Draft Keene Road Market Efficiency Transmission Upgrades Needs Assessment

Scope of Work and Assumptions

Planning Advisory Committee Meeting

Michael I. Henderson

DIRECTOR, REGIONAL PLANNING AND COORDINATION

BACKGROUND and SUMMARY

Background: Market Efficiency Transmission Upgrades

- As described in the Open Access Transmission Tariff (OATT), Market Efficiency Transmission Upgrades (METUs) "are designed primarily to provide a net reduction in total production cost to supply the system load".
- As a result of the Keene Road economic study, the ISO has recognized the potential for an METU to be warranted.
- The economic study must be updated with study assumptions to enable the ISO to determine whether the threshold production cost savings test required for an METU is met. The ISO anticipates that this update work will be completed by December 2016.

Summary: Keene Road Market Efficiency Transmission Upgrades Needs Assessment

- Today the ISO is seeking PAC input on the Scope of Work and Assumptions
  - Background material is shown for review and framing the discussion
  - GridView production cost simulations will be used to evaluate the need for METUs in the Keene Road area
  - Draft results (metrics) will be discussed by the November PAC meeting
- Several draft assumptions build on the 2016 Economic Study Scenario 4, the "No Retirement Scenario," and the Keene Road Economic Study
  - Common draft assumptions for the Keene Road METU Study and those used for Scenario 4 appear in the Appendix
    - See PAC discussions at http://www.iso-ne.com/static-assets/documents/2016/06/a9_2016_economic_study_assumptions.pdf
  - Assumptions differing from Scenario 4 will be emphasized today

Keene Road Needs Assessment Process

This study is an ISO priority

- Stakeholders may wish to refer to the Evaluation of Increasing the Keene Road Export Limit final report posted at http://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx for further background information
- The ISO seeks input from the PAC
  - The ISO plans to build upon existing data bases, study assumptions, and techniques used in the 2016 Economic Study Scenario 4
  - As an METU Needs Assessment, some differences from the 2016 Economic Study Scenario 4 and the 2015 Economic Study of the Keene Road area should be expected
- PAC presentations will be structured to discuss the general PAC study issues upfront
  - PAC members are encouraged to review detailed information appearing in the Appendix
  - PAC members should contact PACMatters@iso-ne.com to provide additional comments or questions

Keene Road Market Efficiency Transmission Upgrade Draft Study Year Assumptions

- The proposal is to study three discrete years
- Simulate 2020 based on an estimate of when a potential transmission solution of a modest size could be placed in service
- Using a ten-year horizon from the 2020 in-service date, simulate 2025 and 2030
  - Using 2025 and 2030 allows for modeling efficiency because these years are already under evaluation in the 2016 Economic Study
  - As necessary, the years in between can be interpolated from this data

Summary: Scope of Work Needs Assessment

- Update the GridView production cost data base for the years 2020, 2025, and 2030
  - Build on the 2016 Economic Study GridView model for Scenario 4, which is very similar for 2025 and 2030
- Simulate production cost cases with the Keene Road export limit modeled at:
  - 165 MW (existing limit)
  - 195 MW
  - 225 MW
  - 255 MW (no Keene Road area congestion anticipated)
- Show the following metrics for each level of Keene Road export limit
  - Production cost
  - LSE Energy Expenses
  - Congestion
  - LMPs in Keene Road area, Maine, and at the Hub
  - Environmental emissions
- With the Keene Road interface unconstrained, show MW flows and time duration curves for the Keene Road and Orrington South interfaces

Summary: Generator and Import Assumptions

- Most updates require few changes from the 2016 Economic Study data base Scenario 4
  - Generator representation throughout the system (heat rates, ramp rates, etc.) *
  - 2016 EIA fuel forecast with seasonal adjustments *
  - Air emission allowances prices ***
  - Economic order of $0 cost resources and imports determined by threshold prices *
  - Production profiles for wind and PV resources *
  - Production profiles for hydro **
  - Modeling of pumped storage**
  - Profiles for imports from neighboring systems **
- A major change from Scenario 4 is to include only units with signed interconnection agreements (IAs), FCA commitments, other "existing CELT 2016 generators"
  - Do not include generators that have I.3.9 approvals, but without IAs

* Use essentially the same values for Scenario 4 simulations of 2025 and 2030. Update some values for 2020.

** Base on the 2015 Economic Study method

*** Update values

Summary: Transmission and Net Demand Assumptions

- Use RSP bubble representation to reflect potential transmission system constraints
  - Limitations potentially affecting Keene Road resources are voltage or stability limited
- Load, EE, and PV forecasts
  - Create 2020 case consistent with CELT 2016
  - For 2025 and 2030, use same representation as the 2016 Economic Study data base for Scenario 4

NEXT STEPS

Schedule

- Keene Road Needs Assessment discussion with PAC
  - Draft results for stakeholder discussion by November 2016
  - Final results posted by December 2016
- Discussion regarding the decision to move forward with a competitive solicitation – tentative for December 2016
  - Depending on this decision, a timeline of additional steps would be expected to be discussed with the PAC in January 2017

Questions

METRICS TO BE PROVIDED

Annual Results

Resource Metrics – Economic

GridView Results – Tabular Format Except as Noted

- Systemwide production costs
  - Includes energy production plus unit commitment costs ($)
- Average Locational Marginal Prices by RSP bubble ($/MWh)
  - Keene Road area, BHE, ME, SME, and CMA/NEMA
- Load-Serving Entity Energy Expenses (LSEEE) ($)
  - The total electric energy revenues that resources and imports from neighboring systems would receive for supplying electric energy to the wholesale market plus the cost of congestion
- Congestion ($)
  - Difference in LSEEE results among cases with different Keene Road export limits
- Interface flows of Keene Road and Orrington South for the Keene Road interface unconstrained
  - Percent of time that interfaces are above 100% of limit
  - Annual duration curves
  - Chronological Excel Spreadsheet (Does this provide useful information?)

Resource Metrics – Environmental

GridView Results – Tabular Format Except as Noted

- Total air emissions
  - CO2
  - NOx
  - SO2

Does PAC Want the ISO to Provide Additional Metrics?

Questions

APPENDIX I
DETAILED ASSUMPTIONS

Most Assumptions Common with Scenario 4 of the 2016 Economic Study

Changes are shown in red

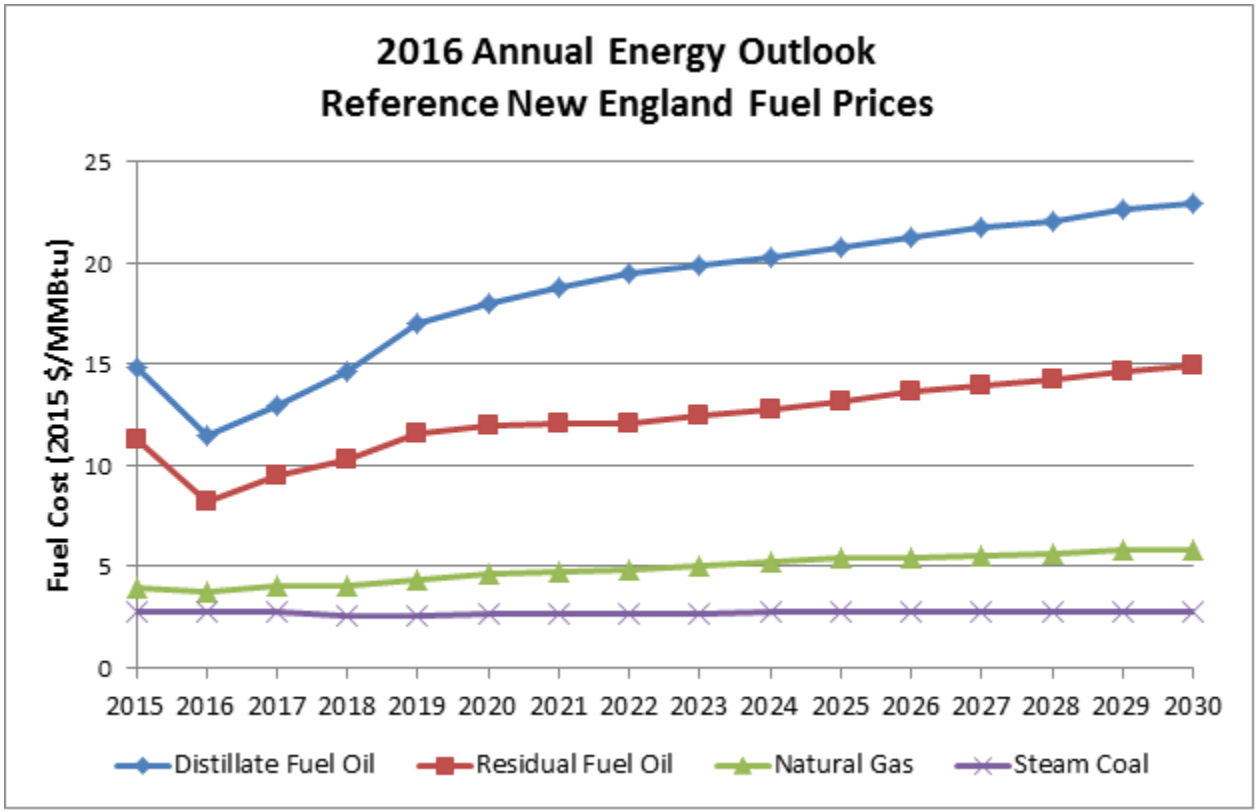
Simulation Tools and Assumptions Miscellaneous

- ABB GridView Production Simulation Model
  - Generation production simulation using pipe and bubble format
- Simulation Years – 2020, 2025, and 2030

Common Simulation Tools and Assumptions Fuel Prices

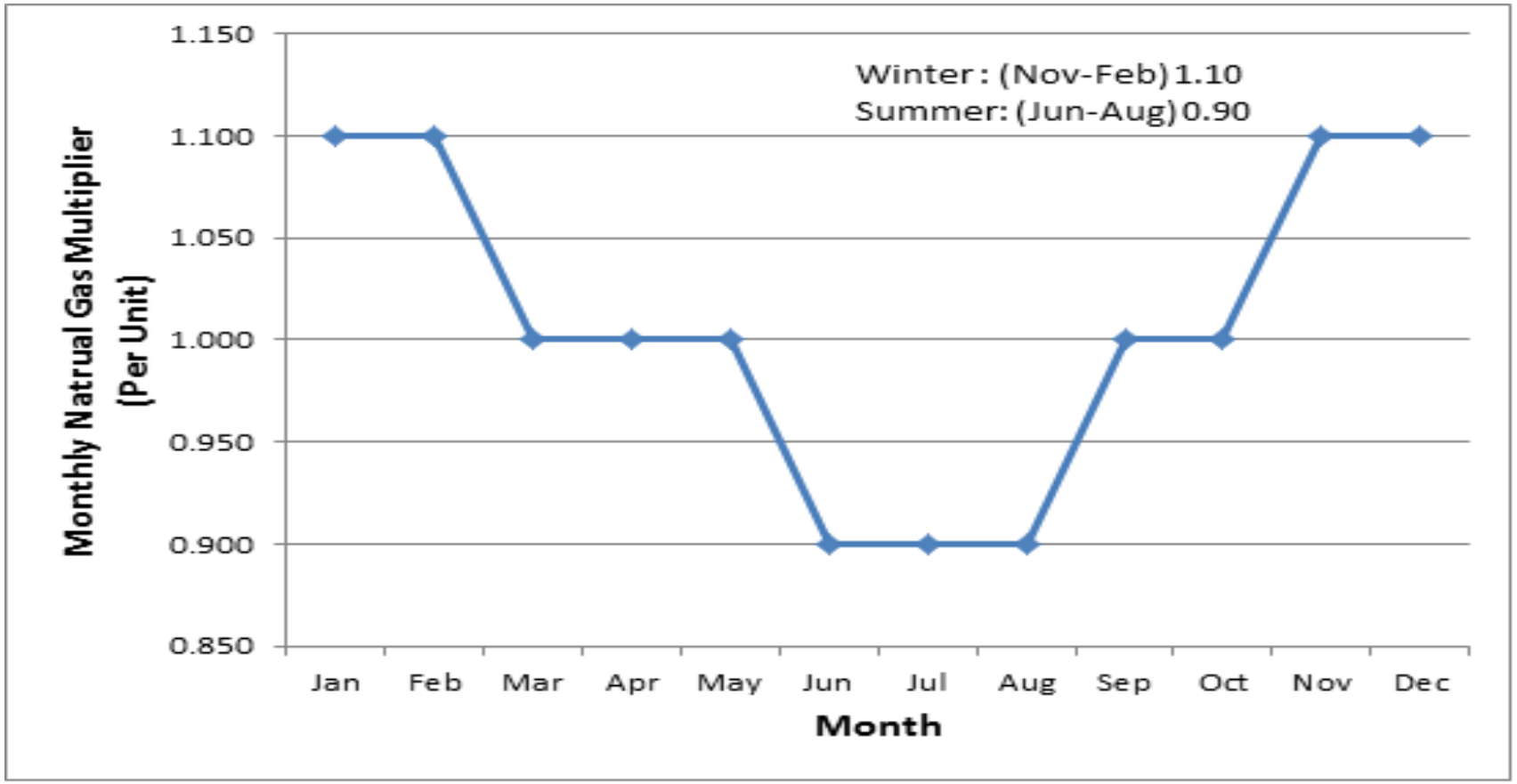
- Based on 2016 EIA Annual Energy Outlook fuel price forecast for New England
  - Similar to the 2016 Economic Study model
    - Natural gas prices are increased 10% over the nominal price in the winter and reduced 10% of the nominal price in the summer
    - Reflect the EIA Appendix prices for New England coal, oil, and natural gas

Fuel Price Forecast: EIA's 2016 AEO Base Forecast



- *Source of the fuel prices: http://www.eia.gov/forecasts/aeo/ as of September 12, 2016.*

Fuel Price Forecast: Per Unit Multiplier for Monthly Natural Gas Price Assumptions (2020, 2025, and 2030)



Internal Transmission Interface Limits (MW)

Single-Value, Summer Peak,[1] Non-Firm, Transmission Interface Limits for Use in Subarea Transportation Models

Interface	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Orrington South Export	1325	1325	1325	1325	1325	1325	1325	1325	1325	1325
Surowiec South	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
Maine-New Hampshire	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900
Northern New England-Scobie + 394	3100	3100	3100	3100	3200[c]	3200	3200	3200	3200	3200
North-South	2100	2100	2100	2675[a]	2725[c]	2725	2725	2725	2725	2725
East-West	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
West-East	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200
Boston Import (N-1)	4850	4850	4850	5700[a]	5700	5700	5700	5700	5700	5700
Boston Import (N-1-1)	4175	4175	4175	4600[a]	4600	4600	4600	4600	4600	4600
SEMA/RI Export	3400	3400	3400	3400	3400	3400	3400	3400	3400	3400
SEMA/RI Import (N-1)	-	-	1280[b]	1280	1280	1280	1280	1280	1280	1280
SEMA/RI Import (N-1-1)	-	-	720[b]	720	720	720	720	720	720	720
Southeast New England Import (N-1)	-	-	-	5700[a]	5700	5700	5700	5700	5700	5700
Southeast New England Import (N-1-1)	-	-	-	4600[a]	4600	4600	4600	4600	4600	4600
Connecticut Import (N-1)	2950	2950	2950	2950	3400[d]	3400	3400	3400	3400	3400
Connecticut Import (N-1-1)	1750	1750	1750	1750	2200[d]	2200	2200	2200	2200	2200
SW Connecticut Import (N-1)	2500	2500	2500	2500	2500	2800	2800	2800	2800	2800
SW Connecticut Import (N-1-1)	1750	1750	1750	1750	1750	1900	1900	1900	1900	1900

- The internal transmission interface limits for 2025 will also be used for 2030.
- N-1 limits will be used in the 2016 METU Study.
- SWCT Limits are different in 2020 from 2025
- For full notes associated with this table, please see the presentation:

http://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf

External Transmission Interface Import Capability (MW)

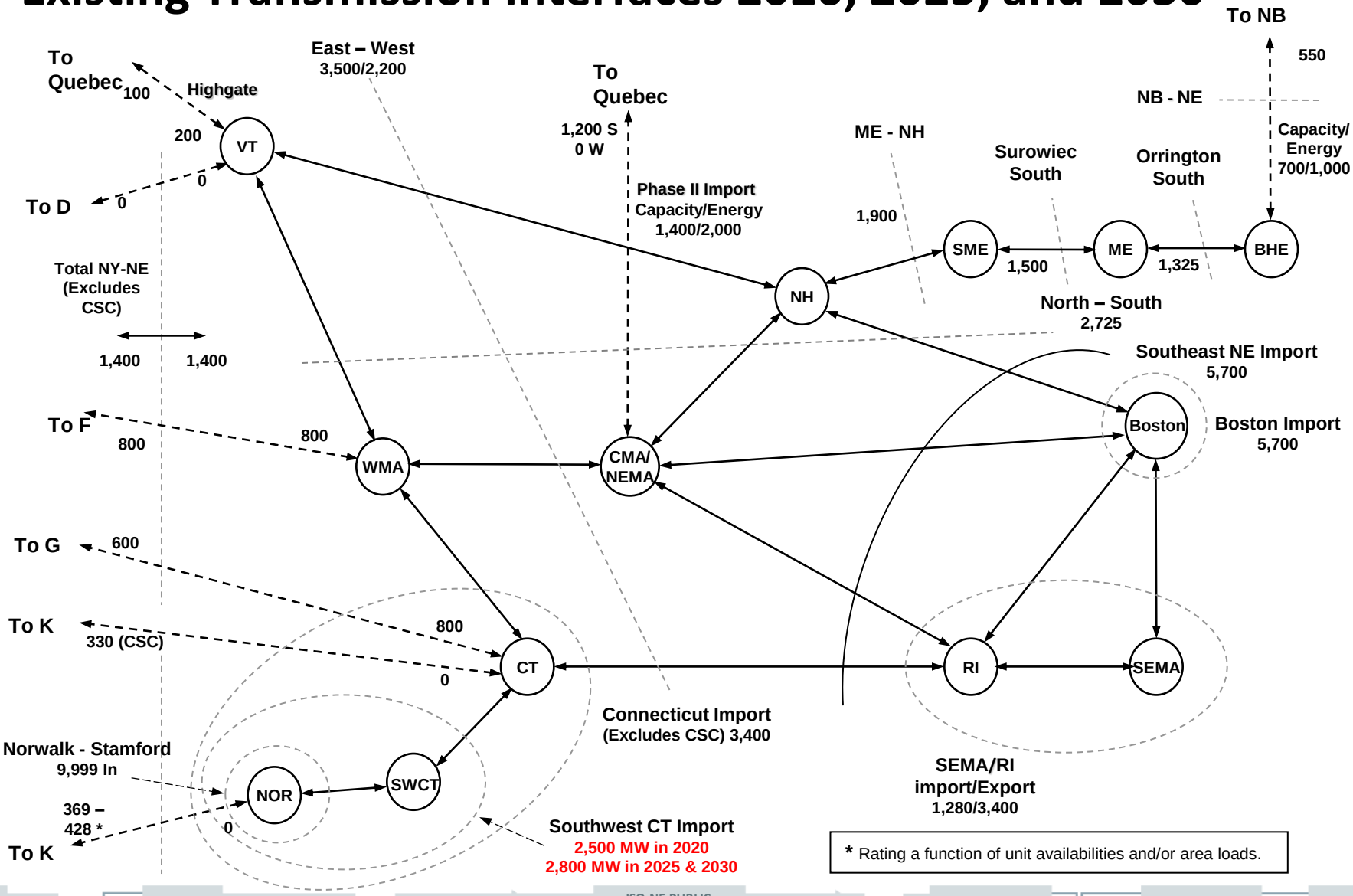
Single-Value, Summer Peak,[1] Non-Firm, Transmission Interface Limits for Use in Subarea Transportation Models

Interface	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
New Brunswick-New England (energy import capability)[2]	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
New Brunswick-New England (capacity import capability)	700	700	700	700	700	700	700	700	700	700
HQ-New England (Highgate) (energy import capability)[3]	217	217	217	217	217	217	217	217	217	217
HQ-New England (Highgate) (capacity import capability)	200	200	200	200	200	200	200	200	200	200
HQ-New England (Phase II) (energy import capability)[4]	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
HQ-New England (Phase II) (capacity import capability)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Cross-Sound Cable (CSC) (energy import capability)[5]	330	330	330	330	330	330	330	330	330	330
Cross-Sound Cable (CSC) (capacity import capability)	0	0	0	0	0	0	0	0	0	0
New York-New England (energy transfer capability)[6]	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
New York-New England (capacity transfer capability)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400

- The external transmission interface limits for 2025 will also be used for 2030.
- For full notes associated with this table, please see the presentation:

http://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf

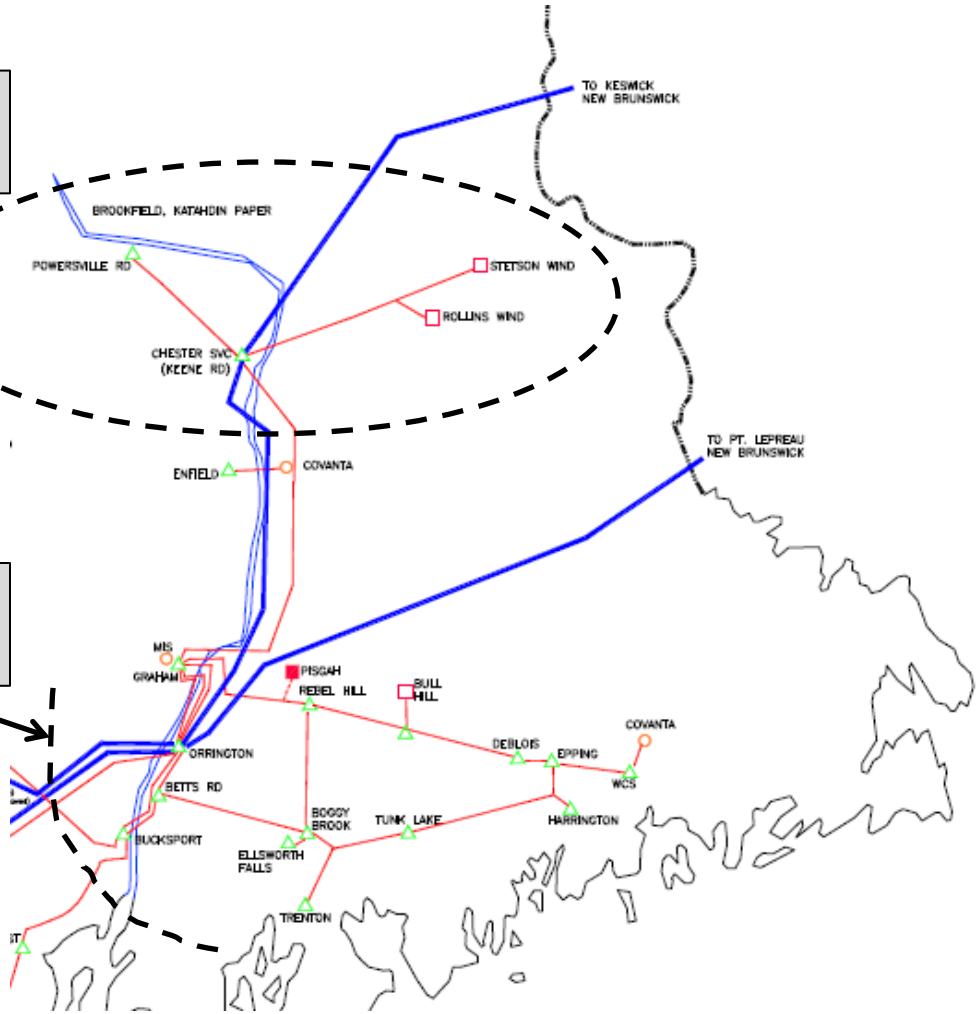
New England Pipe and Bubble Representation (MW)
Existing Transmission Interfaces 2020, 2025, and 2030



Detail of Keene Road Export-constrained Area

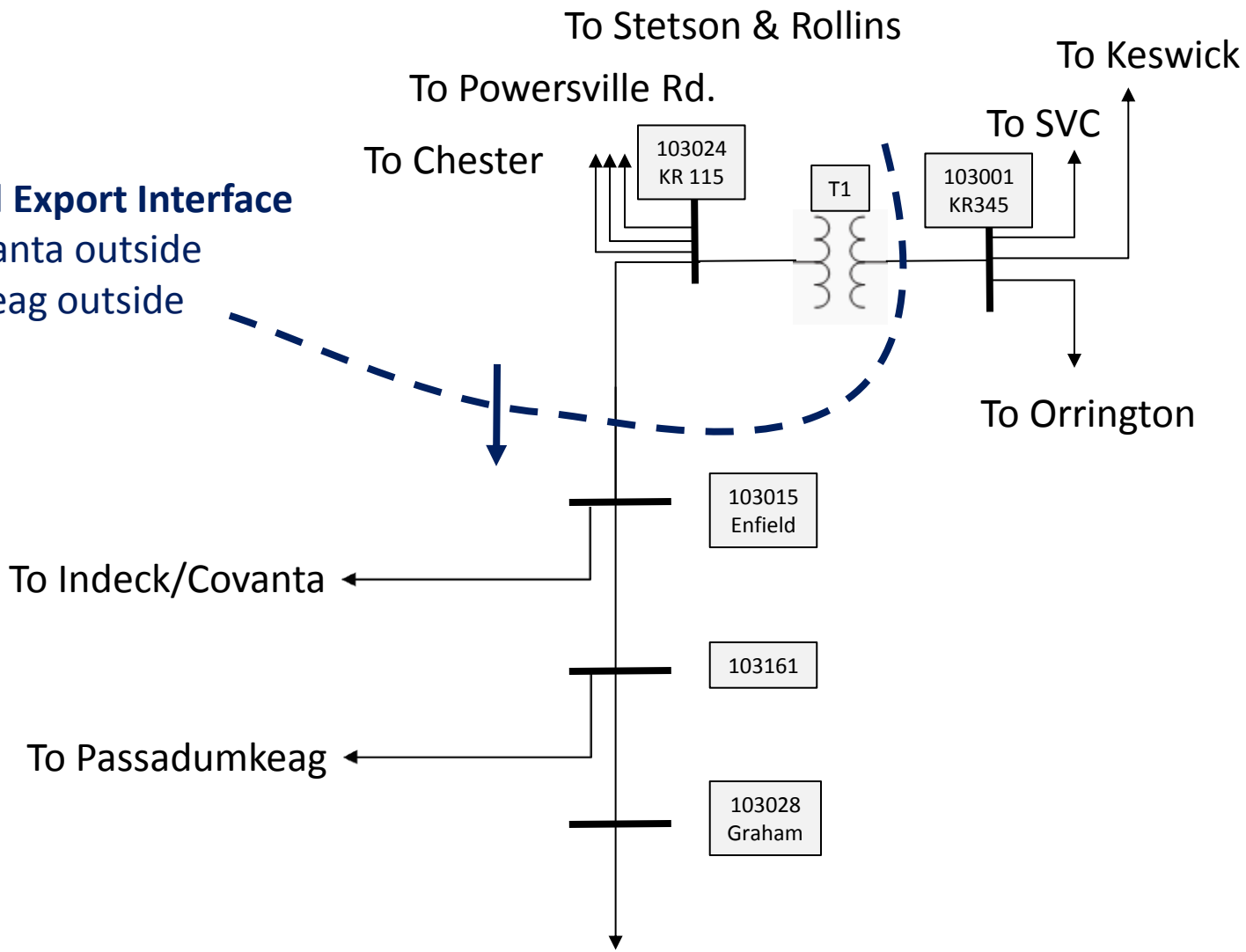
Keene Road Export-Constrained Area

Orrington-South Interface (1325 MW)



Keene Road Export Interface Definition

Keene Road Export Interface
Indeck/Covanta outside
Passadumkeag outside



Environmental Emissions Allowances Assumptions (updated values)

- Future Environmental Air Emission Allowances Prices
  - 2020
    - CO_2 = $14.67 /ton
    - NO_x = $45.00 /ton
    - SO_2 = $5.00 /ton
  - 2025
    - CO_2 = $19.42 /ton
    - NO_x = $40.00 /ton
    - SO_2 = $5.00 /ton
  - 2030
    - CO_2 = $24.14 /ton
    - NO_x = $15.00 /ton
    - SO_2 = $ 5.00 /ton

Source: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Input_Assumptions/2016%20CARIS%202%20Input%20Data%20Summary.xls

Net Load Shape

- Similar to all economic studies, all cases will use a 2006 load shape to achieve time-synchronized models for gross load, EE, and PV (and wind generation)
  - The ISO has standard models that have been vetted before stakeholders and are readily available
  - The model will reflect separate MW values for gross peak load, EE, and PV with locations that are consistent with the 2016 CELT
- Simulations for 2020 and 2025 will reflect the gross peak load, EE, and PV quantities summarized in the 2016 CELT
- Quantities for 2030 can be determined using previous methodologies and 2016 CELT quantities
  - 2030 values (peak, EE, and PV) can be calculated using the 2016 CELT values for 2025 and growing them to the year 2030 using data from 2024 and 2025
    - Example: For 2030 Peak Load: the 50-50 gross peak of 2025 x [(50-50 gross peak of 2025/50-50 gross peak of 2024) ^{5}]
    - Example: For 2030 EE and PV: total value for the year 2025 + [incremental growth for the year 2025 x 5]

Gross New England 50/50 Peak Demand and Annual Energy for All Scenarios

New England	2020	2025	2030
Peak (MW)	30,276	31,794	33,343 (a)
Annual Energy (GWh)	146,486	152,731	158,969 (b)

(a) Gross 50/50 Peak calculation for 2030 = 31,794 MW x $(31,794/31,493)^5$ = 33,343 MW
(b) Gross Annual Energy calculation for 2030 = (152,731 GWh /151,513 GWh)^5 x 152,731 GWh = 158,969 GWh

Passive Demand Resources

- Capacity
  - The annual growth of passive demand resources for 2026 through 2030 is assumed to be exactly the same incremental amount of passive demand capacity forecasted for 2025, which is 179 MW
- Energy
  - The annual growth of passive demand resource energy additions for 2026 through 2030 is assumed to be exactly the same incremental amount of passive demand energy forecasted for 2025, which is 255 GWh

Total Amount of Passive Demand Resources			
Year	2020	2025	2030
Capacity (MW)	2,812	3,844	4,739
Energy (GWh)	16,801	24,559	25,834

Behind the Meter Photovoltaic (BTM PV) Reductions in Peak Load and Energy

- The same amounts of BTM PV added in 2025 (26 MW of peak load reduction and 123 GWh of energy production) are assumed to be added annually through 2030
- The total BTM PV values (shown below) reduce the gross peak load and energy for 2025 and 2030

Assumed BTM PV Peak Load Reduction/Name Plate and Energy Production			
Year	**2020**	**2025**	**2030**
Peak Load Reduction/ Nameplate (MW)	**676/1,818 (37.2% of Nameplate)**	**828/2,307 (35.9% of Nameplate)**	**958/2,777 (34.5% of Nameplate)**
Energy Production (GWh)	**2,278**	**2,959**	**3,574**

Active Demand Resources and Storage

- Real-time Emergency Generation (RTEG) will not be simulated
- Simulate FCA 10 Active DR
  - Dispatch to peak shave based on price activation
- Model existing pumped storage units
  - Pumped storage will be modeled similar to how it was treated in the 2015 Economic Studies
  - Dispatched to equalize the daily high and low loads
  - Pumped storage will be assumed to have approximately 78% efficiency

Active Demand Resources

- Active DR (Real-Time DR) assumptions are based on FCA 10 results, but exclude RTEGs
- Annual peak remains the most stressful hour – which suggests activation of this resource during times of high prices

Year	2020	2025	2030
Capacity (MW)	319	319	319
Energy (GWh)	1.6 (Dispatched at $500)	1.6 (Dispatched at $500)	1.6 (Dispatched at $500)

Hydro Production Profiles

- Use method similar to the 2015 Economic Study for Keene Road
  - Simulate all hydro except for the Keene Road area with diurnal profiles based on average values for 2013, 2014, and 2015
  - The Keene Road area will be based on the maximum production for 2013, 2014, and 2015

Interchange with Neighboring Systems

- Use energy profiles for Quebec, the Maritimes, and New York with a methodology similar to the 2015 Economic Studies
  - Use diurnal profiles based on average values for 2013, 2014, and 2015
  - Separate the profiles used for the Cross Sound Cable (CSC) and
  - NY AC interconnections
  - Simulate imports as price takers that never set the clearing price
  - Assume $10 import threshold price for curtailments of all imports

Capacity

The ISO will not conduct detailed FCA deliverability tests

- Existing resource retirement in accordance with FCA 10 results
- Imports updated to reflect assumption used in FCA 10 qualified imports
- Assume the NICR value for 2020 (FCA 11), which was presented to the RC on September 20
- Assume a reserve margin of 14% above the gross 50/50 peak load net of BTM PV would meet NICR for 2025 and 2030
  - This is a reasonable base scenario assumption based on NICR summarized in recent RSPs
  - EE is considered a resource
  - Capacity values for wind units were based on reliability hours
- Deliverability may be assumed because:
  - There is very little load growth
  - With the exception of the growth of EE, the resource mix is the same for 2020, 2025, and 2030
  - GridView results will show transmission congestion across major interfaces*

* Scenario 4 showed little congestion, which was attributable to wind expansion beyond the amounts to be simulated in the proposed METU needs assessment study

FCA 10 Capacity Exceeds NICR (MW)

	Year	2020	2025	2030
1	FCA 10 Cleared Renewables (Bio, LFG, etc.)	976	976	976
2	FCA 10 Cleared Solar	62	62	62
3	Forecast EE & ADR w/o RTEG	3131	4163	5058
4	FCA 10 Cleared Nuclear	3347	3347	3347
5	FCA 10 Cleared Hydro & Pumped Storage	3116	3116	3116
6	Resource Serving Citizen Block Load	30	30	30
7	Imports [a]	1510	1510	1510
8	FCA 10 Cleared Wind Capacity	135	135	135
9	FCA 10 Cleared Gas Capacity	16676	16676	16676
10	FCA 10 Cleared Oil Capacity	6109	6109	6109
11	FCA 10 Cleared Coal Capacity	917	917	917
12	Total Resource Modeled	36009	37041	37936
13	Net ICR [b]	34070	35302	36919

a. Based on the FCA 10 qualified import capacity with deration resulting from tie benefits.

b. 2020, 2025, and 2030 total resources exceed their corresponding NICRs.

Resource Models

- Units with signed interconnection agreements (IA), FCA commitments, other “existing CELT 2016 generators”
  - Do not include generators that have I.3.9 approvals, but without IAs

	Resources with signed Interconnection Agreements				
Queue Position	Project Name	Unit	Fuel Type	Summer MW	State
89	Cape Wind Turbine Generators	WT	WND	454	MA
178	Brockton Combined Cycle	CC	NG DFO	332	MA
273	Palmer Renewable Energy	ST	WDS	36.7	MA
300	Canton Mountain Winds	WT	WND	19.25	ME
333	Bingham Wind	WT	WND	184.8	ME
349	Pisgah Mountain	WT	WND	9	ME
358	Medway Hydro Expansion	HD	WAT	4.78	ME
384	CPV Towantic Energy Center	CC	NG DFO	745	CT
387	Footprint Combined Cycle Unit	CC	NG	715.6	MA
390	Spruce Ridge Wind Farm	WT	WND	50.82	NH
396	Berkshire Wind Increase	WT	WND	19.8	MA
397	Hancock Wind Project	WT	WND	51	ME
400	Downeast Wind	WT	WND	90	ME
403	Pisgah Mountain Increase (see Q349)	WT	WND	9.07	ME
404	MATEP -3rd CTG	GT	DFO NG	100	MA
406	Canton Increase and CNR (see Q300)	WT	WND	22.8	ME
412	PSEG Bridgeport Harbor CCGT Expansion	CC	DFO NG	509.6	CT
421	Spruce Ridge Wind CNR (see Q390)	WT	WND	50.82	NH
438	Potter Repowering	GT	NG	63.27	MA
440	Wallingford Energy Center	GT	NG	350	CT
443	Brockton Combined Cycle CNR Increase	CC	NG	354.9	MA
444	Medway Peaker - SEMARI	GT	DFO NG	207.7	MA
449	Canal 3	CC	DFO NG	333	MA
477	Deerfield Wind Project	WT	WND	30	VT
481	GRE Capacity Uprate	CC	NG	762	NH
530	Bridgeport Energy Wet Compression Upgrade	CC	NG	578	CT
546	NEA Bell. Uprate (Northeast Energy Associates, LP)	CC	DFO NG	314.7	MA
377	Harrington Street PV Project (QF)	PV	SUN	9.75	MA
405	Block Island Wind Farm	WT	WND	29	RI

Generator and Operating Reserve Modeling

- Generation Operating Characteristics
  - Known operating characteristics (heat rate, ramp rate, minimum down time, minimum up time, etc.) will be used
- Operating reserve requirement is determined in real time
  - Based on the first and second largest system contingencies
  - Resource profiles (hydro / wind / interchange etc) excluded
- Current operating reserve requirements
  - 120% of the first contingency in ten minutes split between
    - Ten-Minute Spinning Reserve (TMSR) = 50%
    - Ten-Minute Non-Spinning Reserve (TMNSR) = 50%
  - Thirty-Minute Operation Reserve (TMOR) not modeled
    - Assumed to be adequate
    - Provided by hydro, pumped storage and quick-start resources
    - Reasonable assumption except, possibly, at times of peak loads

PROFILES OF SOME RESOURCES

Many Resources Represented by Profiles

- Demand Resources
  - Energy Efficiency is derived from the initial (gross) load profile
  - Active Demand resource
    - FCA 10 ADR assumed to be price activated at $500 – not represented by a profile
- Renewable resources generate when “resource” is available
  - Photovoltaic
  - On shore wind
  - Off shore wind
- Local New England hydro
- Imports
  - Existing ties
- Energy Storage (Pumped Storage)

Production Simulation with Resource Profiles

- Many resources cannot be dispatched using production cost
  - Some technologies have zero or “indeterminate” production cost
  - Can be “curtailed” using assumed “threshold” prices
  - Some resource profiles can be developed to:
    - Peak-shave and valley-fill loads
    - Levelize loads
- Order is the same as used in Scenario Analysis
- Example of sequential load shape adjustment
  - After load shape adjustments nuclear, gas, oil, coal, biomass, etc. resources will be dispatched

Load Profiles “Dispatch”

- Energy Efficiency (EE)
  - EE and ADR adjustment shape derived from initial load shape
  - Assumed lowest “threshold” dispatch price of $0/MWh
- Photovoltaic (PV)
  - Second lowest “threshold” dispatch price of $1.00/MWh

Load Profiles – “Dispatch,” cont.

- On-Shore wind
  - “Threshold” dispatch price of $4.00/MWh
    - Dispatched down before nuclear
    - Higher priority than local hydro
- Off-Shore wind
  - “Threshold” dispatch price of $4.00/MWh
    - Dispatched down before nuclear
    - Higher priority than local hydro
- Local New England Hydro
  - “Threshold” dispatch price of $4.50/MWh
    - Dispatched down before wind
    - Higher priority than interchange

Load Profiles – "Dispatch," cont.

- Interchange over existing ties
  - Quebec (Highgate and Phase II), New Brunswick and New York
  - "Threshold" dispatch price of $10.00/MWh for all imports
- Pumped Storage
  - 1,665 MW of pumped storage generation modeled in GridView

NEW ENGLAND PIPE AND BUBBLE DIAGRAM

RSP Area Abbreviations

New England Pipe and Bubble Representation, cont. Abbreviations of Subareas in Diagram

BHE	Northeastern Maine
ME	Western and central Maine and Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire; eastern Vermont; and southwestern Maine
VT	Vermont and southwestern New Hampshire
Boston	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts and northeastern Massachusetts
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts and Newport, Rhode Island
RI	Part of Rhode Island bordering Massachusetts
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk and Stamford, Connecticut

Questions