Scenario Analysis –
Final Modeling Assumptions

April 30, 2007

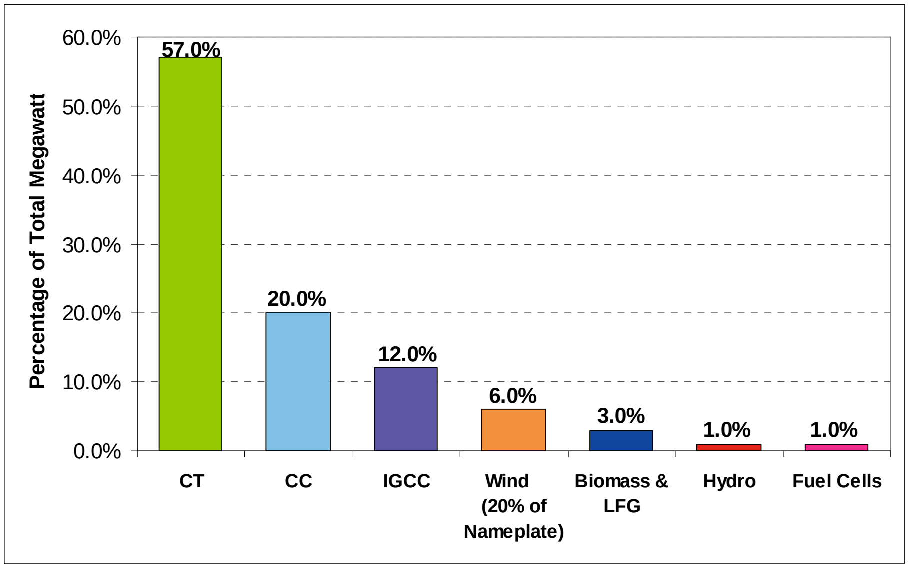
Stakeholder Input

- **Technical experts provided comments/information**
  - Fuel forecasts
  - Need for additional natural gas infrastructure
  - Profiles of wind, photo-voltaic (PV), and energy efficiency resources
- **Open Stakeholder Meetings held to discuss detailed technical issues**
  - Power Supply Planning Committee
    - Assumptions and data inputs
    - Modeling characteristics, capital and dispatch costs
  - Demand Response Working Group
    - Energy efficiency and demand response costs and characteristics
  - Environmental Advisory Group
    - Emission modeling and rates, environmental metrics
  - Transmission Owners Working Group
    - Transmission and distribution conceptual costs
  - Metrics Working Group
    - Type and format of Scenario Analysis information to be provided
- **Plenary meetings**
  - Review scope of work, assumptions, and results

Scenario Analysis General Assumptions

- **Summer Peak Load = 35,000 MW**
- **Total system energy = 174,000 GWh**
- **Capacity**
  - Existing 2007 = 30,777 MW (summer)
  - New capacity added
    - 2,600 MW Queue Mix common to all scenarios
    - 5,400 MW based on Scenario

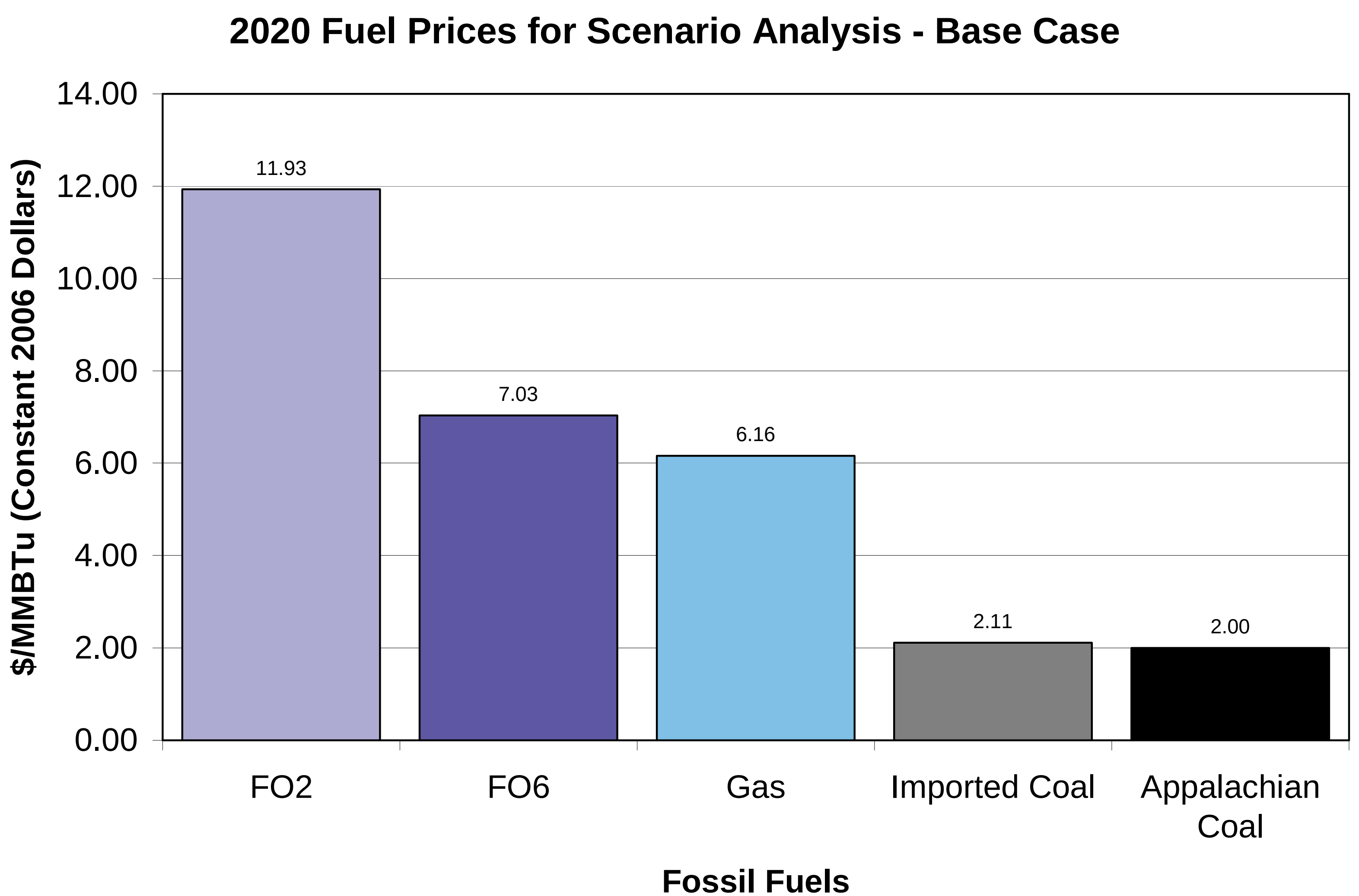
SA Queue Mix



Scenario Analysis – 7 Scenarios

1. **Market Mix of Resources "Queue Mix"**
2. **Energy Efficiency (EE) and Demand Response (DR)**
   – Both EE and DR are considered resources
3. **Nuclear**
4. **Coal IGCC – without carbon capture and sequestration (CCS) and with CCS as sensitivity case**
5. **Natural Gas Combined Cycle**
6. **Renewable Resources**
7. **Imports: hydro and/or low emitting resources**

Fuel Prices – Base Case (2006 $)



New Power Plant Assumptions

Technology	MW	Heat Rate (Btu/kWh)	Equipment Availability %	Total Plant Costs (2006 $/kW)	Sources
IGCC w/o CO_2 Capture	600	8,600	80	2500-3500	EPA, EPRI, MIT, DOE
IGCC with 90% CO_2 Capture	500	9,750	80	2900-3900	EPA, EPRI, UN, MIT
NG Combined Cycle	400	6,500	90	800-1000	GE
NG Comb Turbine	100	8,500	90	500-700	GE
Nuclear	1080	10,000	90	3000-5000	Westinghouse, NEI
Fuel Cell*	1	8,000	95	3500-4000	Fuel Cell Energy
Biomass	40	14,000	90	2500-3500	CT Plants, NH DES
Hydro	5	N/A	90	3000-4000	NE Developer
Landfill Gas	5	10,500	90	2000-2500	NE Plants
CHP*	5	9,750	90	1000-1500	Solar Turbines
Photovoltaics	1	20%**	98	4000-6000	UMASS RERL
Wind On-shore	1.5	N/A	90	1500-2000	UMASS RERL Levitan
Wind Off-shore	3.5	N/A	90	2000-2500	UMASS RERL Levitan

*Data is for electric production only **PV Conversion Efficiency: sunlight to AC power

SA New Power Plants Emission Rate Assumptions

Technology	MW	Heat Rate (Btu/kWh)	SO_2 (lb/MBtu)	NO_x (lb/MBtu)	CO_2 (lb/MBtu)	Sources
IGCC w/o CO_2 Capture	600	8,600	0.03	0.01	210	EPA, EPRI, MA DEP
IGCC w/ 90% CO_2 Capture	500	9,750	0.03	0.01	21	EPA, EPRI, MA DEP
NG Combined Cycle	400	6,500	0.0006	0.01	120	GE
NG Combustion Turbine	100	8,500	0.0006	.03	120	GE
Nuclear	1080	10,000	0	0	0	Westinghouse, NEI
Fuel Cell*	1	8,000	0.0006	0.0088	120	Fuel Cell Energy
Biomass	40	14,000	0.02	0.075	170**	NE Plants, NH DES
Hydro	5	N/A	0	0	0	NE Developer
Landfill Gas	5	10,500	0.2	0.03	0	NE Developer, Solar Turbines
CHP*	5	9,750	0.0006	0.014	120	Solar Turbines, MA DEP
Photovoltaics	1	20%	0	0	0	UMASS RERL
Wind	1.5-3.5	N/A	0	0	0	UMASS RERL, Levitan

*Data is for electric production only

**Biomass fuel cycle is considered carbon neutral

SA Emission Values Assumptions in 2020 (2006$)

Type Emission	Emission Value ($/ton)	Source
SO_2	969	EIA AEO 2006
NO_x	2,345	EIA AEO 2006
CO_2	3, 20, 40	Synapse Report
Mercury	[Not modeled in the dispatch. Emissions calculated in post-processing]	

SA Other Environmental Assumptions

- **CO_2 Sequestration costs:**
  - CO_2 capture costs reflected in a $400/kW higher IGCC plant cost and heat rate
  - Assumed cost of $25 per ton for CO_2 transportation, monitoring and storage costs and reflected in the dispatch price
  - 5400 MW of IGCC with 90% CO_2 capture yields 34.9 million tons of CO_2 annually for sequestration
- **Water Requirements**
  - Assumed wet cooling towers would be required for large new fossil and nuclear plants
  - Developed gallon per minute per MW estimates with the help of ISO's EAG and PSPC for three technologies
    - Nuclear requires 15.8 gal/min/MW
    - IGCC requires 12.2 gal/min/MW
    - Natural gas combined cycle requires 3.8 gal/min/MW

SA Land Assumptions – New Generation

- Used existing generation plant sites and proposed projects
- Developed a low and high estimate of acres per MW were possible
- Generally considered total site for large plants or physical space needs for smaller projects with appropriate public exclusion
- Some sites i.e. wind require a large area for separation of turbines but cleared land is much smaller
- Did not include offsite requirements for waste storage
- Multiplied by MW of technology in each scenario

SA Land Assumptions – Generation

Generation Technology	Low Requirement Acres/MW	High Requirement Acres/MW	Sources
Combustion Turbine	0.025	0.03	Chelsea, Billerica
Nuclear	0.2	0.375	VT Yankee, Seabrook
IGCC	0.07	0.5	NRG, EPA, AEP
NGCC	0.024	0.024	Granite Ridge
Biomass	0.36	0.36	Russell Project
Fuel Cells	0.07	0.07	Fuel Cell Energy
Hydro	0.2	0.2	NE Developer
Landfill Gas	0.0	0.2	NE Developer
CHP	0.025	0.03	Same as Comb Turbine
Photovoltaics	10	14	Spain, Portugal projects
Wind Onshore	5.0	30	VERA, RI Study
Wind Offshore	30	30	Cape Wind, RI Study

SA New Power Plants Variable Costs: Fuel & Emission Values (2006$)

Technology	Size MW	Heat Rate Btu/kWh	Fuel Prices $/MWh	Emission Values $/MWh	Total Fuel & Emissions $/MWh
PV and Wind, on and off-shore			0	0	0
Landfill Gas	5	10,500	0	1.4	1.4
Nuclear	1080	10,000	17.0***	0	17.0
IGCC w/ 90% CO_2 capture	500	9,750	19.5	2.3	21.8
IGCC w/o CO_2 capture	600	8,600	16.0	17.1	33.1
NG Combined Cycle	400	6,500	40.1	7.9	47.9
Fuel Cell*	1	8,000	49.3	9.4	58.7
NG Comb Turbine	100	8,500	52.4	10.5	62.9
Biomass**	40	14,000	46.6	25.2	71.8
CHP*	5	9,750	60.1	12.0	72.1

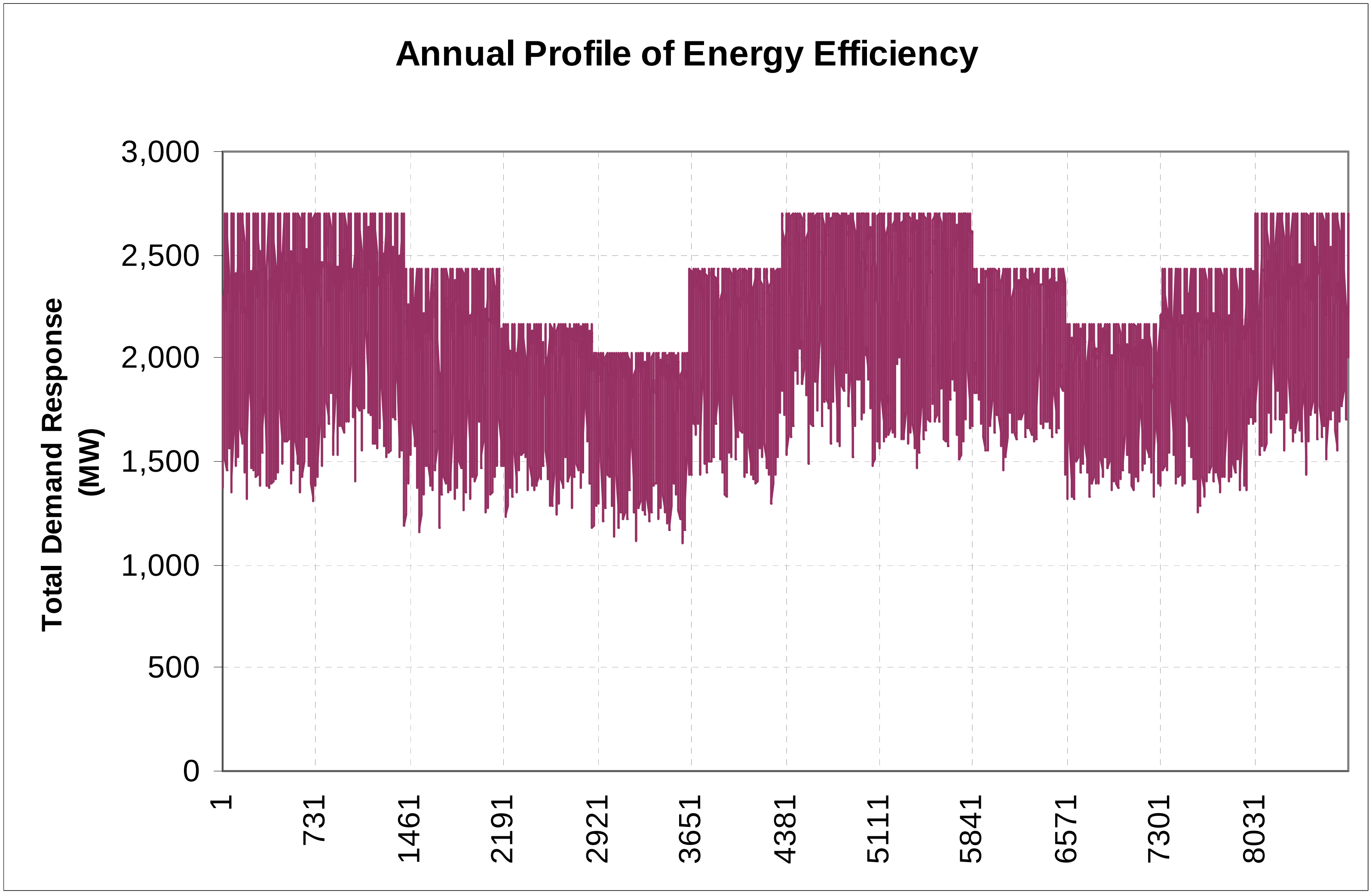
*Data is for electric production only **Biomass fuel cycle is considered carbon neutral ***Includes O&M and waste disposal

Energy Efficiency, Wind, Photovoltaic and Import Energy Assumptions

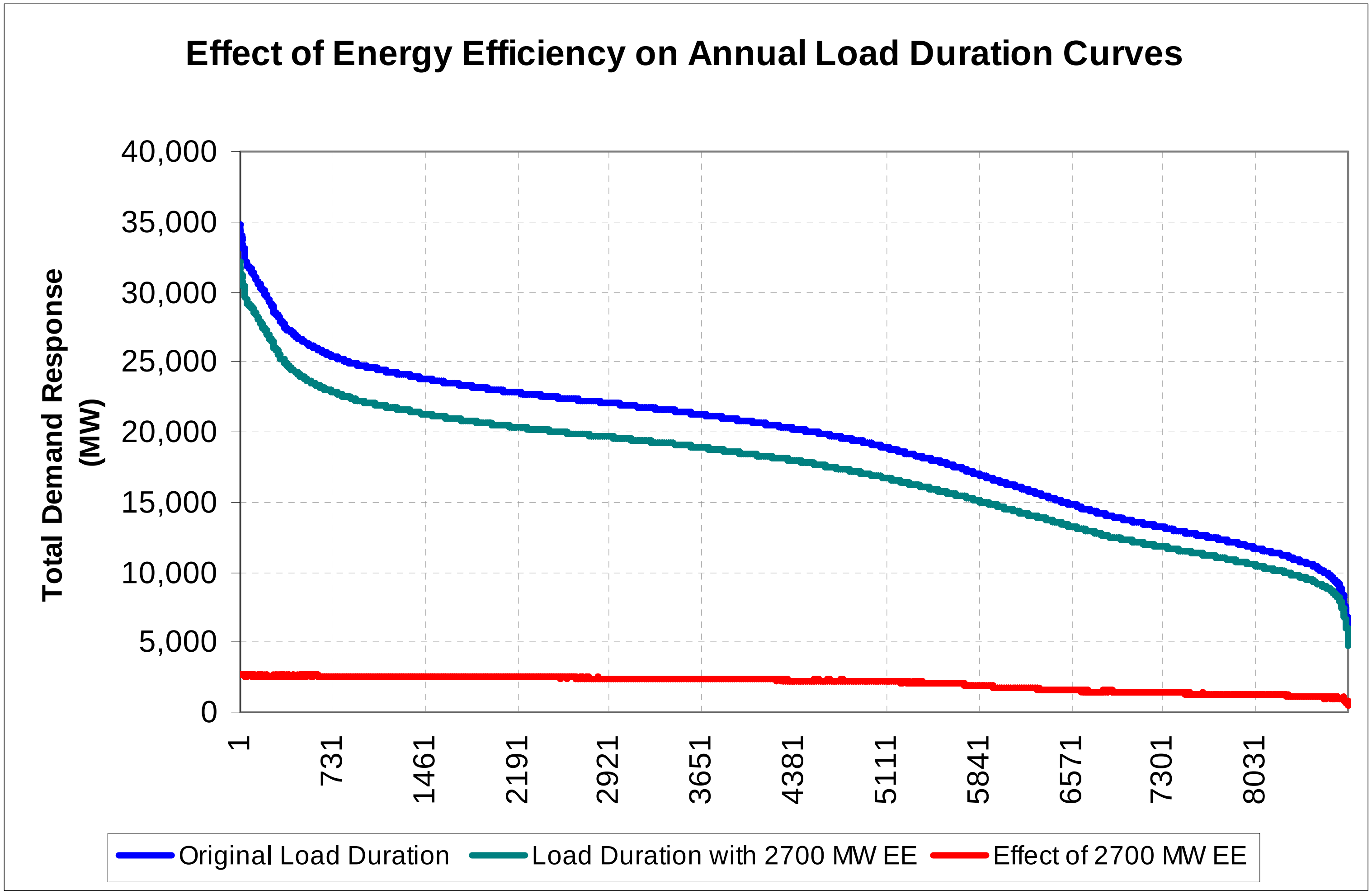
Revised Energy Efficiency Approach

- **Each day has daily peak load reduction of 2700 MW**
  - EE in non-peak hours of each day
    - Greatest amount of EE occurs at time of daily peak load
    - Decreased proportionally to its ratio of the daily peak load
    - EE_h = 2700 - 2700 * [1 - (hour load / daily peak) * 1.043]
      - The ‘1.043’ factor is used to adjust energy to the target 18 TWh
  - Total energy from Energy Efficiency is 18,003 GWh
- **For Case 2E**
  - Double Energy Efficiency Case
  - Total energy from Energy Efficiency 36,006 GWh

Final EE Profile



Effect of EE on Load Duration Curves



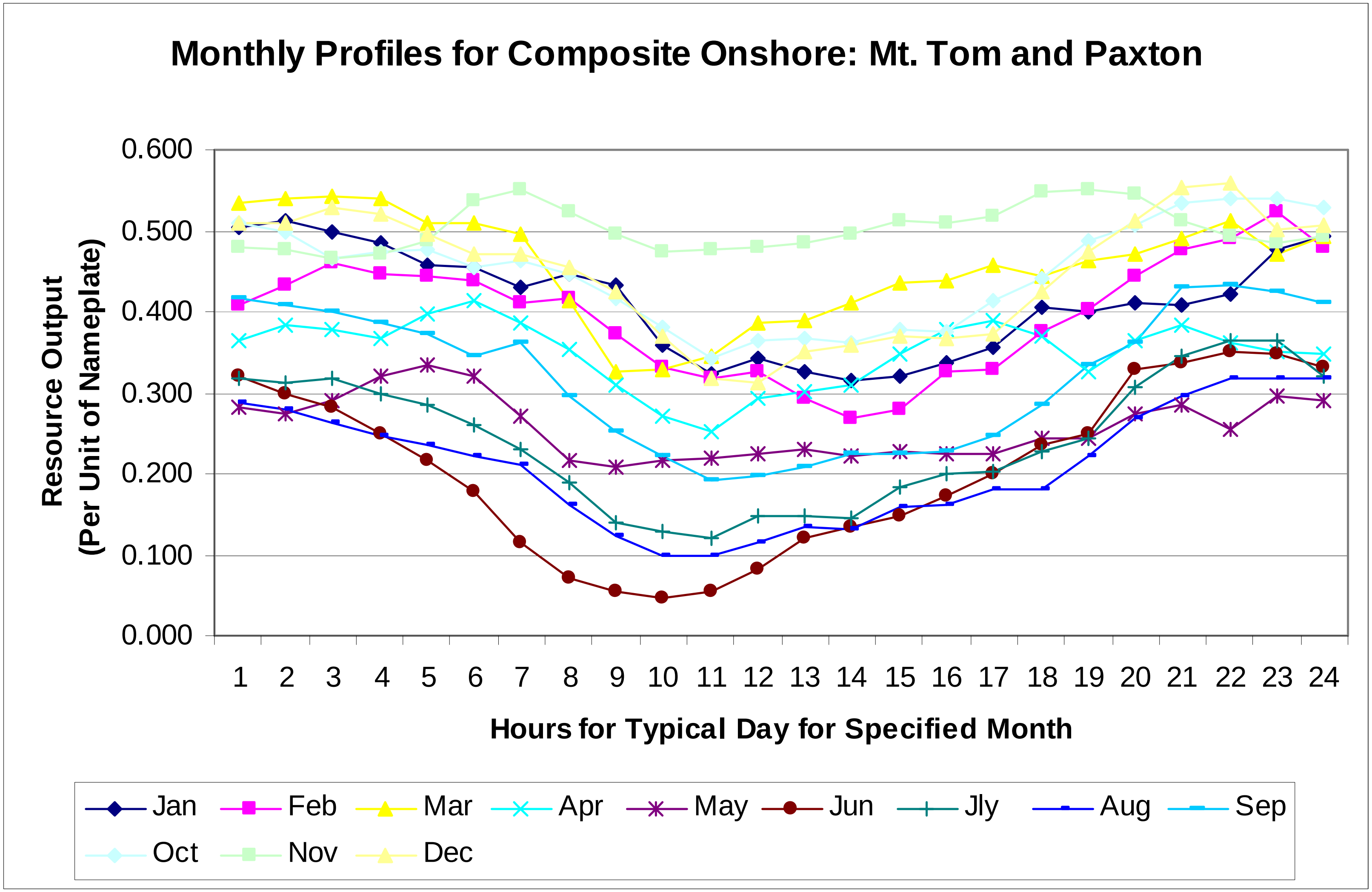
SA New England Energy Efficiency Costs

- The New England states recent energy efficiency program results show annual costs from 110 to 400 $/kW/yr. These are levelized costs based on a typical energy efficiency measure life of 13 years and a 7% return yielding an annual charge rate of 12%.
- With this annual charge rate these program costs translate to an equivalent capitalized cost of 920 to 3300 $/kW of demand reduction

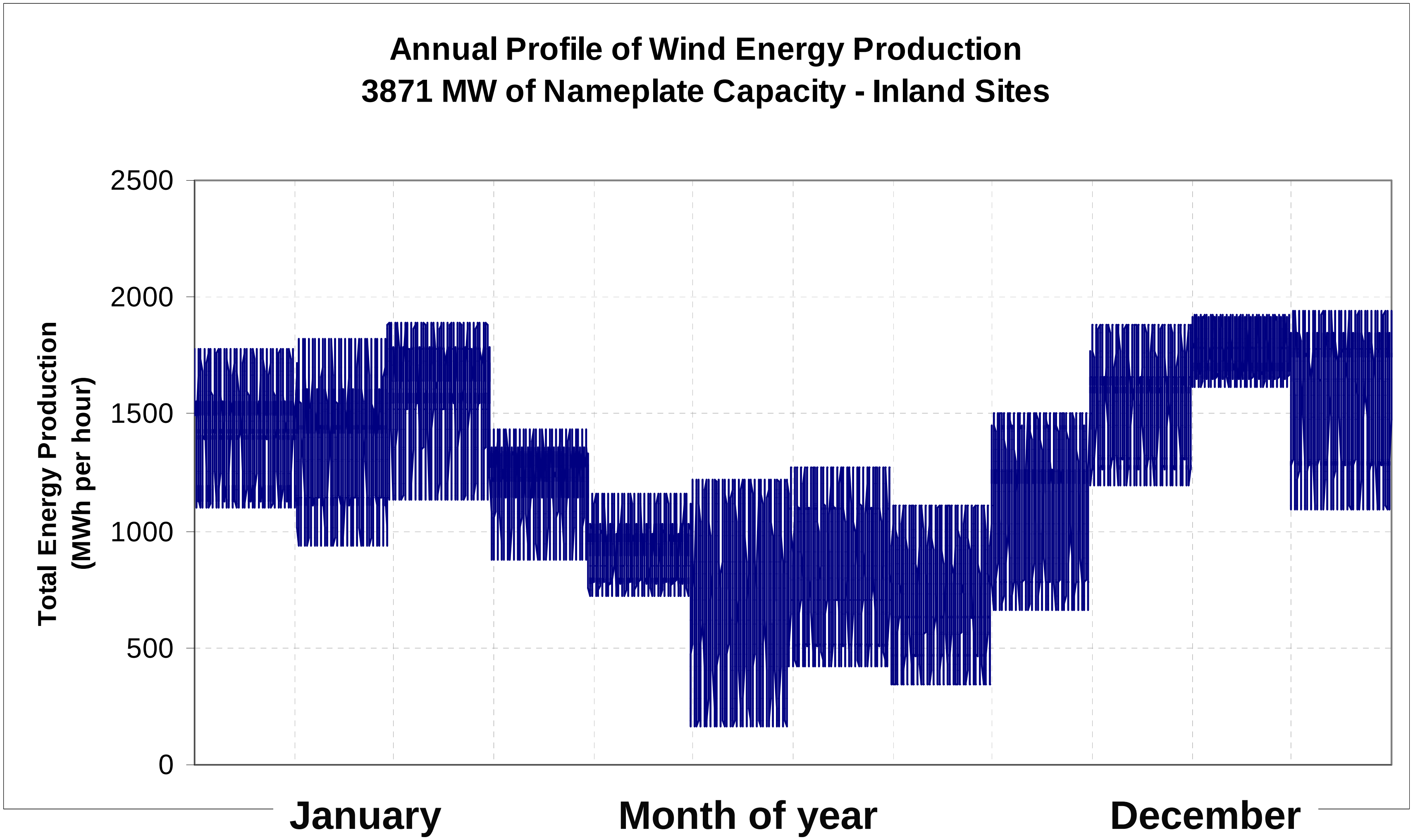
Wind Data

- Developed by Levitan and Associates (LAI)
- Used 2005 hourly wind data for two inland sites and three offshore sites
- Developed hourly daily profile for an average day for each month
- Averaged inland and offshore sites profiles

Composite Wind Profile for Onshore



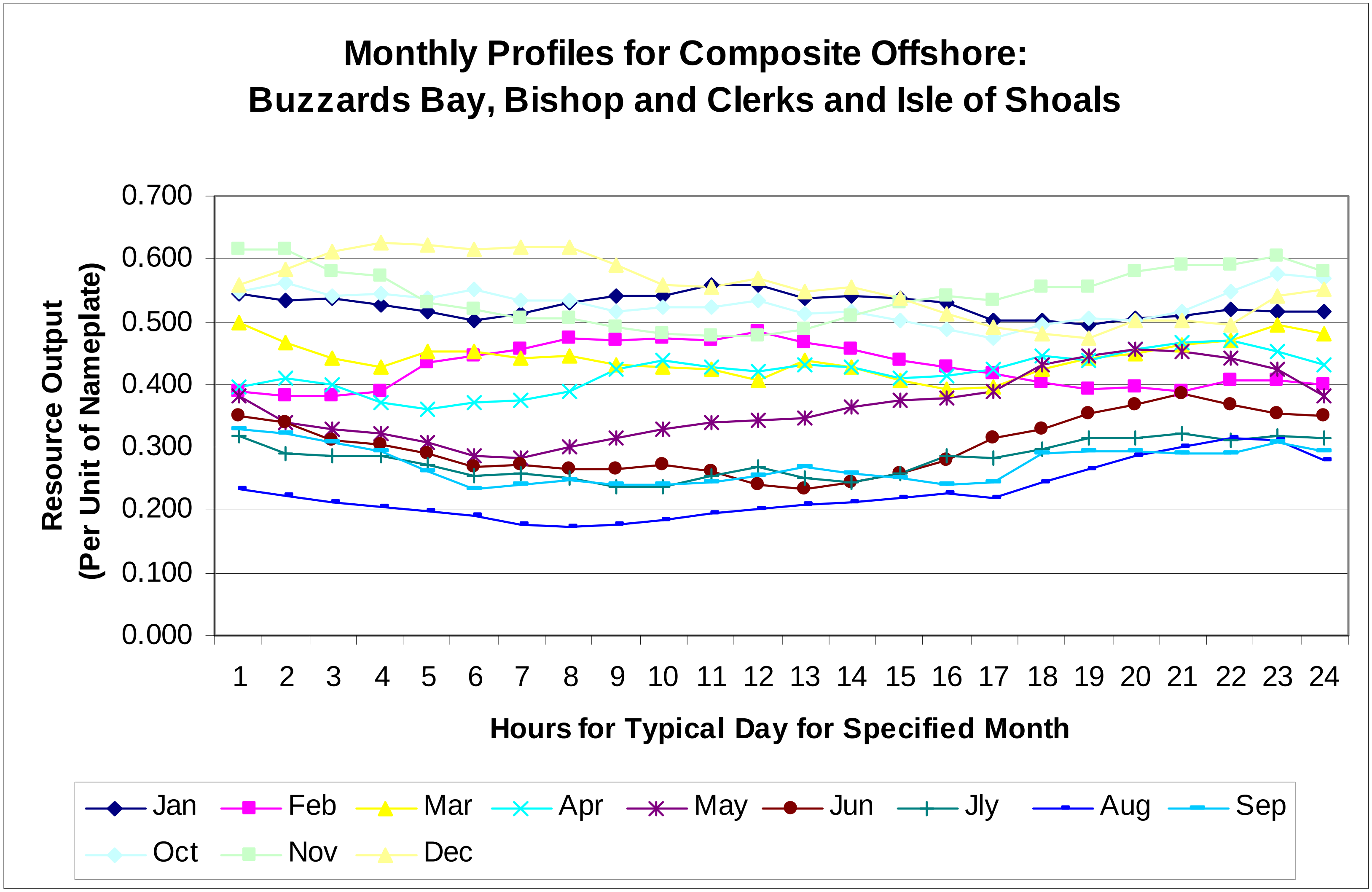
Annual Onshore Wind Generation Profile (by month of year)



Composite Wind Profile for Offshore

	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
1	0.545	0.388	0.499	0.395	0.382	0.350	0.318	0.233	0.328	0.548	0.615	0.559
2	0.535	0.382	0.468	0.410	0.338	0.338	0.291	0.221	0.321	0.563	0.615	0.583
3	0.536	0.381	0.441	0.400	0.328	0.309	0.286	0.214	0.308	0.541	0.580	0.612
4	0.527	0.390	0.426	0.371	0.321	0.306	0.288	0.206	0.293	0.544	0.571	0.625
5	0.517	0.434	0.453	0.359	0.309	0.291	0.274	0.197	0.263	0.539	0.530	0.622
6	0.504	0.447	0.453	0.372	0.287	0.268	0.255	0.191	0.234	0.552	0.520	0.616
7	0.514	0.458	0.443	0.375	0.283	0.272	0.260	0.177	0.240	0.534	0.504	0.618
8	0.529	0.472	0.445	0.388	0.302	0.266	0.253	0.175	0.246	0.533	0.504	0.619
9	0.542	0.471	0.430	0.424	0.315	0.266	0.237	0.176	0.240	0.515	0.490	0.589
10	0.542	0.473	0.429	0.439	0.329	0.274	0.238	0.183	0.242	0.523	0.480	0.557
11	0.557	0.471	0.423	0.427	0.341	0.262	0.255	0.194	0.244	0.525	0.479	0.556
12	0.557	0.484	0.407	0.419	0.342	0.242	0.267	0.201	0.253	0.535	0.479	0.570
13	0.539	0.465	0.438	0.431	0.346	0.234	0.249	0.208	0.270	0.513	0.488	0.548
14	0.539	0.457	0.428	0.428	0.365	0.2440	0.2450	0.2139	0.2577	0.517	0.509	0.555
15	0.539	0.437	0.407	0.409	0.376	0.2593	0.2587	0.2185	0.2521	0.501	0.530	0.536
16	0.530	0.429	0.393	0.414	0.379	0.2794	0.2853	0.2268	0.2415	0.487	0.540	0.512
17	0.501	0.418	0.395	0.426	0.390	0.3138	0.2817	0.2175	0.2452	0.473	0.533	0.492
18	0.503	0.402	0.426	0.447	0.430	0.3292	0.2957	0.2428	0.2886	0.494	0.556	0.482
19	0.496	0.391	0.441	0.437	0.447	0.355	0.314	0.267	0.295	0.505	0.555	0.474
20	0.506	0.395	0.449	0.455	0.455	0.369	0.313	0.286	0.292	0.501	0.578	0.501
21	0.510	0.391	0.461	0.468	0.454	0.384	0.322	0.300	0.291	0.518	0.591	0.501
22	0.520	0.408	0.471	0.470	0.443	0.367	0.312	0.314	0.291	0.548	0.591	0.494
23	0.515	0.406	0.494	0.452	0.423	0.354	0.319	0.310	0.306	0.577	0.606	0.542
24	0.517	0.400	0.482	0.432	0.381	0.351	0.316	0.278	0.292	0.568	0.580	0.551
	0.526	0.427	0.442	0.419	0.365	0.303	0.281	0.227	0.272	0.527	0.543	0.555
	Average Summer Capacity Value			0.2598		Annual Capacity Factor with 100 percent Mechanical Availability						0.407
	Average Winter Capacity Value			0.4677								

Composite Wind Profile for Offshore



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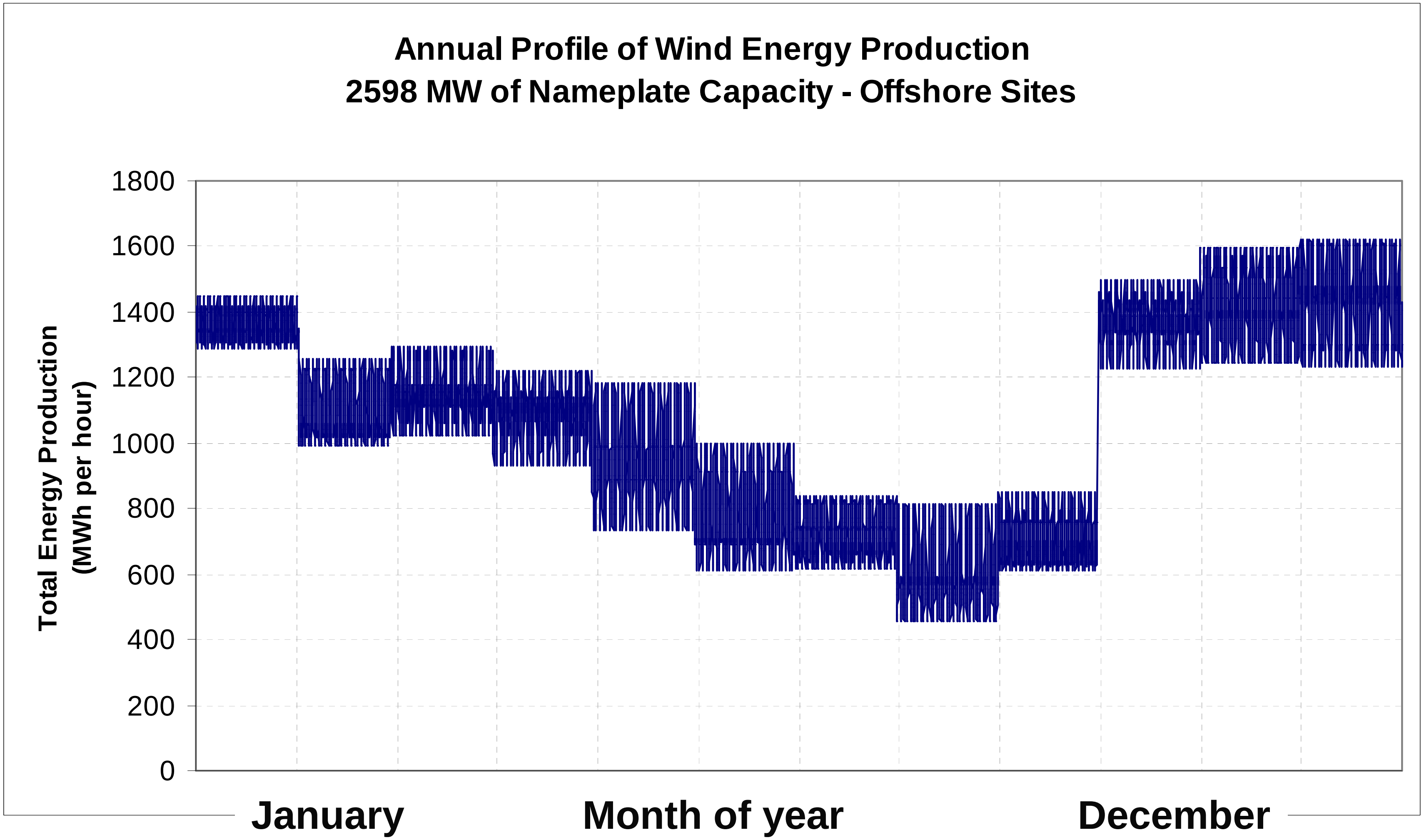

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	0.526	0.427	0.442	0.419	0.365	0.303	0.281	0.227	0.272	0.527	0.543	0.555
	Average Summer Capacity Value			0.2598		Annual Capacity Factor with 100 percent Mechanical Availability						0.407
	Average Winter Capacity Value			0.4677								

Wind Capacity Terms

- **Nameplate capacity** is the maximum design capacity of a wind turbine. In SA this is 1.5 MW for land-based turbines and 3.5 MW for offshore turbines
- **Capacity value (CV)** is the capacity output (MW) of a wind turbine at the time of the system peak
- **FCM Capacity** is the capacity value (MW) calculated by the FCM method for determining Qualified Capacity of interim resources i.e. the average output during the hours ending 2 to 6 PM during the months June through September
- **Capacity factor** is the energy produced over a specific time, usually a year, divided by the nameplate rating and the hours in the period (8760 in the case of a year)

Wind Capacity

- **Wind "capacity value" is used in two ways**
  - First: In the simulation runs, to set the total kWh from wind
  - Second: In the post-processing, to determine an amount of nameplate wind capacity needed to produce that wind energy
    - The "user spreadsheet tools," will allow the user to vary the CV assumption and relative capacity costs
- **FCM (summer) capacity calculated using Levitan wind study profiles**
  - 19 % for onshore
  - 26 % for offshore
- **Annual capacity factors calculated from Levitan wind study profiles and adjusted for turbine availability**
  - 32% for onshore
  - 35% for offshore

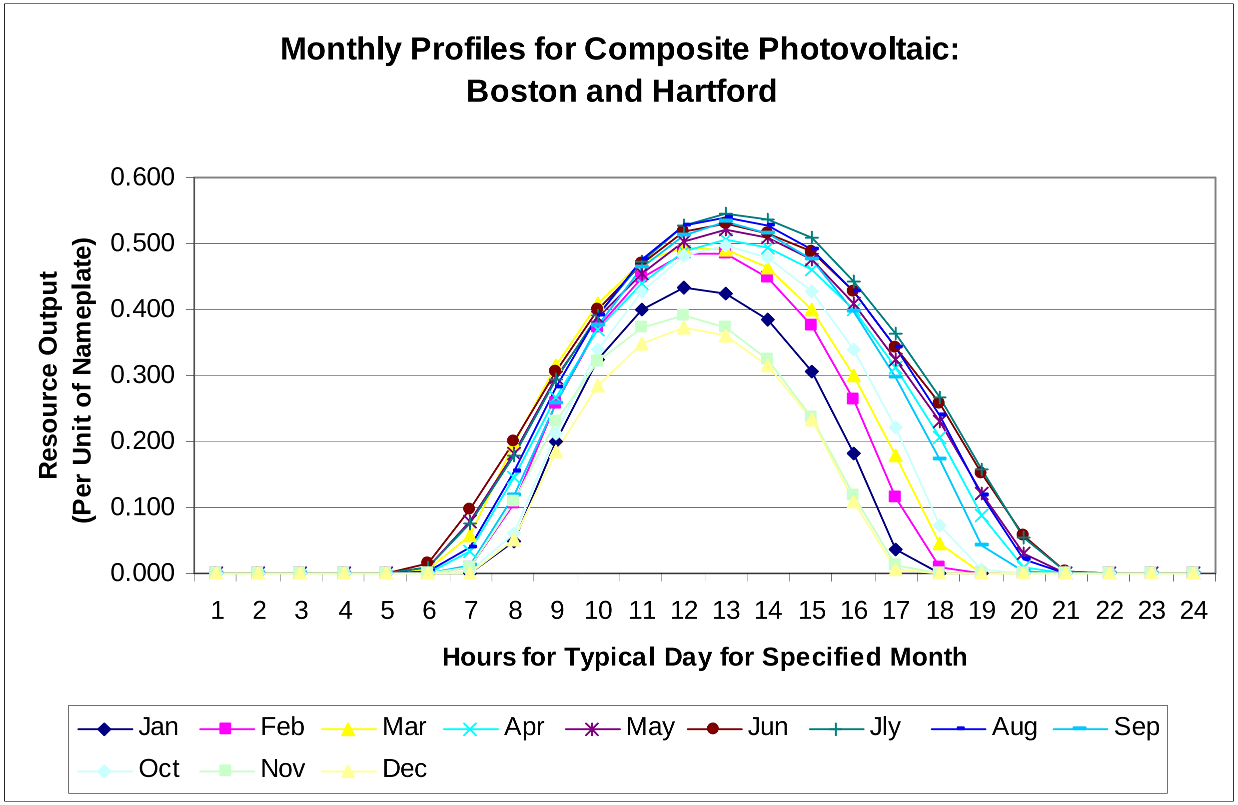
To Meet the Required FCM Capacity Need More Installed Nameplate Capacity (MW)

- **To obtain 675 MW of FCM capacity from the wind resource, need to add several times more nameplate capacity:**
  - 3,484 MW nameplate for inland (assumed 19% FCM)
  - 2,598 MW nameplate for offshore (assumed 26% FCM)
- **Effect of assumed 90 percent mechanical availability and distribution losses increases these requirements more**
  - 3,871 MW nameplate for inland wind
  - 2,886 MW nameplate for offshore wind

Solar Photovoltaic Data

- Developed by UMASS Amherst Renewable Energy Research Lab
- To represent New England sites used Boston and Hartford insolation data from the National Renewable Energy Lab for 1961 to 1990 to develop hourly daily profile for an average day for each month. Then averaged the data for these two sites
- Assumed PV systems are 20% efficient in conversion of insolation to AC power

Composite Profile for Photovoltaics



Composite Profile for Photovoltaics

	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.005	0.001	0.009	0.016	0.008	0.002	0.000	0.000	0.000	0.000
7	0.000	0.008	0.059	0.033	0.078	0.097	0.076	0.040	0.013	0.002	0.010	0.001
8	0.048	0.107	0.197	0.146	0.183	0.199	0.178	0.155	0.118	0.059	0.109	0.050
9	0.201	0.259	0.317	0.267	0.296	0.307	0.294	0.281	0.257	0.211	0.231	0.184
10	0.325	0.372	0.408	0.369	0.388	0.400	0.392	0.392	0.375	0.338	0.320	0.286
11	0.399	0.447	0.472	0.440	0.454	0.469	0.474	0.475	0.464	0.428	0.373	0.350
12	0.433	0.485	0.495	0.489	0.502	0.517	0.528	0.526	0.512	0.482	0.390	0.372
13	0.425	0.484	0.490	0.506	0.522	0.530	0.546	0.539	0.533	0.497	0.371	0.362
14	0.384	0.447	0.464	0.494	0.508	0.5159	0.5378	0.5276	0.5141	0.480	0.325	0.315
15	0.305	0.375	0.400	0.460	0.475	0.4893	0.5081	0.4905	0.4755	0.428	0.236	0.233
16	0.182	0.262	0.299	0.400	0.411	0.4278	0.4436	0.4258	0.3967	0.341	0.119	0.108
17	0.035	0.116	0.180	0.314	0.325	0.3418	0.3623	0.3422	0.2959	0.220	0.012	0.007
18	0.000	0.010	0.045	0.207	0.230	0.2568	0.2679	0.2408	0.1715	0.074	0.000	0.000
19	0.000	0.000	0.001	0.089	0.120	0.152	0.157	0.120	0.044	0.006	0.000	0.000
20	0.000	0.000	0.000	0.009	0.030	0.057	0.055	0.022	0.003	0.000	0.000	0.000
21	0.000	0.000	0.000	0.000	0.001	0.004	0.003	0.001	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.114	0.141	0.160	0.176	0.189	0.199	0.201	0.191	0.174	0.149	0.104	0.094

Average Summer Capacity Value: 0.4016

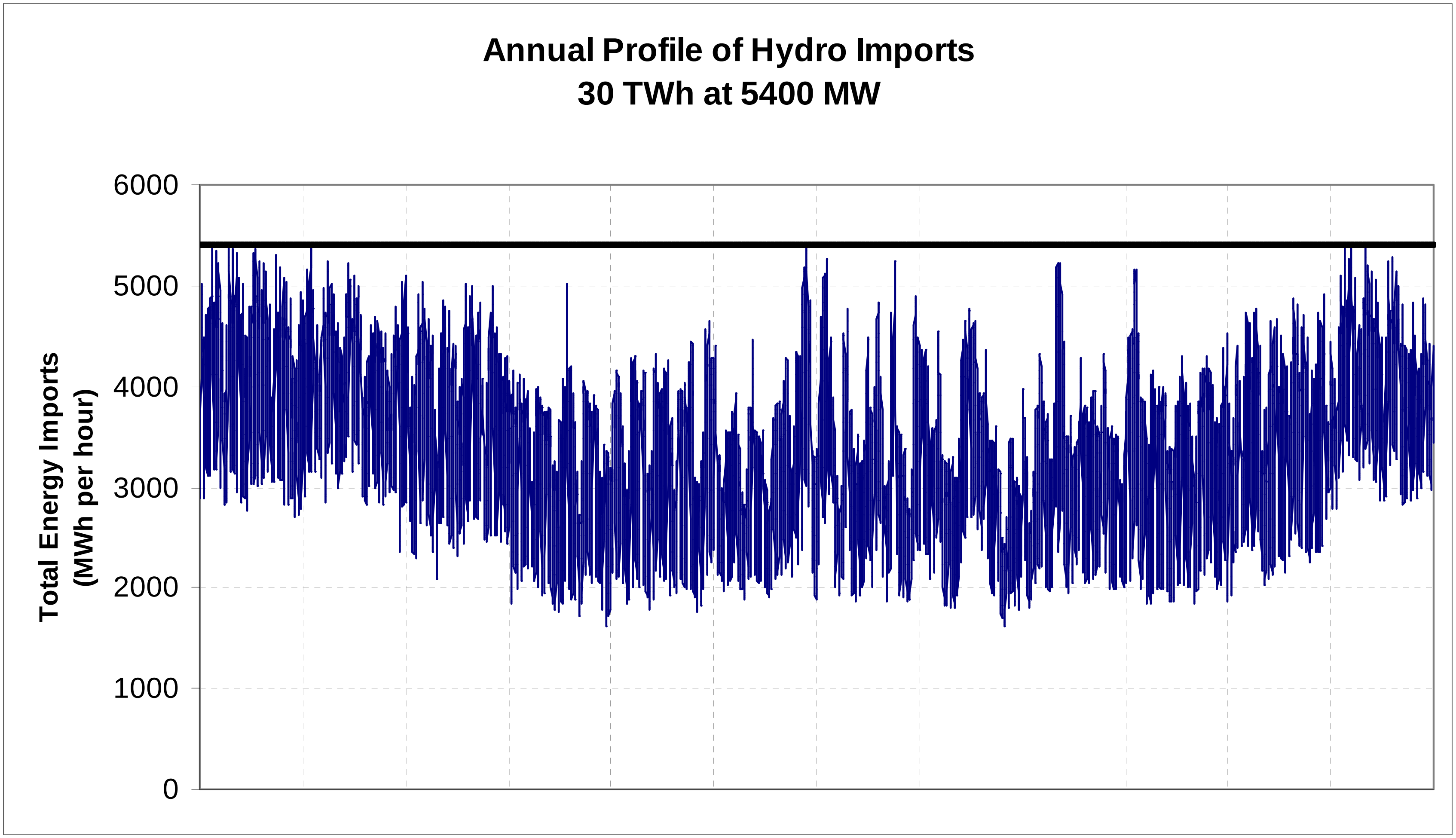
Average Winter Capacity Value: 0.0488

Annual Capacity Factor with 100 percent Mechanical Availability: 0.158

To Meet FCM Capacity More PV Nameplate Capacity is Required

- **PV FCM Qualified Capacity is 0.40 of Nameplate**
- **Nameplate needed is 1720 including effect of 98% availability**
- **PV annual capacity factor is 15.5 %**

30 TWh Hydro Import with Winter Energy Bias



Transmission and Distribution Assumptions

Assumptions for "Incremental" Transmission System for Supply Side Scenarios

- Assume Worcester (Millbury) is the geographic load center of NE
- Estimated cost range/mile from supply points to Millbury
- Source to Millbury
  - **Quebec/Labrador/New Brunswick to Millbury**
  - **Niagara to Utica / Utica to Millbury**
  - **Vt. Yankee, Pilgrim, Seabrook and Millstone Nuclear sites to Millbury**
  - **NW Maine Aroostook County to Millbury**
  - **Cape Cod to Millbury**
- Estimates are for 1,500 MW Capacity Lines
- DC and/or AC facilities (and costs) used as appropriate
- Based on 2007 Costs

Basic Assumptions - AC Lines

Line Cost/mile: 1,500 MW 345kV Line

US	$1.5-3.0 M per mile for lines	Plus $1.0 M per mile for sub-station cost
CAN	$1.0-2.0 M per mile for lines	

Route distance

	Queue, Coal and nuclear	Gas CC case	Hydro
High	average "as the crow flies" distance from Vt. Yankee, Seabrook, Pilgrim and Millstone to Millbury plus 20% for routing	10 miles per unit plus 20% for routing	To NY Border/to Utica/to Niagara To Canadian Border to Labrador/New Brunswick border to Pt. Lepreau
Low	5 miles per internal source unit plus 20% for routing	5 miles per unit plus 20% for routing	•To Canadian Border/To New Brunswick Border •To NY Border

Basic Assumptions - DC Lines (for Hydro / Import cases)

Line Cost/mile:
1,500 MW
450 kV Line

US	$1.5-3.0 M per mile for lines	Plus $250 M for each con- verter station
CAN	$1.0-2.0 M per mile for lines	Plus $250 M for each con- verter station

Route distance

High	Hydro •To NY Border/to Utica/to Niagara •To Canadian Border to Labrador
Low	•To Canadian Border •To NY Border

Number of Transmission Lines (1500 MW) Assumed for various cases

	# of lines
Each scenario adding 5400 MW of supply-side resources	4
Each retirement case (assuming 8900 MW total added, including replacement of retired capacity)	6
Each additional 3,500 MW EE/DR sensitivity case (for net 2,900 MW of scenario technology resources added)	2
Wind cases: • Off shore, given 20% qualified mw • On shore, given 20% qualified mw	 2 2

Range of Cost Estimates for Transmission Elements

	Scenarios – Incremental 8,000 MW Note: all cases have the same 2,600 MW of resources reflecting proposals in the ISO-NE Queue as of 9/30/06	Common Assumptions		Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)		Replace 2,700 MW of DR with 2,700 MW of EE[1]	Replace 2,700 MW of EE with 2,700 MW of DR[1]	Retire 3500 MW and replace with Scenario Technology		Decreased Imports of Low-Emission Resources (- 7 TWh)[1]	
		Total Low Mi & Low ($M)	Total High Mi & High ($M)	Total Low Mi & Low ($M)	Total High Mi & High ($M)			Total Low Mi & Low ($M)	Total High Mi & High ($M)	Total Low Mi & Low ($M)	Total High Mi & High ($M)
1	Mix of currently proposed resources (5400 MW blend reflecting the fuel mix exhibited recently by the market (i.e., "the Queue")	**61**	**1814**	**30**	**907**			**135**	**2721**	**61**	**1814**
2	Additional EE and DR with 2700 MW of DR and 2700 MW of EE	**0**	**0**	**0**	**0**	**X**	**X**	**0**	**0**	**0**	**0**
3	Nuclear – 5400 MW	**61**	**1814**	**30**	**907**			**135**	**2721**	**61**	**1814**
4	Advanced clean coal – 5400 MW Without Carbon Sequestration	**61**	**1814**	**30**	**907**			**135**	**2721**	**61**	**1814**
5	Natural Gas (Combined Cycle) – 5400 MW	**61**	**288**	**30**	**144**			**135**	**432**	**61**	**288**

Range of Cost Estimates for Transmission Elements

	Scenarios – Incremental 8,000 MW Note: all cases have the same 2,600 MW of resources reflecting proposals in the ISO-NE Queue as of 9/30/06	Common Assumptions		Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)		Replace 2,700 MW of DR with 2,700 MW of EE[1]	Replace 2,700 MW of EE with 2,700 MW of DR[1]	Retire 3500 MW and replace with Scenario Technology		Decreased Imports of Low-Emission Resources (- 7 TWh)[1]	
6	Renewables – 5,400 MW (including a combo of wind (on/off shore), hydro, biomass, landfill gas, Combined Heat and Power, fuel cells, Photo Voltaics 1/8 each)	581	3936	291	1968			871	5904	581	3936

Range of Cost Estimates for Transmission Elements

	Scenarios – Incremental 8,000 MW Note: all cases have the same 2,600 MW of resources reflecting proposals in the ISO-NE Queue as of 9/30/06	Common Assumptions		Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)		Replace 2,700 MW of DR with 2,700 MW of EE[1]	Replace 2,700 MW of EE with 2,700 MW of DR[1]	Retire 3500 MW and replace with Scenario Technology		Decreased Imports of Low-Emission Resources (- 7 TWh)[1]	
7	Increased Imports of Hydro and/or other Low Emission Resources (30 TWh of imports										
7a	Millbury- Canadian Border (AC)	**3060**	**7200**	**1530**	**3600**			**4590**	**10800**	**3060**	**7200**
7b	Millbury-Labrador (Source) (AC)	**3060**	**20400**	**1530**	**10200**			**4590**	**30600**	**3060**	**20400**
7c	Millbury- NY (Border) (AC)	**1040**	**2448**	**520**	**1224**			**1560**	**3672**	**1040**	**2448**
7d	Millbury- NY (Utica) (AC)	**1591**	**3744**	**796**	**1872**			**2387**	**5616**	**1591**	**3744**
7e	Millbury- NY (Niagara) (AC)	**3366**	**7920**	**1683**	**3960**			**5049**	**11880**	**3366**	**7920**
7f	Millbury - New Brunswick Border (AC)	**3794**	**8928**	**1897**	**4464**			**5691**	**13392**	**3794**	**8928**
7g	Millbury - St. Johns (AC)	**4406**	**10368**	**2203**	**5184**			**6609**	**15552**	**4406**	**10368**

Range of Cost Estimates for Transmission Elements

	Scenarios – Incremental 8,000 MW Note: all cases have the same 2,600 MW of resources reflecting proposals in the ISO-NE Queue as of 9/30/06	Common Assumptions		Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)		Replace 2,700 MW of DR with 2,700 MW of EE[1]	Replace 2,700 MW of EE with 2,700 MW of DR[1]	Retire 3500 MW and replace with Scenario Technology		Decreased Imports of Low-Emission Resources (- 7 TWh)[1]	
7	Increased Imports of Hydro and/or other Low Emission Resources (30 TWh of imports										
7a	Millbury- Canadian Border (DC)	**3860**	**8000**	**1930**	**4000**			**5790**	**12000**	**3860**	**8000**
7b	Millbury-Labrador (Source) (DC)	**5860**	**16930**	**2930**	**8465**			**8790**	**25395**	**5860**	**16930**
7c											
7d	Millbury- NY (Utica) (DC)	**2335**	**3080**	**1167**	**1540**			**3502**	**4620**	**2335**	**3080**
7e	Millbury- NY (Niagara) (DC)	**3414**	**6560**	**1707**	**3280**			**5121**	**9840**	**3414**	**6560**
7f	Millbury - New Brunswick Border (DC)	**0**	**0**	**0**	**0**			**0**	**0**	**0**	**0**
7g	Millbury - St. Johns (DC)	**0**	**0**	**0**	**0**			**0**	**0**	**0**	**0**

Method for Developing Distribution Cost Savings Due to EE and DR

- Estimate the distribution equipment capital investment savings over the 13-year period (2007-2020), assuming 5400 MW of EE and DR were added
  - Assume an average annual load reduction of 415 MW per year (5400MW / 13 years)
  - Develop a $ / MW value for distribution equipment investment
  - Estimate a low and high % of distribution equipment that would need to be installed, considering the lumpiness of equipment additions and the sensitivity of the load change to impact expansion plans
  - Multiply the (percentage) x ($ / MW cost) x (5400 MW) to calculate the estimated capital saved

Method for Developing Distribution Costs Savings due to EE and DR - Detail

- Estimated distribution capital cost required to serve 415 MW of load = $100K/MW
  - Based on a various distribution substation configurations (single transformer, dual transformer, addition of second transformer)
  - Increased by 10% to account for line equipment
- Estimated low & high percentage values were 20% & 60%, based on:
  - Estimate of 1500 - 2500 individual main line distribution circuits and 500- 1500 distribution substations in NE
  - Load reduction/ circuit would be only 0.2 MW if reduction spread equally over each circuit and 0.4 MW per substation
  - Not all growth in load requires distribution investment (e.g., if a circuit / distribution substation is 70 % loaded and load growth increased loading to 90%, no capital investment would be needed. If the circuit were loaded to 85% and load growth would increase loading to 105%, capital saving would be needed).
  - Independent of load growth, distribution investment would still be required for some situations, e.g.:
    - equipment needed for storm related damage
    - connecting new customers or serving fast growing areas
    - replacement of equipment that must be moved (road work)
    - replacing outdated equipment
    - additions required for power quality, protection and reliability issues
  - Distribution capital to meet the extreme summer and winter peak loading by circuit. All circuits do not peak at the time of the system peak so EE and DR would have to be controlled circuit by circuit.
- Calculated investment savings Range
  - $100K/MW x .2 x 5400MW ~ $100M
  - $100K/MW x .6 x 5400MW ~ $325M

Range of Distribution Credit Adjustments

		A		D		E	F	G		H		I	
	Scenarios – Incremental 8,000 MW Note: all cases have the same 2,600 MW of resources reflecting proposals in the ISO-NE Queue as of 10/31/06	Common Assumptions		Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)		Replace 2,700 MW of DR with 2,700 MW of EE[1]	Replace 2,700 MW of EE with 2,700 MW of DR[1]	Retire 3500 MW and replace with Scenario Technology		High Carbon Allowance Prices[1]		Low Carbon Allowance Prices[1]	
		Total Low ($M)	Tota l High ($M)	Total Low ($M)	Total High ($M)	Total Low ($M)	Total High ($M)	Total Low ($M)	Total High ($M)	Total Low ($M)	Total High ($M)	Total Low ($M)	Total High ($M)
1	Mix of currently proposed resources (5400 MW blend reflecting the fuel mix exhibited recently by the market (i.e., "the Queue")			**-65**	**-211**								
2	Additional EE and DR with 2700 MW of DR and 2700 MW of EE	**-100**	**-325**			**-100**	**-325**	**-165**	**-536**	**-100**	**-325**	**-100**	**-325**
3	Nuclear – 5400 MW			**-65**	**-211**								
4	Advanced clean coal – 5400 MW Without Carbon Sequestration			**-65**	**-211**								
5	Natural Gas (Combined Cycle) – 5400 MW			**-65**	**-211**								
6	Renewables – 5,400 MW (including a combo of wind (on/off shore), hydro, biomass, landfill gas, Combined Heat and Power, fuel cells, Photo Voltaics 1/8 each)			**-65**	**-211**								
7	Increased Imports of Hydro and/or other Low Emission Resources (30 TWh of imports			**-65**	**-211**								

SA Land Assumptions – Transmission

- **ISO and Transmission Owners developed low and high ROW estimates for transmission circuits and converted them to acres per mile**
  - Low: 82.5 feet = 9.9 acres per mile
  - High: 165 feet = 19.8 acres per mile
- **Developed low and high conceptual mileages for the different routes for the scenarios and assumed straight line distance plus 20%**
- **Multiplied miles times acres per mile times number of circuits for land requirements**

SA Land Assumptions – Transmission

Route	Low miles	High Miles	Scenarios using routes
Millbury to points within New England	6	76	Queue, Nuclear, IGCC
Connecting NGCC plants to grid	6	12	NGCC
On Shore Wind	6	240	Renewables
Off Shore Wind	108	108	Renewables
Imported Energy	300	372	Imports