	1
NGRID (5)	Klinekill Tap	Hudson	6.13	S	2012	115	115	1
NGRID	Lockport	Mortimer	56.18	S	2014	115	115	1
O & R	Ramapo	Sugarloaf	16.00	W	2011	138	138	1
O & R	Hillburn	Sloatsburg	3.00	S	2011	69	69	1
O & R	Harriman	-	-	S	2011	69	69	1
O & R	Snake Hill	-	-	W	2012	138	138	1
O & R	Hartley	-	-	W	2012	69	69	1
O & R	East Wallkill	-	-	S	2012	69	69	1
O & R	Montvale (PJM)	-	-	S	2013	69	69	1
O & R	Little Tor	-	-	W	2013	138	138	1
O & R	Tappan	-	-	W	2013	69	69	1
O & R	O&R's Line 26	Sterling Forest	xfmr	W	2014	138/69	138/69	1
O & R	New Hempstead	-	-	W	2014	138	138	1
O & R	Hillburn	Pomona	7	W	2016	138	138	1
O & R	Sugarloaf	Shoemaker	7.00	W	2016/17	69	138	2
O & R	ConEd's Line Y94	Lovett	xfmr	S	2017	345/138	345/138	1
O & R	Lovett	West Nyack	12.80	W	2018	138	138	1
O & R	Pomona	West Haverstraw	5	W	2018	138	138	1
O & R	Burns	Nanuet	2.6	W	2019	69	69	1
RGE	Station 135	Station 424	4.98	W	2011	115	115	1
RGE	Station 13A	Station 135	3.17	W	2011	115	115	1
RGE	Station 180	Station 180	Cap Bank	S	2011	115	115	1
RGE	Station 128	Station 128	Cap Bank	S	2011	115	115	1
RGE	Station 42	Station 124	Phase Shifter	W	2012	115	115	1
RGE	Station 67	Station 418	3.50	W	2012	115	115	1
RGE	Station 124	Station 124	Phase Shifter	S	2013	115	115	2
RGE	Station 124	Station 124	SVC	S	2013	115	115	1
RGE	Bulk Power System (BPS) Station	Rochester, NY	New Station	W	2013	345/115	345/115	1
RGE	NYPA SR1-39 345kV Line	Rochester, NY	xfmr	W	2013	345/115	345/115	1
RGE	NYPA NR-2 345kV Line	Rochester, NY	xfmr	W	2013	345/115	345/115	1
RGE	BPS Station	Station 418	TBD	W	2013	115	115	1
RGE	BPS Station	Station 23	TBD	W	2013	115	115	1

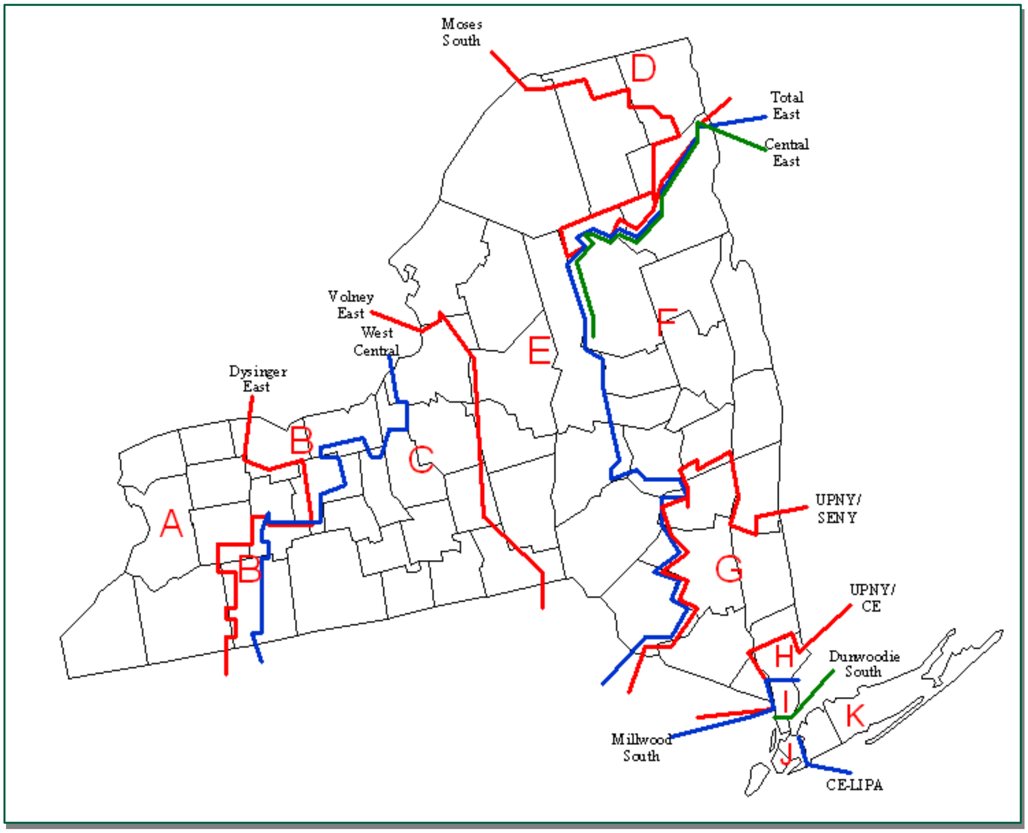
1.5. Thermal, Voltage, Stability and Short Circuit Analysis Introduction

The NYISO staff reviewed the results of the thermal, voltage, and stability analyses of the SRIS performed for each of the CY11 projects, and the results of other previously performed system studies (*e.g.,* most recent Area Transmission Review of the New York Bulk Power System, the Reliability Needs Assessment Study, etc.). As part of the CY11 process, NYISO staff identified specific study tasks (Study Plan) to be performed, as deemed relevant for identifying the “but for” SUFs as triggered by CY11 projects, under the MIS requirements, or, alternatively, for informational purposes. The specific Study Plan was circulated among CY11 IPFSWG for comments.

ATBA/ATRA transfer assessments: Based on the electrical location of CY11 projects, the following interfaces were proposed via the Study Plan definition process, as potentially impacted, therefore they were further evaluated in the ATBA and ATRA (thermal, voltage, stability): Dysinger East, West Central (Western NY), UPNY-SENY, and UPNY-ConEd (see **Figure 1.5.1.** below). Also, NY to NE and NE to NY thermal transfer assessments were performed.

For the transfer assessments, a uniform dispatch (*i.e.,* the “t0 cases”, starting from the “original cases”) was employed in Zones A through I in ATBA: All the units were placed in-service and generating at a given percentage of the unit Pmax, except specific units which were dispatched differently (*e.g.,* wind, nuclear plants, run of river units, solar, battery, flywheel, etc.). The base area interchange schedule was maintained. The ATRA starting transfer case was based on this ATBA transfer case, with CY11 dispatched at maximum against specific units throughout NYCA. While shifting power to stress an interface, the units that were set to a uniform dispatch are increased or decreased on a zonal basis, observing their maximum MW limit (Pmax). Different sources and sinks were used depending on the interface that was being analyzed, as detailed under each section. Some interfaces used shifts to discrete units to avoid creating local overloads.

Figure 1.5.1. NY Map with “A through K” Zones and Interfaces



ATBA/ATRA base case assessments: Thermal, voltage, stability, and short circuit (bus fault) assessments were performed on the two (ATBA and ATRA) systems, as deemed relevant for identifying the “but for” SUFs as triggered by CY11 projects, under the MIS requirements, or, alternatively, for informational purposes. Otherwise, the SRIS results already provided a good indication of each project’s relative impact on the system behavior, and already flagged potential operational limitations, which will be mostly addressed by security dispatch or other operational means.

As noted above, besides the assessments performed specifically for this study, NYISO also reviewed and referred to the results of the thermal, voltage, stability, short circuit, and resource adequacy studies performed in accordance with Applicable Reliability Standards (as defined in NYISO OATT / Attachment X) and applicable NYISO Study Guidelines, Procedures, and Practices. The most recent review of the New York State Bulk Power System is the 2010 (study year 2015) Comprehensive Area Transmission Review submitted in 2011 to NPCC, which concluded that the NY Bulk Power Transmission System, as planned through the year 2015, is in conformance with the NPCC and NYSRC criteria.

The results of the specific CY11 assessments are discussed in the following sections.

2. Thermal, Voltage, and Stability Transfer Analysis

2.1. Thermal Transfer Assessments

NYISO staff used the Siemens PTI PSS®MUST program to perform the thermal analysis. The NYCA open and closed interfaces identified in **Section 1.5** and all the 100 kV and above transmission lines in the vicinity of these interfaces were monitored. The definition of the selected interfaces is in **Appendix C.**

Approximately two thousand design criteria contingencies were evaluated on both ATBA and ATRA systems, developed as described in **Sections 1.4** and **1.5**. All contingencies studied were in accordance with the Applicable Reliability Rules (*e.g.,* NERC Reliability Standards, NPCC Directory 1, the NYSRC Reliability Rules, etc). The Design Criteria Contingencies examined include the individual opening of all lines connected between buses with base voltage between 100 kV and 765 kV and all appropriate common structure, stuck breaker, generator, multiple element, and loss of DC contingencies. Phase Angle Regulators (PARs) maintained their scheduled power flow pre-contingency, but were fixed at their corresponding pre-contingency angle for post-contingency. The general direction of generation shifts was from the North and West to Southeastern New York. When an interface besides the one being studied became limiting, the general shift pattern was modified, within the base case conditions and limitations, to minimize this effect. However, no attempt was made to find the maximum limits based on an ideal shift pattern.

Sources and sinks for transfers:

Dysinger East:

Source: all units in Ontario and Zone A in proportion to the difference between Pmax and Pgen.

Sink: all units in Zones G, H and I in proportion to the difference between Pgen and zero.

West Central

Source: all units in Ontario, Zone A and B in proportion to the difference between Pmax and Pgen.

Sink: all units in Zones G, H and I in proportion to the difference between Pgen and zero.

UPNY-SENY

Source: all units in Ontario and Zones A through F in proportion to the difference between Pmax and Pgen.

Sink: all units in Zone J in proportion to the difference between Pgen and zero.

UPNY-ConEd

Source: all units in Ontario and Zones A through G in proportion to the difference between Pmax and Pgen.

Sink: all units in Zone J in proportion to the difference between Pgen and zero.

2.1.1. Internal NYCA Study Interfaces

Tables 2.1.1.1 and **2.1.1.2**. provide summaries for the normal and emergency transfer criteria thermal transfer limits determined for the selected interfaces (in **bold** font), under the study assumptions. Additional details regarding the thermal analysis results are provided in **Appendix C.**

Table 2.1.1.1 – Normal Transfer Criteria - Thermal Limits for Internal NYCA Study Interfaces (MW)

Interface	CY11 ATBA		CY11 ATRA	
	Open	Closed	Open	Closed
Dysinger East	**2687 (1)** …. 2893 (2)	**4616 (1)** …. 4863 (2)	**2688 (1)** **….** 2836 (2)	**4624 (1)** **…** 4802 (2)
West Central	**1385 (1)** …. 1590 (2)	**3315 (1)** …. 3562 (2)	**1391 (1)** …. 1543 (2)	**3329 (1)** **….** 3510 (2)
UPNY-SENY	**4740 (3)**	**5965 (3)**	**4748(3)**	**5988(3)**
UPNY-ConEd	3192 (3) …. **4562 (4)**	5898 (3) … **7268 (4)**	4264(3) … **4294(4)**	6985(3) … **7015(4)**

Notes:

1. **S. Perry-Wethersfield 230 kV at Long Time Emergency (LTE)** limit for stuck breaker (SBK or SB) at Niagara 345kV**;**
2. Niagara-NewRochester 345 kV at LTE, for L/O Somerset -NewRochester 345 kV;
3. **Leeds-Pleasant Valley 345 kV at LTE** for L/O Athens-Pleasant Valley 345 kV**;**

   Note: At the time of initiating the CY11, Athens SPS was proposed to be retired by the 2016 study timeframe, therefore the LTE rating was observed; however, latest developments indicated that the SPS will be extended beyond 2016, hence the normal limits are higher than shown if the SPS effects would be considered.
4. **Rock Tavern-Ramapo 345 kV at LTE** for SBK at Fishkill 345 kV, or L/O Roseton-Fishkill, etc.

Table 2.1.1.2 – Emergency Transfer Criteria - Thermal Limits for Internal NYCA Study Interfaces (MW)

Interface	CY11 ATBA		CY11 ATRA	
	Open	Closed	Open	Closed
Dysinger East	**2790 (1)** …. 3212 (2)	**4740(1)** ….. 5247 (2)	**2805 (1)** … 3155 (2)	**4765(1)** … 5186 (2)
West Central	**1489 (1)** …. 1912 (2)	**3440 (1)** … 3947 (2)	**1510 (1)** ….. 1867 (2)	**3472 (1)** …. 3900 (2)
UPNY-SENY	**5394 (3)**	**6620 (3)**	**5397 (3)**	**6638 (3)**
UPNY-ConEd	3872 (3) **5942 (4)**	6578 (3) **8647 (4)**	4958 (3) 5243 (5) **5684 (4)**	7680 (3) 7964 (5) **8405 (4)**

Notes:

1. **S. Perry-Wethersfield 230 kV** at normal rating precontingency**;**
2. Niagara-NewRochester 345 kV at Short Time Emergency (STE) limit, for L/O Somerset -NewRochester 345 kV;
3. **Leeds-Pleasant Valley 345 kV at STE** for L/O Athens-Pleasant Valley 345 kV**;**
4. **Rock Tavern-Ramapo 345 kV at STE** for L/O Roseton-E.Fishkill 345 kV**;**
5. Coopers Corners-Middletown 345 kV at STE for L/O RockTavern-CPV Valley 345 kV.

Following are some of the key observations for this thermal transfer study:

Dysinger East and **West Central interfaces**: The normal and emergency transfer limits did not change significantly from ATBA to ATRA (*e.g.,* +1 MW normal criteria, +15 MW emergency criteria, etc). The limiting element continues to be South Perry to Wethersfield 230 kV (on StolleRd-Meyer 230 kV corridor where the prior Class Year projects interconnected).

UPNY - SENY interface: For both normal and emergency criteria, the limiting element continues to be Leeds - Pleasant Valley 345 kV at LTE (assumes Athens SPS retired in the 2016 timeframe of the study), and STE respectively, both for L/O Athens - Pleasant Valley 345 kV. The limit did not change significantly between ATBA and ATRA (+8 MW for normal criteria, +3 MW for emergency criteria), mainly due to the compound effect of CPV Valley and Cricket Valley and the redispatch employed in the cases.

As also observed during the CY09 studies, the proposed interconnection of CPV Valley to one of the UPNY-SENY interface elements changes the interface definition. CPV Valley's proposed interconnection is to the Coopers Corners - Rock Tavern 345 kV line #42, using in part, a parallel path to the most limiting element (*i.e.,* Leeds-Pleasant Valley 345 kV). This changes the interface definition from Coopers Corners - Rock Tavern 345 kV to Coopers Corners to CPV Valley 345 kV, with the project belonging to Zone G (Hudson Valley). Different UPNY-SENY limits can be identified depending on where the interface flow is monitored. If the flow is monitored upstream of CPV (with CPV in Zone G), the limits will look lower; if the flow is monitored downstream, the limits will add the flow from CPV and look higher. Similarly, Cricket Valley, which is proposed to interconnect on another element that defines UPNY-SENY interface (and also a NY to NE tie) (*i.e.,* Pleasant Valley to Long Mountain 345 kV), injects power below the most constraining UPNY-SENY element, Leeds-Pleasant Valley 345 kV, therefore having a relieving effect.

UPNY-ConEd interface: The normal and emergency limits decreased from ATBA to ATRA by approximately -270 MW, mainly due to the compound effect of the upstream projects (CPV Valley and Cricket Valley) and their dispatch.

Conclusion:

Any internal NYCA transfer limit reductions and transmission limitations identified by this study are observed under specific system conditions, study assumptions, and dispatch patterns modeled in the respective study cases, and can be managed through the normal operating procedures of the NYISO and/or TOs; therefore they are not considered a degradation of the system reliability or non-compliance with NERC, NPCC or NYSRC reliability standards. Consequently, under the NYISO Minimum Interconnection Standard requirements, no SUFs are required to address them.

2.1.2. External NYCA Study Interfaces

The original ATBA and ATRA cases were used, and modified to increase the NNC Path (i.e., Northport - Norwalk 138 kV cables, Northport PAR, Norwalk autotransformer) imports into LIPA to 200 MW (from 100 MW), for both NE to NY and NY to NE thermal transfer limits calculation. The updated results are presented in **Table 2.1.2.1**. below.

Sources and sinks for transfers:

NY-NE: Source: specific units in NY. Sink: specific units in NE.

NE-NY: Source: specific units in NE. Sink: specific units in NY.

Table 2.1.2.1. shows NY to NE (both directions) limits for the benchmark cases (*i.e.,* ATBA and ATRA before upgrades). These results, labeled as 1i. (NY import) and 1e. (NY export), identified all elements becoming more limiting in ATRA (red font) as compared with the ATBA (*i.e.,* elements/contingency pairs for which the interface limit is less than in the ATBA). The second set of results (labeled as 2e. and 2i.) shows the effect of the proposed SUFs (2e'. and 2i'. reflect updated results using actual ratings and impedances, as provided by ConEdison and Northeast Utilities (NU)).

Table 2.1.2.1 Thermal Transfer Limits for NY-NE, NE-NY (MW)		Normal			Emergency		
		ATBA	**ATRA**	**Delta**	**ATBA**	**ATRA**	**Delta**
NE to NY- (i=imports into NY) (includes NNC and CSC, for limit without them extract (200+330)	**1i. Benchmark** i.e.: original ATBArev3b, ATRArev1a cases, with NNC at 200 into LI (scale gen up200NE, down 200LI)	**ReynXtr345/115** LO Alps-NSctl-- **1518**	**NrthpPAR138** / SB PV, or PV-CV,etc--**620** **NNC NE cable**1,2,3 **/** SB PV--778,793,805 **NNC NY cables** / SB PV--1041, 1050, 1070 **ReynXtr** / Alps-NSctl345--1119 **PV-CV** / NSctBus345 --1200 **PV-CV** prectg--1224 **Norwalk NE Autoxtr** / PV-CV, SB PV--1269	-898	**ReynXtr** / LO Alps-NSctl-- **2598**	**PV-CV** prectg--**1224** **NNC PAR, NE autotr /** PV-CV--1277 **PV-CV** / bus Alps or NSctl--1667 **Reyn xtr** / NSctl-Alps--2196 BearSwamp-NE230kV--2739	-1374
	2i. Add in-kind PV to CV second 345 kV line 2 x PV-CV: 1195/1386/1685 MVA		**ReynXtr / Alps-NSctl--1286** **ReynXtr / busNSctl-1340** **PV-CV2 / PV-CV1--1659**	-232		**PV-CV2** / PV-CV1--**2237** **Reyn. xtr / NSctl-Alps--2451**	-361
	2i'. Updated data, per ConEd, NU: Add 795 ACSS Mallard PV to CV second 345 kV line - current line PV-CV: 1195/1386/1685 MVA actual 2nd line: bundled 795 ACSS Mallard:**1204.6 / 1983.9** / **2252.2 MVA** (with actual ConEd CV-NE record imped. data. Note: NU's section imped. did not change from the existing one, new NU ratings also reflected)		**ReynXtr / Alps-NSctl--1228** ReynXtr / busNSctl;NSctBus--1281 **PV-CV1 / PV-CV2--1552**	-290		**PV-CV1 / PV-CV2--2129** Reyn. xtr / NSctl-Alps--2417 Reyn. xtr / NSctlBus77--2505 PV-CV#2 prectg--2620	-469

Table 2.1.2.1

Thermal Transfer Limits for NY-NE, NE-NY (MW)

		Normal			Emergency		
		ATBA	**ATRA**	**Delta**	**ATBA**	**ATRA**	**Delta**
NY to NE (e=exports from NY) (includes NNC and CSC, for limit without them add (200+330)	**1e. Benchmark** *i.e.:*original ATBArev3b, ATRArev1a cases, with NNC at 200 into LI (scale gen up200NE, down 200LI	**PV-NE398NY** / Millstn3, or DC Ph.II-- **947**	**CV-NE398NY** / Millstn3, or DC Ph II--**610** **LM-NE398NY** / Millstn--818 **LM-NE398NY /** Seabrook--1037	-337	**NE398NY-PV /** Millstn 3 **-- 1490**	**CV-NE398NY /** Millstn 3--**1155** CV-NE398NY prectg --1303 LM-NE398NY / Millstn 3-- 1314 **LM-NE398NY** / prectg--1489	-335
	2e. Add in-kind PV to CV 2nd 345 kV line, reconductor CV-NE-LM **For Imports:** **PV-CV: 2nd line** (in kind): 1195/1386/1685 MVA **For Exports: recond CV-NE; NE-LM** **CV-NE398:** 1195/1386/1685; **target:1320/ 1630/ newRateC** **LM-NE398:** 1297/1500/1772; **target:1320/ 1630/ newRateC**		LM-NE398 / Millstn3--957 CV-NE398 / Millstn3--957 CV-NE-LM prectg--1497 Note: these results show the target Rate B necessary to bring the limits back to the ATBAlimits. The Rating Authority provided actual line ratings and impedances, and the results are below	**10**		**CV-NE398NY /** Millstn 3**--1050** LM-NE398NY / Millstn 3-- 1200 **CV-NE398NY-LM prectg --1497** Note: the above Rate C results do not reflect the new Rate C corresponding to the new Rate B. The Rating Authority provided actual line ratings and impedances, and the results are below.	-440
	2e'. Updated data, per NU, ConEd: **Add 795 ACSS Mallard PV to CV 2nd 345 kV line, reconductor CV-NE-LM** **For Imports:** **PV-CV: 2nd line**: 795 ACSS Mallard 1328 MVA summer; 1204.6 / 1983.9 / 2252.2 MVA **For Exports: recond CV-NE; NE-LM:** **ConEd's CV-NE398: current:** 1195/1386/1685; **actual:1323, 1986, 2221 MVA (**twin bundled 795 kcmil 30/19 ACSS Mallard cond) NU's **LM-NE398: current:** 1297/1500/1772; **actual: 1428/ 1715/ 2329 MVA** (2156 ACSS Bluebird); no impedance change, per NU.		**LM-NE398 / HVDC Ph II--1188** **LM-NE398 / LO Milstn3--1201**	241		**CV-NE398 / prectg--1602** **LM-NE / prectg--1780** **NE398NY-CV/ HVDC-Ph2 or Millstn 3--2044**	112

Legend:

Red font elements**:** ATRA limits below the ATBA limits;

PV = Pleasant Valley 345 kV;

CV = Cricket Valley 345 kV;

LM = Long Mountain 345 kV;

NE = New England; NY = New York;

SB = Stuck Breaker;

prectg. = before any contingency, aka “base case limit”;

NrthpPAR138 / SB PV, or PV-CV, etc -- **620** = **limiting element name_kV**/ limiting contingency pair(s) – study interface MW value corresponding to the limiting elements / contingency pair;

NNC Path = LIPA’s NorthportPAR, NU’s Norwalk autotransformer, LIPA/NU Northport-Norwalk 138 kV submarine cables.

NE-NY interface (**NY imports from NE**):

Table 2.1.2.1. 1i. results (before the Cricket Valley SUF solution): The normal limit decreased from ATBA to ATRA by approximately -900 MW, while the emergency one decreased by -1400 MW. The limiting element changed from the Reynolds Rd. 345/115 kV transformer (for L/O Alps – New Scotland 345 kV) in ATBA, to the Northport 138 kV PAR (for stuck breaker at Pleasant Valley 345 kV) in ATRA.

The proposed interconnection of the Cricket Valley project on the Pleasant Valley to Long Mountain 345 kV tie line with NE directly impacts these limits calculations: *e.g.,* for NE to NY transfers, when the respective tie line is severed, approximately 40% of the flow on the lost tie gets “picked up” by LIPA’s NNC path, as re-routed via Connecticut network, having a major impact on both NE and LIPA’s systems; with Cricket Valley heavily loading the tie pre-contingency, the effect increased significantly, triggering the NNC Path elements (*i.e.,* NNC 138 kV Northport PAR, Norwalk 115/138 kV autotransformer, and the 3x138 kV cables), to become the most limiting.

Note: For these interfaces, the flow on the tie is monitored from Cricket Valley to Long Mountain, with the Cricket Valley project belonging to NY, Zone G.

Table 2.1.2.1. 2i’. results (with the Cricket Valley SUF solution and actual ratings, as provided by ConEd and NU): under the studied scenario, the proposed addition of the second PV-CV parallel line has the effect of restoring the thermal import limits to an acceptable level. The normal limit is -290 MW lower than in the ATBA, with Reynolds Transformer 345/115 kV as limiting element for loss of Alps - New Scotland 345 kV. The emergency limit is -469 MW lower than the ATBA with PV-CV as limiting for loss of the other PV-CV.

NY-NE interface (**NY exports to NE**):

Table 2.1.2.1. 1e. results (before the Cricket Valley SUF solution): The normal and emergency limits decreased from ATBA to ATRA by approximately -330 MW, due to the Cricket Valley project interconnection on the Pleasant Valley to Long Mountain tie (Line #398). The limiting element is Pleasant Valley to Long Mountain 345 kV (becoming Cricket Valley to Long Mountain 345 kV in ATRA), for loss of NE's HVDC Phase II or loss of NE's Millstone 3 plant under both normal and emergency criteria.

Table 2.1.2.1. 2e. shows thermal limits results for the Cricket Valley SUF target solution. Under the studied scenario, if the CV to NE border to LM 345 kV segment is upgraded to a minimum of Rate A = 1320 MVA (from 1195 MVA) and Rate B = 1630 MVA (from 1386 MVA), the ATRA normal export limit will be restored back to the ATBA (benchmark) one. Also, there is no minimum Rate C (Long Time Emergency Rating) identified: The emergency criterion is not used as a design basis; hence the 2e. ATRA results still reflect the current Rate C of 1685 MVA for the NY segment and 1772 MVA for the NE segment.

Table 2.1.2.1. 2e'. shows thermal limits results using the actual ratings and impedances, as provided by ConEdison and NU.

Conclusions:

The degradation in transfer limits of the NY-NE external interface as result of the Q310 Cricket Valley project is deemed to have an adverse reliability impacts under the MIS because the impacts cannot be managed through normal operating procedures of the NYISO and/or CTO. This conclusion was based on comprehensive input received during this study process from ISO-NE, ConEdison, LIPA, and the NYISO.

ISO-NE performed various sensitivities to assess the impact of Cricket Valley on the imports from NY and exports into NY; the results are summarized in the "QP-310 Cricket Valley – NNC/NE-NY Transfer Analysis 10222012" report. The study concluded that the project has an adverse impact on both NE import and exports capabilities, and also on the operability of the system.

2.1.2.1. Cricket Valley: Additional SUFs

Initially, two potential solutions were identified:

1. Reconductoring of Pleasant Valley to Cricket Valley to Long Mountain, along with upgrading the NNC Path elements (*i.e.,* the Northport PAR, the Norwalk autotransformer, and the 3x138 kV submarine cables, as identified in **Table 2.1.2.1**), referred to as “the single line solution”.

2. Adding a second Pleasant Valley to Cricket Valley 345 kV line, while reconductoring the Cricket Valley to Long Mountain 345 segment, referred to as “the second line solution”.

1. “The single line solution”: Based on the feedback received from LIPA, ISO-NE, NU, and Con Edison, and also on NYISO’s review, the NYISO has concluded that a single line upgrade (for CV to PV segment) is unacceptable. Without a second tie line, the project will continue to be isolated into NE’s system for a single contingency (*i.e.:* loss of the PV-CV 345 kV tie with NY), with 40% of the flow being picked up by LIPA via Connecticut and NNC Path, while ISO-NE has no operational control on the project.

The Developer suggested a permanent Special Protection System (SPS) type of scheme that would trip a number of units when such contingency would occur. Based on the feedback received from ISO-NE and Con Edison, and also on the NYISO’s review, the NYISO concluded that such a permanent SPS is also unacceptable.

2. “The second line solution”: In the absence of an acceptable alternative, the NYISO has concluded that a second Pleasant Valley-Cricket Valley line will be required as a System Upgrade Facility (SUF) for the Cricket Valley Energy Center project; building a second tie line would mitigate the effects of isolating the project into NE, while restoring the NE to NY interface thermal limits to an acceptable level. Building the second PV to CV line will also mitigate the impacts on LIPAs/NU’s NNC path for NE to NY transfers (as shown in **Table 2.1.2.1**.).

This “second line solution” includes a proposed reconductoring of the Cricket Valley to Long Mountain segment (part owned by Con Edison, part by NU), in order to restore the NY to NE thermal transfer limits back to the baseline limits.

This solution was determined to be the only acceptable option and triggered more detailed studies and re-assessments.

Selected re-assessments were performed for the “second line solution” package in order to either identify system impacts, or to identify cost estimates and time to construct. The re-assessments are summarized in **Section 10. Cricket Valley SUFs Re-assessments** (either as standalone results, or incorporated under the applicable sections, as identified).

2.2. Voltage Transfer Assessments

Siemens PTI's PSS/E was used to evaluate the voltage transfer limits in accordance with the NYISO Transmission Planning Guideline #2-0, and with consideration of the voltage limits practice (Exhibit A-2 of NYISO Transmission and Dispatching Operations Manual, formerly known as "OP-1 limits") which specifies minimum and maximum voltage limits at key New York State Bulk Power System buses. The required post-contingency voltage limit is typically within 5% of nominal, unless specifically defined (*e.g.,* OP1 limits).

A set of power flow cases with increasing transfer levels was created from the ATBA and ATRA base cases described in **Sections 1.4** and **1.5.** Generation shifts were used to obtain an increase in transfers across the particular interface being studied. The first part of the shift was similar with the thermal assessments for all interfaces studied, while unique shifts particular to each interface were employed to complete the shifts, within the limitations and condition of the base case. Appropriate contingencies were then selected to run on the particular set of transfer cases for an interface to evaluate the system response for that interface.

In this analysis, all areas in NYCA except New York City use the traditional constant power (*i.e.,* constant MVA) model for load to conservatively represent the restoration of load to its pre-contingency state. The Con Edison voltage-varying load model is used to model the New York City load in both pre and post-contingency power flow cases.

The reactive power of generators is regulated, within the capabilities of the units, to hold scheduled voltage in both the pre-contingency and post-contingency power flows. Tap settings of PARs and autotransformers are adjusted (within their capabilities) to regulate power flow and voltage, respectively, in the pre-contingency power flow base cases, but are fixed at their corresponding pre-contingency settings in the post-contingency power flow base cases. Similarly, switched shunt capacitors and reactors are switched at pre-determined voltage levels in the pre-contingency power flow base cases, but are held at their corresponding pre-contingency position in the post-contingency power flow base cases. In accordance with NYISO operating practice, SVC and FACTS devices are held at or near zero output in the pre-contingency power flow base cases, but are allowed to regulate voltage, within their capabilities, in the post-contingency power flow base cases.

As the transfer across an interface is increased, the voltage-constrained transfer limit is determined to be the lesser of (a) the pre-contingency power flow at which the post-contingency voltage falls below the OP-1 post-contingency limit, or (b) 95% of the pre-contingency power flow at the "nose" of the post-contingency PV curve (as per [5]). The "nose" is the point at which the slope of the PV curve becomes infinite (vertical) and reaches the point of voltage collapse. This operating point occurs when the reactive capability supporting the power transfer becomes exhausted. The region near the “nose of the curve” is generally referred to as the region of “voltage instability.” Therefore, the voltage-constrained transfer limit is intended to ensure adequate post-contingency voltage and to avoid operating within this region of voltage instability

For the Dysinger East and West Central evaluation the following contingencies were simulated:

FAULT DE01 L/O STOLLE - H.SHELDON (67)
FAULT DE02 L/O WETHRSFIELD - MEYER (85/87)
CONTINGENCY LOG#01 L/O SOMERSET
CONTINGENCY LOG#02 L/O GINNA
CONTINGENCY LOG#08 L/O 9-MILE PT 2
FAULT ST03 L/O WATERCURE-OAKDALE (4-31 LINE)
FAULT VE08 L/O OAKDALE-FRASER (32-LINE)
FAULT VE09 L/O LAFAYETTE-LAPEER (4-36 LINE)
FAULT WC04 L/O SOMERSET-ROCHESTER (SR1-39)
FAULT WC12a L/O NewRochester-Rochester-PANN
FAULT WC12b L/O SOMERSET-NEW ROCH-PANN

For the UPNY-SENY and UPNY-ConEd evaluation the following contingencies were simulated:

FAULT CE07 L/O NORTHERN MARCY SOUTH DBL CKT
FAULT CE08 L/O SOUTHERN-MARCY SOUTH DBL CKT.
CONTINGENCY LOG#03 L/O INDIAN PT 2
CONTINGENCY LOG#09 L/O RAVENSWOOD #3
FAULT TE32 L/O NEW SCOTLAND BUS (77-ALPS SIDE)
FAULT TE33 L/O NEW SCOTLAND BUS (99-GILBOA SIDE)
FAULT TE38 L/O ROSETON-FISHKILL CKT. (RFK-305)
FAULT TE43 L/O LEEDS - PV CKT 2 (92)
FAULT UC02 L/O Y86/Y87 CKT.
FAULT UC18 L/O Y88/Y94 CKT. (BUCHANAN RIVER CROSSING)
FAULT UC20 TWR W89/W90
FAULT UC21 TWR 30/31
FAULT UC26 TWR 67/68 L/O BOWLINE #1 & #2
FAULT UC27 SBK ROCK TAV 345 (77 & CCRT-42)
FAULT UC30 TWR 34/42 at ROCK TAVERN

Transfer sources / sinks:

Dysinger East/West Central: Source (all units): 65% Ontario, 35% Zone A.

Sink (all units): 45% Zone C, 35% Zone F, 20% Zone G.

UPNY-SENY/UPNY-ConEd: Source (all unit): 50% Zone A, 45% Zone C, 5% Zone F.

Sink (unit specific): 100% Zone J.

Table 2.2.1 provides summaries for the voltage-constrained transfer limits determined for the selected interfaces. Additional details regarding the voltage analysis results are provided in **Appendix D**.

Table 2.2.1 – Voltage-Constrained Transfer Limits for CY11 Study Interfaces (MW)

	Normal				**Emergency**			
Interface	**Open**	**Closed**	**Open**	**Closed**	**Open**	**Closed**	**Open**	**Closed**
	CY11 t0 ATBA		**CY11 t0 ATRA**		**2016 t0 ATBA**		**2016 CY11 t0 ATRA**	
Dysinger East	3058 (1) **3069 (2)** 3102 (3)	5558 (1) **5658 (2)** 5764 (3)	3036 (1) **3039 (3a)**	5421 (1) **5488 (3a)**	3058 (1) **3069 (2)** 3102 (3)	5558 (1) **5658 (2)** 5764 (3)	3036 (1) **3039 (3a)**	5421 (1) **5488 (3a)**
West Central	1681 (1) **1710 (2)** 1744 (3)	4181 (1) **4333 (2)** 4433 (3)	1655 (1) **1713 (3a)** 1734 (1a)	4041 (1) **4162 (3a)** 4223 (1a)	1681 (1) **1710 (2)** 1744 (3)	4181 (1) **4333 (2)** 4433 (3)	1655 (1) **1713 (3a)** 1734 (1a)	4041 (1) **4162 (3a)** 4223 (1a)
UPNY-SENY	**5838 (4)** 5903 (5) …… 5992 (9)	**7319 (4)** 7377 (7) …… 7440 (9)	**5114 (4a)** 5197 (7) ….. 5218 (9)	**6568 (4a)** 6606 (7) …. 6643 (9)	**5838 (4)** 5903 (5) …… 5992 (9)	**7319 (4)** 7377 (7) …… 7440 (9)	**5114 (4a)** 5197 (7) ….. 5218 (9)	**6568 (4a)** 6606 (7) …. 6643 (9)
UPNY-ConEd	**4366 (4)** 4409 (7) …. 4444 (9)	**7231 (4)** 7296 (7) ….. 7357 (9)	**4578(4a)** 4644 (7) ….. 4664 (9)	**7439 (4a)** 7534 (7) ….. 7569 (9)	**4366 (4)** 4409 (7) …. 4444 (9)	**7231 (4)** 7296 (7) ….. 7357 (9)	**4578(4a)** 4644 (7) ….. 4664 (9)	**7439 (4a)** 7534 (7) ….. 7569 (9)

Notes:

1. Station 80 345 kV bus voltage for pre-contingency condition;

1a. Station 80 345 kV bus voltage for SB at New Rochester 345 kV;

2. 95% voltage collapse criteria for **breaker failure at S255 345 kV** (New Rochester) (L/O Kin-S255-S80);

3. 95% voltage collapse criteria for L/O Ginna;

3a. 95% voltage collapse criteria for **L/O Ginna,** or **L/O 9MPt2,** or **breaker failure at S255 345 kV;**

4. **95% voltage collapse** criteria for **L/O Ravenswood** 3 or for **L/O TWR 89/90** (Pleasantville-Dunwoodie 345 kV);

4a. 95% voltage collapse criteria for **L/O TWR 89/90** (Pleasantville-Dunwoodie 345 kV);

5. 95% voltage collapse criteria for L/O TWR Y86/Y87 (E. Fishkill –Pleasantville 345 kV), or Marcy SS, or IP2;

6. 95% voltage collapse criteria for L/O TWR Y67/68 (Ladentown-W Hav-Bowl345 kV);

7. Dunwoodie 345 kV pre-fault;

9. Sprainbrook or Dunwoodie 345 kV for L/O TWR 89/90.

   - Branchburg - Ramapo PARs set on 440 MW into NY for all t0 cases.

Following are some key observations for this voltage transfer assessment.

Dysinger East/West Central interfaces: Both normal and emergency limits occur for the 95% voltage collapse criteria for breaker failure at Station 255 (*i.e.,* New Rochester 345 kV substation) in ATBA, or loss of (I/O) Ginna, or loss of 9 Mile Point 2, or for breaker failure at Station 255, in ATRA. There is a decrease from ATBA to ATRA of about -40 MW for Dysinger East open interface, mainly due to the redistribution of flows between the two systems. West Central limits remain unchanged (+3 MW).

UPNY-SENY: Both normal and emergency limits occur for the 95% voltage collapse criteria for loss of Tower 89/90 (Pleasantville-Dunwoodie 345 kV) for ATBA, and loss of Tower 89/90, or loss of Ravenswood 3 for ATRA. The ATRA limits are approximately -700 MW lower, mainly due to the change in the dispatch to accomodate CY11 projects CPV Valley and Cricket Valley.

UPNY-ConEd: Both normal and emergency limits occur for the 95% voltage collapse criteria for loss of Tower 89/90 (Plesantville-Dunwoodie 345 kV), or loss of Ravenswood 3. The ATRA limits are approximately +200 MW higher than ATBA due to the effects of flow redistribution.

Conclusion:

Any internal NYCA transfer limit reductions and transmission limitations identified by this study are observed under specific system conditions, study assumptions, and dispatch patterns modeled in the respective study cases, and can be managed through the normal operating procedures of the NYISO and/or TOs, therefore they are not considered a degradation of the system reliability or non-compliance with NERC, NPCC or NYSRC reliability standards. Consequently, under the NYISO MIS requirements, no SUFs are required to address them.

2.3. Stability Transfer Assessments

For stability transfer analysis test purpose, two “margin cases” for ATBA and two “margin cases” for CY11 ATRA were created, one to assess Western NY interfaces (Dysinger East, West Central), and one to assess UPNY-SENY/UPNY-ConEd.

Initially, the target flows for each margin case will be 11.1% above the more restrictive of the emergency thermal or voltage limits identified under the study conditions (see **Tables 2.3.1** and **2.3.2**). If such stressed levels cannot be reached due to voltage collapse, and as per Transmission Planning Guideline #3, (Stability), fictitious reactive devices could be added so the levels will be reached in order to test the system for stability purposes. Selected key bulk power system design criteria contingencies are then applied on each of the margin cases. If the system is stable at these stressed levels, then it can be concluded that the system does not have a more controlling stability limit; if the system is unstable, then the interface levels will be decreased in steps in order to identify the level where the system is stable. Then a controlling stability limit will be identified as 90% of the respective transfer levels (providing a 10 % margin, as per the Transmission Planning Guideline #3).

The dynamic representation used in this analysis was developed from the ATBA/ATRA 2016 summer peak load and the ERAG/MMWG 2011 series with updates from PJM and other NPCC areas. The real power load models used for various Areas within NERC were (1) constant current (power varies with the voltage magnitude), (2) constant impedance (power varies with the square of the voltage magnitude) for New York and New England, and (3) 50% constant current and 50% constant impedance for Ontario, Nova Scotia, and Cornwall. Reactive load was modeled as constant impedance for all Areas except Hydro Quebec, which uses a 13% constant current and 87% constant impedance model for reactive load.

Table 2.3.1 ATBA Stability Margin Case Interface MW Levels

	Target level for the margin case	**Actual ATBA margin case**	
DyE	3,108	3100	Western NY (CE at 2580 MW)
WC	1,665	1675	
US	5,994	6425	UPNY/SENY-UPNYConEd (CE at 2925 MW)
UC	4,884	4925	

Table 2.3.2 ATRA Stability Margin Case Interface MW Levels

	Target level for the margin case	Actual ATRA margin case	
DyE	3,108	3145	Western NY (CE at 2611 MW)
WC	1,665	1711	
US	5,661	5725	UPNY/SENY-UPNYConEd (CE at 2906MW)
UC	5,084	5143	

Conclusions

Under the study assumptions:

Western NY margin cases were found stable for the assessed contingencies.

UPNY-SENY/UPNY-ConEd margin case was found stable for the assessed contingencies.

The testing results for **ATBA** and **ATRA** margin cases, listing the design criteria contingencies evaluated and a determination of the overall system response as being stable or unstable, along with selected plots are provided in the **Appendix E**.

3. Transfer Limits Summary

Table 3.1. below summarizes the most controlling (lowest) limit among the thermal, voltage and stability MW levels identified in the above sections. This analysis was not intended to determine the maximum limits based on an ideal shift pattern, but rather to show the relative impact of the addition of the CY projects, along with the respective dispatch pattern, on the ATBA system.

Table 3.1. Transfer Limits Summary (showing most controlling limit (MW)

CY11 Study Interfaces	Normal Transfers				Emergency Transfers			
	CY11 ATBA		CY11 ATRA		CY11 ATBA		CY11 ATRA	
	Open	Closed	Open	Closed	Open	Closed	Open	Closed
Dysinger East	2687 (1Tn)	4616 (1Tn)	2688 (1Tn)	4624 (1Tn)	2790 (1Te)	4740(1Te)	2805 (1Te)	4765 (1Te)
West Central	1385 (1Tn)	3315 (1Tn)	1391 (1Tn)	3329 (1Tn)	1489 (1Te)	3440 (1Te)	1510 (1Te)	3472 (1Te)
UPNY-SENY	4740 (3Tn)	5965 (3Tn)	4748 (3Tn) +76 (5)	5988 (3Tn) +76 (5)	5394 (3Te)	6620 (3Te)	5114 (4aV) +70 (5)	6568 (4aV) +92 (5)
UPNY-ConEd	4366 (4V)	7231 (4V)	4294 (4T) +33 (5)	7015 (4T) +33 (5)	4366 (4V)	7231 (4V)	4578 (4aV) +70 (5)	7439 (4aV) +102 (5)

Notes:

1Tn/e. S. Perry-Wethersfield 230 kV at LTE/STE for stuck breaker at Niagara 345 kV

3Tn/e. Leeds-Pleasant Valley 345 kV at LTE/STE for L/O Athens-Pleasant Valley 345 kV

Note: At the time of initiating the CY11, Athens SPS was proposed to be retired by the 2016 study timeframe, therefore the LTE rating was observed for normal criteria; however, latest developments indicated that the SPS will be extended beyond 2016, hence the normal limits are higher than shown if the SPS effects would be considered (by observing a higher STE rating for normal criteria).

4V. 95% voltage collapse criteria for L/O Ravenswood 3 or for L/O TWR 89/90 (Pleasantville-Dunwoodie 345 kV)

4aV. 95% voltage collapse criteria for L/O TWR 89/90 (Pleasantville-Dunwoodie 345 kV)

4T. Rock Tavern-Ramapo 345 kV at LTE for stuck breaker at Fishkill 345 kV, or L/O Roseton-Fishkill, etc.

5 – Increase in the limit for the ATRA case with the 2nd PV-CV 345 kV proposed line.

4. Local Thermal and Voltage Assessments

Following are some of the key observations for this local thermal and voltage assessment. Based on SRIS conclusions, selected design criteria contingencies were re-evaluated. Siemens PTI's MUST program was used to simulate the selected contingencies. **Appendix F** contains details, along with oneline powerflow diagrams to show projects' location (for exemplification only, not all network details may show).

Findings by Zone and project:

Zone A

Q 198 Arkwright Summit Wind Farm (79.8 MW wind generation project, proposed to interconnect on National Grid-Niagara Mohawk's Dunkirk – Falconer 115 kV Line #161):

Potential issue:

Under the study assumptions and base cases dispatch, loss of both Dunkirk 115kV buses (stuck breaker between the buses) results in very low voltages on the 115kV system in the area of Dunkirk in the ATBA case. The voltage issues are exacerbated in the ATRA and leads to a voltage collapse on the 115kV system in the area of Dunkirk.

Potential mitigation:

National Grid plans to install a second in-series bus tie breaker which would eliminate this contingency. Since Arkwright Summit may be in-service before this additional breaker is installed, undervoltage relaying will be installed and set to trip the plant off.

Potential issue:

Under the study assumptions and base cases dispatch, loss of the Dunkirk 115kV #1 bus or loss of the 161/162 tower results in low voltages on the 115kV system in the area of Dunkirk in the ATRA case.

Potential mitigation:

Turning on all of the capacitors on the Arkwright Summit generators will mitigate these voltage issues. The LTC on the plant transformer can be used to ensure that no overvoltages occur within the Arkwright plant.

Zone B

Q 169 Alabama Ledge Wind Farm (79.8 MW wind generation project, proposed to interconnect on National Grid-Niagara Mohawk's Lockport – Oakfield 115 kV Line #112). This project was withdrawn from the queue as of June 1, 2012, by the Developer.

Zone G

Q349 Taylor Biomass (19 net MW generation project, proposed to interconnect on Central Hudson's Rock Tavern – Maybrook 69 kV line)

Under the study assumptions and base cases dispatch, no thermal and voltage issues were found with this project.

Q251 CPV Valley (677.6 net MW generation project proposed to connect to NYPA's 345 kV Line #42 Coopers Corners to Rock Tavern).

Potential issue:

Under the study assumptions and base cases dispatch, for the tower outage of the 34 and 42 lines (Coopers Corners to Rock Tavern, CPV Valley to Rock Tavern), the entire output of CPV Valley gets rerouted via Coopers Corners. This results in an approximate 210% overload on the West Woodbourne 115/69 kV transformer in the ATRA compared to approximately 180% in the ATBA case. Also, overloads on the Honk Falls-Kerhnkmk 69 kV line, Galevile-Kerhnkmk 69 kV line, Modena 115/69 kV transformer, Galevile-Modena6 69kV line, and Honk Falls-Kerhnk P 69 kV line increased from up to 134% in the ATBA to 157% in the ATRA.

Potential mitigation:

There are overload relays on the West Woodbourne 115/69 kV transformer and overload relays at Honk Falls that will trip the low side of the West Woodbourne 115/69 kV transformer. The operation of the relaying and tripping of the West Woodbourne 115/69 kV transformer will mitigate the overloads.

Potential Issue:

Under the study assumptions and base cases dispatch, the stuck breaker RMP_77-2X and RMP_345_77-94-2 caused up to a 7% LTE overload on the Chester-Shoemaker 138kV line. Also, the Chester-Sugarloaf 138kV line was at 100% LTE. These contingencies were approximately 10% higher in the ATRA compared to the ATBA. These overloads occurred in the study cases due to the 138 kV picking up some of the transfers with Rock Tavern to Ramapo 345 kV line out and also picking up some of the load at Ramapo with the Ramapo 345/138 kV transformer out.

Potential mitigation:

The generation on or upstream of the 345 kV path can be shifted to effectively reduce the transfers seen by the 138 kV and/or increasing generation downstream will mitigate the overloads. In addition, reconductoring the lines and replacing the transformer will also mitigate the overloads.

Under the Minimum Interconnection Standard these potential issues can be managed or prevented to occur through the normal operating procedures of the NYISO and/or TOs, therefore they are not considered a degradation of the system reliability or non-compliance with NERC, NPCC or NYSRC reliability standards.

Q310 Cricket Valley Energy Center (1019.9 net MW generation project proposed to connect to ConEd's 345 kV Line #398 Pleasant Valley – Long Mountain (New England)).

Under the study assumptions and base cases dispatch, no thermal and voltage issues were found with this project.

N-1-1 Sensitivity[8] Analysis:

Under the study assumptions and base cases dispatch, no thermal and voltage issues were found with this project. However, as similarly noted above under the CPV Valley section, there were issues found in the Middletown tap/Shoemaker/Chester area. As noted above, the generation on or upstream of the 345 kV path, including the CY11 projects, can be shifted to effectively reduce the transfers seen by the 138 kV and/or increasing downstream generation will mitigate the overloads. In addition, reconductoring the lines and replacing the transformer will also mitigate the overloads (this solution has not been elected by any party).

[8] On selected contingencies, at the CTO's request.

Zone J

Q 201 & 224 Berrians GT and Berrians GT II (250 MW (net summer output) generation project proposed to interconnect to Con Edison's Astoria West 138 kV Substation).

Potential issue:

Under the study assumptions and base cases dispatch, pre-contingency loading on Vernon-E – Greenwood 138kV increased by 20%, Queensbridge – Astoria W 138kV increased by 20%, and Goethals 25 & 26 345kV increased by 10%, but none of the lines were overload.

Potential mitigation: None required.

Potential issue:

Under the study assumptions and base cases dispatch, the 25 and 26 lines (Goethals – Gowanus 345 kV) increased loading by approximately 10% for loss of the other. The loading in both the ATBA and the ATRA was above LTE, but under STE. Con Edison allows the use of STE ratings for cable circuits under Exception 20 of the NYS Reliability Council Reliability Rules. The cables were not above their STE rating. This increase in loading is simply a function of the redispatch of the system for Berrians.

Potential mitigation: None required.

N-1-1 Sensitivity[8] Analysis:

Under the study assumptions and base cases dispatch, no thermal and voltage issues were found with this project.

Q 351 Linden VFT Uprate (15 MW increase in VFT capability) existing VFT interconnected to Con Edison's Goethals 345 kV Substation).

Potential issue:

For a stuck breaker at Goethals 345 kV, or the outage of the G23L&M circuit, the Goethals-Linden 345 kV PAR (the A PAR) line was over its limit.

Potential mitigation:

The local generation (*e.g.,* Linden Cogentech) along with Linden VFT would be dispatched pre-contingency to prevent the post-contingency issues.

N-1-1 Sensitivity[8] Analysis:

Under the study assumptions and base cases dispatch, no thermal and voltage issues were found with this project.

Conclusion:

Unless specified otherwise, any potential issues identified by this study are observed under specific system conditions, study assumptions, and dispatch patterns modeled in the respective study cases, and can be managed through the normal operating procedures of the NYISO and/or TOs, therefore are not considered a degradation of the system reliability or non-compliance with NERC, NPCC or NYSRC reliability standards. Consequently, under the NYISO Minimum Interconnection Standard requirements, no SUFs are required to address them. However, either the affected Developers or the Transmission Owners (TO) may elect to address any potential issue (as related with their project impacts) by submitting a Study Request under the NYISO Transmission Expansion process per Sections 3.7 or 4.5 of the NYISO OATT.

5. Local Stability Assessment

This section describes local stability assessment performed in the scope of the CY11 Facilities Study (SUF) and discusses the obtained results.

5.1 Study Approach

The major goals of the CY11 local stability assessment is to evaluate CY11 projects' dynamic responses and NYCA's dynamic responses to CY11 projects' local contingencies and, based on simulation results, to find out if there is a need for SUFs addressing local stability issues.

According to the CY11 Facilities Study Work Plan submitted to the IPFSWG, the work began with a review of studies performed for the CY11 projects at previous stages of the Interconnection Process. Mostly, results of these studies are described in the following documents:

- CY11 projects' SRIS reports;
- CY06-CY10 Facilities Study Reports (Part 2).

The CY11 local stability assessment also used the following materials and information:

- Findings of materiality determination and other supplemental stability analyses having been conducted for some of the CY11 projects and also for non-CY11 projects before the CY11 Facilities Study commenced;
- The most recent information on power devices utilized by the CY11 projects (supplied by project developers, equipment manufacturers and dynamic model developers);
- Applicable materials included in the CY11 Facilities Study, Part 1 reports prepared for individual CY11 projects.

The next stage of the work was the development of the ATRA11 dynamic setup (NYCA with the CY11 projects). In both ATRA11 power flow base case and the ATRA11 dynamics data part of the setup, all most recent data updates supplied by CY11 Facilities Study participants were implemented. Applicable changes were also made in the ATBA11 (NYCA without the CY11 projects) databases prepared for comparative analyses.

At the next stage of the CY11 local stability assessment, 64 local contingency scenarios were simulated, along with conducting relevant sensitivity analyses. Evaluation of CY11 projects' and NYCA's stability was performed in accordance with the NYISO Transmission Planning Guideline #3-0.

After the CY11 local stability simulation runs on the original ATRA11 power flow case (hereafter called "the original simulations") were completed, analyses carried out in the course of parallel CY11 studies identified the need for SUFs for the Q#310 Cricket Valley Energy Center project. These SUFs were intended to prevent degradation of transfer interface limits between New York and New England power systems in both directions (see Section 2.1.2). Therefore, another ATRA11 dynamic setup version was developed and additional stability simulations were performed to evaluate the performance of the Q#310 project with the SUFs. The results of this analysis are included in Section 5.10. Also, some additional analyses were conducted to account for the modeling data update supplied for the Q#224 Berrians GT II project.

With respect to the Q#351 Linden VFT Uprate analysis, a FERC Order in Docket No. EL12-64 determined that the 15 MW uprate was not subject to the interconnection process. After the FERC's Order was issued, further study of the Q#351 project was therefore unnecessary. The simulation results pertaining to this project included in this section were obtained prior to the FERC's Order issuing date. These results are left in the report to demonstrate the stability performance of the Linden VFT project at the level of 315 MW.

To perform all stability simulations, the Siemens PTI PSS/E software (Version 30.3.3) was applied: the PSSDS4 dynamics program (its standard mode) for contingency calculations and the PSSPLT program for plotting calculation results. Detailed simulation plots showing both individual CY11 projects' and NYCA's phenomena are included in Appendix G.

5.2 Power Flow Cases and Dynamic Simulation Setups

The ATRA11 dynamic setup (for NYCA with the CY11 projects) developed for the local stability assessment is a derivative from the ATBA11 Rev. 3 dynamic setup (the file CY11_Sum16_ATBA_Rev3_stability.zip is available through the NYISO ePlanning). In accordance with the CY11 local stability assessment scope, contingencies are to run on the summer peak load case for the Study Year 2016.

The main database applied for the CY11 local stability assessment is ATRA11 Rev.1 (the file CY11_Sum16_ATRA_Rev1_stability.zip is available through NYISO ePlanning). This database was used for the original ATRA11 local stability simulations.

When adding the CY11 projects' dynamics data, the most recent information supplied by project developers, equipment manufacturers and dynamic model developers was reflected. In addition to the dynamics data, a few power flow data updates were implemented. Some of the updates were received in the course of studies parallel to the CY11 Facilities Study work.

As a result, the power flow base case CY11_Sum16_ATRA_Rev1a.sav prepared for the local stability analysis (as part of the ATRA11 dynamic setup) differs from that applied in the CY11 local thermal and voltage assessments (Section 4). Also, the dynamics part of the ATRA11 setup differs from that applied in CY11 stability transfer limit analysis (Section 2).

Table 5.2 specifies the names of the major PSS/E files included in the databases ATBA11 Rev. 3 and ATRA11 Rev. 1: power flow base case (SAV) files, power flow converted case (CNV) files, dynamics data (DYR) files and snapshot (SNP) files.

Table 5.2 – Major Power Flow Case and Dynamic Setup Files

File Type	ATBA11 Rev. 3	ATRA11 Rev. 1 [1]
SAV	*CY11_Sum16_ATBA_Rev3.sav*	*CY11_Sum16_ATRA_Rev1a.sav*
CNV	*CY11_Sum16_ATBA_Rev3.cnv*	*CY11_Sum16_ATRA.cnv* [2]
DYR	*2016SUM-2010Series-Final-ds_rev3.dyr*	*CY11_Sum16_ATRA.dyr*
SNP (no plotting channels)	*CY11_Sum16_ATBA_nochan.snp*	*CY11_Sum16_ATRA_nochan.snp*
SNP (channels for NYCA)	*CY11_Sum16_ATBA_chan.snp*	*CY11_Sum16_ATRA_chan.snp*
SNP (channels for NYCA and for CY11 Projects)		*CY11_Sum16_ATRA_chan_CY11.snp*

[1.] These ATRA11 Rev. 1 files were used in simulations for all CY11 projects. In addition, another dynamic setup was developed to evaluate Q#349 Taylor Biomass contingencies that created a 69 kV island with the subject project. For these contingencies, consistently with the project SRIS, the load at Maybrook (bus 126140, MAYBROOK) was represented in more detail: two buses (125211 MAYBROOK_A and 125212 MAYBROOK_B were created; then, dynamic models were included in the setup to represent these two loads as well as the Montgomery load, also within the island (bus 125114 MONTGMRY. More information can be found in Section 5.3. The major dynamics data, power flow and snapshot files that constitute this Q#349-project-specific setup are as follows: CY11_Sum16_ATRA_Q#349-islanding.dyr, CY11_Sum16_ATRA_Q#349-i.cnv and CY11_Sum16_ATRA_chan_CY11_Q#349-i.snp.

[2.] This CNV power flow case was used in most ATRA11 local stability simulations as input to contingency files. For some CY11 projects, however, derivatives of this CNV case had to be created prior to stability simulations. Besides Q#249 Taylor Biomass, for which the CNV case CY11_Sum16_ATRA_Q#349-i.cnv was applied, an example can be Q#224 Berrians GT II.

The dynamic database applied for additional simulations accounting for the Q#310 Cricket Energy Center SUFs (dynamic setup ATRA11 Rev. 2) is described in Section 5.10.

To convert the SAV power flow cases for switching studies (while preparing CNV cases), in accordance with NYISO practices and based on available information, the active power load models used for various network areas were as follows:

- Constant current – for Hydro Quebec, New Brunswick, MAAC and ECAR;
- Constant impedance – for NYCA and New England; and
- 50% constant current and 50% constant impedance – for Ontario, Nova Scotia and Cornwall.

Reactive load was modeled as constant impedance for all areas except Hydro Quebec, which used a 13% constant current and 87% constant impedance model for reactive load.

The full set of dynamic setup building files, dynamic model and data files and miscellaneous auxiliary files needed to create the ATRA11 dynamic setup and to perform stability simulations is described in the ReadMe file included in the database CY11_Sum16_ATRA_Rev1_stability.zip.

It is also worth making a few notes on major PSS/E numerical solution arrangements made in the study.

The major solution settings were as follows:

- Numerical integration time step size (DELT): 4.1667 ms (¼ of a of 60 Hz cycle);
- Algebraic solution parameters: NIT = 400; ACCEL = 0.5 and TOL = 0.0001;
- The Network Frequency Dependence option is disabled.

While most contingency runs assumed the above default settings, some model investigations and sensitivity analyses required that parameters be varied.

In most situations, to evaluate the dynamic response of both CY11 projects and NYCA, the simulation interval of 20 seconds was sufficient. However, due to miscellaneous modeling concerns, in some cases the interval had to be increased up to 50 seconds.

5.3 Dynamic Models Used in the Dynamic Setup ATRA11

The ATRA11 Rev. 1 dynamic setup uses the most recent revisions of relevant user-written PSS/E models of new power system components to ensure, to the extent possible, that none of the known modeling issues would adversely affect the quality of simulations. For the conventional CY11 projects, relevant standard or user-written PSS/E models are applied to represent generators, power system stabilizers (PSSs), excitation systems and turbine-governors. For each CY11 projects, all dynamic models as well as their dynamics data were subject to both NYISO's and project developer's review. For most projects, after a discussion, either the dynamic model or the data were updated or revised.

Table 5.3 summarizes the information on all dynamic models representing the CY11 projects in the ATRA11 Rev. 1 dynamic setup.

Table 5.3 – Dynamic Models Used for CY11 Projects

#	Q#	Project Name	Dynamic Models	
1	Q#198	Arkwright Summit Wind Farm	*S_SFSWT* (Suzlon S88 2.1 MW WTG) [1]	
2	Q#224	Berrians GT II	GT	*GENROU, PSS2A, ESST4B, GAST2A*
			ST	*GENROU, PSS2A, EXAC1, IEESGO* [4]
3	Q#251	CPV Valley	CTs	*GENROU, UST6B* [1], *WESGOV*
			ST	*GENROU, UST6B* [1], *UPSS2B* [1]
4	Q#310	Cricket Valley Energy Center	CTs	*GENROU, ESST4B, GGOV1, PSS2A*
			STs	*GENROU, ESST4B, IEEEG1, PSS2A*
5	Q#349	Taylor Biomass [2, 3]	CT	*GENSAE, UAC8B* [1], *SOLAGT* [1]
			ST	*GENSAE, UAC8B* [1]
6	Q#351	Linden VFT Uprate	*GEVFT* (Variable Frequency Transformer – VFT) [1]	

1. A user-written PSS/E model. Otherwise, the model is PSS/E standard.

2. For Q#349 Taylor Biomass, the combustion unit (CT) is modeled with a governor (model SOLAGT) active in the time frame of stability simulations. The steam unit (ST) has no governor, since this ST, which is a heat recovery steam generator (HRSG), utilizes the exhaust heat from the CT unit.

3. For simulating the Q#349 Taylor Biomass contingencies that create a 69 kV island with the project, consistently with the project SRIS, load frequency models LDFRBL are added to the dynamic setup to represent the loads within the island: at bus 125114 (MONTGMRY) and buses 125211 (MAYBROOK_A) and 125212 (MAYBROOK_B). The model LDFRBL is intended to make

these three loads sensitive to local bus frequency. Note that simulations with the islanding were performed with Network Frequency Dependence option of the PSS/E program enabled.

[4.] In the original simulations for Q#224 Berrians GT II, the turbine of the steam unit (ST) was represented by the turbine-governor model IEESGO, which was consistent with the information available by the time when the ATRA11 Rev. 1 dynamic setup was finalized. However, on 09/27/2012, the project developer, with reference to GE Energy materials, provided an update stating that the project should be modeled with no turbine control model for the ST. Therefore, the Q#224 local contingencies were rerun with IEESGO disabled. The difference between simulations with and without IEESGO on the ST was insignificant (see also Section 5.8).

5.4 Dynamic Modeling and Simulation Issues

In NYISO studies during recent years, numerous dynamic modeling and simulation concerns occurred due to the performance of dynamic models of new power system components such as WTGs, photovoltaic inverters (solar power plants) and energy storage devices. While the Class Year 2011 includes only one wind generation project, many wind plants are part of the ATBA11 dynamic setup. Also, the latter includes a solar plant model and a flywheel energy storage device model.

For some of these devices, a number of newly discovered modeling issues that had had or could have an adverse impact on the quality of simulations were addressed prior to or in parallel with the development of the ATBA11 and ATRA11 dynamic setups. Therefore, these dynamic setups include most up-to-date versions of the corresponding models.

For the Suzlon S88 2.1 MW WTG, which is used by Q#198 Arkwright Summit Wind Farm, a few consecutive S_SFSWT model versions had been supplied by the manufacturer to address issues identified prior to the ATBA11/ATRA11 development. However, at a late stage of the ATRA11 development, while implementing project developer’s updates on the collector system representation, the current S_SFSWT version was found to be inappropriate in terms of PSS/E initialization. To ensure a more robust initialization, Suzlon developed a new S_SFSWT version with which the dynamic setup ATRA11 was able to initialize.

It is also worth noting that, as before, the way the new model S_SFSWT calculates the output reactive power (QELEC) makes it necessary that the Qmax and Qmin settings in the power flow case applied in stability simulations differ from those applied in power flow analyses.

5.5 Stability Assessment Criteria

In the scope of the CY11 Facilities Study, stability evaluations were made for both CY11 projects and the rest of the New York State power system (NYCA). Stability was assessed in accordance with the criteria provided for the “generation stability” and the “system stability” sections of the NYISO Transmission Planning Guideline #3-0.

When simulation results were in question, additional calculations on longer intervals and/or with different solution settings as well as relevant sensitivity analyses were performed in order to eliminate an adverse impact of modeling issues and data uncertainties, to better understand observed phenomena and to double-check stability evaluation results.

5.6 *Plotting and Presenting Simulation Results*

Simulation plots obtained as a result of simulations are included in Appendix G.

The following phenomena are shown on the plots:

- ANGLE (abbreviated as A): machine rotor angle of a synchronous generator (in degrees);
- BsFREQ (abbreviated as F): bus frequency (in Hz);
- EFD (abbreviated as EFD): field voltage of a synchronous generator (in pu);
- MW and MVAr flows: active and reactive power flow through a branch (in pu);
- PELEC and QELEC (abbreviated as P and Q): output active and reactive power of a generator (in pu);
- PMECH (abbreviated as PM): mechanical power of a generator (in pu);
- SPD (abbreviated as S): rotor speed (in Hz) or speed deviation (in pu);
- VOLT (abbreviated as V): generator terminal or other bus voltage (in pu).

To present simulation results for each local contingency, the report uses a set of plots divided into two major parts:

- Part 1 – project phenomena (that is, phenomena for the individual CY11 project for which the subject local contingency is simulated along with phenomena in some representative nearby network elements);

- Part 2 – NYCA phenomena (around the whole NYCA).

Below, both parts of the plotting set are described in more detail.

<u>Part 1: Individual Project Phenomena (Appendix G.Q#-1)</u>

Part 1 plotting depends on the nature of the project. The Part 1 set can be in turn divided into two parts. Generally, Part 1.1 plots show phenomena for individual project units (that is, either WTG equivalents or actual synchronous generators/turbines or VFT channels), while Part 1.2 rather characterizes the project as a whole: it shows POI phenomena and, for the projects with conventional generation and the Q#351 project with a VFT, phenomena in some nearby generators (either NYCA's or those in a neighboring power system – NE or PJM).

<u>Part 1.1 – Project's Units Phenomena</u>

For Q#198 Arkwright Summit Wind Farm (with Suzlon S88 2.1 MW WTGs), which is the only one wind generation project in the Class Year 2011, Part 1.1 includes 4 diagrams – one for each of the four WTG equivalents assumed by the project power flow representation. The following phenomena are shown for each WTG equivalent: generator terminal voltage (V), rotor speed (S) and active (P) and reactive (Q) powers. These plots are shown on the interval of 20 seconds. Simulation plots demonstrating the LVRT capability of this project (on the interval of 0.5 to 2.5 seconds) are included in Appendix G.Q#198-1-LVRT.

For Q#351 Linden VFT Uprate, which utilizes a VFT device, Part 1.1 includes 4 diagrams: first, plots for phenomena in VFT Channels 1 and 3 (note that both power flow and dynamic representation of the VFT device assumes three identical channels); second, plots for voltage (V) and frequency (F) at two buses on the PJM side and the same for the NY side.

For each of the other four CY11 projects, all of them with conventional generation, Part 1.1 includes plots for each project unit (either gas/combustion or steam): first, it shows voltage (V), speed deviation (S), active (P) and reactive (Q) power; then, its shows angle (A), speed deviation (S), field voltage (EFD) and mechanical power (PM).

Part 1.2 – Project's POI Phenomena

Generally, Part 1.2 shows POI bus voltage (V) and frequency (F) and also MW and MVAr flows from the project into the POI bus. Note that for Q#310 Cricket Valley Energy Center, Part 1.2 shows the MW flow through the 345 kV line to the New England power system (branch 128284 Q310APDUYARD – 119272 NE_398_NY CKT 1); for Q#351 Linden VFT Uprate, Part 1.2 shows flows from PJM to VFT and flows from VFT to NY.

In addition, for the four non-wind generation projects and also for Q#351 Linden VFT Uprate, Part 1.2 shows phenomena (A, S, P and Q) in some representative conventional generator(s) electrically close to the subject project, which provides more insight into the power system stability.

These generators are as follows:

- for Q#224 Berrians GT II – AST 3 Generator 1 (bus 126654);
- for Q#251 CPV Valley – Q#349 Taylor Biomass CT (bus 126152);
- for Q#310 Cricket Valley Energy Center – ROCKY RIVER Generator 1 (bus 126657) in the ISO-NE system;
- for Q#349 Taylor Biomass – Montgomery Generator 2 (bus 125114);
- for Q#351 Linden VFT Uprate – COGENGT1 Generator 1 (bus 126159) in NYCA and TOSCONUG Generator 1 (bus 218344) in the PJM system.

Within each Appendix G-Q#-1, Part 1.1 plots are immediately followed by Part 1.2 plots – they are not separated.

Part 2: NYCA Phenomena (Appendix G-Q#-2)

For NYCA, the set of plots provided for each contingency consists of 3 full pages (4 diagrams per page) and shows phenomena for representative NYCA interfaces, buses and generators, all of them geographically distributed among the power system:

- Page 1: active power (MW) flow for 12 NYCA interfaces;
- Page 2: voltage (V) and frequency (F) for 6 NYCA buses;
- Page 3: machine rotor angle (A) for 6 synchronous generators and relative machine rotor angle (in degrees) – also 6 values.

For the Part 1 and Part 2 plots, both their formats and scales, to the extent possible, are consistent with those in the CY09 and CY10 local stability assessments. The plotting window depends on project and contingency. Usually, the plotting window is 20 seconds; however, in some cases, the plotting interval is different in order to fully illustrate relevant phenomena. To characterize the LVRT capability of Q#198 Arkwright Summit Wind Farm, the window of 2 seconds is used.

All stability simulation plots are included in Appendix G (Local Stability Simulation Plots). Table 5.6 is intended to facilitate the navigation.

Table 5.6 – Appendix G Navigation Guide

#	Q#	Project Name	Simulation	Part/Phenomena	Appendix
1	Q#198	Arkwright Summit Wind Farm	Local Contingencies	Part 1: Q#198	G.Q#198-1
				Part 2: NYCA	G.Q#198-2
2	Q#224	Berrians GT II	Local Contingencies	Part 1: Q#224	G.Q#224-1
				Part 2: NYCA	G.Q#224-2
3	Q#251	CPV Valley	Local Contingencies	Part 1: Q#251	G.Q#251-1
				Part 2: NYCA	G.Q#251-2
4	Q#310	Cricket Valley Energy Center [1]	Local Contingencies	Part 1: Q#310	G.Q#310-1
				Part 2: NYCA	G.Q#310-2
5	Q#349	Taylor Biomass	Local Contingencies	Part 1: Q#349	G.Q#349-1
				Part 2: NYCA	G.Q#349-2
6	Q#351	Linden VFT Uprate	Local Contingencies	Part 1: Q#351	G.Q#351-1
				Part 2: NYCA	G.Q#351-2

[1.] Results of the additional simulations performed for Q#310 Cricket Valley Energy Center with the SUFs (see Section 5.10) are included in two appendix parts: Part 3 (Q#310 phenomena) – Appendix G.Q#310-3 (2nd PV-CV line) and Part 4 (NYCA phenomena) – Appendix G.Q#310-4 (2nd PV-CV line). The augmented Q#310 section structure is shown in Table 5.10-3.

5.7 Local Contingencies Simulated in CY11 ATRA

For all CY11 projects, most local contingency scenarios were based on descriptions and data proposed at earlier stages of the Interconnection Process. Some scenarios were updated based on the information that had been provided by transmission owners, project developers and their consultants. In addition, some more contingencies were proposed by connecting transmission owners.

In many cases, contingency scenarios were intentionally stressed. That is, while the logic of a scenario evaluated in the CY11 local stability assessment was identical or similar enough to that assumed by a previously evaluated scenario, either the fault type or the fault clearing procedure (stages, times) assumed more severe conditions.

For many contingencies, to implement the fault clearing scenario for an actual breaker layout of the project POI substation, consistently with what was done in previous stability studies (in the project SRIS, relevant Facilities Studies, etc.), special project-specific power flow cases (with dummy buses or tapped transmission lines) needed to be prepared.

The full CY11 local contingency set, which includes 64 scenarios, is shown in Table 5.7. For reader's convenience, Table 5.7 is divided into portions – for individual CY11 projects.

For most contingencies, in addition to the ID used in this study, Table 5.7 specifies another ID – see column "Other ID, If Any." This "Other ID" is the name used for this or for a pretty much similar contingency scenario in previous stability studies performed for the subject project.

For Q#198 Arkwright Summit Wind Farm, the local contingencies were also used to evaluate the project's LVRT capability (see Section 5.9).

For each of the local contingencies, the first disturbance (usually, a fault) is always applied at t = 1.0 s. The simulation interval depends on the project and contingency. In most cases, the interval of 20 seconds is sufficient.

To make the contingency scenarios more transparent, their descriptions in terms of format, comments and style are made consistent, to the extent possible, with those used at previous Interconnection Process stages.

In the contingency descriptions, the following acronyms are used: "NC" for "normal clearing", "DC" for "delayed clearing" and "SB" for "stuck breaker." In addition, "NTC-fault" means a (three-phase-to-ground) no-topology-change fault (a fault whose clearing procedure does not assume tripping network elements). NTS-fault simulations are intended to provide more insight into stability assessment (in particular, when evaluating the LVRT capability of a wind power plant).

Table 5.7 – Local Contingency Descriptions – Q#198 Arkwright Summit Wind Farm

#	Contingency ID	Other ID, If Any	Contingency Description	
1	LC_Q#198-01	LC01	3-phase fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (NC) Clear Dunkirk 115 kV Clear Arkwright 115 kV (clear fault)	 @ 4.5 ~ @ 28.5 ~
2	LC_Q#198-02	LC03	3-phase fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (NC) Clear Falconer 115 kV Clear Homer Hill 115 kV (clear fault)	 @ 4.5 ~ @ 34.5 ~
3	LC_Q#198-03	LC13	L-G fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (SB) Clear Dunkirk 115 kV Clear Arkwright 115 kV (clear fault)	 @ 17.5 ~ @ 28.5 ~
4	LC_Q#198-04	LC15	L-G fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (SB) Clear Falconer 115 kV Clear Homer Hill 115 kV (clear fault)	 @ 17.5 ~ @ 34.5 ~
5	LC_Q#198-05	LC16	L-G fault on Homer Hill to Falconer 115 kV 154 Line @ Homer Hill (SB) Clear Homer Hill 115 kV Clear Falconer 115 kV (clear fault)	 @ 17.5 ~ @ 34.5 ~
6	LC_Q#198-06	LC17	3-pjase fault on Arkwright to Dunkirk 115 kV 161 Line @ Arkwright (NC) Clear Arkwright 115 kV Clear Dunkirk 115 kV (clear fault)	 @ 4.5 ~ @ 28.5 ~
7	LC_Q#198-07	#198-08	3-phase fault @ Q198_COLL 34.5 kV bus (NTC-fault, 9.0 ~) Clear Q198_COLL 34.5 kV bus	 @ 9.0 ~
8	LC_Q#198-08	N/A	3-phase fault on Falconer - MOON-162 115 kV branch @ MOON-162 (SB) Trip MOON-162 - EDNK162 115 kV branch Trip MOON-162 - FALCONER and HARTFLD1 115 kV lines (clear fault)	 @ 9.0 ~ @ 36.0 ~

Table 5.7 – Local Contingency Descriptions – Q#224 Berrians GT II

#	Contingency ID	Other ID, If Any	Contingency Description
9	LC_Q#224-01	LC01t	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 31.5 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breaker 1N, Queensbridge 7E & 8E open, Astoria breaker 2N sticks - 24.0 ~ Astoria breaker 3N opens - 31.0 ~ Hell Gate breaker 6 opens - 31.5 ~ Bruckner 13 kV breakers 4TS & 4TN open (final clearing) - Trip machines when its generator rotor angle deviation reach approximately 180°
10	LC_Q#224-02	LC02	SLG fault @ ASTORIA W-N 138 kV bus QUENBRDG on Line 28241 (DC, 31.5 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breaker 1N, Queensbridge 7E & 8E open, Astoria breaker 2N sticks - 24.0 ~ Astoria breaker 3N opens - 31.0 ~ Hell Gate breaker 6 opens - 31.5 ~ Bruckner 13 kV breakers 4TS & 4TN open (final clearing)
11	LC_Q#224-03	LC03	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NC, 5.5 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breakers 1N & 2N, Queensbridge 7E & 8E open, clear fault
12	LC_Q#224-04	LC04	SLG fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NC, 5.5 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breakers 1N & 2N, Queensbridge 7E & 8E open, clear fault
13	LC_Q#224-05	LC05	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 13.0 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breaker 2N, Queensbridge 7E & 8E open, Astoria breaker 1N sticks - 13.0 ~ Astoria breaker 10N & bus tie breaker BT opens (final clearing)
14	LC_Q#224-06	LC06	SLG fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 13.0 ~) Fault at Astoria West on feeder 28241 to Queensbridge - 5.5 ~ Astoria breaker 2N, Queensbridge 7E & 8E open, Astoria breaker 1N sticks - 13.0 ~ Astoria breaker 10N & bus tie breaker BT opens (final clearing)
15	LC_Q#224-07	LC07	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NTC-fault, 9 .0 ~) Clear @ 9.0 ~ (NTC-fault)
16	LC_Q#224-08	N/A	3-phase fault @ QUENBRDG 138 kV BUS 126475 (NTC-fault, 9.0 ~) Clear @ 9.0 ~ (NTC-fault)

Table 5.7 – Local Contingency Descriptions – Q#251 CPV Valley

#	Contingency ID	Other ID, If Any	Contingency Description
17	LC_Q#251-01	LC 01	3-phase fault @ SHOEMAKER (MIDDLETOWN) on high side of transformer (NC) Loss of 345/138 kV transformer @ SHOEMAKER Loss of line from COOPERS-CORNERS to SHOEMAKER to ROCK TAVERN Clear SHOEMAKER transformer @ 4 ~ Clear COOPERS - SHOEMAKER - ROCK TAVERN line (clear fault) @ 4 ~
18	LC_Q#251-02	LC 02	3-phase fault @ SHOEMAKER (MIDDLETOWN) on low side of transformer (NC) Loss of 345/138 kV transformer @ SHOEMAKER Clear SHOEMAKER transformer (clear fault) @ 4 ~
19	LC_Q#251-03	LC 03	3-phase fault @ SHOEMAKER (MIDDLETOWN) on high side of transformer (DC) Loss of 345/138 kV transformer @ SHOEMAKER Loss of line from COOPERS CORNERS to SHOEMAKER to ROCK TAVERN Clear COOPERS - SHOEMAKER - ROCK TAVERN line @ 4 ~ Clear SHOEMAKER transformer (clear fault) @ 12 ~
20	LC_Q#251-04	LC 04	3-phase fault @ SHOEMAKER (MIDDLETOWN) on low side of transformer (DC) Loss OF 345/138 kV transformer @ SHOEMAKER Clear SHOEMAKER transformer @ 4 ~ Clear fault @ 12 ~
21	LC_Q#251-05	LC 05	3-phase fault @ COOPERS CORNER on CCRT-34 (DC) STK @ COOPERS trips one 345/115 kV transformer Clear COOPERS - SHOEMAKER - ROCK TAVERN line @ 4 ~ Clear 345/138kV SHOEMAKER transformer @ 4 ~ Clear one 345/115kV COOPERS CORNERS transformer (clear fault) @ 12 ~
22	LC_Q#251-06	LC 06	3-phase fault @ ROCK TAVERN on CCRT-42 (DC) STK @ ROCK TAVERN trips ROCK TAVERN - RAMAPO 345 kV Clear CPV VALLEY - ROCK TAVERN 345 kV line @ 4 ~ Clear ROCK TAVERN - RAMAPO 345 kV line (clear fault) @ 12 ~
23	LC_Q#251-07	LC 07	3-phase fault @ COOPERS CORNERS on CCRT-42 (DC) STK @ COOPERS CORNERS trips MARCY - COOPERS CORNERS 345 kV Clear COOPERS CORNERS CPV_VALY 345 kV line @ 4 ~ Clear COOPERS CORNERS - MARCY 345 kV line (clear fault) @ 12 ~
24	LC_Q#251-08	LC 08	3-phase fault @ ROCK TAVERN on ROCK TAVERN-RAMAPO 345 kV line (DC) Clear ROCK TAVERN - RAMAPO 345 kV line @ 4 ~ Clear ROCK TAVERN - CPV VALLEY line @ ROCK TAVERN end @ 12 ~ Clear ROCK TAVERN - CPV VALLEY line @ CPV VALLEY end @ 14 ~
25	LC_Q#251-09	N/A	3-phase fault @ CPV VALLEY on CCRT-42 (line to ROCK TAVERN trips) (NC) Clear CPV VALLEY - ROCK TAVERN line @ 4 ~
26	LC_Q#251-10	N/A	3-phase fault @ CPV VALLEY on CCRT-42 (line to COOPERS CORNERS trips) (NC) Clear CPV VALLEY - COOPERS CORNER line @ 4 ~
27	LC_Q#251-11	N/A	3-phase fault @ ROCK TAVERN (line to ROSETON trips) (DC) STK @ ROCK TAVERN trips ROCK TAVERN - ROSETON 345 kV Clear CPV VALLEY - ROCK TAVERN 345 kV line @ 4 ~ Clear ROCK TAVERN - ROSETON 345 kV line (clear fault) @ 12 ~
28	LC_Q#251-12	N/A	3-phase fault @ ROCK TAVERN (lines to RAMAPO and ROSETON trip) (DC) STK @ ROCK TAVERN trips ROCK TAVERN - RAMAPO 345 kV STK @ ROCK TAVERN trips ROCK TAVERN - ROSETON 345 kV Clear CPV VALLEY - ROCK TAVERN 345 kV Line @ 4 ~ Clear ROCK TAVERN - RAMAPO 345 kV Line @ 12 ~ Clear ROCK TAVERN - ROSETON 345 kV Line (clear fault) @ 12 ~

Table 5.7 – Local Contingency Descriptions – Q#310 Cricket Valley Energy Center [3]

#	Contingency ID	Other ID, If Any	Contingency Description
29	LC_Q#310-01	LC01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (4.5 ~ clearing) (NC) Open Q310-PLEASANT VALLEY (clear fault) @ 4.5 ~
30	LC_Q#310-02	LC02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (4.5 ~ clearing) (NC) Open Q310-LONGMTN 4.5 ~ (clear fault) @ 4.5 ~
31	LC_Q#310-03	LC03	No fault. Loss of Q310 generation
32	LC_Q#310-04	LC04	SLG fault @ Q310. SB 52-4 Trip Q310-PLVALLEY 4.5 ~ & GT2+ST2 10.0 ~ (SB) Open Q310-PLEASANT VALLEY @ 4.5 ~ Trip Q310 GT2 & ST2 (clear fault) @ 10.0 ~
33	LC_Q#310-05	LC05	SLG fault @ Q310 SB 52-1 Trip Q310-LONGMTN 4.5 ~ & GT1+ST1 10.0 ~ (SB) Open Q310-LONGMTN @ 4.5 ~ Trip Q310 GT1 & ST1 (clear fault) @ 10.0 ~
34	LC_Q#310-06 [1]	LC01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (5.0 ~ clearing) (NC) Open Q310-PLEASANT VALLEY (clear fault) @ 5.0 ~
35	LC_Q#310-07 [1]	LC02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (5.0 ~ clearing) (NC) Open Q310-LONGMTN (clear fault) @ 5.0 ~
36	LC_Q#310-08 [2]	LC04	SLG fault @Q310 SB 52-4 Trip Q310-PLVALLEY 5.0 ~ & GT2+ST2 20.0 ~ (SB) Open Q310-PLEASANT VALLEY @ 5.0 ~ Trip Q310 GT2 & ST2 (clear fault) @ 20.0 ~
37	LC_Q#310-09 [2]	LC05	SLG fault @Q310 SB 52-1 Trip Q310-LONGMTN 5.0 ~ & GT1+ST1 20.0 ~ (SB) Open Q310-LONGMTN @ 5.0 ~ Trip Q310 GT1 & ST1 (clear fault) @ 20.0 ~
38	LC_Q#310-10	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-MILLWOOD 345 kV line (NC) Open PLTVLLEY-MILLWOOD (clear fault) @ 5.0 ~
39	LC_Q#310-11	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-ATHENS 345 kV line (NC) Open PLTVLLEY-ATHENS (clear fault) @ 5.0 ~
40	LC_Q#310-12	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-PL.VAL 1 transformer (NC) Trip PLTVLLEY-PL.VAL 1 345/115 kV transformer (clear fault) @ 5.0 ~
41	LC_Q#310-13	FB345NC01	3-phase fault @ FROST BRIDGE 345 kV Trip line 3208 to N BLOOMFIELD (NC) Trip FROST BRIDGE - N BLOOMFIELD line 3208 (clear fault) @ 5.0 ~
42	LC_Q#310-14	FB345NC02	3-phase fault @ FROST BRIDGE 345 kV Trip line 352 to LONG MTN (NC) Trip FROST BRIDGE - LONG MTN line 352 (clear fault) @ 5.0 ~
43	LC_Q#310-15	FB345NC03	3-phase fault @ FROST BRIDGE 345 kV; Trip line 329 to SOUTHINGTON (NC) Trip FROST BRIDGE - SOUTHINGTON line 329 (clear fault) @ 5.0 ~
44	LC_Q#310-16	N/A	3-phase fault @ LONG MTN 345 kV; Trip LONG MTN - PLUMTREE line (NC) Trip FROST LONG MTN - PLUMTREE 345 kV line (clear fault) @ 5.0 ~

[1] Unlike that in the original contingency (LC01 or LC02), here the clearing time is 5 cycles.

[2] Unlike those in the original Contingency (LC04 or LC05), here the clearing time is 5 cycles at the first stage and 15 cycles at the second stage of the fault clearing procedure.

[3] For the additional simulations performed for the Q#310 projects with the SUFs, contingency scenarios are described in Section 5.10, Table 5.10-2.

Table 5.7 – Local Contingency Descriptions – Q#349 Taylor Biomass

#	Contingency ID	Other ID, If Any	Contingency Description
45	LC_Q#349-01	LC01	3-phase fault @MAYBROOK 69kV / CLR 1TR (NC) Open TR1 69/13.8kV (clear fault) @ 6.0 ~
46	LC_Q#349-02	LC02	3-phase fault @ MAYBROOK 69kV / CLR 2TR (NC) Open TR1 AND TR2 69/13.8kV (clear fault) @ 6.0 ~
47	LC_Q#349-03	LC03 [1]	3-phase fault @MAYBROOK 13.8kV / CLR 1TR (60 ~ clearing) Open TR1 69/13.8kV (clear fault) @ 60.0 ~
48	LC_Q#349-04	N/A	3-phase fault @MONTGMRY 69kV / CLR MONTGMRY generation (NC) Drop generation @ MONTGMRY 69kV (clear fault) @ 12.0 ~
49	LC_Q#349-05	IC01 [2]	3-phase fault @ Rock Tavern 115 kV bus Time (~) Sequence of Events 0 115 kV bus #2 fault occurs 4 Rock Tavern protective relays operate 4.6 DTT received @ Taylor Biomass 5.1 Taylor Biomass auxiliary relay operates (assume 0.5 ~) 6 Rock Tavern 69 kV breaker clears (optimistic 2 ~) 7 Rock Tavern 115 kV bus #2 breakers clear 8.1 Taylor Biomass breaker clears (assume 3 ~ breaker)
50	LC_Q#349-06	IC02 [2]	Rock Tavern 69 kV WM line breaker opens without a fault (with DTT) Time (~) Sequence of Events 0 Rock Tavern 69 kV breaker opens (no fault) 0.6 DTT received @ Taylor Biomass 1.1 Taylor Biomass auxiliary relay operates (assume 0.5 ~) 4.1 Taylor Biomass breaker clears (assume 3 ~ breaker)
51	LC_Q#349-07	IC03 [2]	3-phase fault @ 115 kV line with Rock Tavern 115 kV breaker failure Time (~) Sequence of Events 0 115 kV line fault occurs 1 Rock Tavern protective relays operate 4 Rock Tavern 115 kV line breaker fails to clear 16 Rock Tavern breaker failure relay times out 16.6 DTT received @ Taylor Biomass 17.1 Taylor Biomass auxiliary relay operates (assume 0.5 ~) 18 Rock Tavern 69 kV breaker clears (optimistic 2 ~) 19 Remaining Rock Tavern 115 kV bus #2 breakers clear 20.1 Taylor Biomass breaker clears (assume 3 ~ breaker) 1 sec Montgomery unit trips
52	LC_Q#349-08	IC04 [2]	Rock Tavern 69 kV WM line breaker opens without a fault Time (~) Sequence of Events 0 Rock Tavern 69 kV breaker opens (no fault)

1. For this contingency, the simulation interval is 50 seconds.

2. These contingencies, which create a 69 kV island, were evaluated upon Central Hudson Gas & Electric Corporation request and in order to determine the impact of the project on area bus voltages and frequencies associated with the islanding condition occurring after the loss of Rock-Tavern 115/69 kV transformer. The contingencies were evaluated following the logic of the project SRIS (where they were simulated as contingencies IC01 through IC04); in particular, for IC01 through IC03, a direct transfer trip (DDT) scheme was simulated to trip the project in the event of the Rock-Tavern 115/69 kV transformer loss. Details on the modeling arrangements required for the simulations in both power flow and dynamics can be found in Sections 5.2 and 5.3 above.

Table 5.7 – Local Contingency Descriptions – Q#351 Linden VFT Uprate

#	Contingency ID	Other ID, If Any	Contingency Description
53	LC_Q#351-01	NC-3PH-FDR22	3-phase fault on feeder 22 near Goethals N 345kV substation (NC) Trip Goethals N-Fresh Kills 345kV line 22 Clear both ends @ 4.5 ~
54	LC_Q#351-02	NC-3PH-FDR25	3-phase fault on feeder 25 near Goethals N 345kV substation (NC) Trip Goethals N-Gowanus-41SR-Farragut 345kV line 25&41 & Gowanus N transformer Clear both ends @ 4.5 ~
55	LC_Q#351-03	NC-3PH-FDR26	3-phase fault on feeder 26 near Goethals S 345kV substation (NC) Trip Goethals S-Gowanus-Farragut 345kV line 26&42 & Gowanus S transformer Clear both ends @ 4.5 ~
56	LC_Q#351-04	NC-3PHLCOG	3-phase fault on Linden Cogeneration 345kV bus (NC) Trip G23L&M, Linden Cogeneration & VFT Clear both ends @ 4.5 ~
57	LC_Q#351-05	NC-3PH-RAV	3-phase fault @ Rainey 345 kV bus (NC) Trip Ravenswood 3 generation Clear both ends @ 4.5 ~
58	LC_Q#351-06	SB-1PH-FRKILL-B3 [1]	3-phase fault @ Fresh Kills 345kV bus (SB 3) Trip Goethals S-Fresh Kills 345kV line 21 and generator AK 3 Clear Goethals S @ 4.5 ~ Clear Fresh Kills and generator AK 3 (clear fault) @ 15.0 ~
59	LC_Q#351-07	SB-1PH-GOETH-ALTB3 [1]	3-phase Fault @ Goethals 345 kV (SB 3) Trip feeders 22 and 25/41 & Gowanus N transformer Clear feeder 25/41 (Farragut-Gowanus Section) @ 4.5 ~ Clear feeder 22 (clear fault) @ 14.0 ~
60	LC_Q#351-08	SB-1PH-GOETH-B5 [1]	3-phase fault @ Goethals 345 kV bus (SB 5) Trip feeder A2253 & Goethals PAR @ 4.5 ~ Trip Feeder 22 (clear fault) @ 14.0 ~
61	LC_Q#351-09	SB-1PH-GOETH-B6 [1]	3-phase fault @ Goethals S 345 kV bus (SB 6) Trip Feeders 21 and G23L&M, turn off VFT & Linden Cogeneration Clear FRESH KILLS end @ 4.5 ~ Trip feeders G23L&M, turn off VFT & Linden Cogeneration (clear fault) @ 14.0 ~
62	LC_Q#351-10	SB-1PH-GOETH-B7 [1]	3-phase fault @ Goethals S 345 kV bus (SB 7) Trip Feeder A2253 & Goethals PAR and 26/42 & Gowanus N Transformer Clear feeder 26/42 and reactor R26 @ 4.5 ~ Clear feeder A2253 & Goethals PAR (clear fault) @ 14.0 ~
63	LC_Q#351-11	SB-1PH-GOETH-B8 [1]	3-phase fault @ Goethals 345 kV bus (SB 8) Trip G23L&M and 26/42 & Gowanus N transformer, turn off VFT Clear feeder 26/42 and reactor R26 @ 4.5 ~ Clear Feeder G23L&M, turn off VFT (clear fault) @ 14.0 ~
64	LC_Q#351-12	N/A	3-phase fault @ G22_MTX5 230 kV bus (NC) Trip G22_MTX-TOSCO 230 kV line (clear fault) @ 9.0 ~

[1.] While the original contingency scenario applied in the project SRIS (see the next column to the right) assumed an SLG fault, in ATRA11 simulations, a similar scenario with a 3-phase fault with the same clearing time was applied.

5.8 ATRA11 Local Contingency Assessment Results

The results of ATRA11 local contingency simulations are summarized in Table 5.8. For reader's convenience, Table 5.8 is divided into portions – for individual CY11 projects. Where simulation results need explanation or discussion, relevant notes are made following each portion.

All simulation plots illustrating the projects' phenomena and NYCA phenomena in response to the local contingencies are included in Appendix G (its structure is explained in Table 5.6).

Table 5.8 – Simulation Results for Q#198 Arkwright Summit Wind Farm Local Contingencies LC_Q#198 01 through 08

#	Cont. ID	Contingency Description	NYCA Stability	Project Stability
1	LC_Q#198-01	3-phase fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (NC)	Stable	Stable [1]
2	LC_Q#198-02	3-phase fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (NC)	Stable	Stable
3	LC_Q#198-03	L-G fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (SB)	Stable	Stable [1,2]
4	LC_Q#198-04	L-G fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (SB)	Stable	Stable
5	LC_Q#198-05	L-G fault on Homer Hill to Falconer 115 kV 154 Line @ Homer Hill (SB)	Stable	Stable
6	LC_Q#198-06	3-phase fault on Arkwright to Dunkirk 115 kV 161 Line @ Arkwright (NC)	Stable	Stable [1]
7	LC_Q#198-07	3-phase fault @ Q198_COLL 34.5 kV bus, (NC) (NTC-fault, 9.0 ~)	Stable	Stable
8	LC_Q#198-08	3-phase fault on Falconer - MOON-162 115 kV branch @ MOON-162 (SB)	Stable	Stable

[1] <u>Q#198 Arkwright Summit Wind Farm – Contingencies 01, 03 and 06</u>

All three contingencies involve a fault on the Arkwright – Dunkirk 115 kV line (Line 161). No matter whether it is a 3-phase or a single-line-to-ground fault, whether it is normally cleared or there is a stuck breaker and also at which end of the line the fault occurs, the post-contingency terminal voltage of the equivalent WTG with the shortest feeder (that is, the voltage of Generator 4G, bus 146714) is slightly below 0.95 pu. This does not seem to be a real concern (note that based on project developer's information, the WTGs can operate within the ±10% continues range at the generator terminals).

However, it should be noted that (as simulation with the current dynamic model S_SFSWT suggest) this bus voltage as well as the other WTG equivalents' terminal voltages noticeably depend on the parameters of the equivalent WTG feeders. In the course of the local stability assessment, the project developer was supplying updates on these parameters; the local contingency simulations assumed the most up-to-date available information. If there are project changes considerably affecting equivalent feeders' parameters (say, feeder lengths or cable types) or the reactive power capability of individual WTGs, it is recommended that the project developer make sure that post-contingency WTG terminal voltages are within appropriate range.

[2] Q#198 Arkwright Summit Wind Farm – Contingency 03

The ATRA11 base case power flow voltage assessment (see Section 4) has identified as a potential issue low voltages on the 115 kV system in the area of Dunkirk in case the loss of both Dunkirk 115 kV buses (stuck breaker between the buses): while the voltages were low in the ATBA11 case, the effect was exacerbated in the ATRA11 case and eventually led to a voltage collapse in the area of Dunkirk. In Section 4, mitigation measures are proposed. At the same time, stability simulations for Contingency 03 did not reveal inappropriately low post-contingency voltages.

Table 5.8 – Simulation Results for Q#224 Berrians GT II.
Local Contingencies LC_Q#224 01 through 08 [3]

#	Cont. ID	Contingency Description	NYCA Stability	Project Stability
9	LC_Q#224-01	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 31.5 ~)	Stable [1]	Tripped [2]
10	LC_Q#224-02	SLG fault @ ASTORIA W-N 138 kV bus QUENBRDG on Line 28241 (DC, 31.5 ~)	Stable	Stable
11	LC_Q#224-03	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NC, 5.5 ~)	Stable	Stable
12	LC_Q#224-04	SLG fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NC, 5.5 ~)	Stable	Stable
13	LC_Q#224-05	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 13.0 ~)	Stable	Stable
14	LC_Q#224-06	SLG fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (DC, 13.0 ~)	Stable	Stable
15	LC_Q#224-07	3-phase fault @ ASTORIA W-N 138 kV bus on QUENBRDG Line 28241 (NTC-fault, 9 .0 ~)	Stable	Stable
16	LC_Q#224-08	3-phase fault @ QUENBRDG 138 kV BUS 126475 (NTC-fault, 9 .0 ~)	Stable	Stable

[1] Q#224 Berrians GT II – Contingency 01

The AST 3 Generator 1 (bus 126654) trips in both ATRA11 and ATBA11, which is consistent with results of the project SRIS and does not suggest that the project adversely affects NYCA stability.

[2] Q#224 Berrians GT II – Contingency 01

The project is tripped when generator rotor angle deviation reaches approximately 180°. This logic is consistent with that in the project SRIS. From the project SRIS, the same scenario without tripping would be an extreme contingency whose simulation would not be realistic; at the same time, the tripping of the project, which is an approximation to the protection action, produces a more realistic scenario.

[3] Q#224 Berrians GT II – All Contingencies

On 09/27/2012, after the original ATRA11 local stability simulations were finalized, the Q#224 project developer supplied an update on the modeling of the turbine for the steam unit (ST) (see Table 5.3, Note 4). After that, the Q#224 contingencies were rerun assuming no IEESGO model for the ST. The difference between simulations with and without IEESGO was insignificant. Also, this sensitivity analysis showed that there was no need to rerun (with the updated Q#224 project representation) local contingencies for any other CY11 project. Note that stability plots included in Appendices G,Q#224-1 and G,Q#224-2 pertain to the dynamic setup with the model IEESGO.

Table 5.8 – Simulation Results for Q#251 CPV Valley.
Local Contingencies LC_Q#251 01 through 12

#	Cont. ID	Contingency Description	NYCA Stability	Project Stability
17	LC_Q#251-01	3-phase fault @ SHOEMAKER (MIDDLETOWN) on high side of transformer (NC)	Stable	Stable
18	LC_Q#251-02	3-phase fault @ SHOEMAKER (MIDDLETOWN) on low side of transformer (NC)	Stable	Stable
19	LC_Q#251-03	3-phase fault @ SHOEMAKER (MIDDLETOWN) on high side of transformer (DC)	Stable	Stable
20	LC_Q#251-04	3-phase fault @ SHOEMAKER (MIDDLETOWN) on low side of transformer (DC)	Stable	Stable
21	LC_Q#251-05	3-phase fault @ COOPERS CORNER on CCRT-34 (DC)	Stable	Stable
22	LC_Q#251-06	3-phase fault @ ROCK TAVERN on CCRT-42 (DC)	Stable	Stable
23	LC_Q#251-07	3-phase fault @ COOPERS CORNERS on CCRT-42 (DC)	Stable	Stable
24	LC_Q#251-08	3-phase fault @ ROCK TAVERN on ROCK TAVERN-RAMAPO 345 kV line (DC)	Stable	See [1, 2]
25	LC_Q#251-09	3-phase fault @ CPV VALLEY on CCRT-42 (line to ROCK TAVERN trips) (NC)	Stable	Stable
26	LC_Q#251-10	3-phase fault @ CPV VALLEY on CCRT-42 (line to COOPERS CORNERS trips) (NC)	Stable	Stable
27	LC_Q#251-11	3-phase fault @ ROCK TAVERN (line to ROSETON trips) (DC)	Stable	Stable
28	LC_Q#251-12	3-phase fault @ ROCK TAVERN (lines to RAMAPO and ROSETON trip) (DC)	Stable	Stable

[1] Q#251 CPV Valley – Contingency 08

In the project SRIS, this contingency was unstable. The SRIS report indicates that such a scenario, which represents a three-phase fault with delayed clearing in combination with a loss of multiple elements, is very severe and, therefore, should be considered to be a NERC Type D extreme event. For such events, NERC criteria do not require that all units be stable. Thus, the SRIS report concludes that the project has no system detrimental effect.

In the CY09 FS local stability assessment (the Q#251 project was also a member of the Class Year 2009), this contingency was also unstable. While both combustion units (CTs) and NYCA were stable and positively damped, the steam unit (ST) went transiently unstable. However, in CY09, running the contingency with both the power system stabilizer (PSS) (model UPSS2B) and the excitation system (model UST6B) on the ST unit disabled eliminated its instability. It was concluded in the CY09 Facilities Study report that tuning ST excitation system parameters might be a mitigation measure ensuring stability even for such a severe disturbance.

In the ATRA11 simulation, this contingency with the ST unit as modeled in the ATRA11 dynamic setup (that is, with both the PSS model and the excitation system model enabled and assuming the current dynamics data), the unit went transiently unstable.

Following the logic of the CY09 simulation for this contingency scenario, both the PSS model and the excitation system model on the ST unit were disabled. However, unlike what was observed in the CY09 simulation, the ST unit went transiently unstable and was tripped by the over-speed protection relay. As to both CTs and NYCA, they were stable and positively damped. The stability plots included in Appendix G.3.1 relate to this simulation.

Running this simulation with no PSS and excitation system on the ST unit was intended to find out whether tuning ST unit excitation system parameters could be a mitigation measure. The simulations results did not provide grounds for such a conclusion. In any case, however, since it is not required that all project units be stable for such an extreme contingency, the tripping of the ST unit is not considered to be a stability issue.

[2] Q#251 CPV Valley – Contingency 08

In this contingency simulation, while the steam unit (ST) trips no matter whether its PSS and excitation system are enabled or not, both combustion units (CTs) of the project are stable and positively damped. Note that in the ATRA11 dynamic setup, consistently with the ATBA11 dynamic setup, the CTs are modeled with PSSs (see Table 5.3).

In the course of the CY09 FS local stability assessment for the project, none of the simulations identified a need for stabilizers on the CTs. It was concluded there that it should be at the discretion of the project developer to determine whether such stabilizers would need to be installed to address other concerns; if determined, it would be project developer's responsibility to ensure that all project stabilizers are properly tuned. The results of CY11 ATRA11 simulations do not contradict this conclusion.

Table 5.8 – Simulation Results for Q#310 Cricket Valley Energy Center Local Contingencies LC_Q#310 01 through 16 [6]

#	Cont. ID	Contingency Description	NYCA Stability	NE [1] Stability	Project Stability
29	LC_Q#310-01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (4.5 ~ clearing) (NC)	Stable	Stable	Stable [2]
30	LC_Q#310-02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (4.5 ~ clearing) (NC)	Stable	Stable	Stable [2]
31	LC_Q#310-03	No fault. Loss of Q310 generation	Stable	Stable	Tripped [3]
32	LC_Q#310-04	SLG fault @ Q310. SB 52-4 Trip Q310-PLVALLEY 4.5 ~ & GT2+ST2 10.0 ~ (SB)	Stable	Stable	Stable [2, 4]
33	LC_Q#310-05	SLG fault @ Q310 SB 52-1 Trip Q310-LONGMTN 4.5 ~ & GT1+ST1 10.0 ~ (SB)	Stable	Stable	Stable [5]
34	LC_Q#310-06	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (5.0 ~ clearing) (NC)	Stable	Stable	Stable [2]
35	LC_Q#310-07	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (5.0 ~ clearing) (NC)	Stable	Stable	Stable [2]
36	LC_Q#310-08	SLG fault @Q310 SB 52-4 Trip Q310-PLVALLEY 5.0 ~ & GT2+ST2 20.0 ~ (SB)	Stable	Stable	Stable
37	LC_Q#310-09	SLG fault @Q310 SB 52-1 Trip Q310-LONGMTN 5.0 ~ & GT1+ST1 20.0 ~ (SB)	Stable	Stable	Stable
38	LC_Q#310-10	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-MILLWOOD 345 kV line (NC)	Stable	Stable	Stable
39	LC_Q#310-11	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-ATHENS 345 kV line (NC)	Stable	Stable	Stable
40	LC_Q#310-12	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-PL.VAL 1 transformer (NC)	Stable	Stable	Stable
41	LC_Q#310-13	3-phase fault @ FROST BRIDGE 345 kV Trip line 3208 to N BLOOMFIELD (NC)	Stable	Stable	Stable
42	LC_Q#310-14	3-phase fault @ FROST BRIDGE 345 kV Trip line 352 to LONG MTN (NC)	Stable	Stable	Stable
43	LC_Q#310-15	3-phase fault @ FROST BRIDGE 345 kV; Trip line 329 to SOUTHINGTON (NC)	Stable	Stable	Stable
44	LC_Q#310-16	3-phase fault @ LONG MTN 345 kV; Trip LONG MTN - PLUMTREE line (NC)	Stable	Stable	Stable

[1.] Q#310 Cricket Valley Energy Center – All Contingencies

Here, the processes were monitored for the ROCKY RIVER Generator 1 (bus 126657).

[2.] Q#310 Cricket Valley Energy Center – Contingencies 01, 02, 04, 06 and 07

For these contingencies, oscillations with frequency of 1.6 Hz occur on the post-fault interval. They can be observed in the curves of project generators' output active power, rotor speed and field voltage, in the project POI voltage, etc. Electrically close NYCA and NE power system elements also exhibit 1.6 Hz oscillations. The oscillations become sustained about 10 seconds after the instant when the fault is cleared and, based on 50-second simulations for the same scenarios, do not seem to grow. From additional tests, these oscillations are not caused by numerical solution problems (and, therefore, the oscillations cannot be eliminated by adjusting solution parameters).

The size of the oscillations is very small. For example, in response to Contingency 04, the maximum peak-to-peak values are as follows: less than 0.3% in the output active power and less than 1% in the field voltage for GT1 and ST1; less than 0.0004 pu in the POI voltage. In the electrically close parts of the New York power system and the New England power system, the oscillations are even weaker.

Due to the negligible size, the 1.6 Hz oscillations do not seem to be a real concern. However, generally speaking, the fact that a power system component exhibits oscillations of unclear nature (with frequency within the PSS/E bandwidth) can be a manifestation of a small-signal stability issue. Thus, while very small in size, the 1.6 Hz oscillations triggered further investigation.

In the project SRIS report, there is no mention of such oscillations. It must be noted, however, that SRIS simulations assumed substantially different dynamics data for both gas and steam units (the project parameters used in the ATRA11 simulations were supplied to the NYISO in the course of the ATRA11 dynamic setup development). In addition, the SRIS stability analysis was performed using a different dynamic simulation program – the Powertech Lab’s DSATools software. If the 1.6 Hz oscillations observed in PSS/E-based ATRA11 simulations are a modeling effect, it may very well be that another software package do not reproduce it.

To provide more insight into the observed phenomena, contingencies similar to those in the title were run on the ATBA11 dynamic setup (that is, in the absence of the Q#310 project). In the ATBA11 simulations, two Athens plant units (combustion and steam), close enough to the Q#310 project, were selected for monitoring. In these ATBA11 tests, small 1.6 Hz oscillations were present in Athens machines’ rotor angle, output active power and field voltage. However, comparing to those in ATRA11, the oscillations in ATBA11 were even weaker.

Thus, while the 1.6 Hz oscillations in ATRA11 seem to be inherited from ATBA11, the Q#310 project slightly exacerbates the effect. On the other hand, the onset of 1.6 Hz oscillations in ATBA11 is rather a proof that it is not some small-signal instability introduced by the Q#310 project that causes the 1.6 Hz oscillations in ATRA11. There is no evidence that this insignificant difference in the size of the 1.6 Hz oscillations is anything but a modeling effect.

Based on the results obtained, the 1.6 Hz oscillations in ATRA11 should not be considered as an issue that would suggests an adverse impact of the Q#310 project on any power system (New York's or New England's). However, if other dynamic simulations are performed for the project after the CY11 Facilities Study stage, especially those based on more accurate EMTP-type tools, it is recommended that the issue be revisited should any oscillations of this kind be observed.

[3] Q#310 Cricket Valley Energy Center – Contingency 03

All project generators (both gas and steam) are tripped by the contingency scenario.

[4] Q#310 Cricket Valley Energy Center – Contingency 05

Unit 2 (both gas and steam turbine generators) is tripped by the contingency scenario; the remaining Units 1 and 3 are stable and positively damped.

[5] Q#310 Cricket Valley Energy Center – Contingency 05

Unit 1 (both gas and steam turbine generators) is tripped by the contingency scenario; the remaining Units 2 and 3 are stable and positively damped.

[6] Q#310 Cricket Valley Energy Center – All Contingencies

Simulations with the SUFs identified for the Q#310 project are described in Section 5.10.

Table 5.8 – Simulation Results for Q#349 Taylor Biomass
Local Contingencies LC_Q#349 01 through 08 [1]

#	Cont. ID	Contingency Description	NYCA Stability	Project Stability
45	LC_Q#349-01	3-phase fault @MAYBROOK 69kV / CLR 1TR (NC)	Stable	Stable
46	LC_Q#349-02	3-phase fault @ MAYBROOK 69kV / CLR 2TR (NC)	Stable	Stable
47	LC_Q#349-03	3-phase fault @MAYBROOK 13.8kV / CLR 1TR (60 ~ clearing)	Stable	Stable
48	LC_Q#349-04	3-phase fault @MONTGMRY 69kV / CLR MONTGMRY generation (NC)	Stable	Stable
49	LC_Q#349-05 [2, 3]	3-phase fault @ Rock Tavern 115 kV bus	Stable	See [4, 5]
50	LC_Q#349-06 [2, 3]	Rock Tavern 69 kV WM line breaker opens without a fault (with DTT)	Stable	See [4, 5]
51	LC_Q#349-07 [2, 3]	3-phase fault @ 115 kV line with Rock Tavern 115 kV breaker failure	Stable	See [4, 5]
52	LC_Q#349-08 [2, 3]	Rock Tavern 69 kV WM line breaker opens without a fault	Stable	See [4, 5]

[1] Q#349 Taylor Biomass – All Contingencies

The dynamics data applied for the project in the ATRA11 dynamic setup "as is" are the same as those in the ATBA11 dynamic setup. On the other hand, the (final) stability simulations in the project SRIS used a slightly different set of parameters for the turbine-governor model SOLAGT (for the CT unit). In particular, the difference between the ATRA11 and final SRIS parameters is that in the latter set, the droop mode and protections of the governor were activated.

In the course of ATRA11 simulations, all contingencies were run on both sets of SOLAGT parameters. The difference in the results, including those for the contingencies 05 through 08 (creating a 69 kV island), was found insignificant in terms of study conclusions. Note that the stability plots in Appendix G.6 are for the case of original SOLAGT parameters included in the dynamic setup ATRA11.

[2] Q#349 Taylor Biomass – Contingencies 05 through 08

As already indicated, these contingencies, which create a 69 kV island, were evaluated upon Central Hudson Gas & Electric Corporation request. The intent of simulations was to determine the impact of the project on area bus voltages and frequencies associated with the islanding conditions occurring after the loss of Rock-Tavern 115/69 kV transformer. The island created by these contingencies includes Rock Tavern, Maybrook and Montgomery 69 kV buses, the Montgomery generator and the very Q#349 project. Note that the Montgomery generator (bus 125114) is very small: Pgen = Pmax = 0.2 MW pre-contingency (in the power flow case).

[3] Q#349 Taylor Biomass – Contingencies 05 through 08

This note summarizes SRIS observations (for the islanding contingencies) as a starting point for consequent ATRA11 considerations. In the SRIS, these contingencies (as IC01 through IC04) were run on a light load power flow case assuming that the total pre-contingency load within the island was about 9.7 MW and 5 MW (two sub-cases). For all these islanding contingencies, the rest of NYCA was stable. The processes within the island depended on contingency scenario.

Contingencies IC01 through IC03 involve the tripping of the project by a direct transfer (DDT) scheme. When the load total was 9.7 MW, post-contingency bus voltages over 1.05 pu were observed within the island for none of the contingencies. Due to the decelerating of the Montgomery generator, it was eventually tripped by the under-speed protection, and the entire island shut down. The highest bus frequency within the island was about 61.5 Hz. When the total load was 5 MW, the results were very similar. Based on these simulations, the SRIS indicated that it could not be concluded that such scenarios would lead to a successfully operating island.

For Contingency IC04, where the project fails to be tripped by the DDT, when the total load was 9.7 MW, no excessive voltages were observed post-contingency, either, and the highest bus frequency was about 64 Hz (eventually, the frequency settled at about 63 Hz). When the total load was 5 MW, the CT unit was tripped by the generator protection, after which the maximum frequency was about 65 Hz, and the island continued to operate.

Nevertheless, the SRIS report indicated that in actual operation there would be a cross-trip scheme since the ST unit cannot operate without the CT unit in-service. Thus, the SRIS concluded, the island would shut down immediately following the trip of the CT unit since the small Montgomery generator (the only remaining generation) would be unable to supply the island.

[4] Q#349 Taylor Biomass – Contingencies 05 through 08

This note summarizes the ATRA11 simulation results (pertaining to both sets of the model SOLAGT parameters).

For all subject contingencies, NYCA was stable and positively damped. For none of the subject contingencies, the post-contingency bus voltages within the 69 kV island exceeded 1.05 pu; nor (on the interval of a few seconds after a contingency was applied) did any bus frequency reach the level of 61 Hz. For Contingency 08, where the project fails to be tripped by the DDT, both the project and the Montgomery generator went unstable.

In the ATRA11 simulations, the islanding contingencies were run on the 2016 summer peak power flow case, where the total pre-contingency load within the island was about 18.2 MW. That is, the load was far above that in the SRIS case with 9.7 MW, for which the SRIS indicated that it could not be concluded that Contingency 08 (IC04 in the SRIS) would lead to a successfully operating island. Thus, the ATRA11 results do not contradict the SRIS results.

At this point, it should be noted that with regard to the ATRA11 islanding simulations, a question was raised as to whether the approach to the modeling of island (proposed in the SRIS and described in Section 5.3 of this report) would ensure sufficient accuracy of such evaluations. In particular, there were concerns about the applicability and parameters of the load frequency models LDFRBL used for the Montgomery (MONTGMRY) and Maybrook (MAYBROOK_A and MAYBROOK_B) buses. During a discussion with participation of Central Hudson Gas & Electric Corporation, Siemens PTI and the NYISO, Siemens PTI indicated that the impact of the load frequency models LDFRBL on the voltages and frequencies within the island should be insignificant. It was concluded therefore that the simulation results based on the SRIS approach to the modeling of the island are sufficient.

[5] Q#349 Taylor Biomass – Contingencies 05 through 08

As already mentioned, in the course of the ATRA11 simulations, these contingencies were run on a power flow case derived from the 2016 summer peak case. Central Hudson Gas & Electric Corporation expressed a concern as to whether the bus voltages within the 69 kV island would be appropriate under light load conditions and proposed that Contingency 08 (IC04) as the most critical scenario be evaluated for the possible minimum level of the total active power load within the island (this level was specified as 5 MW).

To perform the assessment, the summer peak load case (CY11_Sum16_ATRA_Q#349-i) was modified in the following manner: a 1 MW load at Montgomery and a 2 MW load at each of the two Maybrook 13.8 kV buses. Then, contingencies IC01-IC04 were run on sub-cases with different total reactive power load within the island: -3 MVAr, 0 MVAr and 3 MVAr. For all four contingencies, the bus voltages within the island were below 1.05 pu. As expected, the worst case scenario was IC04 with the total load of 5 MW, -3 MVAr. Here, the maximum transient voltages at Montgomery and Maybrook were about (slightly below) 1.04 pu. Contingency IC04 simulation plots showing the bus voltages are included in Appendix G.Q#349-1 (in the end).

That is, under the same modeling assumptions as those in the SRIS, no overvoltages have been identified for the specified light load conditions. Thus, no SUFs addressing related concerns are required.

Table 5.8 – Simulation Results for Q#351 Linden VFT Uprate
Local Contingencies LC_Q#351 01 through 12

#	Cont. ID	Contingency Description	NYCA Stability	PJM Stability [1]	Project Stability
53	LC_Q#351-01	3-phase fault on feeder 22 near Goethals N 345kV substation (NC)	Stable	Stable	Stable
54	LC_Q#351-02	3-phase fault on feeder 25 near Goethals N 345kV substation (NC)	Stable	Stable	Stable
55	LC_Q#351-03	3-phase fault on feeder 26 near Goethals S 345kV substation (NC)	Stable	Stable	Stable
56	LC_Q#351-04	3-phase fault on Linden Cogeneration 345kV bus (NC)	Stable	Stable	Tripped [3]
57	LC_Q#351-05	3-phase fault @ Rainey 345 kV bus (NC)	Stable	Stable	Stable
58	LC_Q#351-06	3-phase fault @ Fresh Kills 345kV bus (SB 3)	Stable [2]	Stable	Stable
59	LC_Q#351-07	3-phase Fault @ Goethals 345 kV bus (SB 3)	Stable [2]	Stable	Stable
60	LC_Q#351-08	3-phase fault @ Goethals 345 kV bus (SB 5)	Stable [2]	Stable	Stable
61	LC_Q#351-09	3-phase fault @ Goethals S 345 kV bus (SB 6)	Stable [2]	Stable	Tripped [3]
62	LC_Q#351-10	3-phase fault @ Goethals S 345 kV bus (SB 7)	Stable [2]	Stable	Stable
63	LC_Q#351-11	3-phase fault @ Goethals 345 kV bus (SB 8)	Stable [2]	Stable	Tripped [3]
64	LC_Q#351-12	3-phase fault @ G22_MTX5 230 kV bus (NC)	Stable	Stable	Stable

[1] Q#351 Linden VFT Uprate – All Contingencies

Here, the processes were monitored for the TOSCONUG Generator 1 (bus 218344).

[2] Q#351 Linden VFT Uprate – Contingencies 06 through 11

As already mentioned, while the similar contingency scenario in the project SRIS assumed an SLG fault, in ATRA11 simulations, the scenario with a 3-phase fault and the same clearing time was applied instead, which allowed evaluating the stability of both the project and NYCA for more severe conditions. In all simulations, both NYCA and PJM was stable and positively damped; the project was stable and positively damped unless it was tripped according to a contingency scenario.

For Contingencies 06 through 09, the following Bayonne machines were tripped by over-speed protection: BAY_G1 (Generator 1, bus 128253), BAY_G2 Generator 2, (bus 128647), BAY_G3 (Generator 3, bus 128254), BAY_G4 (Generator 4, bus 128248) and BAY_G5 (Generator 5, bus 128255). In addition, for Contingencies 06 through 08, over-speed tripping was observed for the following Linden Cogeneration machines: COGENST1 (Generator 1, bus 126664), COGENST2 (Generator 1, bus 126665) and COGENST3 (Generator 1, bus 126666).

However, when the same contingencies were run on the dynamic setup ATBA11 (that is, with Linden VFT at a 300 MW level), exactly the same Bayonne and/or Linden Cogeneration machines tripped. That is, the tripping of these Bayonne/Linden Cogeneration machines for the considered severe contingency scenarios is an ATBA issue.

[3] Q#351 Linden VFT Uprate – Contingencies 06 through 11

Both the project and the Linden Cogeneration (Generators 1 at COGENGT buses 126659 through 126666) are tripped according to the contingency scenario.

Based on these results, Q#351 Linden VFT Uprate (with a 315 MW VFT) adversely affects neither the NYCA's responses to the subject contingencies.

Concluding the discussion of the Q#251 simulation results, it is worth noting again that as a result of the FERC's Order of Oct. 1, 2012 in Docket No. EL12-64 (see Section 5.1), further study of the Q#351 project was not necessary. These results, including relevant stability plots in Appendix G, are left in the report to demonstrate the stability performance of the Linden VFT project at the level of 315 MW.

Summary of Observations for All CY11 Projects

Based on the overall simulation results for the CY11 local contingency scenarios, none of the CY11 projects has an adverse impact on the NYCA stability. No need for SUFs addressing local stability concerns has been identified.

5.9 LVRT Analysis for Q#198 Arkwright Summit Wind Farm

Appendix G to the Large Generator Interconnection Agreement contained in Attachment X of the NYISO OATT requires that wind generation meet either the Transition Period or Post-Transition Period LVRT Standard.

In general, wind generation plants are susceptible to being tripped by either their voltage protection or frequency protection relays for close-in faults at the POI or one-bus-away faults from the POI. In terms of network topology, the local contingencies described in Table 5.7 are of the kind required by LVRT simulations.

In the CY11 Facilities Study, there is the only one wind generation project – Q#198 Arkwright Summit Wind Farm. Its compliance with the Post-Transition Period LVRT Standard was evaluated for all Q#198 local contingencies shown in Table 5.7.

Simulation plots demonstrating the LVRT capability of Q#198 Arkwright Summit Wind Farm are included in Appendix G.Q#198-1-LVRT. Table 5.9 below summarizes the LVRT analysis results.

Table 5.9 – LVRT Simulation Results for CY11 Wind Generation Projects

#	Cont. ID	Contingency Description	LVRT
1	LC_Q#198-01	3-phase fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (NC)	OK
2	LC_Q#198-02	3-phase fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (NC)	OK
3	LC_Q#198-03	L-G fault on Dunkirk to Arkwright 115 kV 161 Line @ Dunkirk (SB)	OK
4	LC_Q#198-04	L-G fault on Falconer to Homer Hill 115 kV 154 Line @ Falconer (SB)	OK
5	LC_Q#198-05	L-G fault on Homer Hill to Falconer 115 kV 154 Line @ Homer Hill (SB)	OK
6	LC_Q#198-06	3-phase fault on Arkwright to Dunkirk 115 kV 161 Line @ Arkwright (NC)	OK
7	LC_Q#198-07	3-phase fault @ Q198_COLL 34.5 kV bus, (NC) (NTC-fault, 9.0 ~)	OK
8	LC_Q#198-08	3-phase fault on Falconer - MOON-162 115 kV branch @ MOON-162 (SB)	OK

Based on the findings of the CY11 Facilities Study stability analysis and also on the SRIS results, it appears that Q#198 Arkwright Summit Wind Farm will comply with the Post-Transition Period LVRT Standard.

As a general note, depending on the configuration of a wind plant and wind conditions, individual WTGs operate under conditions that can differ noticeably. Different wind speeds/directions and different feeder lengths are among the factors that can make WTG operating conditions differ.

Therefore, it is a possibility that in response to a disturbance, some individual WTGs will trip, while the others will not. A difference in conditions under which real WTGs may operate differently should be accounted for when actual protection relay settings are selected by project developers. For the subject Q#198 Arkwright Summit Wind Farm project, due to its configuration (with large difference in feeder lengths), this is especially important (see also Section 5.8, notes on Q#198 results).

It is assumed the Q#198 Arkwright Summit Wind Farm project developer is responsible for selecting WTG control parameter settings and voltage and frequency protection relay settings to ensure that the LVRT Standard is fully met. Also, the project must meet the NPCC under-frequency curve.

5.10 Local Stability Assessment for Q#310 Cricket Energy Center with SUFs

Outside of the CY11 local stability assessment and after its original simulations were completed, parallel NYISO and ISO-NE studies identified that the Q#310 project caused significant degradation of transfer interface limits between the New York and New England power systems in both directions.

Based on the consequent NYISO and ISO-NE analyses, in January 2013, the NYISO made a determination regarding the SUFs required for the Q#310 project. As per the determination, the SUFs include a second Pleasant Valley - Cricket Valley 345 kV line and reconductoring of the Cricket Valley - Long Mountain 345 kV line (see also Section 2.1.2). As a result, additional simulations of Q#310 local stability contingencies were needed in order to evaluate the impact of the SUFs.

An upgraded dynamic setup revision – ATRA11 Rev. 2 – was developed to conduct the analysis. The file CY11_Sum16_ATRA_Rev2_stability.zip is available through the NYISO ePlanning. Table 5.10-1 specifies the major components if this setup.

Table 5.10-1 – Major Power Flow Case and Dynamic Setup Files

File Type	Dynamic Setup ATRA11 Rev. 2 [1]
SAV	*CY11_Sum16_ATRA_Rev2.sav* [2, 3]
CNV	*CY11_Sum16_ATRA_Q#310-2nd-CKT.cnv* [3]
DYR	*CY11_Sum16_ATRA.dyr*
SNP (no plotting channels)	*CY11_Sum16_ATRA_nochan.snp*
SNP (channels for NYCA)	*CY11_Sum16_ATRA_chan.snp*
SNP (channels for NYCA and for CY11 projects)	*CY11_Sum16_ATRA_chan_CY11.snp*

[1.] This dynamic setup was used only for the additional Q#310 simulations.

[2.] To develop this power case, the case CY11_Sum16_ATRA_Rev1a.sav used in the original stability simulations was augmented with the 2nd Pleasant Valley - Cricket Valley 345 kV line (hereafter referred to as the “2nd PV-CV line”). For the Cricket Valley - Long Mountain 345 kV line, the parameters were assumed to be the same as those in the original simulations.

[3.] Except for these two power flow cases, the dynamic setup components are the same as those in the dynamic setup ATRA11 Rev. 1.

To evaluate the impact of the SUFs, the same 16 local contingencies were run on the upgraded power flow case (CY11_Sum16_ATRA_Q#310-2nd-CKT.cnv). The contingency descriptions are as follows.

Table 5.10-2 – Local Contingency Descriptions – Q#310 Cricket Valley Energy Center (Case with the 2nd PV-CV Line)

#	Contingency ID	Other ID, If Any	Contingency Description
65	LC_Q#310-01	LC01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (4.5 ~ clearing) (NC) Open Q310-PLEASANT VALLEY CKT 1 (clear fault), CKT-2 in-service @ 4.5 ~
66	LC_Q#310-02	LC02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (4.5 ~ clearing) (NC) Open Q310-LONGMTN 4.5 ~ (clear fault) @ 4.5 ~
67	LC_Q#310-03	LC03	No fault. Loss of Q310 generation
68	LC_Q#310-04	LC04	SLG fault @ Q310. SB 52-4 Trip Q310-PLVALLEY 4.5 ~ & GT2+ST2 10.0 ~ (SB) Open Q310-PLEASANT VALLEY SKT 1, CKT-2 in-service @ 4.5 ~ Trip Q310 GT2 & ST2 (clear fault) @ 10.0 ~
69	LC_Q#310-05	LC05	SLG fault @ Q310 SB 52-1 Trip Q310-LONGMTN 4.5 ~ & GT1+ST1 10.0 ~ (SB) Open Q310-LONGMTN @ 4.5 ~ Trip Q310 GT1 & ST1 (clear fault) @ 10.0 ~
70	LC_Q#310-06	LC01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY (5.0 ~ clearing) (NC) Open Q310-PLEASANT VALLEY CKT 1 (clear fault), CKT-2 in-service @ 5.0 ~
71	LC_Q#310-07	LC02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (5.0 ~ clearing) (NC) Open Q310-LONGMTN (clear fault) @ 5.0 ~
72	LC_Q#310-08	LC04	SLG fault @Q310 SB 52-4 Trip Q310-PLVALLEY 5.0 ~ & GT2+ST2 20.0 ~ (SB) Open Q310-PLEASANT VALLEY CKT 1, CKT-2 in-service @ 5.0 ~ Trip Q310 GT2 & ST2 (clear fault) @ 20.0 ~
73	LC_Q#310-09	LC05	SLG fault @Q310 SB 52-1 Trip Q310-LONGMTN 5.0 ~ & GT1+ST1 20.0 ~ (SB) Open Q310-LONGMTN @ 5.0 ~ Trip Q310 GT1 & ST1 (clear fault) @ 20.0 ~
74	LC_Q#310-10	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-MILLWOOD 345 kV line (NC) Open PLTVLLEY-MILLWOOD (clear fault) @ 5.0 ~
75	LC_Q#310-11	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-ATHENS 345 kV line (NC) Open PLTVLLEY-ATHENS (clear fault) @ 5.0 ~
76	LC_Q#310-12	N/A	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-PL.VAL 1 transformer (NC) Trip PLTVLLEY-PL.VAL 1 345/115 kV transformer (clear fault) @ 5.0 ~
77	LC_Q#310-13	FB345NC01	3-phase fault @ FROST BRIDGE 345 kV Trip line 3208 to N BLOOMFIELD (NC) Trip FROST BRIDGE - N BLOOMFIELD line 3208 (clear fault) @ 5.0 ~
78	LC_Q#310-14	FB345NC02	3-phase fault @ FROST BRIDGE 345 kV Trip line 352 to LONG MTN (NC) Trip FROST BRIDGE - LONG MTN line 352 (clear fault) @ 5.0 ~
79	LC_Q#310-15	FB345NC03	3-phase fault @ FROST BRIDGE 345 kV; Trip line 329 to SOUTHINGTON (NC) Trip FROST BRIDGE - SOUTHINGTON line 329 (clear fault) @ 5.0 ~
80	LC_Q#310-16	N/A	3-phase fault @ LONG MTN 345 kV; Trip LONG MTN - PLUMTREE line (NC) Trip FROST LONG MTN - PLUMTREE 345 kV line (clear fault) @ 5.0 ~

For the contingencies LC01, LC04, LC06 and LC08, in accordance with the new scenarios, one of the two 345 kV lines between Pleasant Valley and Cricket Valley is tripped to clear the fault, while the other one remains in-service. Note that for any local contingency whose scenario does not differ from that in the original simulation (without the 2nd PV-CV line), the results are also expected to somewhat change due to the change in the network conditions.

Stability plots illustrating the simulations are included in Appendix G, Q#310 as Part 3 and Part 4 – see the navigation guide below. It is worth noting that the PSS/E output (OUT) files pertaining to these simulations have names ending in "_2nd-CKT"

Table 5.10-3 – Appendix G Navigation Guide – Q#310 Appendices

#	Q#	Project Name	Simulation	Part/Phenomena	Appendix
4	Q#310	Cricket Valley Energy Center	Local Contingencies	Part 1: Q#310	G.Q#310-1
				Part 2: NYCA	G.Q#310-2
				Part 3: Q#310	G.Q#310-3 (2nd PV-CV line)
				Part 4: NYCA	G.Q#310-4 (2nd PV-CV line)

The results of the additional Q#310 simulations are shown in Table 5.10-4.

Table 5.10-4 – Simulation Results for Q#310 Cricket Valley Energy Center Local Contingencies LC_Q#310 01 through 16 (Case with the 2nd PV-CV Line)

#	Cont. ID	Contingency Description	NYCA Stability	NE [1] Stability	Project Stability
65	LC_Q#310-01	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY CKT1 (4.5 ~ clearing) (NC)	Stable	Stable	Stable [2]
66	LC_Q#310-02	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (4.5 ~ clearing) (NC)	Stable	Stable	Stable [2]
67	LC_Q#310-03	No fault. Loss of Q310 generation	Stable	Stable	Tripped [3]
68	LC_Q#310-04	SLG fault @ Q310 SB 52-4 Trip Q310-PLVALLEY CKT1 4.5 ~ & GT2+ST2 10.0 ~ (SB)	Stable	Stable	Stable [2, 4]
69	LC_Q#310-05	SLG fault @ Q310 SB 52-1 Trip Q310-LONGMTN 4.5 ~ & GT1+ST1 10.0 ~ (SB)	Stable	Stable	Stable [5]
70	LC_Q#310-06	3-phase fault @ Q310 345 kV Trip Q310-PLTVALLEY CKT1 (5.0 ~ clearing) (NC)	Stable	Stable	Stable [2]
71	LC_Q#310-07	3-phase fault @ Q310 345 kV Trip Q310-LONGMTN (5.0 ~ clearing) (NC)	Stable	Stable	Stable [2]
72	LC_Q#310-08	SLG fault @Q310 SB 52-4 Trip Q310-PLVALLEY CKT1 5.0 ~ & GT2+ST2 20.0 ~ (SB)	Stable	Stable	Stable
73	LC_Q#310-09	SLG fault @Q310 SB 52-1 Trip Q310-LONGMTN 5.0 ~ & GT1+ST1 20.0 ~ (SB)	Stable	Stable	Stable
74	LC_Q#310-10	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-MILLWOOD 345 kV line (NC)	Stable	Stable	Stable
75	LC_Q#310-11	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-ATHENS 345 kV line (NC)	Stable	Stable	Stable
76	LC_Q#310-12	3-phase fault @ PLTVLLEY 345 kV Trip PLTVLLEY-PL.VAL 1 transformer (NC)	Stable	Stable	Stable
77	LC_Q#310-13	3-phase fault @ FROST BRIDGE 345 kV Trip line 3208 to N BLOOMFIELD (NC)	Stable	Stable	Stable
78	LC_Q#310-14	3-phase fault @ FROST BRIDGE 345 kV Trip line 352 to LONG MTN (NC)	Stable	Stable	Stable
79	LC_Q#310-15	3-phase fault @ FROST BRIDGE 345 kV; Trip line 329 to SOUTHINGTON (NC)	Stable	Stable	Stable
80	LC_Q#310-16	3-phase fault @ LONG MTN 345 kV; Trip LONG MTN - PLUMTREE line (NC)	Stable	Stable	Stable

Notes 1 through 5 are the same as those for the original simulations (without the 2md PV-CV line) – see Table 5.8 for the Q#310 project. A comparison of the simulation results with and the without the 2nd PV-CV line have shown that the impact of this SUF on both Q#310 project's and NYCA's dynamic response to all local contingencies is insignificant. The impact of this SUF on the stability performance of the rest of the CY11 projects is negligible.

A sensitivity analysis was conducted to evaluate a possible impact of the other identified Q#310 SUF – the reconductoring of the Cricket Valley - Long Mountain 345 kV line. Since the characteristics of the reconductored line have not yet been determined, as mentioned above, the power flow parameters of line were assumed to be the same as those in the case CY11_Sum16_ATRA_Rev1a.sav. When performing the sensitivity analysis, the line parameters were varied in the range of ±20%. The analysis has shown that the impact of these parameters on the local stability assessment is insignificant.

5.11 Local Stability Assessment Conclusions

1) Based on the ATRA11 simulations of local contingency scenarios, on related comparative and sensitivity analyses and also on the projects' SRIS findings, none of the CY11 projects has an adverse impact on the NYCA stability.

2) The CY11 projects exhibit stable response with positive damping for all relevant local contingencies and do not introduce stability problems.

3) Recommendations based on the CY11 local stability simulation results:

   - Q#198 Arkwright Summit Wind Farm: if there are project changes considerably affecting equivalent feeders' parameters or the reactive power capability of individual WTGs, it is recommended that the project developer make sure that post-contingency WTG terminal voltages are within appropriate range;

4) Based on the ATRA11 local stability simulation results and also on the project's SRIS findings, it appears that Q#198 Arkwright Summit Wind Farm project will comply with the Post-Transition Period LVRT Standard. It is assumed that the project developer is responsible for selecting the WTG control parameter settings and protection system settings to ensure that the LVRT Standard is fully met. It is also assumed that the project must meet the NPCC under-frequency curve.

5) If there are changes or data updates for any of the CY11 projects, including but not limited to updates on equipment and controls parameters (WTG/generator/VFT data, excitation system/PSS data or turbine/governor data, including protection relays data) and on dynamic models representing the equipment and controls, it is a responsibility of the project developer to assess the impact of such changes and updates on project's and NYCA's dynamic responses and, when needed, to perform additional stability analyses, including re-evaluation of the LVRT capability for Q#198 Arkwright Summit Wind Farm.

6) The local stability assessment has not identified a need for SUFs addressing local stability issues for any of the CY11 projects.

7) Based on additional simulations with the SUFs identified for Q#310 Cricket Valley Energy Center (outside of the scope of the local stability assessment), the SUFs have no adverse impact on the Cricket Valley Energy Center and NYCA dynamic responses to Q#310 local contingencies under summer peak load conditions.

6. Special Studies

Each Connecting or Affected Transmission Owner (CTO/ATO) has the opportunity to provide, or request, specific assessments, as related with the current Class Year projects impacts identification. If the assessments are of a different kind than what is usually performed under the CY studies, the results and conclusion will be summarized under this section. If the study types are similar and in addition to the general NYISO studies, there will be references under the applicable sections in this report.

Con Edison identified the need of having an electromagnetic transients (EMT) analysis study performed as part of the NYISO Class Year 2011 Facilities Study, to assess the impacts of the electromagnetic transients propagation in response to the proposed interconnection of the Q#310 Cricket Valley Energy Center project via a new 6-breaker ring gas-insulated substation (GIS), and to develop mitigation solutions for any adverse impacts identified in such analysis. NYISO contracted Mitsubishi Electric Power Products, Inc. (MEPPI) to perform the following tasks:

Task 1: Electromagnetic Transients Model and Validation;

Task 2: Normal and Stuck Breaker Transient Overvoltage Evaluation;

Task 3: Transformer-Limited Fault Analysis;

Task 4: X/R Ratio, AC Decrement, and TRV Analysis for 345 kV Breakers near the project;

Task 5: Transmission Line Switching Analysis;

Task 6: Transformer Energizing Analysis;

Task 7: Lightning Surge Analysis and Impacts on Surge Arrester Placement;

Task 8: Provide Report and Recommendations for Mitigation Solutions.

Task 9: Re-evaluation of the above, in the event that NYISO identifies any SDU or SUF in the electrical vicinity of Cricket Valley.

Note: At the time of this EMP study, the design of the Cricket Valley GIS (gas-insulated substation) was not finalized. Therefore, detailed analyses for phenomena such as very fast transient overvoltages and ferroresonance were not included in this scope of the EMT study. It is recommended that once the equipment supplier is chosen and detailed parameters for the GIS and connected equipment are known, analyses be performed (during the detailed design engineering phase) to verify that there are no concerns for fast transient overvoltages and ferroresonance.

The results are detailed in a separate report prepared by MEPPI, titled "Q310 Cricket Valley Energy Center Electromagnetic Transients Analysis". There were no additional SUFs identified by this study as needed.

Also, ISO-NE identified the need of performing several studies, to assess the impact of Q#310 Cricket Valley Energy Center project on ISO-NE system, due to the fact that this project is proposed to interconnect on a tie between NY and NE, *i.e.,* Pleasant Valley to Long Mountain 345 kV (Line 398). Also, ISO-NE performed re-assessments for the proposed 2nd Pleasant Valley-Cricket Valley 345 kV line, and for the reconductoring of Pleasant Valley to Long Mountain segment. The results are detailed in a separate report prepared by ISO-NE and its consultants, titled "QP-310 Cricket Valley – NNC NE-NY Transfer Analysis 10222012", and also "Draft Stability Study Report for the Proposed Combined Cycle Project Q277.5 Interconnecting to the 345kV line between Pleasant Valley and Long Mountain R049-12 Stability Study Report_Q277 5_rev2.pdf".

There were no additional network upgrades identified by the studies. The second Pleasant Valley to Cricket Valley 345 kV line solution, along with the reconductoring of the Cricket Valley to Long Mountain proposed package addresses ISO-NE's concerns.

7. Resource Reliability Assessment

Attachment S requires that the baseline system (ATBA) must meet the Applicable Reliability Requirements[9] The NYISO annually conducts studies to determine the statewide Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) needed to meet these reliability requirements. The most recent of these studies[10] completed before the start of this study established a 16.0% IRM requirement on a statewide basis, an 83% locational Installed Capacity (ICAP) requirement in the New York City zone, and a 99% locational ICAP requirement in the Long Island zone.

As an initial assessment, a projection of these ICAP requirements is tested on the baseline system for the study period of five years (2012-2016). Following that, a Multi-Area Reliability Simulation (MARS) is performed to determine the forecast risk, in terms of Loss of Load Expectation (LOLE) over the study period. This measurement of risk is then compared to the NPCC and NYSRC criteria of one day in ten years, or 0.1 days/year, to ascertain whether any generic measures are needed.

7.1. Reliability Analysis Assumptions

For this analysis, the NYISO staff used the most recently completed 2012 IRM study database, which is established and maintained by the NYISO for the NYSRC. Appropriate adjustments in that database were made to fit the assumptions of this study.

Table 7.1 below shows the assumptions used the 2012 IRM study report and any assumption changes made for this analysis.

[9] NYSRC Reliability Rules, NPCC Basic Design and Operating Criteria, NERC Planning Standards, NYISO rules, practices and procedures, and local Transmission Owner criteria included in FERC Form No. 715

[10] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2012 Through April 2013," December 2, 2011. Report available at www.nysrc.org.

Table 7.1 – Reliability Assumptions

BASE CASE ASSUMPTION	2012 IRM REPORT	CY11 ATBA RA ANALYSIS
NYCA existing Capacity	All Capacity in the NYCA per the 2011 Gold Book Table III-2.	No Change
NYCA Unit Ratings	Based on 2011 Gold Book	No Change
Planned Capacity	IRM study see Page 30-32	Per the 2016 ATBA case
Unit Availability	NERC-GADS 2006-2011	No Change, NERC class average for proposed units.[11]
Unit Maintenance Schedule	Scheduled, adjusted for historic performance	No Change
Neighboring Control Areas	As provided by neighboring Control Areas through CP-8	No Change
Load Model	2002 NYCA shape	No Change
Peak Load Forecast	Based on NYISO Interim IRM forecast (10/11)	Based on forecast in 2011 Gold Book
Load Model Uncertainty	Includes updated load growth uncertainty model	No Change
External ICAP	Grandfathered external contracts totaling 2,220 MW	No Change
Emergency Operating Procedures (excluding SCR/EDRP below)	735 MW load relief	No Change
Special Case Resources/Emergency Demand Response Program	2,192 and 148 MW respectively	No Change
Transfer Limits[12]	As model in 2012 IRM study.	No Change
Inter-control Area reserve sharing priority	As model in 2012 IRM study.	No Change

[11] Wind unit output is based on 2002 hourly wind readings taken at or near the project sites. Characteristics of these readings have shown weekday summer hours (2pm to 6pm) availability of 10-11% and annual availability of roughly 30%.
[12] See NYCA Transfer limit diagram on the next page

Figure 7.1 New York Topology used for the Class Year 2011 Resource Adequacy Study

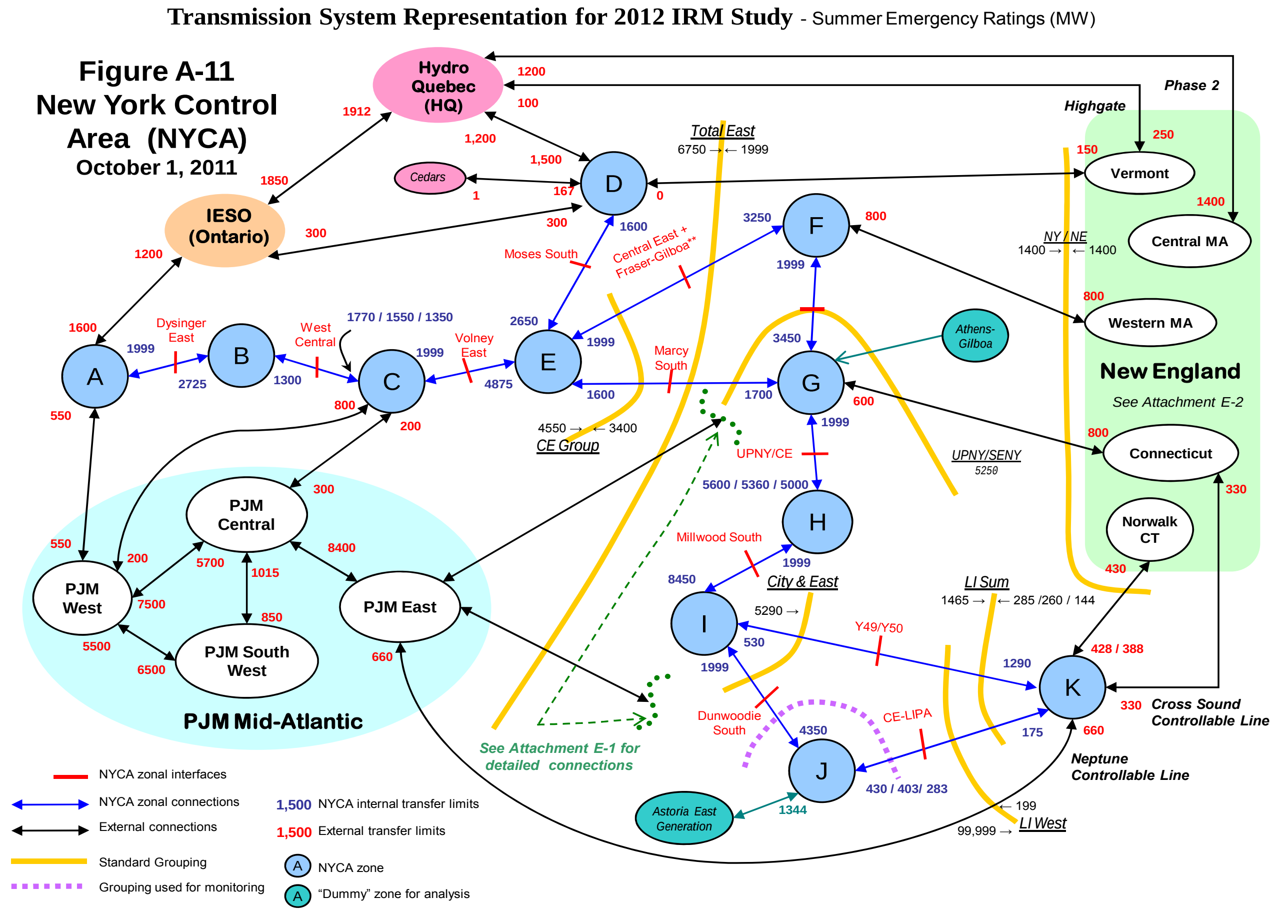
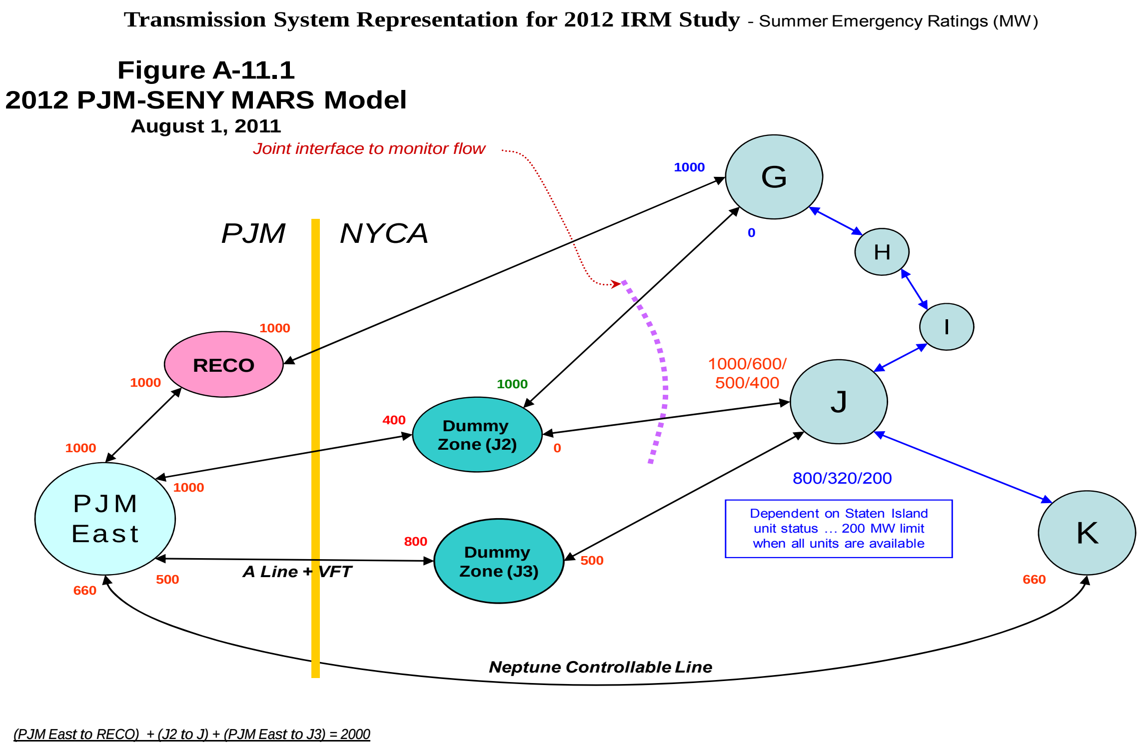


Figure 7.2 Breakout of Southeast NY Topology



7.1.1. Capacity assumptions changes from the 2011 Load & Capacity Data Book

The starting point for capacity in this analysis is that which is modeled in the 2012 IRM study. The "2011 Load & Capacity Data" (2011 Gold Book) forms the basis for the 2012 IRM study. Changes to the Gold Book for the 2012 IRM study are highlighted below and are tabulated in **Table 7.1.1.**

Retirements:

Glenwood ST04	116 MW	Zone K
Glenwood ST05	113 MW	Zone K
Far Rockaway ST04	105 MW	Zone K

Planned Units for 2012:

(These units had a signed interconnection agreement and/or RPS agreement by August 1, 2011.)

Astoria Energy II	576 MW	Zone J
Bayonne Energy Center	500 MW	Zone J
BP Solar	32 MW	Zone K
Enxco Solar	6.5 MW	Zone K
Cody Road Wind	10 MW	Zone C
Howard Wind	55 MW	Zone C
Allegany Wind	73 MW	Zone A

The following wind units were listed at 50% of their output in the IRM study:

Belmont/Ellenburg II	5.3 MW	Zone D
Windfarm Prattsburgh	39.1 MW	Zone C
Stony Creek Wind Farm	44.3 MW	Zone C
Marble River Wind 1 and 2	108.2 MW	Zone D

* The total amount of wind in the IRM model is 1,648 MW (nameplate rating).

Table 7.1.1 – Capacity by Zone in 2012 IRM study

Zone	2011 GOLD BOOK*	Less Units With no CRIS	Additions Retirements Net Purch's	Total	SCR's	Grand Total
A	4904	4822	-91	4731	408	5140
B	793	788	0	788	126	914
C	6420	6406	156	6561	143	6704
D	1632	1631	1188	2819	471	3290
E	1029	1026	0	1026	51	1077
F	4367	4357	29	4386	146	4532
G	3010	3002	-47	2954	75	3029
H	2089	2089	0	2089	10	2099
I	3	2	0	2	46	47
J	9091	9062	1376	10438	554	10992
K	5549	5471	464	5935	162	6097
	38887	38654	3075	41729	2192	43921

7.1.2. Changes to capacity assumptions from 2012 IRM study

Allegany Wind (72.5 MW in zone A) and Enxco Solar (6.5MW in zone K) were forecast in the 2012 IRM to be in service for the summer of 2012. The 2011 CY (2012 ATBA) did not list these units as having CRIS, therefore the units were removed for this study. Also, the Upton Solar facility had a slightly lower rating in the ATBA versus the IRM. The below table (**Table 7.1.2.1)** shows the differences, in starting assumptions, between this analysis and the 2012 IRM Study.

Table 7.1.2.1 Unit Changes to Start 2011 CY Study

Unit	2012 IRM Value	ATBA Value For 2012
Allegany Wind	72.5 MW	0 MW
Enxco Solar Farm	6.5 MW	0 MW
Upton Solar Farm	32 MW	31.5 MW
NE import	50 MW	0 MW

Based on these differences and the units expressed in the below **Table 7.1.2.3**, the starting point for the study changes from **Table 7.1.1** above to the below **Table 7.1.2.2.**

Table 7.1.2.2 Starting point (year 2012) for RA analysis:

Zone	2011 GOLD BOOK*	Less Units With no CRIS	Additions Retirements Net Purch's	Total	SCR's	Grand Total
A	4904	4822	-163	4659	408	5067
B	793	788	0	788	126	914
C	6420	6406	156	6561	143	6704
D	1632	1631	1188	2819	471	3290
E	1029	1026	0	1026	51	1077
F	4367	4357	0	4357	146	4504
G	3010	3002	-69	2933	75	3008
H	2089	2089	0	2089	10	2099
I	3	2	0	2	46	47
J	9091	9062	1376	10438	554	10992
K	5549	5471	457	5928	162	6090
	38887	38654	2945	41599	2192	43792

Table 7.1.2.3 below shows the units added to this analysis based on the ATBA for 2012. Units that already exist in the 2012 IRM Study are not shown.

Table 7.1.2.3: ATBA Units (not captured in 2012 IRM study):

Hudson Transmission Project	660.0 MW	Zone J
Nine Mile Point 2 Uprate -Phase I	96.3 MW	Zone C

ATBA Wind Units (not captured in IRM study):

Munnsville	5.5 MW	Zone E
Ellenburg II (remaining 50%)	5.3 MW	Zone D
Prattsburgh (r-50%)	39.1 MW	Zone C
Stony Creek Wind Farm (r-50%)	44.3 MW	Zone C
Marble River Wind 1 and 2 (r-50%)	108.2 MW	Zone D

St. Lawrence Wind Farm	79.5 MW	Zone E
Ball Hill Windpark	90.0 MW	Zone A
Beekmantown Windfarm	19.5 MW	Zone D
West Hill Windfarm	31.5 MW	Zone C

ATBA Reratings (not captured in IRM study):

Nine Mile Point 2 Uprate -Phase II	71.7 MW	Zone C

ATBA Retirements (not captured in IRM study):

Ravenswood 3-4	-31.7 MW	Zone J
Standard Binghamton	-41.3 MW	Zone C
Sithe Massena	-82.2 MW	Zone D
Beebee station 13	-15.0 MW	Zone B

7.1.3. Changes to Load Assumptions from 2012 IRM Study

Based on the information provided in Table I-2a of the 2011 Gold Book, the load in NYCA is expected to grow by 567 Megawatts during the five years under study (2012-2016). This growth has been tempered by the inclusion of the Public Service Commission's Energy Efficient Portfolio Standard (EEPS) program. Growth in NYC is expected to total 245 MW while the peak load on Long Island is expected to increase by 165 MW over the period. The load forecasts for the years 2012-2016 are included below in the year by year figures shown on **Tables 7.2.1** through **7.2.6**.

7.2. Year by Year Comparison Analysis

The projects (additions and retirements) are shown above in **Table 7.1.2** while **Tables 7.2.1** through **7.2.6** below, show a year by year break out of forecast capacities and loads, along with projected statewide and locational requirements.

Table 7.2.1 - Projected Resource Adequacy Capacities, Loads, and Requirements by Zone for 2012

Summer Capability Period (MW)												
2012	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**TOTAL**
Table 7.1.2.2 Capacity:	5067.3	914.0	6703.6	3289.6	1077.0	4503.6	3007.7	2099.1	47.5	10991.8	6090.4	**43791.6**
ADDITIONS:												
Hudson Transmission Project												0
Nine Mile 2 Uprate -Phase I			96.3									96.3
Munnsville												0
Ellenburg II (remaining 50%)				5.3								5.3
Prattsburgh (r-50%)				39.1								39.1
Stony Creek Wind Farm (r-50%)			-44.3									-44.3
Marble River Wind 1 and 2 (r-50%)				-108.2								-108.2
St. Lawrence Wind Farm												0
Ball Hill Windpark	90.0											90
Beekmantown Windfarm												0
West Hill Windfarm												0
Nine Mile Point 2 Uprate -Phase II												0
Ravenswood 3-4										-31.7		-31.7
Standard Binghamton			-41.3									-41.3
Sithe Massena				-82.2								-82.2
Beebee station 13		-15.0										-15
2012 RA Capacity	**5157.3**	**899.0**	**6714.3**	**3143.6**	**1077.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**10960.1**	**6090.4**	**43699.6**
Forecast Load										11607	5521	33335.0
Projected Requirement										9633.8	5465.8	38668.6
Projected excess/(deficiency)										**1326.3**	**624.6**	**5031.0**

Table 7.2.2 - Projected Resource Adequacy Capacities, Loads, and Requirements by Zone for 2013

Summer Capability Period (MW)												
2013	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**TOTAL**
Table 7.1.2.2 Capacity:	**5067.3**	**914.0**	**6703.6**	**3289.6**	**1077.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**10991.8**	**6090.4**	**43791.6**
ADDITIONS:												
Hudson Transmission Project										660.0		**660**
Nine Mile 2 Uprate -Phase I			96.3									**96.3**
Munnsville												**0**
Ellenburg II (remaining 50%)				5.3								**5.3**
Prattsburgh (r-50%)				39.1								**39.1**
Stony Creek Wind (r-50%)			44.3									**44.3**
Marble River 1 and 2 (r-50%)				108.2								**108.2**
St. Lawrence Wind Farm												**0**
Ball Hill Windpark	90.0											**90**
Beekmantown Windfarm												**0**
West Hill Windfarm												**0**
Nine Mile 2 Uprate -Phase II												**0**
Ravenswood 3-4										-31.7		**-31.7**
Standard Binghamton			-41.3									**-41.3**
Sithe Massena				-82.2								**-82.2**
Beebee station 13		-15.0										**-15**
2013 RA Capacity	5157.3	899.0	6802.9	3360	1077.0	4503.6	3007.7	2099.1	47.5	11620.1	6090.4	**44664.6**
Forecast Load										11720	5593	33433
Projected Requirement										9727.6	5537.1	38782.3
Projected excess/(deficiency)										**1232.5**	**553.3**	**5934.8**

Table 7.2.3 - Projected Resource Adequacy Capacities, Loads, and Requirements by Zone for 2014

Summer Capability Period (MW)												
2014	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**TOTAL**
Table 7.1.2.2 Capacity:	5067.3	914.0	6703.6	3289.6	1077.0	4503.6	3007.7	2099.1	47.5	10991.8	6090.4	**43791.6**
ADDITIONS:												
Hudson Transmission Project										660.0		**660**
Nine Mile 2 Uprate -Phase I			96.3									**96.3**
Munnsville												**0**
Ellenburg II (remaining 50%)				5.3								**5.3**
Prattsburgh (r-50%)				39.1								**39.1**
Stony Creek Wind (r-50%)			44.3									**44.3**
Marble River 1 and 2 (r-50%)				108.2								**108.2**
St. Lawrence Wind Farm												**0**
Ball Hill Windpark	90.0											**90**
Beekmantown Windfarm												**0**
West Hill Windfarm			31.5									**31.5**
Nine Mile 2 Uprate -Phase II			71.7									**71.7**
Ravenswood 3-4										-31.7		**-31.7**
Standard Binghamton			-41.3									**-41.3**
Sithe Massena				-82.2								**-82.2**
Beebee station 13		-15.0										**-15**
2014 RA Capacity	**5157.3**	**899.0**	**6906.1**	**3360**	**1077.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**11620.1**	**6090.4**	**44767.8**
Forecast Load										11785	5617	33609
Projected Requirement										9781.6	5560.8	38986.4
Projected excess/(deficiency)										**1838.5**	**529.6**	**5781.4**

Table 7.2.4 - Projected Resource Adequacy Capacities, Loads, and Requirements by Zone for 2015

Summer Capability Period (MW)												
2015	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**TOTAL**
Table 7.1.2.2 Capacity:	**5067.3**	**914.0**	**6703.6**	**3289.6**	**1077.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**10991.8**	**6090.4**	**43791.6**
ADDITIONS:												
Hudson Transmission Project										660.0		**660**
Nine Mile 2 Uprate -Phase I			96.3									**96.3**
Munnsville					5.5							**5.5**
Ellenburg II (remaining 50%)				5.3								**5.3**
Prattsburgh (r-50%)				39.1								**39.1**
Stony Creek Wind (r-50%)			44.3									**44.3**
Marble River 1 and 2 (r-50%)				108.2								**108.2**
St. Lawrence Wind Farm					79.5							**79.5**
Ball Hill Windpark	90.0											**90**
Beekmantown Windfarm				19.5								**19.5**
West Hill Windfarm			31.5									**31.5**
Nine Mile 2 Uprate -Phase II			71.7									**71.7**
Ravenswood 3-4										-31.7		**-31.7**
Standard Binghamton			-41.3									**-41.3**
Sithe Massena				-82.2								**-82.2**
Beebee station 13		-15.0										**-15**
2015 RA Capacity	**5157.3**	**899.0**	**6906.1**	**3379.5**	**1162.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**11620.1**	**6090.4**	**44872.3**
Forecast Load										11830	5646	33678
Projected Requirement										9818.9	5589.5	39066.5
Projected excess/(deficiency)										**1801.2**	**500.9**	**5805.8**

Table 7.2.5 - Projected Resource Adequacy Capacities, Loads, and Requirements by Zone for 2016

Summer Capability Period (MW)												
2016	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**TOTAL**
Table 7.1.2.2 Capacity:	**5067.3**	**914.0**	**6703.6**	**3289.6**	**1077.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**10991.8**	**6090.4**	**43791.6**
ADDITIONS:												
Hudson Transmission Project										660.0		**660**
Nine Mile 2 Uprate -Phase I			96.3									**96.3**
Munnsville					5.5							**5.5**
Ellenburg II (remaining 50%)				5.3								**5.3**
Prattsburgh (r-50%)				39.1								**39.1**
Stony Creek Wind (r-50%)			44.3									**44.3**
Marble River 1 and 2 (r-50%)				108.2								**108.2**
St. Lawrence Wind Farm					79.5							**79.5**
Ball Hill Windpark	90.0											**90**
Beekmantown Windfarm				19.5								**19.5**
West Hill Windfarm			31.5									**31.5**
Nine Mile 2 Uprate -Phase II			71.7									**71.7**
Ravenswood 3-4										-31.7		**-31.7**
Standard Binghamton			-41.3									**-41.3**
Sithe Massena				-82.2								**-82.2**
Beebee station 13		-15.0										**-15**
2016 RA Capacity	**5157.3**	**899.0**	**6906.1**	**3379.5**	**1162.0**	**4503.6**	**3007.7**	**2099.1**	**47.5**	**11620.1**	**6090.4**	**44872.3**
Forecast Load										11880	5708	33749
Projected Requirement										9860.4	5650.9	39148.8
Projected excess/(deficiency)										**1759.7**	**439.5**	**5723.5**

The above **Tables 7.2.1** to **7.2.6** show that if the current New York City Locational Capacity Requirement of 83% of the forecast peak load was projected out through 2016, existing resources coupled with projected ATBA resources could meet those requirements. Similarly, if the Long Island current 99% requirement was projected, existing and projected ATBA identified resources could meet those requirements throughout the period of 2010 through 2016. Other zones within NYCA, having no specific locational requirements, were not evaluated.

The resource reliability requirement for NYCA is to meet the 16.0% IRM for the 2012 capability year. These tables show that the existing resources along with those identified in the ATBA are sufficient to meet a projected statewide Installed Reserve Margin of 16.0% throughout the analysis period. Table 7.2.7 shows a statewide summary of the above tables, on a margin basis.

Table 7.2.7 - Load and Capacity Schedule for baseline case (ATBA)

Base Forecast – Summer Capability (MW)	2012	2013	2014	2015	2016
Peak Load	33335	33433	33609	33678	33749
Resource Capability Before Adjustments	43792	43792	43792	43792	43792
Additions to Baseline Case	78	1043	1146	1250	1250
Retirements from Baseline Case	-170	-170	-170	-170	-170
Resource Capability	43700	44665	44768	44872	44872
Required Capability (16% Reserve Req't)	38669	38782	38986	39066	39149
Actual Reserve	10365	11232	11159	11194	11123
Reserve Margin %	31.1%	33.6%	33.2%	33.2%	33.0%
Proposed Resource Additions	0	0	0	0	0
Adjusted Reserve Margin %	31.1%	33.6%	33.2%	33.2%	33.0%

7.3. MARS Analysis

The above analysis indicates that existing and planned resources are sufficient to meet forecast load if the current locational and statewide capacity requirements were projected as unchanged throughout the analysis period of 2012 through 2016. The statewide and locational requirements are set only for the upcoming capability year and are subject to change for future years. In order to determine if actual reliability criteria are met, MARS analyses must be performed.

The results of the analyses show that the currently projected statewide reserve margin can be met over the period of 2012 through 2016 using the ATBA forecast projects. Similarly, these forecast projects are sufficient to meet the currently projected Locational Capacity Requirements (LCRs) over the same study period.

Although the system modeled with these ATBA resources meets the projected reserve margin requirements over the study period, it does not guarantee that the Loss of Load Expectation criterion of 0.1 days/year can be met. To confirm that these projected resources laid out against the forecast loads can meet the LOLE criterion, Multi Area Reliability Simulations (MARS) were performed for each of the years in the study period. The results of these runs are shown in Table 7.3.1 and indicate a system more reliable than criteria over the entire study period.

In addition to the cases indicated above, a sensitivity analysis was performed changing the dynamic ratings to static ratings on two interfaces. The first change reduced the UPNY/CE interface (see Figure 7.1) to a static level of 4300 MW. The next change froze the zone J3 to zone J interface (see Figure 7.1.1) at its lowest existing rating of 400 MW. Finally, an existing generating unit, whose output was reduced as the result of storm activity in 2011, does not return to full 'pre-storm' output. This sensitivity also resulted in a reliability measure better than criteria.

Table 7.3.1 MARS Results

	CY_2011 IPFS RA Study												
		Area J				Area k				NYCA			
Case		LOLE	Cap	Load	%cap	LOLE	Cap	Load	%cap	LOLE	Cap	Load	RM[1]
0	2012 IRM Tech Study Base case[2]	0.001	10993	11607	94.7%	0.000	6097	5521	110.4%	0.001	43923	33335	31.8%
1	With 2016 ATBA updates for 2012[3]	0.001	10960	11607	94.4%	0.000	6090	5521	110.3%	0.001	43701	33335	31.1%
2	With 2016 ATBA updates for 2013	0.000	11620	11722	99.1%	0.000	6090	5593	108.9%	0.001	44666	33433	33.6%
3	With 2016 ATBA updates for 2014	0.000	11621	11785	98.6%	0.000	6090	5617	108.4%	0.001	44769	33609	33.2%
4	With 2016 ATBA updates for 2015	0.000	11621	11830	98.2%	0.000	6090	5646	107.9%	0.001	44874	33678	33.2%
5	With 2016 ATBA updates for 2016	0.001	11621	11880	97.8%	0.001	6090	5708	106.7%	0.001	44874	33749	33.0%
S1	Reduced interface limits, lower generator output	0.001	11621	11880	97.8%	0.001	6090	5708	106.7%	0.002	44502	33749	31.9%

1 The reserve margin expressed here is the capacity to peak load ratio above 100.
2 As found loads and capacities
3 Lower capacity values, when compared to the IRM capacities, are due to ATBA retirements.

7.4. Conclusions of Resource Adequacy Analysis

A Resource Adequacy analysis was performed for the CY11 Facilities Study. This analysis consisted of two parts. The first part was an examination of the existing and projected capacities over the years 2012 through 2016 along with the forecast peak loads, compared against a projection of statewide and locational capacity requirements. This analysis showed that there would be no capacity shortages for the ATBA system.

Although meeting a projected requirement gives an indication of the characteristics of a future system, it is most important to know if that forecast of capacities and peak loads meets the NPCC and NYSRC resource adequacy requirements. The second part of this analysis determined the LOLE risk for the NYCA system for all the years of the study period. In addition, a sensitivity case was modeled reducing two interface limits and one generator's output. Results of these analyses showed a future system well within (below) the LOLE criteria of 0.1 days/year for all years studied.

Therefore, no resource additions are needed to be proposed.

8. Fault Duty Assessment

As shown in the previous sections in this report, the baseline system ATBA does not need any system upgrades to meet the thermal, voltage and stability criteria, as related with the CY11 projects impacts under MIS, nor any generic generation to satisfy Resource Reliability requirements.

8.1. Methodology

The “NYISO Guideline for Fault Current Assessment” was used to set up the parameters in the short circuit representations and generate the initial fault current levels on a consistent, statewide basis. Key assumptions used under this methodology are as follows:

a. All generating units are in service,

b. All transmission lines and transformers are in service,

c. All series elements (series reactors, series capacitors) are in service except those that are normally out of service,

d. Ignore load,

e. Ignore shunts (shunt capacitors, shunt reactors, line charging, etc.),

f. Do not ignore delta-wye transformer phase shift,

g. Do not ignore tap positions of fixed tap transformers,

h. All generator internal voltages are set at 1.0 pu with no phase displacement due to load (*i.e.,* “Flat Gen voltage profile,” which is now called “linear network solution” voltage profile),

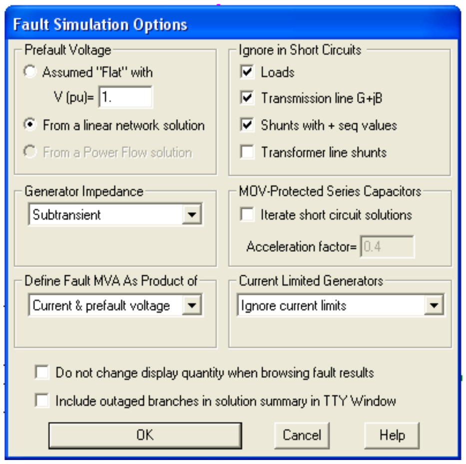
i. Apply the following faults:

j. Three line to Ground,

k. Double line to ground,

l. Single line to ground.

Fault Simulation Options (ASPEN 11.7):



All the above assumptions were used by the NY TOs, except “h”: NYSEG/RG&E use the “flat bus voltage profile” with a pre-fault voltage of 1.05 pu at all buses, in order to calculate fault currents in their systems. Also, NYSEG, Central Hudson, and National Grid submitted breaker ratings derated from the nameplate symmetrical ratings, for initial bus fault screening purposes.

NYISO staff used the above methodology to determine the monitoring buses. All buses impacted by the current class projects by 100 A (*de minimis*) or more define the “monitoring list.” To identify the list, the above fault types were applied on all buses (system substations/nodes are modeled as “buses” in both power flow and short circuit simulation packages) represented in both ATBA and ATRA systems, using the ASPEN Batch Module; all bus faults which resulted in a 100 A or more difference (ATRA_bus_fault minus ATBA_bus_fault > 100A) were identified and included in a preliminary monitoring list (see **Appendix H** for the complete preliminary monitoring list). This preliminary list was then circulated among the impacted Transmission Owners, who were asked to provide the minimum fault interrupting device (FID) rating for each station, or alternatively to identify if there is no FID (e.g., breaker/fuse, etc.) at that station. This method has the goal to assure that no New York State Transmission System bus will be missed, as impacted by a current Class Year project, and also filters out buses with no relevance for this study scope (*i.e.,* not impacted by current Class Year projects under evaluation).

The highest of the three types of faults at each of the selected buses was compared against the respective lowest circuit breaker rating at that substation to determine whether the fault duty exceeds the lowest FID rating.

A “higher than lowest FID rating” bus fault does not automatically mean that each circuit breaker at the respective station will be overdutied. Only an Individual Breaker Analysis (IBA) can identify what fault current a particular FID will see. When a “fault duty higher that the lowest FID” was identified through the initial bus fault assessment, the respective Transmission Owner was contacted and asked to perform the IBA assessment. NYISO does not have an IBA universal methodology defined; therefore, each Transmission Owner uses its own methodology. When there is no methodology defined, a standard, conservative methodology will be used, in which the breaker in question is the last breaker opened to clear the fault, regardless of the voltage level.

8.2. Bus Fault Assessment Results

Appendix H shows a complete monitoring list and fault duty results. The bus fault current magnitudes are shown in the appendix, for three phase to ground (3LG), a double line to ground (2LG), and a single line to ground (1LG) faults applied at each of the substations evaluated. The table also includes the lowest circuit breaker rating at each of these substations for comparison with the substations’ fault currents, as provided by the respective Transmission Owner.

ATBA

Among the monitoring buses, the following were found to have the fault current exceeding their lowest FID rating: Fishkill Plains 115 kV (Central Hudson) and Astoria West 138 kV (Con Edison). Below is a summary **Table 8.2.1** showing only these substations and the baseline system results.

Table 8.2.1. Stations impacted by CY11 and having the bus fault exceeding the lowest FID rating:

						CY11 ATRA rev 2				CY11 ATBA rev 1				CY11ATRA minus ATBA bus fault by type
Bus Name	Nom kV	BusName&kV	Transmission Owner	Lowest Fault Interrupting Device (FID) Rating - 2016 projection Amperes	Notes	3LG (Amp)	2LG	1LG	ATRA max	3LG (Amp)	2LG	1LG	ATBA max	delta max
FISH PL	115	FISH PL115	Central Hudson	23,600	CHG&E's IBA indicates no overdutied breakers	24,165	23,623	21,313	24,165	24,040	23,513	21,215	24,040	125
AST-WEST-N	138	AST-WEST-N138	ConEd	45,000	USPG's G2N still overdutied in ATRA after IBA (45,754 A) ; not overdutied in ATBA	42,873	47,202	49,340	49,340	40,445	44,502	46,518	46,518	2,822
AST-WEST-S	138	AST-WEST-S138	ConEd	45,000	USPG's G1N still overdutied in ATRA after IBA (45,754 A) ; not overdutied in ATBA	42,873	47,202	49,340	49,340	40,445	44,502	46,518	46,518	2,822

Con Edison and Central Hudson performed Individual Breaker Analysis (IBA) for the above substations.

Central Hudson's IBA concluded that no breaker is overdutied at Fishkill Plains 115 kV in both the ATBA and ATRA.

Con Edison's IBA determined that no breaker is overdutied at Astoria West 138 kV in the ATBA. The Interim Operating Protocol for Astoria East and West Fault Current Mitigation, approved by the Operating Committee on May 6, 2010, was reflected in the ATBA and ATRA modeling assumptions, *i.e.,* the "dual yard" plants Astoria 3 and 4 were modeled at Astoria West 138 kV, while Astoria 5 plant was modeled at Astoria East 138 kV.

ATRA

The statewide ATRA case is essentially the same as the ATBA case, except that it includes all CY11 projects and system modifications that go with those projects (CY11 ATRA = ATBA + CY11 projects). The purpose of this case is to identify what incremental impacts these projects have, and how much it will cost to mitigate those impacts.

Among the CY11 monitoring buses, the following were found to have the fault current exceeding their lowest FID rating in ATRA: Fishkill Plains 115 kV (Central Hudson), Astoria West 138 kV (Con Edison), Ramapo 138 kV (ORU) and 115 kV Southington Ring 1 and Ring 2.

Con Edison and Central Hudson performed Individual Breaker Analysis (IBA) for the above substations.

Central Hudson's IBA concluded that no breaker is overdutied at Fishkill Plains 115 kV in both the ATBA and ATRA.

Orange and Rockland's (ORU) Ramapo 138 kV: There is a proposed project in the CY11ATBA case, *i.e.,* Hilburn to Pomona 138kV line. This project is now listed in the 2012 Gold Book as a non-firm. Without this line, the max fault levels at Ramapo 138 kV are around 37.5 kA in ATRA, hence below the 40 kA min rating, (confirmed by ORU).

NU's IBA concluded that no breaker is overdutied at 115 kV Southington Ring 1 and Ring 2 in ATRA.

Con Edison's IBA determined that two breakers, *i.e.,* the 45 kA breakers G1N and G2N, belonging to Astoria 3 plant feeders and owned by PowerGen, become overdutied in the ATRA, due to NRG's Q201 Berrians GT project (Note: Q224 Berrians II reflects additional capability of the Q201Berrians plant, with no additional equipment, hence no additional fault impact). The cost to replace the two breakers owned by US PowerGen is estimated at $3,450,000 (includes 15% margin). The two breakers do not fall within the definition of New York State Transmission System. Therefore, their replacement is not categorized as SUFs for the purpose of this study. These breakers must nonetheless be replaced in order to accommodate the interconnection of the Q201 Berrians GT project.

ATRA with the second PV-CV 345 kV line (Re-assessment)

Appendix H1 shows all buses impacted by the CY11 projects by 100 A or more, with the updated 2nd PV-CV line included (identified as an SUF for Q310 Cricket Valley project). The second line addition increases the total bus fault in the electrical vicinity (e.g., by 3,300 A at Pleasant Valley 345 kV, less and less as the electrical distance increases). However, as related with the impacted buses in the vicinity of the 2nd PV-CV line, the faults are still below the available lowest fault interrupting device rating, as provided by the station owners.

Based on the Northeast Utilities input, the reconductoring of the Cricket Valley to Long Mountain 345 kV segment to an ACSS 2156 conductor will not change the impedances of the line; it will, however, increase the thermal rating above the target ratings identified in this study; hence, there are no fault duty impacts.

ATRA with Rest of State (ROS) SDU (Re-assessment)

Appendix H2 shows all buses impacted by the CY11 projects (including their SUFs) by 100 A or more, with the Rest of State SDU included (SDU identified as needed for CY11 projects in order to be deliverable throughout ROS Capacity Region, see the Deliverability Report for details). The proposed ROS SDU is an 18 % series capacitor on Leeds - Hurley 345 kV line, to be installed at Hurley 345 kV substation.

The proposed ROS SDU increases the total bus fault in the electrical vicinity (*e.g.,* by 1,180 A at Hurley 345 kV, less and less as the electrical distance increases). However, as related with the impacted buses in the vicinity of the ROS SDU, the faults are still below the available lowest fault interrupting device rating, as provided by the station owners.

9. Headroom Impact

Headroom is the functional or electrical capacity of a System Upgrade Facility (or the electrical capacity of a System Deliverability Upgrade) that is in excess of the functional or electrical capacity actually used by a Developer's generation or merchant transmission project.

9.1. Electrical Headroom

During prior Class Year studies, various SUFs were identified in order to reliably interconnect the respective Class Year projects into the system. Some of those SUFs (*e.g.,* series reactors, circuit breaker, etc.) created measurable capabilities (Amperes, or other discrete electrical units) larger than what was needed for the Class Year projects to which costs for such SUFs were allocated. This created "Electrical Headroom," which can be used by future Class Year projects (ATRA) or by load growth and changes in load pattern system modifications (ATBA).

Attachment S requires that future Class Year projects pay for Electrical Headroom usage to owners of the Headroom. If the fault current contribution is equal to or higher than the "*de minimus*," the Developer is responsible for reimbursement of the Headroom used. If such impact is identified, the NYISO calculates the Headroom usage and cost responsibility in accordance with the terms of the settlement of the Class 2001 litigation [9] and applicable rules under Attachment S.

During this CY11 assessment, it was identified that there are several substations ("buses") identified in the prior years as having Electrical Headroom and are impacted by CY11 projects by 100 A or more, therefore Headroom usage and cost reimbursement are calculated.

Table 9.1.1 shows all substations that may have Headroom ("Electrical Headroom Substations"), as identified in various CY studies, starting with CY01.

Table 9.1.1. List of all "Electrical Headroom Substations," as compiled from prior class reports

Station Name	Transmission Owner	Notes
ATRA CY01: Substations potentially having Electrical Headroom		
345 kV		
~~FARRAGUT~~	~~ConEd~~	extinguished CY10
RAINEY	ConEd	
SPRN BRK	ConEd	
138 kV		
AST-EAST-E	ConEd	
AST-EAST-W	ConEd	
~~AST-WEST~~	~~ConEd~~	extinguished CY11
CORONA (N)	ConEd	
CORONA (S)	ConEd	
E 13 ST	ConEd	
GRENWOOD	ConEd	
QUEENSBG	ConEd	
SHM CRK	ConEd	
69kV		
~~E RIVER~~	~~ConEd~~	extinguished CY10
Catch-up Class Year (2003-2005): Substations potentially having Electrical Headroom		
138 kV		
E.G.C	LIPA	
69 kV		
RULAND	LIPA	
ATRA CY06: Substations potentially having Electrical Headroom		
69 kV		
BRKHAVEN	LIPA	
HOLBRK1	LIPA	

Since the fault current was above the breaker rating for the Farragut 345 kV and the East River 69 kV breakers, their Headroom accounts were extinguished during the CY10 process. Also, during this CY11 study, Astoria West 138 kV had the fault current above the breaker rating; hence the Headroom will be extinguished. Among the remaining electrical Headroom substations, three CY11 projects (Q201 Berrians GT, Q 251 CPV Valley and Q310 Cricket Valley) initially impact six of the CY01-created Headroom substations (as a combined effect). However, individual impacts over 100 A are identified only for four of the CY01-created Headroom substations: Con Edison's Sprainbrook 345 kV, Rainey 345 kV, Queensbridge 138 kV and Sherman Creek 138 kV substations.

Table 9.1.2 below summarizes the results of such combined impact, creating a list for the detailed analysis. These results reflect the addition of the 2nd PV-CV 345 kV line, as an SUF for the Cricket Valley project.

Table 9.1.2. Combined CY11 Impacts on "Electrical Headroom-holder Substations"

			CY11 ATRArev3a (with 2nd PV-CV Line and CV-NE recond updated impedance)				CY11 ATBArev1				CY11ATRA - CY11ATBA delta Amp >= 100 A				CY11 Updated Total Amp Headroom after "ATBA" usage
Bus Name (per Aspen)	**Nom. kV**	**Lowest FID Rating** (Amperes)	**3LG(A)**	**2LG**	**1LG**	**max**	**3LG(A)**	**2LG**	**1LG**	**max**	**3LG(A) delta**	**2LG delta**	**1LG delta**	**max delta**	**Amp**
															M'=LFIDR-MaxATBA
RAINEY	345	63,000	50,849	54,167	53,797	54,167	50,646	53,986	53,644	**53,986**	203	181	153	**203**	**9,014**
SPRN BRK	345	63,000	53,418	52,758	45,655	53,418	51,909	51,444	44,896	**51,909**	1,509	1,314	759	**1,509**	**11,091**
QUEENSBG	138	63,000	41,775	47,312	45,771	47,312	39,538	44,683	43,475	**44,683**	2,238	2,628	2,296	**2,628**	**18,317**
SHM CRK	138	63,000	45,009	46,024	40,328	46,024	44,765	45,806	40,193	**45,806**	244	218	135	**244**	**17,194**
EGC-1	138	80,000	66,103	71,153	70,861	71,153	65,976	71,042	70,768	**71,042**	127	111	93	**127**	**8,958**
EGC-2	138	80,000	66,100	71,146	70,855	71,146	65,973	71,035	70,762	**71,035**	127	111	93	**127**	**8,965**

Below are the steps taken in order to identify the new $/Amp value needed to calculate how much $ the CY11 project(s) will reimburse the CY01 owners of the respective Electrical Headroom SUFs, and as related with the impacted buses.

1. Calculate the **depreciation** on the Headroom value:

Table 9.1.3. Calculation of Depreciation after the prior Class Year Payments

Bus Name	**Nom kV**	**Transmission Owner**	**Lowest FID Rating (Ampers)**	**Headroom value $**	**Annual Depreciation rate (%)**	**Depreciation Years**			**Depreciation ($)**	**New Depreciated Total Headroom $Value ($)**
				up to and including prior CY payments, as applicable	**from TO**	**Depreciated to year** *(due to prior CY impacts calculations)*	**To depreciate to year**	**Number of years**		
				A	**S**	**T1**	**T2**	**T=T2-T1**	**U= A*S*T / 100**	**V = A - U**
RAINEY	345	ConEd	63,000	$4,766,719	2.5	2010	2013	3	357,504	**4,409,215**
SPRN BRK	345	ConEd	63,000	$8,146,912	2.5	2010	2013	3	611,018	**7,535,893**
QUEENSBG	138	ConEd	63,000	$284,822	2.5	2009	2013	4	28,482	**256,340**
SHM CRK	138	ConEd	63,000	$166,710	2.5	2009	2013	4	16,671	**150,039**

2. Calculate **new $/Amp** value of Headroom after "ATBA" usage, to be used for CY11 usage $ reimbursement.

Table 9.1.4. Updated $/Amp Calculation

Bus Name	Nom kV	Lowest Breaker Rating (LBR) Amp	New $/Amp Calculation: New Depreciated Total Headroom $Value (2010) ($)	Headroom Expired (1=No, 0=yes)	CY11 Updated Total Headroom after "ATBA" usage Amp (LBR -MaxATBA)	New CY11 $/kA Headroom Value $/Amp
			V	α	M'	*O' = V* α / M'*
RAINEY	345	63,000	$4,409,215	1	9,014	**$489**
SPRN BRK	345	63,000	$7,535,893	1	11,091	**$679**
QUEENSBG	138	63,000	$256,340	1	18,317	**$14**
SHM CRK	138	63,000	$150,039	1	17,194	**$9**

3. Identify CY11 projects Amperes usage.

Table 9.1.5. Q201 Berrians GT Amp Usage

Bus Name (per Aspen)	Nom. kV	Transmission Owner (TO)	CY11 ATRArev3a Amp: 3LG(A)	2LG	1LG	max	CY11 ATRA with Berrians off Amp (for project usage calculation): 3LG(A)	2LG	1LG	max	CY11ATRA minus CY11ATRA_BerriansOut-NRG10-13in delta bus faults Amp (project Amp usage): 3LG(A) Delta	2LG Delta	1LG Delta	max Delta *(usage>=100A)*
														P_1
RAINEY	345	ConEd	50,849	54,167	53,797	54,167	50,818	54,137	53,771	54,137	31	30	26	31
SPRN BRK	345	ConEd	53,418	52,758	45,655	53,418	53,394	52,736	45,640	53,394	24	22	15	24
QUEENSBG	138	ConEd	41,775	47,312	45,771	47,312	39,543	44,688	43,478	44,688	2,232	2,624	2,293	**2,624**
SHM CRK	138	ConEd	45,009	46,024	40,328	46,024	44,944	45,962	40,284	45,962	66	62	44	66
EGC-1	138	LIPA	66,103	71,153	70,861	71,153	66,101	71,151	70,860	71,151	2	2	1	2
EGC-2	138	LIPA	66,100	71,146	70,855	71,146	66,098	71,144	70,853	71,144	2	2	1	2

Table 9.1.6. Q251 CPV Valley Amp Usage

Bus Name (per Aspen)	Nom. kV	Transmission Owner (TO)	CY11 ATRArev3a Amp				CY11 ATRA with CPV off Amp (for project usage calculation)				CY11ATRA minus CY11ATRA_CPVOut delta bus faults Amp (project Amp usage)			
			3LG(A)	2LG	1LG	max	3LG(A)	2LG	1LG	max	3LG(A) Delta	2LG Delta	1LG Delta	max Delta *(usage>=100A)*
														$P_{1'}$
RAINEY	345	ConEd	50,849	54,167	53,797	54,167	50,812	54,135	53,770	54,135	37	32	27	37
SPRN BRK	345	ConEd	53,418	52,758	45,655	53,418	53,118	52,499	45,510	53,118	300	259	145	**300**
QUEENSBG	138	ConEd	41,775	47,312	45,771	47,312	41,775	47,311	45,771	47,311	1	1	0	1
SHM CRK	138	ConEd	45,009	46,024	40,328	46,024	44,975	45,995	40,312	45,995	34	29	16	34
EGC-1	138	LIPA	66,103	71,153	70,861	71,153	66,080	71,133	70,845	71,133	23	19	16	23
EGC-2	138	LIPA	66,100	71,146	70,855	71,146	66,077	71,127	70,838	71,127	23	19	16	23

Table 9.1.7. Q310 Cricket Valley Amp Usage

Bus Name (per Aspen)	Nom. kV	Transmission Owner (TO)	CY11 ATRArev3a Amp				CY11 ATRA with CricketValley off Amp (for project usage calculation)				CY11ATRA minus CY11ATRA_CricketOut delta bus faults Amp (project Amp usage)			
			3LG(A)	2LG	1LG	max	3LG(A)	2LG	1LG	max	3LG(A) Delta	2LG Delta	1LG Delta	max Delta *(usage>=100A)*
														$P_{1''}$
RAINEY	345	ConEd	50,849	54,167	53,797	54,167	50,721	54,055	53,702	54,055	128	113	95	**128**
SPRN BRK	345	ConEd	53,418	52,758	45,655	53,418	52,273	51,760	45,078	52,273	1,145	998	577	**1,145**
QUEENSBG	138	ConEd	41,775	47,312	45,771	47,312	41,771	47,308	45,768	47,308	5	4	3	5
SHM CRK	138	ConEd	45,009	46,024	40,328	46,024	44,871	45,902	40,257	45,902	139	122	72	**139**
EGC-1	138	LIPA	66,103	71,153	70,861	71,153	66,006	71,067	70,789	71,067	98	86	72	98
EGC-2	138	LIPA	66,100	71,146	70,855	71,146	66,002	71,061	70,783	71,061	98	85	72	98

4. Identify CY11 **$ reimbursement** based on CY11 Amp usage greater than or equal to 100 Amp (Note: EGC 138 kV was not impacted by 100 A or more by any individual project, hence not shown below).

Note: % allocation as defined in the 2004 Financial Settlement, and as applied in prior CY.

Table 9.1.8. CY11 Q201 Berrians $ Reimbursement to CY01

Bus Name	Nom kV	Transmission Owner	Lowest Breaker Rating (Ampers)	New CY11 $/kA Headroom Value $/Amp	CY11 Berrians payments to CY01: CY11 Berrians Reimbursement to CY01 *(if project usage P>=100A)* $	Total CY11 Berrians $ reimbursement to CY01 $	To CY01 East River $	To CY01 NYPA $	To CY01 SCS Astoria $
				O'	**R = P_1*O'**	sum R	46.12%	31.09%	22.78%
RAINEY	345	ConEd	63,000	$489	$0	**$36,720**	16,936	11,417	8,366
SPRN BRK	345	ConEd	63,000	$679	$0				
QUEENSBG	138	ConEd	63,000	$14	**$36,720**				
SHM CRK	138	ConEd	63,000	$9	$0				

Table 9.1.9. CY11 Q251 CPV Valley $ Reimbursement to CY01

Bus Name	Nom kV	Transmission Owner	Lowest Breaker Rating (Ampers)	New CY11 $/kA Headroom Value $/Amp	CY11 CPV Valley payments to CY01: CY11 CPV Reimbursement to CY01 *(if project usage P>=100A)* $	Total CY11 CPV $ reimbursement to CY01 $	To CY01 East River $	To CY01 NYPA $	To CY01 SCS Astoria $
				O'	**R' = P_1*O'**	sum R	46.12%	31.09%	22.78%
RAINEY	345	ConEd	63,000	$489	$0	**$203,632**	$93,922	$63,316	$46,394
SPRN BRK	345	ConEd	63,000	$679	**$203,632**				
QUEENSBG	138	ConEd	63,000	$14	$0				
SHM CRK	138	ConEd	63,000	$9	$0				

Table 9.1.10. CY11 Q310 Cricket Valley $ Reimbursement to CY01

Bus Name	Nom kV	Transmission Owner	Lowest Breaker Rating (Ampers)	New CY11 $/kA Headroom Value $/Amp	CY11 Cricket Valley payments to CY01: CY11 CricketValley Reimbursement to CY01 *(if project usage P>=100A)* $	Total CY11 CricketValley $ reimbursement to CY01 $	To CY01 East River $	To CY01 NYPA $	To CY01 SCS Astoria $
				O'	R'' = $P_{1''}$*O'	sum R	46.12%	31.09%	22.78%
RAINEY	345	ConEd	63,000	$489	$62,759	**$842,010**	$388,362	$261,810	$191,839
SPRN BRK	345	ConEd	63,000	$679	**$778,043**				
QUEENSBG	138	ConEd	63,000	$14	$0				
SHM CRK	138	ConEd	63,000	$9	$1,209				

9.2. Functional Headroom

Starting with CY07 studies, the NYISO Tariff (Attachment S) included a new category of Headroom, *i.e.,* "Functional Headroom," which would provide for Headroom payments for certain SUFs, (*e.g.,* system protection facilities, a shared ring bus, etc.) that have an excess functional capacity not readily measured in Amperes or other discrete electrical units.

As defined in Attachment S, in the case of Functional Headroom, the use that each subsequent project makes of the entity-created Headroom will be measured solely by using the total number of projects in the current and prior Class Years needing or using the System Upgrade Facility.

No CY11 projects were identified as using functional Headroom.

10. Cricket Valley SUFs Re-assessments

In order to evaluate the impacts of adding the second PV-CV 345 kV line and reconductoring of CV-LM 345 kV segment, the NYISO performed selected re-assessments. Below are the results and conclusions of such studies.

10.1. UPNY –SENY, UPNY-ConEd Thermal and Voltage Transfer Limits Impacts

As shown below, both thermal/voltage normal and emergency limits on UPNY-SENY increase by approximately +80 MW with the addition of the second (in-kind) PV-CV line, mostly due to the redistribution of the flow on the two parallel lines (lower equivalent impedance - > higher flow into NY injected at Pleasant Valley).

Table 10.1.1. Normal Transfers Thermal Limits

Interface	CY11 t0 ATBA		CY11 t0 ATRA		t0 ATRA with PV-CV 2nd line	
	Open	**Closed**	**Open**	**Closed**	**Open**	**Closed**
UPNY-SENY	**4740 (3)**	**5965 (3)**	**4748(3)**	**5988(3)**	**4824 (3)**	**6064 (3)**
UPNY-ConEd	3192 (3) **4562 (4)**	5898 (3) **7268 (4)**	4264(3) **4294(4)**	6985(3) **7015(4)**	**4327 (4)** 4345 (3)	**7048 (4)** 7067 (3)

Notes:

3. **Leeds-Pleasant Valley 345 kV** at 1538 MVA LTE for L/O Athens-Pleasant Valley 345 kV;

   At the time of initiating the CY11, Athens SPS was proposed to be retired by the 2016 study timeframe, therefore the LTE rating was observed; however, latest developments indicated that the SPS will be extended beyond 2016, hence the normal limits would be higher if the SPS effects would be considered.

4. **Rock Tavern-Ramapo 345 kV at LTE** for SBK at Fishkill 345 kV, or L/O Roseton-Fishkill, etc.

Table 10.1.2. Emergency Transfers Thermal Limits

Interface	CY11 ATBA		CY11 t0 ATRA		CY11 t0 ATRA 2nd PV-CV line	
	Open	**Closed**	**Open**	**Closed**	**Open**	**Closed**
UPNY-SENY	**5394 (3)**	**6620 (3)**	**5397 (3)**	**6638 (3)**	**5479(3)**	**6720(3)**
UPNY-ConEd	3872 (3) **5942 (4)**	6578 (3) **8647 (4)**	4958 (3) 5243 (5) **5684 (4)**	7680 (3) 7964 (5) **8405 (4)**	5046(3) 5272(5) **5721(4)**	7767(3) 7793(5) **8442(4)**

Notes:

3. Leeds-Pleasant Valley 345 kV at 1724 MVA STE for L/O Athens-Pleasant Valley 345 kV;

4. Rock Tavern-Ramapo 345 kV at STE for L/O Roseton-E.Fishkill 345 kV;

5. CoopersCorners-Middletown Tap 345 kV at STE for L/O RockTavern-CPV Valley 345 kV.

Table 10.1.3. Voltage Transfer Limits

	Normal/Emergency					
Interface	**Open**	**Closed**	**Open**	**Closed**	**Open**	**Closed**
	CY11 t0 ATBA		**CY11 t0 ATRA**		**CY11 t0 ATRA** with 2nd CV-PV line	
UPNY-SENY	**5838 (4)** 5903 (5) …… 5992 (9) …… 6008 (6)	**7319 (4)** 7377 (7) …… 7440 (9) …….. 7527 (6)	**5114 (4a)** 5197 (7) ….. 5218 (9) …… 5358 (6)	**6568 (4a)** 6606 (7) …. 6643 (9)	**5185 (4a)** 5236 (7) ….. 5270 (9)	6660 (7) **6671 (4a)** **….** 6715 (9)
UPNY-ConEd	**4366 (4)** 4409 (7) …. 4444 (9)	**7231 (4)** 7296 (7) ….. 7357 (9)	**4578 (4a)** 4644 (7) ….. 4664 (9)	**7439 (4a)** 7534 (7) ….. 7569 (9)	**4648 (4a)** 4683 (7) …… 4717 (9)	**7541 (4a)** 7588 (7) ……. 7644 (9)

Notes:

4. 95% voltage collapse criteria for L/O Rav. 3 or for L/O TWR 89/90 (Pleasantville-Dunw 345 kV);

4a. 95% voltage collapse criteria for L/O TWR 89/90 (Pleasantville-Dunwoodie 345 kV);

5. 95% voltage collapse criteria for L/O TWR Y86/Y87 (E Fishkill -Pleasantville345 kV), or Marcy SS, or IP2;

6. 95% voltage collapse criteria for L/O TWR Y67/68 (Ladentown-W Haverstraw-Bowline345 kV);

7. Dunwoodie 345 kV pre-fault;

9. Sprainbrook or Dunwoodie 345 kV for L/O TWR 89/90;

Branchburg Ramapo PARs at 440 MW into NY for all t0 cases.

10.2. NY to NE Impacts: see **Section 2.1.2., Table 2.1.2.1**.

10.3. LIPA Sensitivities

At LIPA's request, the NYISO has performed a number of sensitivities. The sensitivity cases were developed starting from the original ATBA and ATRA cases with Norwalk –Northport 138 kV Cables (NNC) at 200 MW into LIPA.

10.3.1. Emergency Scenario with the NNC at 428 MW into LI

As shown in **Table 10.3.1.** below, the addition of the second (in-kind) line restores the emergency scenario thermal transfer limit at a level above the baseline limits. Under such high baseline imports on NNC, the Norwalk 115/138 kV autotransformer is limiting for both ATBA and ATRA systems.

Table 10.3.1. Thermal Transfer Limits for Emergency Scenario with NNC at 428 MW into LIPA

	Emergency (MW)				
	ATBA with NNC at 428 into LI	**ATRA with NNC at 428 into LI**	**Initial Delta ATRA - ATBA**	**Delta with 2nd line**	**ATRA with NNC at 428MW into LI and 2nd PV-CV**
NE-NY *(includes NNC and CSC)*	**NorwalkXtr** / LM-PV -- **2030**	**NorwalkXtr** / LM-CV --**478** NorthPAR / LM-CV--497 PV- CV at 1195 MVA prectg --1508	**-1552**	**180**	**NorwalkXtr** / LM-CV --**2210** NorthPAR / LM-CV --2227 CV-PV #2 / CV-PV #1--2517 Reynolds xtr /Alps-NSctl--2586

10.3.2. Emergency Scenario with NNC at 428 MW into NE

For this scenario, the limit between ATBA and ATRA decreases by -300 MW, as defined by the Northport 138 kV PAR for loss of Long Mountain (LM) to Cricket Valley (CV).

Table 10.3.2. Thermal Transfer Limits for Emergency Scenario with NNC at 428 MW into NE

	Emergency (MW)		
	ATBA with NNC at 428 into NE	**ATRA** with 2nd line, RateA/B_target_recondLM-CV and NNC at 428MW into NE *CV-LM Rate C not known at this time; these results reflect current Rate C*	**Delta**
NY to NE *(incl. CSC at 330MW intoLI, NNC@428intoNE)*	**NorthprtPAR** at 675MVA / LM-PV 345kV--**1360** NorwalkXtr at 675MVA **/** LM-PV--**1377**	**NorthprtPAR** / LM-NE-CV--**1052** NorwalkXtr / LM-NE-CV--**1068**	-308

10.3.3. NNC at 200 MW into NE Scenario

For this scenario, the limit between ATBA and ATRA decreases by -160 MW (normal criteria), respectively -333 MW (emergency criteria). However for emergency criteria, the LM to CV line does not reflect the new Rate C. With the new Rate C the limits will be higher.

	Normal		
	ATBA	**ATRA** with 2nd line, RatebrecondLM-CV	**Delta**
NY to NE *(incl. CSCat330 intoLI, NNC@200intoNE)*	**NE-PV** at 1386MVA / Milst3 or HVDCPhII-- **1351**	**Norwalk to FlaxHill** or **Rowayton 115** / LM-CV--**1191** **Nrpt PAR,** or **ElyAve-NorwlkHrbr /** LM-CV--**1284** **……** **NE-CV /** Milst3--**1467**	-160

	Emergency		
	ATBA	**ATRA with 2nd line, RateBrecondLM-CV** *CV-LM Rate C not known at the time, results reflect current Rate C*	**Delta**
NY to NE *(incl CSCat330 intoLI, NNC@200intoNE)*	**NE-PV at 1685MVA /** Milstn3 **-- 1894**	**LM-CV at 1685MVA /** Milstn3**--1561**	-333

10.4. Local Stability: See **Section 5.10.**

10.5. Fault Duty Impacts: See **Section 8**.

11. SUFs and Cost Allocation

The following paragraphs summarize the SUFs identified in various studies performed under the CY11 process, and cost responsibility.

11.1. SUFs Identified via the "Part 2 Studies"

- No SUFs were identified in the ATBA, as related with the CY11 impacts.

- No SUFs were identified from the ATRA voltage, stability assessments, as related with the CY11 impacts.

- SUFs were identified from the ATRA transfer assessments, as related with CY11 Q310 Cricket Valley impacts on NY to NE interface limits. As identified in **Section 2.1.2.1.** Cricket Valley Developer is responsible for the following SUFs:

  1. Adding a second Pleasant Valley to Cricket Valley 345 kV line; and

  2. Reconductoring the Cricket Valley to NE border to Long Mountain 345 kV segment of Line 398.

  The cost estimates are summarized under the **Section 11.2.1. Q310 Cricket Valley Energy Center**.

- The ATRA fault assessment identified two breakers as overdutied, as result of CY11 Berrians GT impacts. The breakers belong to Astoria 3 generation plant, owned by US Power Generation. The estimated cost of replacement is **$3,450,000**. The two breakers do not fall within the definition of the New York State Transmission System. Therefore their replacement is not categorized as SUFs for the purpose of this study. These breakers must nonetheless be replaced in order to accommodate the interconnection of the Q201 Berrians GT project.

- Impact on electrical Headroom:
  - Berrians GT impacts Queensbridge 138 kV; the Developer will reimburse CY01 **$36,720;**
  - CPV Valley impacts Sprainbrook 345 kV; the Developer will reimburse CY01 **$203,632**; and
  - Cricket Valley impacts Sprainbrook 345 kV, Rainey 345 kV and Sherman Creek 138 kV; the Developer will reimburse CY01 **$842,010**.

- No CY11 projects were identified as using functional Headroom.

11.2. SUFs Identified via the "Part 1 Studies" (Design Engineering)

As described above, each "Part 1 Study" addresses CTOAFs required for each project, and also the Local SUFs (*e.g.,* POI connection, related protection/communication facilities), and certain DAFs as related with CTOAFs and SUFs integration. The Part 1 Studies are performed for each project, or combined if, for instance, the projects share a ring bus.

This report **summarizes only the SUFs -** related major equipment, cost, and major milestones, for cost allocation purposes only; all the related details are in the respective studies, grouped by transmission district.

11.2.1. Projects in Con Edison

There are three CY11 combined cycle natural gas (CCNG[13]) generation projects proposed in Con Edison: a 200 MW Berrians GT project, its 50 MW uprate, Berrians II, a 1020 MW Cricket Valley project; and one merchant transmission uprate, *i.e.,* 15 MW Linden VFT Uprate (which was subsequently removed from the Interconnection Process).

Q201 Berrians GT and Q224 Berrians GT II

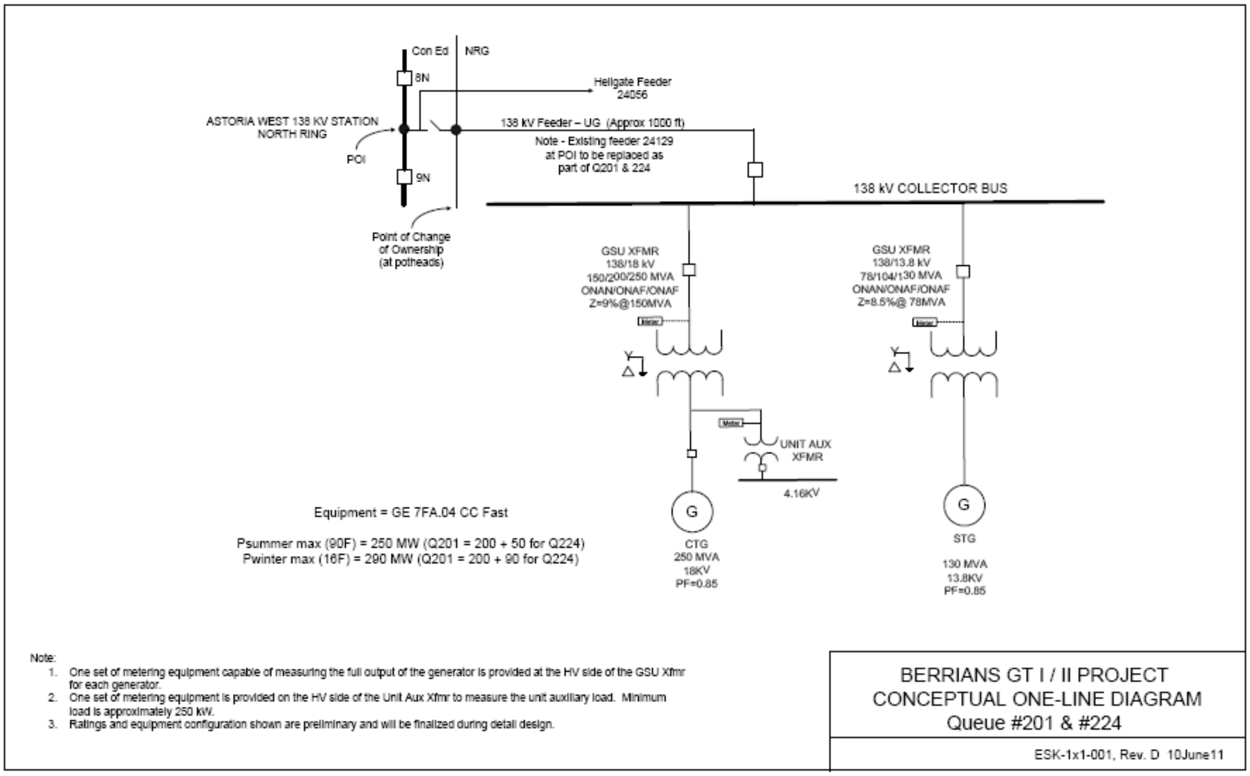
Q201 is a 200 MW CCNG generation project proposed by NRG Energy, Inc. (the Developer) to interconnect to Con Edison's Astoria West 138 kV Substation. Q224 is an uprate (*i.e.,* additional capability) of Q201, with no change in equipment. As part of the Berrians projects, NRG is proposing to retire the existing NRG 10-13 units at the same Point of Interconnection (POI).

The following is a summary of the Local SUFs and their cost estimate, as identified and detailed in Con Edison's study report, titled "*Class Year 2011 (CY11) Q201 and Q224 NRG Energy Berrians GT I and II Connecting Transmission Owner Attachment Facilities & System Upgrade Facilities,"* May 16 2012 revision.

[13] For temperature sensitive output projects, the MW value represents the Maximum Summer Peak Net Output which can be achieved between 85 and 95 F.

The total estimated cost of the work associated with the SUFs is **$2,232,000**, and includes substation work at the POI, and protection system.

Below is a conceptual one-line diagram, as provided by the Developer.



Major milestones were also identified and detailed in the aforementioned study, below is only a summary. The schedule will be further updated during the Interconnection Agreement stage of the Interconnection Process.

Authorization to proceed from NRG	3/2012
Engineering Design	3/2012
Equipment Procurement	3/2012
Begin Substation Construction	6/2013
Developer-specified COD	6/2015

Q310 Cricket Valley Energy Center

Q310 is a 1020 MW CCNG generation project proposed by Cricket Valley Energy Center, LLC (the Developer) to interconnect to Con Edison's portion of Pleasant Valley – Long Mountain 345 kV Line #398 (Note: Long Mountain is owned by Northeast Utilities, NU).

New York Upgrades:

- The total estimated cost of the work associated with the 6-breaker ring new GIS substation at the POI, transmission line work and protection modifications at the remote ends, is **$159,152,400**, as detailed in Con Edison's study report, titled *"Class Year 2011 (CY11) Q310 Cricket Valley Connecting Transmission Owner Attachment Facilities & System Upgrade Facilities".*

  It is estimated to take approximately 44 months to design, procure equipment and construct the identified SUFs required for the interconnection of the Project, details in Con Edison's report.

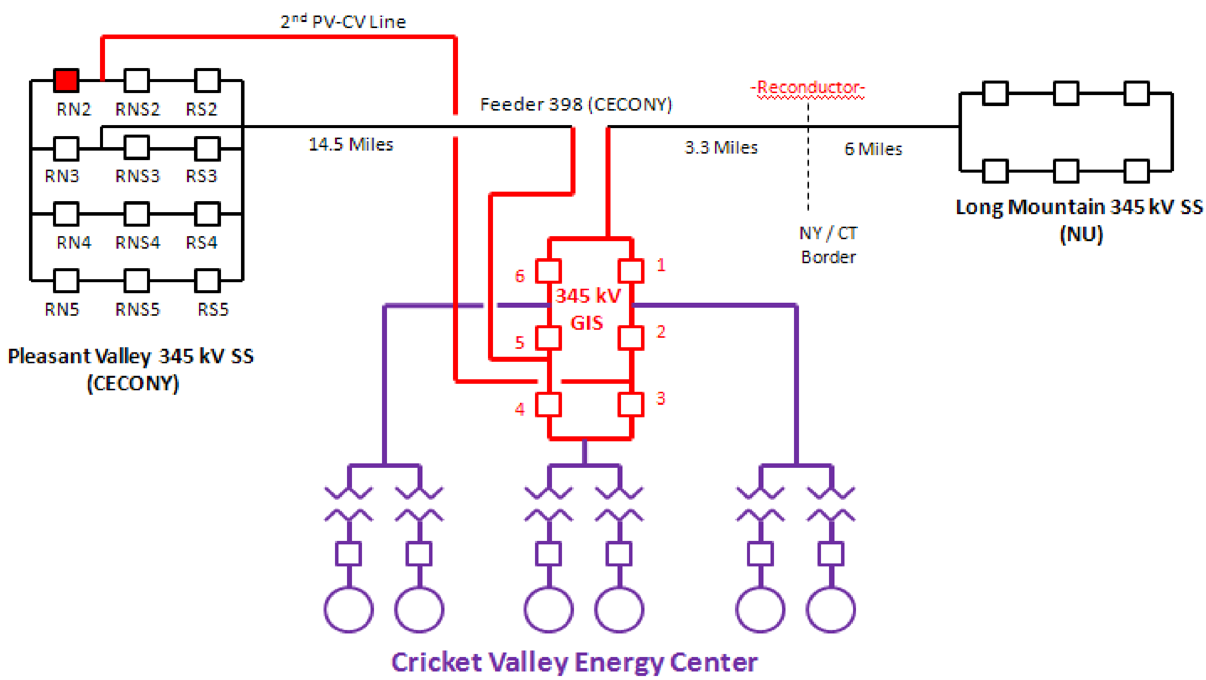
Engineering / Design	1/2014
Equipment Procurement	7/2015
Construction	12/2015

  The schedule will be further updated during the Interconnection Agreement stage of the Interconnection Process.

- Pleasant Valley to Cricket Valley 2nd 14.23 miles parallel line: **$101,900,000** as provided by Con Edison. The new 345 kV circuit is to be constructed of steel pole structures with twin-bundled 795 Aluminum Conductor Steel Supported (ACSS) Mallard conductor, a single shield wire and a single optical ground wire with 72 fibers. More details can be found in the study titled *"Pleasant Valley Substation to Cricket Valley Energy Center Line".*

- Reconductoring of the Cricket Valley to NE border 345 kV segment of Line 398 (approximately 3.5 miles) to a twin-bundled 795 kcmil ACSS Mallard conductor, and two shield wires: $ **15,500,000** as provided by ConEdison, with details in the study titled "*Reconductoring and Extend L-Line from Cricket Valley Energy Center to Connecticut Border*". Both upgrades target to meet the December 2015 overall project schedule.

Cricket Valley One-Line with the SUF solution



The above breaker oneline diagram shows the Q310 project cofiguration with the SUF solution.

Connecticut Upgrades:

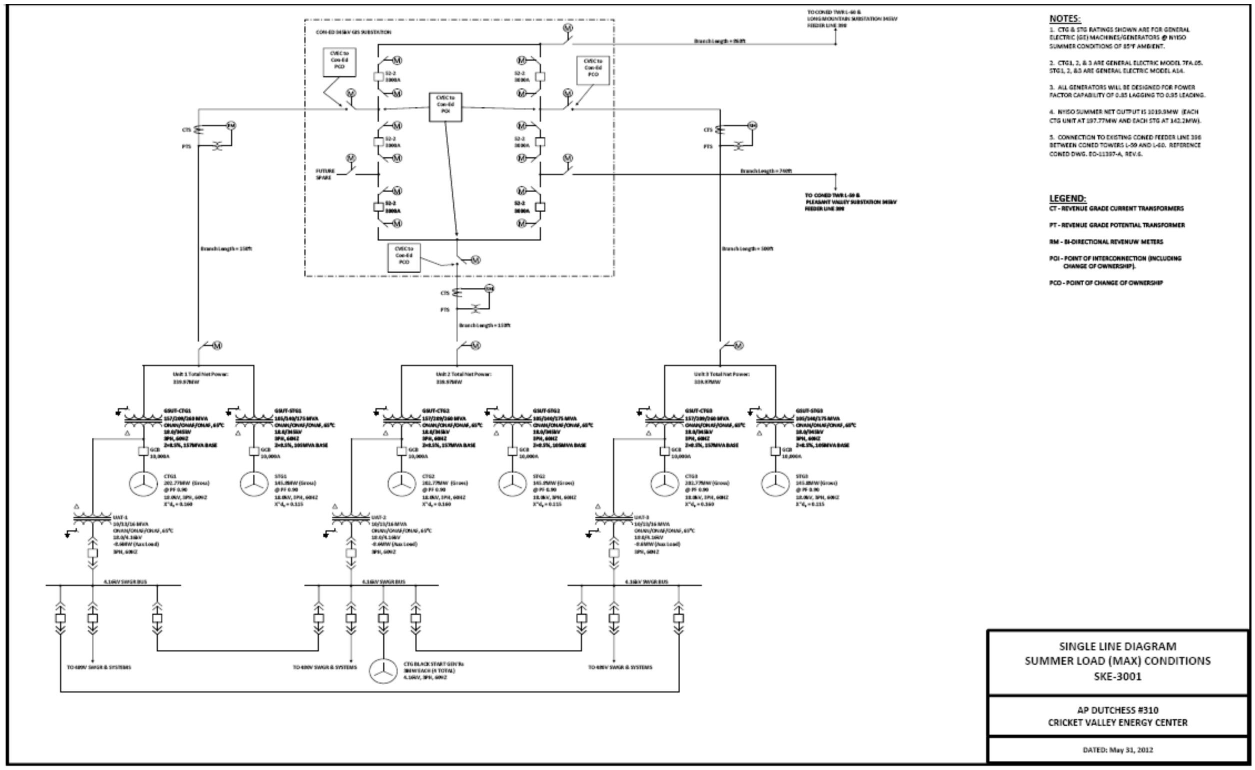
As noted above, the Cricket Valley project is proposed to interconnect to the 345 kV Pleasant Valley to Long Mountain tie Line #398, hence impacting the protection system at Long Mountain. The Long Mountain 345 kV substation is owned by the Northeast Utilities (NU) in New England.

These network upgrades are not part of the New York State Transmission System (*i.e.,* they belong to an external Transmission Owner, NU), and their replacement is therefore not categorized as SUFs for the purpose of this study. These updates must nonetheless be implemented, in order to accommodate the interconnection of the Q310 Cricket Valley project.

- NU performed a protection and communication study to identify the modifications needed at Long Mountain in order to reliably interconnect Cricket Valley. The study, titled “Cricket Valley Energy Center- Long Mountain 345 kV Protection and Communication Report”, identified a cost of **$480,000**.

- Reconductoring of the Long Mountain to NY border (approximately 5.5 miles of 2156 ACSS conductor): **$9,900,000** order of magnitude, with time to construct of 36 months, as provided by NU.

Below is a conceptual one-line diagram, as provided by the Developer.



Q351 Linden VFT Uprate

A FERC Order granting VFT's complaint indicated that Linden VFT's additional 15 MW did not need to go through the Interconnection Process. Removal of this project from the CY11 does not impact any other Project's Cost Allocation.

11.2.2. Projects in National Grid-Niagara Mohawk

There were two CY11 wind[14] generation projects proposed in National Grid Niagara Mohawk's (NGNM) system: 79.8 MW Alabama (withdrawn from queue during CY11 process) and 79.8 MW Arkwright Summit.

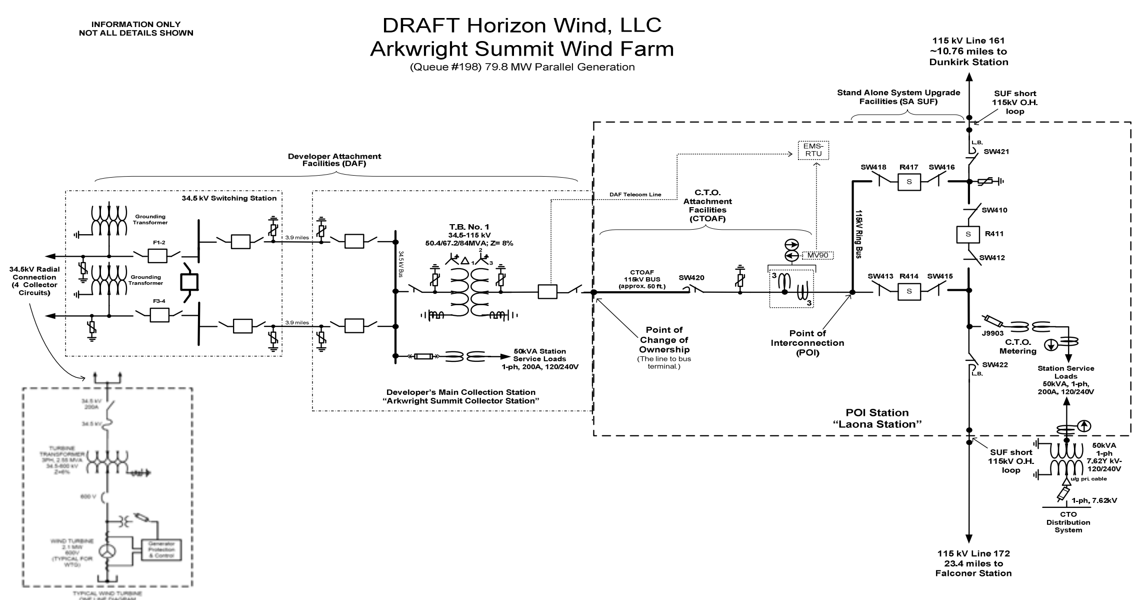
Q198 Arkwright Summit Wind Farm

Q198 is a 79.8 MW wind generation project proposed by New Grange Wind Farm, LLC (the Developer) to interconnect to NGNM's Dunkirk-Falconer 115 kV Line #162.

The following is a summary of the Local SUFs and their cost estimate, as identified and detailed in NGNM's study report, titled "*Class Year 2011 Part 1 Facilities Study Report- Arkwright Summit Wind Farm Project (Queue #198),"* April 27 2012 revision*.*

The total estimated cost of the work associated with the SUFs is **$6,870,000**, and includes the 3-breaker ring at the POI, protection systems at remote ends, etc.

Below is a conceptual one-line diagram, as provided in NGNM's study.



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14 Nameplate MW.

Major milestones were also identified and detailed in the aforementioned study, below is only a summary. The schedule will be further updated during the Interconnection Agreement stage of the Interconnection Process.

Interconnection Agreement executed	12/2012
Written authorization to proceed with engineering and procurement	01/2013
Security provided	01/2013
Engineering design and procurement started	02/2013
Engineering and procurement completed	10/2013
Construction started	11/2013
Construction completed	03/2014
Initial Synchronization	05/2014
Commercial Operation	09/2014
As Built drawings submitted	11/2014
Project Closeout	03/2015

11.2.3. Project in NYPA

There is one CY11 generation project proposed in NYPA's system: 678 MW CPV Valley.

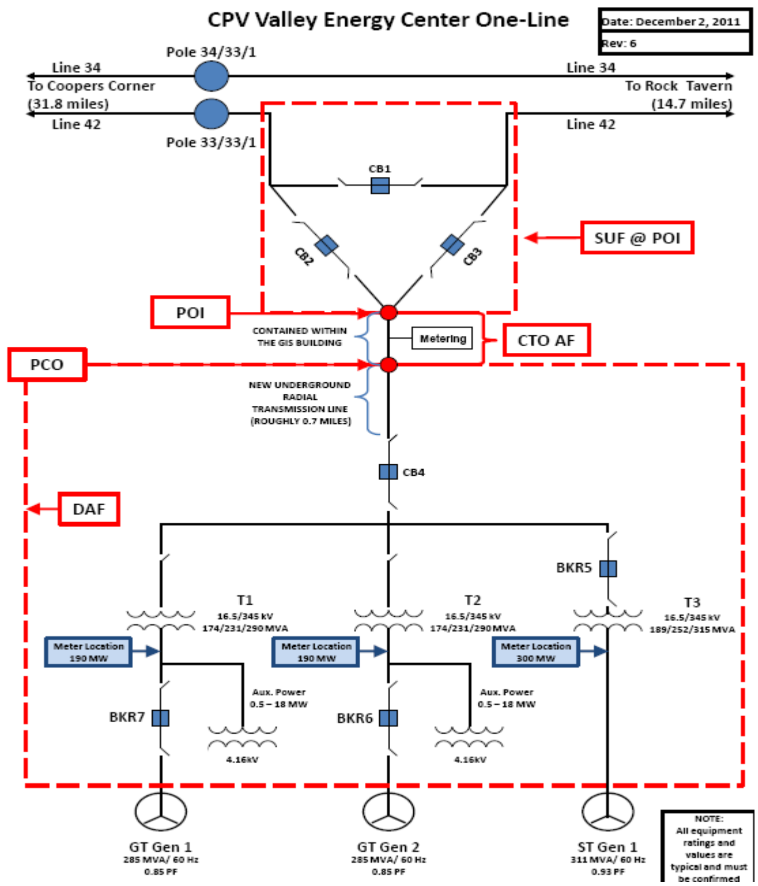
Q251 CPV Valley

Q251 is a 678 MW (summer max net) CCNG generation project proposed by CPV Valley, LLC (the Developer) to interconnect to NYPA's Coopers Corners - Rock Tavern Line #42.

The following is a summary of the Local SUFs and their cost estimate, as identified and detailed in NGNM's study report, titled "*Q251 CPV Valley - Class Year 2011 Part 1 Facilities Study,*" May 25 2012 revision.

The total estimated cost of the work associated with the SUFs is **$22,448,601**, and includes a 3-breaker ring GIS substation at the POI, protection modification at remote ends, transmission work.

Below is a conceptual one-line diagram, as provided by the Developer.



Major milestones were also identified and detailed in the aforementioned study, below is only a summary. The schedule will be further updated during the Interconnection Agreement stage of the Interconnection Process.

Developer Security Posting with CTO	Nov 2012
Signed Interconnection Agreement	Feb 2013
Conceptual Package and Equipment Specifications to NYPA	Apr 2013
NYPA Approval of Major Equipment Specifications	Apr 2013
P&C Package to NYPA (Schematics)	Apr 2013
Present Project for NPCC Approval	Jul 2013
Substation In-Ground Package to NYPA	Nov 2013
Transmission Line Tie-In Design to NYPA	Nov 2013
Issue Purchase Orders for Longer Lead Items	Dec 2013
Issue In-Ground Package for Construction	Dec 2013
Procurement of Transmission Line materials	Dec 2013
P&C Package to NYPA (Wiring)	Feb 2014
Issue Substation Above Ground Package- Construction	Apr 2014

Substation Construction Mobilization	Apr 2014
Transmission Line Construction Mobilization	Apr 2014
Line #42 Outage for Cut-in of SUF at POI Substation	Oct 2014
Energize SUF at POI Substation	Nov 2014
Substation Commissioning	May 2015
Close Out Package to NYPA	Aug 2015
Commercial Operation	May 2016
Turn Over to NYPA	May 2016

11.2.4. Project in Central Hudson

There is one CY11 generation project proposed in Central Hudson system: 19 MW Taylor Biomass.

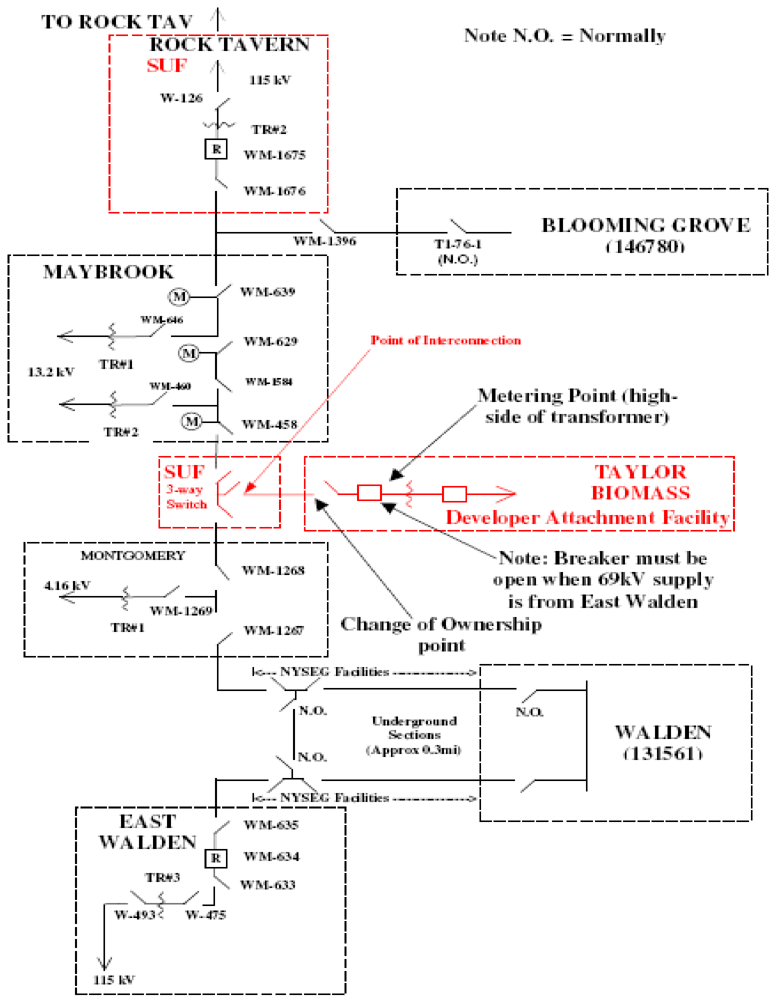
Q349 Taylor Biomass

There is one solid waste generation project proposed to interconnect to Central Hudson's Maybrook-Montgomery 69 kV line, *i.e.,* the 19 MW Taylor Biomass.

The following is a summary of the Local SUFs and their cost estimate, as identified and detailed in Central Hudson's study report, titled "Class Year 2011 (CY11) - Taylor Biomass Plant," June 4, 2012 revision.

The total estimated cost of the work associated with the SUFs is **$357,000**, and includes protection modification at a remote end, communication, and a 3-way switch at the POI.

Below is a conceptual one-line diagram, as provided by the Developer.



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Major milestones were also identified and detailed in the aforementioned study, below is only a summary. The schedule will be further updated during the Interconnection Agreement stage of the Interconnection Process.

Signed Interconnection Agreement	May 2012
Begin CTO review of project interconnection protection and control	July 2012
Issue purchase order for 3-way switch	September 2012
Install line switch	December 2012
Construct tap to Taylor	December 2012
Issue purchase orders for Rock Tavern SUF	January 2013
Complete CTO review of project interconnection protection	March 2013
Begin Rock Tavern construction	April 2013
69kV outage for Rock Tavern construction	June 2013
Project In-Service for testing	September 2013
Project commercial operation	December 2013

12. SUF Cost Allocation Tables

The Initial Round (R1) CY11 SUF Project Cost Allocation and Headroom payments are summarized in the below tables.

Five (5) Business Days after the end of the Final Decision Round, each Developer must signify its willingness to pay the Connecting Transmission Owner and Affected Transmission Owner(s) for its share of the required System Upgrade Facilities and System Deliverability Upgrades by (i) satisfying Headroom payment/security posting obligations, if any, and (ii) paying cash or posting Security (as defined in Attachment S to the OATT), for the full amount of its respective Project Cost Allocation.

Table 12.1.R1 SUF Project Cost Allocation and Headroom ($)

SUF and Headroom $ Summary	Arkwright Q198	Berrians GT Q201	Berrians II* Q224**	CPV Valley Q251	Cricket Valley Q310	Taylor Biomass Q349
SUFs Project Cost Allocation	6,870,000	2,232,000	0	22,448,601	276,552,400	357,000
Headroom (electrical and functional)	0	36,720	0	203,632	842,010	0
Total SUF Project Cost Allocation and Headroom	6,870,000	2,268,720	0	22,652,233	277,394,410	357,000

* Q224 reflects 50 MW of additional capability of Q201, with no equipment additions/changes. In total Q201 and Q224 represent one 250 MW CCGT plant; hence, Q224 without Q201 cannot move forward separately.

The following tables show the same information as the above, presented in different ways.

Table 12.2.R1 SUF Project Cost Allocation - $ Flow from CY11 Project to Transmission Owner

From Project Name	Total $ SUF per project	To ConEd	To NYPA	To NG-NM	To Central Hudson	To NYSEG
Arkwright	**$6,870,000**	n/a	n/a	**$6,870,000**	n/a	n/a
Berrians GT	**$2,232,000**	**$2,232,000**	n/a	n/a	n/a	n/a
Berrians GT II*	**$0**	**$0**	n/a	n/a	n/a	n/a
CPV Valley	**$22,448,601**	n/a	**$20,875,849**	n/a	**$433,752**	**$1,139,000**
Cricket Valley	**$276,552,400**	**$276,552,400**	n/a	n/a	n/a	n/a
Taylor Biomass	**$357,000**	n/a	n/a	n/a	**$357,000**	n/a
Total to Transmission Owner	$308,460,001	**$278,784,400**	**$20,875,849**	**$6,870,000**	**$790,752**	**$1,139,000**

*Q224 reflects 50 MW of additional capability of Q201, with no equipment additions/changes. In total Q201 and Q224 represent one 250 MW CCGT plant; hence, Q224 without Q201 cannot move forward separately.

Table 12.3.R1 SUF Project Cost Allocation (by Study Type) ($)

SUF Major Categories	Arkwright Q198	Berrians GT Q201	Berrians II* Q224**	CPV Valley Q251	Cricket Valley Q310	Taylor Biomass Q349
Part 2 Studies - SUF cost estimates ($)						
2nd PV-CV 345 kV line	0	0	0	0	101,900,000	0
Reconductoring of CV-NE border (ConEd's segment)	0	0	0	0	15,500,000	0
Part 1 Studies - SUF cost estimates ($)						
SUF at POI (e.g.: *n*-breaker ring substation, tap, line work, etc)	5,240,000	2,232,000	0	20,875,849	158,331,400	80,000
Protection SUF at remote ends and/or POI (protection / communication, etc.)	1,630,000	included above	0	1,572,752	821,000	277,000
Total $ SUFs (without Headroom payments)	**6,870,000**	**2,232,000**	**0**	**22,448,601**	**276,552,400**	**357,000**

* Q224 reflects 50 MW of additional capability of Q201, with no equipment additions/changes. In total Q201 and Q224 represent one 250 MW CCGT plant; hence, Q224 without Q201 cannot move forward separately.

Table 12.4.R1 Headroom Reimbursement $

Electrical Headroom Payments from CY11 Project to CY01	Total from CY11 $	To CY01 East River $	To CY01 NYPA $	To CY01 SCS Astoria $
		46.12%	31.09%	22.78%
CY11 Q201 BerriansGT payments to CY01	**$36,720**	$16,936	$11,417	$8,366
CY11 Q251 CPV Valley payments to CY01	**$203,632**	$93,922	$63,316	$46,394
CY11 Q310 Cricket Valley payments to CY01	**$842,010**	$388,362	$261,810	$191,839
Total to CY01	**$1,082,362**	**$499,220**	**$336,543**	**$246,599**

13. Other System Upgrades Cost Summary Tables

Other system upgrades cost is summarized in the below tables.

Table 13.1. New England System Upgrades Cost ($), as provide by NU.

	From Cricket Valley
To NU for Protection/ Communication at Long Mountain 345 kV	$480,000
To NU for reconductoring of LM to NE border of Line 398	$9,900,000

Table 13.2. Other non-SUFs Upgrades

	From Q201 Berrians
To US PowerGen (for Astoria 3 G1N and G2N breakers replacement)	3,450,000

References and Bibliography

1. Attachment S (6/30/2010 revision), Rules to Allocate Responsibility for the Cost of New Interconnection Facilities, NYISO Open Access Transmission Tariff.

2. Attachment X (4/21/2011 revision), Standard Large Facility Interconnection Procedures, New York Independent System Operator Open Access Transmission Tariff.

3. NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System (Directory #1); Northeast Power Coordinating Council, December 1, 2009.

4. Reliability Rules For Planning and Operating the New York State Power System, New York State Reliability Council (NYSRC), Version 29, January 7, 2011.

5. NYISO Transmission Planning Guidelines #2-0 and #3-0, Guidelines for Voltage and Stability Analysis and Determination of Voltage/Stability Based Transfer Limits, New York Independent System Operator, September 28, 1999.

6. NYISO Emergency Operations Manual, New York Independent System Operator, August 2009.

7. 2011 Load and Capacity Data (Gold Book), New York Independent System Operator.

8. NYISO Guideline Fault Current Assessment, New York Independent System Operator, January 30, 2003.

9. Settlement Agreement in KeySpan Energy Development Corp. et al. v. New York Independent System Operator, Inc., FERC Docket Nos. EL02-125-000 and 001 (filed June 14, 2004).

10. New York Control Area Installed Capacity Requirements for the Period May 2010 through April 2011, New York State Reliability Council, L.L.C., Executive Committee Resolution and Technical Study Report;

11. Facilities Studies for prior Class Year projects (log in only): http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp?docs=interconnection-studies/other-interconnection-documents

12. CY11 projects SRISs (log in only): http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp?docs=interconnection-studies/other-interconnection-documents

13. 2005 Comprehensive Area Transmission Review of the New York State Bulk Power Transmission System in the Year 2010, New York Independent System Operator, May 26, 2006.

14. The 2010 Reliability Needs Assessment and The Comprehensive Reliability Plan, NYISO

15. Transmission and Dispatching Operations Manual.