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RELIABILITY ASSESSMENT
POWER MARKET COST/BENEFIT ASSESSMENT
OF
MAINE POWER CONNECTION 2012

Prepared for

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TABLE OF CONTENTS

EXECUTIVE SUMMARY 1

1.0 OBJECTIVE 7

2.0 SCOPE OF EVALUATION 8

3.0 RELIABILITY IMPACT OF THE MAINE POWER CONNECTION 2012 8

4.0 WHOLESALE MARKETS IMPACTS OF THE MPC2012 8

4.1 SOCIALIZED TRANSMISSION MODEL 8
4.2 MERCHANT TRANSMISSION MODEL 22

5.0 CONCLUSIONS 27

APPENDIX A - SOCIALIZED TRANSMISSION MODEL 29

COST BENEFIT ASSESSMENT 29

TRANSMISSION COST BENEFIT ASSESSMENT 29
WHOLESALE POWER SUPPLY MARKET COST BENEFIT 33

APPENDIX B - MERCHANT TRANSMISSION MODEL 38

COST BENEFIT ASSESSMENT 38

TRANSMISSION COST BENEFIT ASSESSMENT 38
WHOLESALE POWER SUPPLY MARKET COST BENEFIT 40

ATTACHMENTS – SOCIALIZED TRANSMISSION MODEL

Attachment 1: MPS Annual Transmission Cost Projection - Status Quo
Attachment 2: ISO-NE Annual Transmission Cost Projection – ISONE 2012 Regional System Plan (RSP) Case
Attachment 3: ISO-NE Annual Transmission Cost Projection – Renewable Portfolio Standards (RPS) Buildout Case
Attachment 4: MPS Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2012 Regional System Plan Case)
Attachment 5: MPS Annual Transmission Cost Projection - Joins ISO-NE (Renewable Portfolio Standards Buildout Case)
Attachment 6: EMEC Status Quo and Joins ISO-NE Annual Transmission Cost Projections (ISO-NE 2012 RSP and RPS Buildout Cases)
Attachment 7: ISO-NE MA Hub Forward Energy Price Projection
Attachment 8: Historical Regional Energy Prices
Attachment 9: NMISA Load and Generation Assumptions – North Region
Attachment 10: MPS Status Quo Power Supply Cost Projection – NMISA North
Attachment 11: MPS Joins ISO-NE Power Supply Cost Projection – NMISA North
Attachment 12: EMEC Status Quo and Joins ISONE Power Supply Cost Projection – NMISA South
Attachment 13: Summary – ISONE 2012 RSP Case Cost/Benefit Assessment
Attachment 14: Summary – RPS Buildout Case Cost/Benefit Assessment
Attachment 15: Summary – NE/Maine Buildout Case Cost/Benefit Assessment

ATTACHMENTS – MERCHANT TRANSMISSION MODEL

Attachment 1: MPS Annual Transmission Cost Projection - Status Quo
Attachment 16: MPS Annual Transmission Cost Projection – Merchant Line Interconnection with ISO-NE
Attachment 17: EMEC Status Quo and Merchant Line Transmission Cost Projection
Attachment 18: ISO-NE Annual Transmission Cost Projection – ISONE 2012 Regional System Plan (RSP) Case
Attachment 19: ISO-NE Annual Transmission Cost Projection – Renewable Portfolio Standards (RPS) Buildout Case
Attachment 20: MPS Status Quo Power Supply Cost Projection – Merchant Line – NMISA North - (ISO-NE 2012 RSP Case)
Attachment 21: MPS Status Quo Power Supply Cost Projection – Merchant Line – NMISA North - (RPS Buildout Case)
Attachment 22: EMEC Status Quo Wholesale Power Supply Cost Projection
Attachment 23: EMEC Merchant Transmission Line Power Supply Cost Projection – NMISA South (ISO-NE 2012 RSP Case and RPS Buildout Case)
Attachment 24: Summary – ISONE 2012 RSP Case Cost/Benefit Assessment
Attachment 25: Summary – RPS Buildout Case Cost/Benefit Assessment
Attachment 26: Summary – NE/Maine Buildout Case Cost/Benefit Assessment

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Report to the Northern Maine Independent System Operator Concerning the Maine Power Connection 2012 8/17/12

EXECUTIVE SUMMARY

Northeast Energy Solutions, LLC (NES) was retained by the Northern Maine Independent System Administrator (NMISA) to conduct a reliability assessment and wholesale power market economic assessment (pursuant to NMISA Market Rules 8 and 9) associated with (1) Maine Public Service Company's (MPS or Maine Public) 2010 proposal to interconnect the Northern Maine Transmission System (NMTS) and the New England Independent System Operator's (ISO-NE or ISO) bulk transmission system (ISO-NE Queue position #324) and (2) Emera Incorporated's (Emera) representations in recent regulatory proceedings that it intends to move forward interconnecting northern Maine to ISO-NE. The new interconnection is referred to in this report as the Maine Power Connection 2012 (MPC2012). This report entails a wholesale power market economic assessment of MPC2012 under (1) a traditional cost-based, socialized model related to cost recovery of the transmission interconnection via northern Maine joining ISO-NE and (2) a merchant transmission project model. A reliability assessment will be performed in the future.

The NMISA is a non-profit entity responsible for the independent administration of the NMTS and electric power markets in Aroostook and Washington counties, with a load of approximately 130 MW. The NMISA administers the wholesale power supply market in northern Maine and the transmission systems of the investor-owned and cooperatively-owned utilities in northern Maine, and its members also include all municipally-owned utilities, generators, suppliers of energy, and large retail customers operating in the control area. The NMISA control area includes two regions, North (comprising the transmission system of MPS) and South (comprising the transmission system of Eastern Maine Electric Cooperative or EMEC), each of which are interconnected only with New Brunswick Power.

In 2008 NES performed a reliability and wholesale power market economic assessment of an interconnection request of MPS, called the Maine Power Connection (MPC). The MPC involved the interconnection of a large wind generation project (Aroostook Wind Energy or AWE) to the NMTS and ISO-NE. A key assumption related to that new

interconnection was the completion of major new transmission facilities principally on the Central Maine Power (CMP) existing transmission system, the so-called Maine Power Reliability Project (MPRP).

The following table provides summary information concerning the MPC related projects:

Project	**Purpose**	**Estimated Capital Cost**	
		Excluding AFUDC	Including AFUDC
AWE	Power generation of 800 MW and 2,300,000 MWh per year.	N/A	$1.6 Billion
MPC	Interconnect AWE to NMTS and ISO-NE. NMTS becomes part of ISO-NE.	$625 Million	$725 Million
MPRP	Upgrade Southern Maine Transmission System. Stated purpose is to meet National Electric Reliability Council (NERC) reliability standards.	$1.55 Billion	$1.80 Billion

Given MPS was requesting NEPOOL membership and the inclusion of MPC in ISO-NE's Regional Network Service (RNS) (via a market efficiency upgrade), the 2008 assessment assumed a Socialized Transmission Model via northern Maine joining ISO-NE. In addition, in 2010 MPS publicly pursued MPC as a merchant transmission line. For this assessment, NES performed an evaluation of both (1) a traditional cost-based, socialized model related to cost recovery of the transmission interconnection via northern Maine joining ISO-NE [Socialized Transmission Model] and (2) a proposed merchant transmission project [Merchant Transmission Model].

This assessment incorporates significant changes from the prior study, including (1) smaller (450 MW vs 800 MW) wind generation projects: (2) updated information concerning ISO-NE transmission plans and related costs; (3) updated information concerning MPS transmission plans and related costs; (4) significant changes in power market energy price futures due to lower natural gas prices and the economy; (5) updated information concerning NMISA wholesale power market load serving costs, including but not limited to ancillary costs; (6) updated information concerning ISO-NE wholesale power market load serving costs, including but not limited to ancillary costs; and (7) updated administrative costs for NMISA and ISO-NE.

MPC2012 is assumed to interconnect two wind generation projects, a 300 MW project located in or around Bridgewater, Maine (Bridgewater Wind or BW) and a 150 MW project located in or around Oakfield, Maine (Oakfield Wind or OW), to the NMTS and ISO-NE. CMP's MPRP was approved and is included in ISO-NE's 2011 Regional System Plan (RSP), received its Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (MPUC) and is currently under construction with expected completion in 2015.

The following table provides summary information concerning the MPC2012 related projects:

Project	**Purpose**	**Estimated Capital Cost**	
		Excluding AFUDC	Including AFUDC
MPC2012	Interconnect BW and OW to NMTS and ISO-NE.	$300 Million	$348 Million

In an effort to make it easier for northern Maine stakeholders to compare the analyses and results of the current assessment to the one performed in 2008, NES has attempted to maintain, to the extent possible, the format presented in the MPC reliability assessment and wholesale power market economic assessment report, dated November 12, 2008.

The following are NES' key findings from this assessment of power market economics on the NMTS and its customers related to the MPC2012:

Either a socialized transmission line interconnecting NMTS to ISO-NE whereby MPS, and possibly EMEC, becoming participants of ISO-NE or a merchant transmission line interconnecting the NMTS to ISO-NE will likely have significant adverse cost implications for northern Maine consumers. This analysis evaluates those cost implications employing data publicly available from, among others, ISO-NE, NMISA, and New Brunswick System Operator (NBSO). One purported purpose of MPC2012 is to deliver the wind capacity, energy, and renewable attributes to New England load principally south of Maine, which obviously requires delivery into ISO-NE. However, in order for power supply attributes to reach load south of Maine additional transmission upgrades in ISO-NE beyond the MPRP and MPC2012 may be necessary.

Socialized Transmission Model

1. If MPS and EMEC become ISO-NE participants, NES projects there will be a significant cost shift for northern Maine consumers (i.e., a cost increase for NMTS customers). This cost shift will occur as a result of substantial transmission-related and wholesale power-related cost increases.

2. The transmission-related cost shift will occur as a result of two distinct but inter-related factors: (a) the socialization of transmission costs across all ISO-NE customer load and (b) the significant capital additions planned for the ISO-NE transmission grid which will be socialized and recovered through ISO-NE's regional transmission rate structure. As discussed in detail below, the impact of these two transmission-related cost shifts (which account for 59% to 85% of the total projected cost shift) is readily estimated from information publicly available.

   Socialization of transmission costs. ISO-NE has a single regional network service ("RNS") rate applicable to all ISO-NE transmission customers. In simple terms, the revenue requirements of each ISO-NE transmission owner is included in a single

melded RNS revenue requirement, which has the effect of increasing the transmission rates for transmission customers of relatively low cost transmission providers and reducing the rates for transmission customers of relatively higher cost transmission providers. MPS is a low-cost transmission provider and NMTS customer transmission costs are expected to be much lower than average ISO-NE transmission costs. The mere inclusion of MPS in ISO-NE and replacement of its OATT transmission rates with the ISO-NE RNS rate will increase transmission costs to northern Maine transmission customers by at least $8.7 million (about a 138% rate increase in transmission and 21% increase in combined T&D rates) in 2015 and most likely significantly more over time as more ISO-NE transmission is added.

ISO-NE capital additions to transmission grid. The regional nature of the ISO-NE RNS rate means that any capital additions to the regional transmission grids will have an impact on the rates paid by all RNS customers. If MPS becomes part of ISO-NE, transmission additions in, for example, Connecticut or Massachusetts will increase the transmission costs of northern Maine transmission customers.

NES modeled three scenarios to estimate the possible transmission costs shifts.

The first case assumed the latest ISO-NE 2012 Regional System Plan (RSP): ISO-NE August 2012 Five Year Regional Network Service (RNS) Forecast plus MPC2012 ($348 million of MPC2012 included in ISO-NE RNS). The cost of the RSP build out is estimated at $7.0 billion for this case.

The second case assumed the ISO-NE Renewable Portfolio Standards (RPS) build out Case: ISO-NE 2012 RSP Case plus additional transmission build out to accommodate renewable generation to meet mandated or proposed Renewable Portfolio Standards (RPS) in New England. The assumed cost of the RPS transmission build out was $23 billion, the midpoint of the $10 billion to $36 billion cost range estimated in the February 2010 New England 2030 Power System Study, performed by ISO-NE.

The third case assumed a future reliability transmission build out in the rest of New England of about $10 billion incremental to the ISO-NE 2012 RSP Case (starting in 2002 when ISO-NE's transmission investment totaled about $2 billion; $22 billion plus $2 billion less investments completed and planned through 2016), which is proportional to Maine's reliability related transmission investments of about $1.8 billion (Maine Power Reliability Project (MPRP), Northeast Reliability Interconnection (NRI), Downeast Reliability Project (DRP), Hancock Reliability Project (HRP), Keene Road, Line 64 Rebuild, etc.).

NES estimates the transmission cost shift to northern Maine consumers to be between $185 million (RSP Case) and $697 million (RPS Case) over a 20 year period. The annual average transmission cost shift is between $9.2 million and $34.8 million (or 1.2 cents/kwh and 4.4 cents per kwh) per year over the 20 years.

This represents an average transmission rate increase between 118% and 445% over the 20 year period. For the reasons discussed in the body of the report, NES believes the cost shift will very likely be in the upper end of the cost shift range.

In addition, even if the RPS transmission build out does not entirely occur, it is very likely that additional ISO-NE transmission investment associated with additional reliability transmission projects in other New England states that have not yet been identified, brought forth, and/or approved will in fact occur. In NES Case 3 , there would be an additional $10 billion of transmission investment in ISO-NE, in which case additional transmission cost shift would occur (**in addition to the RSP Case**) to northern Maine of $222 million (or 1.4 cents/kwh) over 20 years or $11.1 million per year.

3. If MPS and EMEC become part of ISO-NE, then wholesale power supply costs for NMISA load serving participants will also likely increase compared to the status quo. This is because the current cost of wholesale and retail power in northern Maine reflects both the lower net value of power produced in that area, as well as the fact that the area generation supply includes substantial lower cost renewable resources, as well as hydro, nuclear, and coal supplies from the Maritimes (New Brunswick, Prince Edward Island, and Nova Scotia) and Quebec, whereas the supply price in ISO-NE is principally driven by higher cost oil and natural gas-fired generation. Furthermore, NMISA is located in the New Brunswick Control Area, which has historically had, and is expected to continue to have, surplus lower cost power supply to serve load in the region. The wholesale energy prices in New Brunswick have been approximately 15.1% lower than ISO-NE's Maine Zone for the 9 year period (March 2003-February 2012). [Note that the wholesale energy prices in New Brunswick include reliability related out-of-merit dispatch whereas the reliability related charges in ISO-NE are recovered separate from the hourly energy LMP. Therefore, the wholesale energy prices in New Brunswick have really historically been even lower than the 15.1% discussed above. In addition, the return to service of Pt. LePreau in 2012 is likely to further benefit New Brunswick wholesale prices]. Assuming the generation in northern Maine continues to be available and historical cost dynamics continues, NES projects that joining ISO-NE will cause wholesale power supply costs to increase for NMISA participants by $127 million (or 0.8 cents/kwh) over a 20 year period, or an average of $6.4 million per year.

Merchant Transmission Model

1. If, as an alternative to being constructed as a socialized transmission line, MPC2012 is constructed as a merchant transmission line and interconnects the NMTS to ISO-NE, NES projects there will also likely be a significant overall cost shift for northern Maine consumers (i.e., a cost increase for NMTS customers).

2. A transmission cost reduction for NMTS customers will likely occur, principally as a result of additional transmission revenue credits in MPS' annual transmission rate due to likely exports of existing generation to higher valued ISO-NE markets.

   NES estimates the transmission cost reduction to northern Maine consumers to be $15.3 million over a 20 year period. The annual average transmission cost reduction is $0.8 million (or 0.1 cents/kwh) per year over the 20 years.

3. However, northern Maine consumers will pay all or a portion of ISO-NE's transmission rate and MPC2012's transmission rate in their wholesale power supply cost, which is significantly more than the reduction in MPS' local transmission cost. If a merchant transmission line interconnects ISO-NE with the NMTS, then wholesale power supply costs for NMISA load serving participants will likely significantly increase compared to the status quo. The current cost of wholesale power in the northern Maine reflects both the lower net value of power produced in that area, as well as the fact that the area generation supply includes substantial lower cost renewable resources, as well as hydro, nuclear, and coal supplies from the Maritimes and Quebec. In contrast, the supply price in ISO-NE is principally driven by higher cost oil and natural gas-fired generation.

   Furthermore, NMISA is located in the New Brunswick Control Area, which has historically had, and is expected to continue to have, surplus lower cost power supply to serve load in the region. The local generation in northern Maine would likely utilize the merchant line to reach the higher cost ISO-NE market.

   Given the existing lower cost local NMISA generation has historically served northern Maine load and would no longer be available, the power supply would need to be replaced. The merchant line nodal interconnection with ISO-NE would become the new liquid price source for serving northern Maine load. The price would include energy, capacity, and all ISO-NE export related fees, including ISO-NE transmission outservice. The price would also include all or a portion of the MPC2012 transmission rate/cost. As discussed in more detail in this report, given the significant planned transmission build out and the likelihood for even more transmission additions, the ISO-NE transmission out service rates are going to increase significantly in the future. Thus, power supply prices for northern Maine will increase significantly.

   NES estimates the wholesale power supply cost shift to northern Maine consumers to be between $308 million (2012 RSP Case) and $617 million (RPS Buildout Case) over a 20 year period. The annual wholesale power supply cost shift is between $15.4 million and $30.8 million (or 1.9 cents/kwh and 3.9 cents per kwh) per year over the 20 years. For the reasons discussed in the body of the report, NES believes the cost shift will very likely be in the upper end of the cost shift range.

   In addition, as with the Socialized Transmission Model, even if the RPS transmission build out does not occur, it is very likely that additional ISO-NE

transmission investment associated with additional reliability transmission projects in other New England states that have not yet been identified, brought forth, and/or approved will in fact occur. As with the Socialized Model, there would be an additional $10 billion of transmission investment in ISO-NE, in which case an additional wholesale power supply cost shift would occur **(in addition to the 2012 RSP Case)** to northern Maine of $133.9 million (or 0.8 cents/kwh) over 20 years or $6.7 million per year.

Additional Consideration

In order for northern Maine to interconnect with ISO-NE while avoiding a significant cost and rate increase, the near certain significant transmission cost shifts described above (1.2 cents/kwh to 4.4 cents/kwh, excluding the potential incremental increase outlined in Case 3) would have to be offset by wholesale power cost reductions of the same amount. This would require ISO-NE wholesale cost reductions of about 15% to 60% (over the 20 year period) relative to northern Maine, a substantial change from the past when ISO-NE wholesale energy costs have been on the order of 15% higher.

NES believes that there are alternatives available that would insulate NMISA participants from such potential cost shifts while also allowing new wind generation projects to proceed. As mentioned in NES' 2008 report, one approach would be for the new wind generation projects, such as BW or OW, to directly connect to ISO-NE as a generation lead but not interconnect with the NMTS. Under this approach NMTS customers will avoid the expected transmission and power supply cost shift, but preserve a relatively low cost option to directly interconnect with ISO-NE in the future if and when it becomes economically desirable. Even if the wind generation projects do not proceed, in the future the NMTS could still interconnect to ISO-NE directly with a smaller and low cost interconnection as has been studied in the past, and such interconnection cost would likely qualify for socialization in ISO-NE.

1.0 Objective

This report was prepared by NES at the request of the NMISA to support its evaluation of the impact on its wholesale electric market of the proposed MPC2012. In addition to providing an interconnection for wind generation projects to deliver their output to ISO-NE, the MPC2012 also provides a new interconnection to the NMTS at the Mullen substation in Houlton.

A detailed analysis was undertaken of transmission and wholesale electricity market costs of northern Maine under (1) a traditional cost-based, socialized model related to cost recovery of the transmission interconnection via northern Maine joining ISO-NE and (2) a merchant transmission project, compared to the status quo.

2.0 Scope of Evaluation

In accordance with NMISA Market Rule 8, the NMISA is required to conduct an assessment to determine whether a proposed connection of a new facility, such as the MPC2012, may (1) have an adverse impact on reliability of the NMTS; (2) create additional congestion by causing the NMTS to operate at or close to normal operating limits; or (3) provide reliability benefits to the NMTS. Further, in cases where the proposed connection is to become part of the NMTS, the ISA may perform a cost-benefit study of the proposed connection.

In addition, under Market Rule 9, the ISA shall coordinate system planning and development responsibilities to ensure the adequacy and reliability of the NMTS and efficient operation of the northern Maine market.

The scope of this evaluation was intended to be at a high-level in order to identify significant issues and questions that should be highlighted for the NMISA as part of its responsibility to review the reliability and economic impacts related to the MPC2012 under its Market Rules 8 and 9. **This assessment does not include an evaluation of the reliability impact of MPC2012. The evaluation of the reliability impact of MPC2012 is expected to be performed in the future, at which time the reliability assessment will supplement this report.**

This evaluation includes an independent analysis of the potential impact of the MPC2012 on the northern Maine wholesale electricity markets and transmission costs. The evaluation includes an analysis of this impact on both the Northern Region (MPS, Houlton Water Company, Van Buren Power and Light and a small portion of Eastern Maine Electric Cooperative all located in Aroostook County) and the Southern Region (the balance of Eastern Maine Electric Cooperative located in Washington County, electrically isolated from the Northern Region by New Brunswick Power) of the NMISA control area.

3.0 Reliability Impact of the Maine Power Connection 2012

Anticipated to be part of a future supplement to this report. Refer to NES' November 12, 2008 report for an overview of MPC reliability impact issues.

4.0 Wholesale Markets Impacts of the MPC2012

4.1 Socialized Transmission Model

The 2010 merger proceeding between Emera (or BHE Holdings) and MPS and Emera's investment in First Wind proceeding has brought MPC2012 to higher visibility in terms of the potential transmission cost shift MPC2012 would impose on northern Maine ratepayers. The analysis detailed in this section is intended to provide

an estimate of the magnitude of this increased cost under a Socialized Transmission Model.

As described in detail in Appendix A to this report, NES has evaluated the effect of the MPC2012 on the northern Maine power markets, both in terms of the impact on transmission costs and wholesale power supply costs. The fundamental assumption under the Socialized Transmission Model is the MPC2012 interconnection (NMTS to ISO-NE) project being pursued by MPS will result in northern Maine joining ISO-NE. NES' evaluation assumes $300 million (plus AFUDC) of MPC2012 costs (two 345kv transmission lines-evidently impacted by harmonics problems identified in past system studies- from Houlton to Haynesville with terminal equipment) and 76.9% of MPS' current and future (non-MPC2012) costs are included in ISO-NE's regional transmission service tariff.

The cost shift of transmission and wholesale power supply is more fully described in Sections 4.1.1 through 4.1.7 below and in Appendix A.

4.1.1 The transmission costs are related to the costs of transmission which Maine Public Service and other NMISA T&D utilities will need to recover from customers if northern Maine joins ISO-NE. As previously noted, under the ISO-NE transmission cost recovery mechanism the costs of all Pool Transmission Facilities (PTF) (as defined by ISO-NE) are socialized and recovered from all ISO-NE network load serving entities (T&Ds). To the extent that average ISO-NE transmission costs exceed what the costs would be for a T&D utility in northern Maine on a stand-alone basis, a transmission cost shift penalty would be incurred as a result of joining ISO-NE. As demonstrated in Appendix A, the calculation of the transmission-related cost shift requires little more than the current and projected transmission costs of the ISO-NE and NMTS systems.

4.1.2. As explained more fully in Appendix A, unless a special adjustment is made to the normal treatment of PTF cost recovery, the transmission costs of load in the northern Maine market will increase significantly if Maine Public Service and other northern Maine T&D utilities join ISO-NE. This is because the current expected transmission costs of ISO-NE will increase dramatically under the approved ISO-NE 2011 regional system plan (ISO-NE 2011 RSP) and other proposed future transmission additions in New England. For example, the following table shows the historical increase in the ISO-NE regional network service rate, effective 6/1/12, from $14.25/kw/yr (in 1997) to $75.25/kw/yr (approximately a 428% increase) is an indication of the magnitude of transmission additions already completed (379 projects and $5.0 billion from 2002 through 2011):

Historical
ISO-NE RNS Transmission Cost

Year	RNS Rate $/kw/yr	Change %
1997	14.25	
1998	15.57	9.3%
1999	15.36	-1.3%
2000	14.88	-3.1%
2001	14.86	-0.1%
2002	15.14	1.9%
2003	15.60	3.0%
2004	16.82	7.8%
2005	18.88	12.2%
2006	25.77	36.5%
2007	27.91	8.3%
2008	43.76	56.8%
2009	59.95	37.0%
2010	64.83	8.1%
2011	63.87	-1.5%
2012	75.25	17.8%
Annual 2002-2012		17.4%

Under ISO-NE's 2011 RSP and August 2012 Five Year Regional Network Service (RNS) Forecast, it is apparent significant approved transmission additions/projects (approximately another $6.6 billion), the RNS rate will increase substantially more in the next few years. These projects include the Maine Power Reliability Project (MPRP), New England East-West Solutions Intrastate Project (MA, CT, RI), Vermont Reliability Projects, New Hampshire Reliability Projects, Lower SEMA Upgrades, and others. Many other projects are also under study (and not yet included in the ISO-NE RSP), such as the long-term reliability needs assessment for Greater Boston, The Eastern REMVEC Study, and many others internal to ISO-NE transmission. In addition, ISO-NE recently completed a study, New England 2030 Power System Study (dated February 2010), concluding that to meet future Renewable Portfolio Standards (RPS), as currently mandated/proposed, in New England (ISO-NE 2010 Regional Electricity Outlook indicates a 30% standard by 2020), significant additional transmission investment (between $10 billion and $36 billion) will be required to accommodate the renewable projects. The resulting transmission costs associated with these build outs in ISO-NE far exceed the expected transmission costs of Maine Public Service and Eastern Maine Electric Cooperative (EMEC) on a stand-alone/status quo basis.

The following table summarizes the transmission costs under the ISO-NE 2012 RSP Case (ISO-NE's August 2012 Five Year RNS Forecast, and $348 million of MPC2012 are included in RNS):

TABLE 1

PROJECTED TRANSMISSION COSTS
MPS Staus Quo - Socialized Transmission Line
(ISO-NE 2012 RSP Case, MPS/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2015	57.04	133.07	102.5	7,793	39.03	112.06	12.7	927	8,720
2016	60.61	144.27	103.0	8,617	39.29	122.08	12.8	1,057	9,673
2017	67.91	145.90	103.5	8,074	39.56	121.65	12.8	1,053	9,126
2018	66.82	145.83	104.0	8,220	39.82	121.19	12.9	1,049	9,268
2019	67.26	145.55	104.6	8,186	40.09	120.74	13.0	1,045	9,230
2020	67.27	145.28	105.1	8,198	40.37	120.29	13.0	1,041	9,238
2021	67.42	145.04	105.6	8,197	40.64	119.85	13.1	1,036	9,234
2022	67.54	144.80	106.1	8,201	40.92	119.42	13.1	1,032	9,233
2023	67.68	144.58	106.7	8,203	41.21	118.99	13.2	1,028	9,231
2024	67.83	144.38	107.2	8,207	41.49	118.57	13.3	1,024	9,230
2025	67.99	144.19	107.7	8,210	41.78	118.16	13.3	1,019	9,230
2026	68.16	144.02	108.3	8,214	42.08	117.75	13.4	1,015	9,229
2027	68.34	143.87	108.8	8,219	42.37	117.35	13.5	1,011	9,230
2028	68.54	143.74	109.4	8,224	42.67	116.95	13.5	1,006	9,230
2029	68.75	143.58	109.9	8,225	42.98	116.53	13.6	1,002	9,227
2030	68.97	143.48	110.5	8,231	43.29	116.15	13.7	997	9,228
2031	69.20	143.40	111.0	8,237	43.60	115.78	13.8	993	9,229
2032	69.45	143.33	111.6	8,243	43.91	115.42	13.8	988	9,231
2033	69.71	143.29	112.1	8,250	44.23	115.06	13.9	984	9,234
2034	69.98	143.27	112.7	8,257	44.56	114.71	14.0	979	9,237
Total (2015-19)				40,889				5,130	46,019
Total (2015-24)				81,895				10,291	92,186
Total (2015-29)				122,986				15,344	138,331
Total (2015-34)				164,204				20,286	184,490
Annual Avg				8,210				1,014	9,224

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated at $185 million over 20 years or approximately $9.2 million per year (or 1.2 cents/kwh).

As previously mentioned, at the request of the New England governors, ISO-NE conducted a study to determine the necessary transmission investment to interconnect the amount of renewable generation necessary to meet future RPS targets. ISO-NE performed the study and issued its findings in February 2010 in the report titled, New England 2030 Power System Study. ISO-NE determined "New England could support the integration of approximately 8,500 MW of low carbon resources through a combination of offshore and inland wind in New England (5,500 MW) and expanded transmission interconnections with Québec (1,500 MW) and New Brunswick (1,500 MW), for an estimated cost of approximately $10 billion of new Transmission facilities in New England." In addition, the study concluded "The analysis of transmission development required to support the integration of New England wind resources indicates that focusing on offshore wind resource integration results is the most cost effective use of new and existing transmission. This transmission configuration also allows for the integration of some near-shore inland wind resources." By pursuing renewable generation in more remote locations, ISO-NE estimated the cost of new

transmission investment could be as high as $36 billion to meet the RPS target of 30%. To date, essentially 100% of wind generation additions have occurred at remote inland locations and off-shore developments are yet to demonstrate commercial viability.

The following table summarizes the transmission costs under the Renewable Portfolio Standards (RPS) Build out Case (includes the ISO-NE 2012 RSP Case and $23 billion (2009$) (midpoint of ISO-NE estimated cost range) of additional transmission necessary to accommodate the renewable generation projects to meet future RPS levels, are included in RNS):

TABLE 2

PROJECTED TRANSMISSION COSTS
MPS Staus Quo - Socialized Transmission Line
(RPS Buildout Case, MPS/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2015	57.04	172.64	102.5	11,848	39.03	151.82	12.7	1,432	13,280
2016	60.61	223.95	103.0	16,825	39.29	202.16	12.8	2,078	18,903
2017	67.91	266.62	103.5	20,571	39.56	242.97	12.8	2,609	23,180
2018	66.82	308.41	104.0	25,135	39.82	284.59	12.9	3,155	28,290
2019	67.26	350.85	104.6	29,651	40.09	327.06	13.0	3,717	33,369
2020	67.27	394.17	105.1	34,351	40.37	370.42	13.0	4,297	38,648
2021	67.42	392.68	105.6	34,350	40.64	368.73	13.1	4,293	38,643
2022	67.54	391.21	106.1	34,354	40.92	367.06	13.1	4,289	38,642
2023	67.68	389.77	106.7	34,356	41.21	365.40	13.2	4,284	38,641
2024	67.83	388.35	107.2	34,360	41.49	363.75	13.3	4,280	38,640
2025	67.99	386.95	107.7	34,363	41.78	362.12	13.3	4,276	38,639
2026	68.16	385.57	108.3	34,367	42.08	360.50	13.4	4,271	38,639
2027	68.34	384.21	108.8	34,372	42.37	358.89	13.5	4,267	38,639
2028	68.54	382.88	109.4	34,376	42.67	357.30	13.5	4,263	38,639
2029	68.75	381.54	109.9	34,378	42.98	355.72	13.6	4,258	38,636
2030	68.97	380.25	110.5	34,383	43.29	354.15	13.7	4,254	38,637
2031	69.20	378.99	111.0	34,389	43.60	352.59	13.8	4,250	38,639
2032	69.45	377.76	111.6	34,396	43.91	351.05	13.8	4,245	38,641
2033	69.71	376.55	112.1	34,403	44.23	349.52	13.9	4,241	38,644
2034	69.98	375.36	112.7	34,410	44.56	348.01	14.0	4,236	38,647
Total (2015-19)				104,029				12,992	117,022
Total (2015-24)				275,800				34,435	310,234
Total (2015-29)				447,656				55,770	503,426
Total (2015-34)				619,638				76,996	696,634
Annual Avg				30,982				3,850	34,832

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated at $697 million over 20 years or approximately $34.8 million per year (or 4.4 cents/kwh).

As previously noted, there is a substantial amount of planned and proposed new transmission additions in the rest of New England, which have yet to be approved by ISO-NE. With the socialization of the transmission costs in New England, basically each utility (or State) will pay their percentage of the ISO-NE coincident peak load for the transmission projects undertaken by the utility (or State). Without evaluating in detail the future behavior of all other utilities (or States),

one may conclude this is a good outcome for Maine customers. Maine's estimated percentage of ISO-NE coincident peak load is about 8.2 percent, therefore Maine will only pay for 8.2 percent of all its RNS qualified transmission costs in Maine and the rest of New England will pay the remaining 91.8 percent. Maine will, however, also be required to pay 8.2 percent of the cost of ***all*** RNS-qualified transmission investment throughout the rest of New England. As noted above, that can be a very large dollar figure and the customer base in northern Maine over which to spread such costs is extremely limited.

Moreover, to make a more realistic assessment one must evaluate the likely motivations of all the other utilities (or States) in ISO-NE, as well as the magnitude of potential projects in the other States. The following table shows the estimated coincident peak percentage of each ISO-NE State:

New England
Avg Network Peak Load
2011

	MW	%
Vermont	821	4.1%
Rhode Island	1,454	7.2%
Maine	1,657	8.2%
New Hampshire	1,832	9.1%
Connecticut	5,130	25.4%
Massachusetts	9,284	46.0%
Total	20,178	100.0%

Note: Maine Does Not Include MPS and EMEC.

As shown by the table, each State (or Utility in the State) only pays a portion (46.0% or less) of the cost of transmission in their State and therefore will have the motivation to overbuild the transmission system in their State (or Utility Service Territory). In Vermont's case, they only pay 4.1% of the cost of RNS qualified projects in their state. The rest of New England pays the remaining 95.9%. In Massachusetts' case, they only pay 46.0% of the cost of RNS qualified projects in their state. The rest of New England pays the remaining 54.0%. In addition, each utility will pay the ISO-NE RNS rate (regional average cost) and if that utility has actual costs less than the RNS rate they will pay the costs (i.e. subsidize) of the other utilities' transmission projects. The utilities with lower transmission costs will have even more incentive to build out their transmission system (to at least the regional average or RNS rate). Therefore, given this transmission cost payment method there is clearly an incentive for each utility (or State) to build out its transmission system on at least the same proportional basis as the ISO-NE 2012 RSP Case summarized in Table 1 [i.e. Maine buildout (MPRP/NRI/DRP/MPC…) divided by Maine's Percentage of Peak Load]. As

evidence of the likelihood of substantial more build out throughout New England, from the time RSP07 was approved (fall 2007) through February 2008 an additional $2.6 billion of transmission was approved and from the time RSP11 was approved (fall 2011) through March 2012 an additional $1.4 billion was identified/approved.

Assuming the rest of New England States build out transmission proportional to Maine's RNS transmission buildout (approximately $1.8 billion)(in addition to the ISO-NE 2012 RSP Case assumptions above), NMISA load would pay ***an additional*** $222 million over 20 years or $11.1 million per year (or 1.4 cents per kwh) in transmission cost shift from joining ISO-NE.

4.1.3. There will also likely be a cost shift related to wholesale power supply costs for northern Maine if Maine Public and other participants in the NMISA join ISO-NE. This cost shift occurs because (1) of the existence of costs which are incurred by power suppliers in moving capacity and energy from NMISA to ISO-NE, (2) the generation system in the Maritimes is typically and historically a lower cost system than ISO-NE, (3) the cost of ancillary products are higher in ISO-NE compared to NMISA, (4) there are wholesale load serving costs in ISO-NE that are not applicable in NMISA, and (5) the administrative funding costs of ISO-NE/NEPOOL are greater than NMISA. Appendix A provides a detailed estimate of the cost shift that could occur in wholesale power supply costs should Maine Public and other NMISA participants join ISO-NE.

This cost difference between the Maritimes and ISO-NE has been evident since restructuring in Maine was implemented. Supply contracts for standard offer service for each utility (MPS, Houlton Water Company, EMEC, and Van Buren Light & Power) in northern Maine and southern Maine (Bangor Hydro Electric Company or BHE, Central Maine Power Company or CMP) have frequently been executed at different times and for different durations. Therefore, one must either (1) take a long-term comparison of the standard offer service rates to obtain a reasonable representation of the price comparisons between northern Maine and southern Maine (weighted average of BHE/CMP), as shown below, or (2) compare northern Maine and southern Maine SOS prices during periods of time when RFPs and final bid prices for each region were conducted during relatively the same time, also shown below.

The following summarizes the standard offer rates over the long-term, which have been generally higher in southern Maine (BHE and CMP) compared to northern Maine.

Northern Maine vs Southern Maine (BHE/CMP in ISO-NE)
Standard Offer Service Rates
(estimated[1&2])

	Northern Maine[1] $/MWh	Southern Maine[2] $/MWh	Difference $/MWh	Difference %
2003[3]	$59.57	$54.18	$5.40	10%
2004	57.62	56.39	1.23	2%
2005	57.32	69.57	(12.25)	-18%
2006	57.34	89.94	(32.60)	-36%
2007	78.00	90.49	(12.49)	-14%
2008	86.85	101.70	(14.85)	-15%
2009	88.07	87.11	0.96	1%
2010	87.50	81.07	6.43	8%
2011	79.03	77.52	1.51	2%
2012[4]	77.45	86.46	(9.01)	-10%
Average	$72.70	$79.26	($6.56)	-8.3%

Notes: 1) Weighted rate for each customer class and Northern Maine Utilitiy (MPS, HWC,EMEC,VB).
2) Weighted rate for each customer class and Southern Maine Utility (CMP&BHE)
3) March through December.
4) January through February.

As shown above, for the nine year period from March 2003 (beginning of ISO-NE's Standard Market Design) through February 2012 the average cost for retail standard offer service (weighted all classes) has been approximately 8.3% (or $6.56/MWh) less in northern Maine (NMISA North and South Regions) than in southern Maine (Bangor Hydro-Electric Company and Central Maine Power Company, ISO-NE participants).

In addition, the following table summarizes the results of small class SOS RFPs that were conducted during similar timeframes in southern and northern Maine:

Northern Maine vs Southern Maine (BHE/CMP in ISO-NE)
Small Class Standard Offer Service Rates
(comparable final bid dates)

Utility	Final Bid Date				Awarded Average $/MWh	Difference
EMEC	October 30, 2007	91.500			91.500	-7.0%
BHE	January 24, 2008	99.624				
CMP	January 24, 2008	98.194				
BHE/CMP	Weighted	98.425			98.425	
		Mar 08-Mar 09				
HWC	October 30, 2007	86.020			86.020	-12.6%
BHE	January 24, 2008	99.624				
CMP	January 24, 2008	98.194				
BHE/CMP	Weighted	98.425			98.425	
		Apr 10-Mar 11	Apr 11-Mar 12	Apr 12-Mar 13		
EMEC	October 27, 2009	73.540	75.870	78.090	75.833	-11.7%
BHE	September 29, 2009	78.950	82.540	82.860		
CMP	September 29, 2009	82.930	88.150	89.200		
BHE/CMP	Weighted	82.288	87.244	88.177	85.903	
		Apr 10-Mar 11	Apr 11-Mar 12	Apr 12-Mar 13		
HWC	October 27, 2009	79.400	79.400	79.400	79.400	-7.6%
BHE	September 29, 2009	78.950	82.540	82.860		
CMP	September 29, 2009	82.930	88.150	89.200		
BHE/CMP	Weighted	82.288	87.244	88.177	85.903	
		Mar 07-Feb 08	Mar 08-Feb 09			
MPS	December 18, 2006	81.630	85.310		83.470	-10.6%
BHE	January 9, 2007	91.251	95.586			
CMP	January 9, 2007	91.303	95.503			
BHE/CMP	Weighted	91.295	95.516		93.406	
		Mar 09-Feb 10	Mar 10-Feb 11			
MPS	January 12, 2009	83.333	86.250		84.792	-6.4%
BHE	January 12, 2009	89.860	92.500			
CMP	January 13, 2009	86.890	94.110			
BHE/CMP	Weighted	87.369	93.850		90.610	
		Mar 11-Feb 12	Mar 12-Feb 13	Mar 13-Feb 14		
MPS	January 12, 2011	73.000	73.000	73.000	73.000	1.6%
BHE	December 8, 2010	70.330	69.790	74.320		
CMP	December 8, 2010	69.770	71.440	74.590		
BHE/CMP	Weighted	69.860	71.174	74.546	71.860	
				Northern Maine vs Southern Maine		**-7.1%**

As the table indicates, northern Maine small class standard offer service bids (held during similar periods as southern Maine) have averaged about 7.1% less than southern Maine (Bangor Hydro-Electric Company and Central Maine Power Company, ISO-NE participants).

Furthermore, as the following table shows NMISA's hourly wholesale balancing cost for its market (which is related to the NB market clearing price) has been 15.1% (or $8.24/MWh) less than the ME Zone clearing price over the same nine year period of time as the long-term SOS rate comparison.

NMISA Vs ISO-NE
Clearing Prices (Energy Only)

	ISA NB FHMC $/MWh	ISO-NE ME Zone $/MWh	Difference $/MWh	Difference %
2003[1]	$37.06	$47.14	($10.09)	-21%
2004	39.54	48.12	(8.58)	-18%
2005	60.39	70.22	(9.84)	-14%
2006	54.62	56.10	(1.48)	-3%
2007	61.61	63.74	(2.13)	-3%
2008	52.70	75.21	(22.51)	-30%
2009	31.57	40.06	(8.48)	-21%
2010	33.11	47.22	(14.11)	-30%
2011	44.29	44.98	(0.69)	-2%
2012[2]	45.18	32.71	12.48	38%
Average	$46.25	$54.49	($8.24)	-15.1%

Notes: 1) March through December.
2) January through February.

In contrast to the long-term SOS rate comparison, the NMISA vs ISO-NE clearing prices reflect actual prices for exactly the same time period. These clearing prices are hourly averages for each region (NBSO/NMISA and ISO-NE ME Zone) over the same periods of time, indicating fairly consistent lower prices in New Brunswick/northern Maine for the nine year period March 2003 through February 2012. Please note when comparing the NBSO and ISO-NE hourly energy clearing prices, one must understand that generators in New Brunswick receive their bid price, not the marginal clearing price (such as the ISO-NE LMP). The final hourly clearing price in New Brunswick includes out-of-merit dispatch costs necessary to maintain system reliability. The ISO-NE LMP does not include reliability related dispatch costs, which are recovered under separate charges to network load and load serving entities. For example, over the last couple of years first and second contingency charges (paid for by load serving entities) would add approximately $2/MWh to ISO-NE LMP). Other reliability charges (local out-of-merit dispatch to accommodate local transmission work,….) are recovered by the network load in the local utilities transmission rate.

It is also important to note that Point Lepreau, New Brunswick Power's 670 MW nuclear power plant went out of service on March 28, 2008 for refurbishment to add 25 to 30 years of operation. Point Lepreau is in the final stages of refurbishment and is in the process of being restarted in 2012. Therefore, in the future there will be an additional 670 MW of low cost baseload energy in the New Brunswick Power generation portfolio, which should lower the New Brunswick hourly energy clearing price.

The various analytical metrics [long-term standard offer price (weighted all classes), the individual small class RFPs (RFPs conducted during the same

relative time period), and NMISA/NB and ISO-NE hourly energy clearing price comparisons] all provide substantial evidence that the NMISA/NB power supply market has been and is expected to continue to be a lower cost electricity supply market than ISO-NE.

4.1.4. NES' analysis estimates the difference in wholesale costs for northern Maine customers for the status quo versus joining ISO-NE. This analysis calculates the wholesale cost for joining ISO-NE by projecting the future costs of energy and capacity in the ISO-NE market and adding the costs of various load serving/ancillary products and administration. NES then estimated the wholesale load serving cost in northern Maine of the status quo by estimating the amount and cost of northern Maine generation and Maritime generation that would likely be serving the load.

NES estimated the wholesale power supply energy value which would be received by generators located in NMISA's territory from delivering their output to the ISO-NE market and the marginal cost of the existing biomass facilities in northern Maine. It is assumed that the generators would seek to maximize their revenues by setting their price in northern Maine at the greater of (1) their opportunity price in ISO-NE adjusted for a portion (50%) of the costs incurred to deliver energy from northern Maine to ISO-NE (netback costs) or (2) their marginal cost plus a margin. A generator is expected to operate if it is economic compared to supply from the New Brunswick marketplace.

To the extent that adequate generation does not exist or operate in northern Maine, it is assumed that power supply will be available from the surplus Maritime and Quebec marketplace (which would otherwise be sold to ISO-NE) at an energy price equal to the Salisbury node. NES assumed current local generation at Ashland, if economic, and Mars Hill will be exported to ISO-NE (to capture value of southern NE RECs) and, further, did not include in this analysis any new projects currently under development in northern Maine.

With respect to capacity, given logistical transmission and seams issues and risks inherent in the ISO-NE capacity market, NES assumed NMISA/NB generation receives 50% of the ISO-NE capacity value through 2017 then ramping up to 100% in 2022. The New Brunswick/NMISA control area is currently a surplus generation capacity region, and is expected to be a surplus generation capacity region for at least through 2020 (New Brunswick System Operator – 10 Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities in New Brunswick, 2010-2020; dated July 2010). In addition, given New Brunswick Power Generation Company and Hydro Quebec have all but 28 MW of the firm capacity from New Brunswick into ISO-NE, the ability of northern Maine generators to sell capacity into ISO-NE is severely limited.

Note the analysis assumes the MPRP and other New England transmission projects increase ME/NH interface capacity so the benefits of wind generation

projects in northern Maine, including Bridgewater and Oakfield, are realized by the load south of Maine, and as such (1) losses in Maine are reduced, (2) congestion in Maine is reduced, and (3) the projected capacity price in Maine is equal to the region wide cost of new capacity. It is assumed the reduction of losses and congestion results in Maine's LMP basis to the MA HUB increasing from about 96.2% to 98% (approximate regional basis to Hub). Also, NES did not estimate or incorporate any potential reduction in ISO-NE's energy clearing price associated with new wind or other projects participation in the energy market. Such an estimate is not necessary to calculate the cost shift given the energy cost to NMISA participants under the status quo is highly correlated with ISO-NE's energy clearing price (the ISO-NE external Salisbury node with New Brunswick is the common pricing reference point), therefore any reduction in ISO-NE's energy clearing price associated with new wind or other projects will also result in a reduction in energy price for NMISA participants regardless of whether or not northern Maine joins ISO-NE.

The following table summarizes and compares the estimated wholesale power supply market costs for northern Maine under both the status quo and joining ISO-NE options:

TABLE 3

PROJECTED WHOLESALE POWER SUPPLY COSTS
MPS Staus Quo - Socialized Transmission Line
(MPC2012 Socialized Transmission Line, MPS/EMEC Joins ISO-NE)

	Annual Cost (North Region)				Annual Cost (South Region)				Total
	Stand Alone	Join ISO-NE		Cost Increase	Stand Alone	Join ISO-NE		Cost Increase	NMISA Cost Increase
Year	$/MWh	$/MWh	Load MWh	$K	$/MWh	$/MWh	Load MWh	$K	$K
2015	44.42	52.45	676,241	5,430	42.39	54.36	84,061	1,006	6,436
2016	45.71	54.12	679,622	5,719	43.70	56.09	84,481	1,046	6,765
2017	47.87	56.69	683,020	6,024	45.94	58.73	84,903	1,087	7,111
2018	51.25	59.59	686,436	5,725	49.26	61.74	85,328	1,065	6,791
2019	54.96	62.80	689,868	5,410	52.92	65.06	85,755	1,041	6,451
2020	58.88	66.16	693,317	5,048	56.78	68.53	86,183	1,013	6,061
2021	63.39	70.08	696,784	4,659	61.23	72.58	86,614	983	5,642
2022	67.59	73.60	700,268	4,212	65.36	76.21	87,047	944	5,156
2023	77.36	83.53	703,769	4,342	75.09	86.47	87,483	996	5,338
2024	89.78	96.10	707,288	4,476	87.45	99.46	87,920	1,056	5,532
2025	93.47	99.96	710,824	4,615	91.08	103.44	88,360	1,092	5,707
2026	97.24	103.90	714,378	4,759	94.80	107.52	88,801	1,130	5,889
2027	101.17	108.01	717,950	4,910	98.67	111.77	89,245	1,168	6,078
2028	105.19	112.22	721,540	5,067	102.63	116.11	89,692	1,209	6,275
2029	109.54	116.75	725,148	5,230	107.47	120.79	90,140	1,201	6,431
2030	113.98	121.39	728,773	5,400	111.86	125.59	90,591	1,244	6,644
2031	118.62	126.23	732,417	5,577	116.44	130.59	91,044	1,288	6,865
2032	123.45	131.19	736,079	5,699	121.21	135.71	91,499	1,327	7,026
2033	128.48	136.52	739,760	5,952	126.18	141.22	91,956	1,383	7,335
2034	133.72	142.00	743,459	6,152	131.37	146.88	92,416	1,433	7,585
Total (2015-19)				28,308				5,245	33,553
Total (2015-24)				51,045				10,238	61,282
Total (2015-29)				75,625				16,038	91,663
Total (2015-34)				104,404				22,713	127,117
Annual Avg				5,220				1,136	6,356

As indicated, the total wholesale power costs to NMISA load from joining ISO-NE is estimated at $127 million over 20 years or about $6.4 million per year (or 0.8 cents per kwh).

In order to reduce the power supply cost shift impact, NMISA's Northern Region could attempt to become a separate load zone. Since the transmission additions between the Northern Region and southern Maine are likely to be designed to eliminate congestion between these areas, the zonal LMP price difference between the Northern Region and southern Maine will be due to the impact of marginal losses. In this circumstance, NES estimates that the LMP in the NMISA Northern Region would reflect a reduction for marginal losses of about 3% compared to southern Maine, which would be approximately $2.12/MWh or $1.5 million per year from 2015 through 2034. If such a separate load zone was created, the annual average cost shift would be reduced modestly to about $3.7 million for the Northern Region and $4.9 million for all of NMISA over 20 years.

4.1.5. It is important to emphasize that under the status quo, even though NMISA's wholesale power supply cost is less than ISO-NE's power supply cost, NMISA's cost is driven by and highly correlated with ISO-NE's power supply cost. This is because ISO-NE's Salisbury node (external node between ISO-NE and New Brunswick) is the liquid market pricing point for the Maritime marketplace. Therefore, market efficiency and/or cost reductions in ISO-NE also provide a lower power supply cost for NMISA customers in today's marketplace via a lower Salisbury nodal price. For example, if BW or OW directly interconnects with ISO-NE as its own generation lead (i.e., not interconnected with NMTS) and its output results in a lower energy clearing price in ISO-NE, then this impact will be reflected in the Salisbury nodal price and ultimately the price paid by NMISA customers without incurring the risks and costs associated with joining ISO-NE.

4.1.6. Participants in ISO-NE incur the costs of ISO-NE for administering the power supply markets and bulk transmission system, as well as the cost of being NEPOOL participants. Participants of NMISA incur the costs of the ISA for administering the markets and bulk transmission system in northern Maine. Participants include T&D companies, competitive energy providers (CEP), generators, and end users. The following is a summary of administrative costs for ISO-NE/NEPOOL and NMISA:

Comparison of NMISA and ISO-NE/NEPOOL Funding Costs

ISO-NE		2012 Revenue Requirement (excl. True-ups)($K)	Collection Method
ISO-NE Tariff Schedule 1	Scheduling Service (for RNS)	35,756	Monthly Network Load.
ISO-NE Tariff Schedule 2	Energy Administration Service	66,594	Energy Account Participants (TU and Volumetric Charges).
ISO-NE Tariff Schedule 3	Reliablity Administration Service	48,651	Fixed $/MW of Non-Coincident Peak Load (NCPL).
ISO-NE Tariff Schedule 5	NESCOE	2,126	Monthly Network Load.
NEPOOL Participant Expenses			
Participant Expenses (2012 Budget)		4,757	Annual membership fee plus participant expenses (based on sector/size).
Generation Information System Expenses (2012 Budget)		1,065	GIS Billable Load
Total ISO-NE/NEPOOL Participant Revenue Requirement ($K)		158,948	
Wholesale Load (GWh) (2012 CELT Report)		136,111	
ISO-NE Export (GWh) (ISO-NE Sch. 3 Rate Assumption)		9,051	
Total ISO-NE (GWh)		145,162	
ISO-NE Funding Cost ($/MWh)		**1.09**	Assumes Load plus Exports Ultimately Pays ISO-NE/NEPOOL Funding Costs.

NMISA		2012 Revenue Requirement ($K)	Collection Method
NMISA Tariff Schedule 1	ISA Budget (including temporary dissolution cost)	971	Proportional Share of T&D Load, CEP Load, and Energy Exports.
	ISA Budget (temporary dissolution cost)	187	
	ISA Budget (excluding temporary dissolution cost)	783	
Wholesale Load (GWh) (2012 NMISA 7 Year Outlook Report)		749	
NMISA Export (GWh)(2011 Actual)		140	
Total NMISA (GWh)		888	
NMISA Funding Cost - incl. temp. dissolution cost ($/MWh)		**1.09**	Assumes Load and Exports Ultimately Pays NMISA Funding Costs.
ISO-NE Increase from NMISA ($/MWh)		**0.00**	
NMISA vs ISO-NE		**0%**	
NMISA vs ISO-NE ($)		**(2)**	
NMISA Funding Cost - excl. temp. dissolution cost ($/MWh)		**0.88**	Assumes Load and Exports Ultimately Pays NMISA Funding Costs.
ISO-NE Increase from NMISA ($/MWh)		**0.21**	
NMISA vs ISO-NE		**-19%**	
NMISA vs ISO-NE ($)		**(189)**	

NMISA's administrative costs have historically and consistently been less than ISO-NE. As indicated above, NMISA costs currently include a temporary charge to cover dissolution costs in the event NMISA is disbanded and replaced by another entity, such as ISO-NE. With the temporary charge the NMISA cost is approximately equal to ISO-NE's cost. However, excluding the temporary charge, NMISA's cost is 19% less than ISO-NE/NEPOOL's administrative costs. Based on this difference, Northern Maine participants would have to pay about $189K per year more in administrative funding costs if they were ISO-NE participants.

The administrative cost impact from joining ISO-NE is reflected in the transmission and wholesale power supply market cost benefit assessments.

4.1.7. If the MPC2012 interconnection does not proceed and market conditions change, then an alternative transmission connection, such as the long studied connection from Houlton to Haynesville, could be undertaken. NES believes that such a

connection would qualify as PTF under the so-called "Bucksport Rule", which allows a Transmission Owner's principal interconnection to qualify as PTF as long as its system contains at least 25 MW of generation.

4.2 Merchant Transmission Model

As described in detail in Appendix B to this report, NES has evaluated the effect of the MPC2012, constructed as a participant funded merchant transmission line, on the northern Maine power markets, both in terms of the impact on transmission costs and wholesale power supply costs. NES' evaluation assumes $348 million (includes AFUDC) of MPC2012 costs (Houlton to Haynesville and/or Chester) and all existing generation that historically served load in northern Maine export, if economic, their capacity and energy over MPS' current and future (non-MPC2012) transmission system to the higher valued ISO-NE power supply market. The recent merger proceeding between Emera (or BHE Holdings) and MPS and Emera's acquisition in First Wind proceeding has brought MPC2012 to higher visibility in terms of the potential transmission cost shift MPC2012 would impose on northern Maine ratepayers. The analysis detailed here is intended to provide an estimate of the magnitude of this increased cost.

The cost shift of transmission and wholesale power supply is more fully described in Sections 4.2.1 through 4.2.6 below and in Appendix B.

4.2.1. Under the Merchant Transmission Model, NES assumes reservations on MPC2012 are required by both new and existing generators in northern Maine in order for MPC2012 to be constructed. Therefore, the MPS transmission cost in NMISA's Northern Region will be lower than the status quo due to increased revenue credits associated with additional transmission outservice transactions from the existing northern Maine generation (to sell their energy and capacity in higher price ISO-NE market). NMISA's Southern Region transmission costs are also slightly reduced due to the increased Northern Region export volume reducing the Southern Region's share of NMISA administrative costs.

However, the merchant line's nodal interconnection point will become the new liquid price point and supply resource to serve northern Maine load. The price will include energy, capacity, ancillaries and all other export related charges, ***including*** ISO-NE Transmission Outservice (note suppliers that serve northern Maine load from ISO-NE will become external network load transmission customers of ISO-NE and pay ISO-NE's RNS rate, herein referred to as transmission outservice) and the tariff rate of the merchant MPC2012 line. Therefore, northern Maine consumers will likely pay, as part of their power supply costs, all or a substantial portion of ISO-NE's transmission rate/cost and MPC2012 rate/cost under the merchant model.

4.2.2. As explained more fully in Appendix B, the transmission costs of load in the northern Maine market will somewhat decrease if a merchant line interconnects

the NMTS to ISO-NE. This is because the existing NMISA generation that has historically served northern Maine load will now attempt to reach the higher price ISO-NE market by exporting over the current MPS transmission system and the merchant line. The incremental exports will provide additional export revenue credits and lower northern Maine's share of NMISA's administrative costs, and thus lower the MPS and EMEC transmission rates.

The following table summarizes the transmission costs under the Merchant Line Model:

TABLE 4

PROJECTED TRANSMISSION COSTS
MPS Status Quo - Merchant Transmission Line
(MPC2012 Merchant Transmission Line, MPS Remains with NMISA)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Status Quo	Merchant Line	12 CP Load	Cost Increase	Status Quo	Merchant Line	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2015	57.04	50.26	102.5	(695)	39.03	38.57	12.7	(6)	(701)
2016	60.61	53.61	103.0	(721)	39.29	38.82	12.8	(6)	(728)
2017	67.91	59.55	103.5	(866)	39.56	39.07	12.8	(6)	(872)
2018	66.82	60.27	104.0	(681)	39.82	39.33	12.9	(6)	(688)
2019	67.26	60.35	104.6	(722)	40.09	39.59	13.0	(7)	(729)
2020	67.27	60.44	105.1	(717)	40.37	39.85	13.0	(7)	(724)
2021	67.42	60.54	105.6	(726)	40.64	40.11	13.1	(7)	(733)
2022	67.54	60.65	106.1	(731)	40.92	40.38	13.1	(7)	(738)
2023	67.68	60.77	106.7	(737)	41.21	40.65	13.2	(7)	(744)
2024	67.83	60.90	107.2	(743)	41.49	40.93	13.3	(8)	(750)
2025	67.99	61.04	107.7	(749)	41.78	41.20	13.3	(8)	(757)
2026	68.16	61.18	108.3	(755)	42.08	41.48	13.4	(8)	(763)
2027	68.34	61.34	108.8	(762)	42.37	41.77	13.5	(8)	(770)
2028	68.54	61.51	109.4	(769)	42.67	42.06	13.5	(8)	(777)
2029	68.75	61.69	109.9	(776)	42.98	42.35	13.6	(9)	(784)
2030	68.97	61.88	110.5	(783)	43.29	42.64	13.7	(9)	(792)
2031	69.20	62.08	111.0	(790)	43.60	42.94	13.8	(9)	(799)
2032	69.45	62.30	111.6	(798)	43.91	43.24	13.8	(9)	(807)
2033	69.71	62.52	112.1	(806)	44.23	43.55	13.9	(10)	(815)
2034	69.98	62.76	112.7	(814)	44.56	43.86	14.0	(10)	(824)
Total (2015-19)				(3,687)				(31)	(3,718)
Total (2015-24)				(7,339)				(67)	(7,406)
Total (2015-29)				(11,149)				(108)	(11,257)
Total (2015-34)				(15,140)				(154)	(15,294)
Annual Avg				(757)				(8)	(765)

As indicated, the total transmission cost shift (reduction) from the merchant line under these assumptions is estimated at $15.3 million over 20 years or approximately $0.8 million per year (or 0.1 cents/kwh).

However, as previously mentioned, northern Maine consumers will likely pay all or a substantial portion of ISO-NE's transmission outservice and MPC2012's transmission costs embedded in their power supply cost.

4.2.3. There will be a significant cost shift related to the costs of power supply for northern Maine if a merchant transmission line interconnects the NMTS to ISO-NE. This cost shift occurs because (1) it is likely that local low cost generation that historically has served northern Maine load will export their energy and

capacity to ISO-NE once a merchant line is interconnected; (2) the merchant line interconnection nodal point with ISO-NE will become the new liquid price wholesale power supply point for northern Maine; and (3) Maritimes suppliers will likely price their sales to northern Maine relative to the price at the merchant line nodal point. This liquid price point will include energy, capacity, ancillaries, and all ISO-NE export related fees, which ***includes*** ISO-NE transmission outservice. Load served from ISO-NE would also have to pay the MPC2012 transmission tariff rate. As described in detail in Section 4.1, ISO-NE's transmission costs are (1) higher than MPS' current and planned transmission cost and (2) are planned and projected to increase significantly.

4.2.4 NES' analysis as described below estimates the difference in wholesale power supply costs for northern Maine customers for the status quo versus a merchant line interconnection.

Under the status quo, NES estimates the wholesale power supply energy cost with the methodology set forth in the Socialized Transmission Model (Section 4.1).

With a merchant transmission model, NES calculates the wholesale power supply cost by projecting the future costs of energy (assuming Merchant Line interconnection nodal price will equal Salisbury nodal price) and capacity in the ISO-NE market and adding the applicable ISO-NE export related costs, including but not limited to various ancillary products and ISO-NE transmission outservice related costs, as well as the MPC2012 tariff rate. As discussed in more detail in Section 4.1, there are significant approved/planned transmission additions in ISO-NE (ISO-NE 2012 RSP Buildout Case). There are also significant more additions being studied, for example to meet New England's Renewable Portfolio Standards (RPS Buildout Case). In addition, there is a further potential for additional reliability related transmission buildout in ISO-NE. Please note for the Merchant Transmission Model NES assumed Maritime suppliers will serve the northern Maine load at a price equal to the Salisbury node LMP plus 70% of the non-energy supply costs sourced from ISO-NE, including MPC2012's tariff rate/cost. This assumption reflects the potential for existing/new northern Maine renewable generation competition for this load as well as related required costs for back-up and ancillary services should that occur.

Note the analysis assumes the merchant interconnection point with ISO-NE will have the same LMP as Salisbury. Also, NES assumed MPRP and other New England transmission projects increase ME/NH interface capacity so the benefits of northern Maine renewable generation projects, such as BW or OW, are realized by the load south of Maine, and as such (1) losses in Maine are reduced, (2) congestion in Maine is reduced, and (3) the projected capacity price in Maine is equal to the region wide cost of ISO-NE capacity. It is assumed the reduction of losses and congestion results in Salisbury's LMP basis to the MA HUB increasing from about 93.2% to 95.5%.

Also, NES did not estimate or incorporate any potential reduction in ISO-NE's energy clearing price associated with northern Maine generation participation in the ISO-NE energy market. As discussed in Section 4.1, such an estimate is not necessary to calculate the cost shift given the energy cost to NMISA participants under the status quo is highly correlated with ISO-NE's energy clearing price (the ISO-NE external Salisbury node with New Brunswick is a common pricing reference point), therefore any reduction in ISO-NE's energy clearing price associated with new wind generation or other projects will also result in a reduction in energy price for NMISA participants regardless of whether or not a merchant line interconnects northern Maine to ISO-NE.

The following table summarizes and compares the estimated wholesale power supply market costs for northern Maine under both the status quo and merchant line (ISO-NE 2012 RSP Buildout Case) options:

TABLE 5

PROJECTED WHOLESALE POWER SUPPLY COSTS
MPS Status Quo - Merchant Transmission Line
(ISO-NE 2012 RSP Case, MPS Remains with NMISA)

	Annual Cost (North Region)				Annual Cost (South Region)				Total
		Merchant		Cost		Merchant		Cost	NMISA Cost
	Status Quo	Line	Load	Increase	Status Quo	Line	Load	Increase	Increase
Year	$/MWh	$/MWh	MWh	$K	$/MWh	$/MWh	MWh	$K	$K
2015	44.42	70.06	676,241	17,335	42.39	45.10	84,061	227	17,562
2016	45.72	72.55	679,622	18,240	43.71	46.67	84,481	250	18,490
2017	47.87	74.89	683,020	18,461	45.93	48.98	84,903	259	18,720
2018	51.25	77.62	686,436	18,096	49.25	52.28	85,328	258	18,354
2019	54.96	80.64	689,868	17,715	52.91	55.89	85,755	256	17,970
2020	58.90	83.84	693,317	17,290	56.79	59.71	86,183	252	17,542
2021	63.39	87.54	696,784	16,826	61.23	64.07	86,614	246	17,073
2022	67.59	90.90	700,268	16,324	65.36	68.12	87,047	240	16,564
2023	77.36	98.84	703,769	15,117	75.08	77.58	87,483	218	15,336
2024	89.84	108.74	707,288	13,366	87.51	89.60	87,920	183	13,549
2025	93.47	112.29	710,824	13,383	91.08	93.19	88,360	186	13,569
2026	97.24	116.00	714,378	13,401	94.80	96.93	88,801	189	13,590
2027	101.17	119.87	717,950	13,421	98.67	100.82	89,245	192	13,612
2028	105.27	123.90	721,540	13,441	102.71	104.87	89,692	194	13,635
2029	109.54	128.10	725,148	13,463	107.46	109.65	90,140	197	13,660
2030	113.98	132.49	728,773	13,486	111.86	114.05	90,591	199	13,685
2031	118.62	137.07	732,417	13,511	116.44	118.65	91,044	201	13,713
2032	123.45	141.84	736,079	13,538	121.21	123.43	91,499	203	13,741
2033	128.48	146.82	739,760	13,566	126.18	128.41	91,956	205	13,772
2034	133.72	152.01	743,459	13,597	131.37	133.60	92,416	207	13,804
Total (2015-19)				89,846				1,250	91,096
Total (2015-24)				168,771				2,390	171,161
Total (2015-29)				235,880				3,348	239,227
Total (2015-34)				303,579				4,363	307,941
Annual Avg				15,179				218	15,397

As indicated, the total wholesale power costs to NMISA load from merchant line (ISO-NE 2012 RSP Buildout Case) is estimated at $308 million over 20 years or about $15.4 million per year (or 1.9 cents per kwh).

The following table summarizes and compares the estimated wholesale power supply (market) costs for northern Maine under both the status quo and merchant line (ISO-NE RPS Buildout Case) options:

TABLE 6

PROJECTED WHOLESALE POWER SUPPLY COSTS
MPS Status Quo - Merchant Transmission Line
(RPS Buildout Case, MPS Remains with NMISA)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
		Merchant		Cost		Merchant		Cost	NMISA Cost
	Status Quo	Line	Load	Increase	Status Quo	Line	Load	Increase	Increase
Year	$/MWh	$/MWh	MWh	$K	$/MWh	$/MWh	MWh	$K	$K
2015	44.42	74.13	676,241	20,087	42.39	45.67	84,061	275	20,362
2016	45.72	80.70	679,622	23,776	43.71	47.85	84,481	350	24,126
2017	47.87	87.17	683,020	26,849	45.93	50.82	84,903	415	27,264
2018	51.25	94.09	686,436	29,402	49.25	54.80	85,328	474	29,875
2019	54.96	101.36	689,868	32,008	52.91	59.16	85,755	536	32,544
2020	58.90	108.87	693,317	34,645	56.79	63.77	86,183	601	35,246
2021	63.39	112.37	696,784	34,123	61.23	68.19	86,614	604	34,727
2022	67.59	115.60	700,268	33,622	65.36	72.32	87,047	606	34,228
2023	77.36	123.42	703,769	32,415	75.08	81.87	87,483	593	33,008
2024	89.84	133.20	707,288	30,663	87.51	93.96	87,920	567	31,230
2025	93.47	136.63	710,824	30,680	91.08	97.63	88,360	579	31,259
2026	97.24	140.21	714,378	30,698	94.80	101.45	88,801	590	31,289
2027	101.17	143.96	717,950	30,718	98.67	105.41	89,245	602	31,319
2028	105.27	147.87	721,540	30,738	102.71	109.54	89,692	613	31,351
2029	109.54	151.96	725,148	30,760	107.46	114.39	90,140	624	31,384
2030	113.98	156.22	728,773	30,783	111.86	118.87	90,591	635	31,419
2031	118.62	160.68	732,417	30,808	116.44	123.53	91,044	646	31,454
2032	123.45	165.34	736,079	30,835	121.21	128.38	91,499	656	31,491
2033	128.48	170.20	739,760	30,863	126.18	133.43	91,956	667	31,530
2034	133.72	175.28	743,459	30,894	131.37	138.69	92,416	677	31,571
Total (2015-19)				132,122				2,049	134,171
Total (2015-24)				297,590				5,021	302,610
Total (2015-29)				451,184				8,029	459,213
Total (2015-34)				605,368				11,310	616,678
Annual Avg				30,268				566	30,834

As indicated, the total wholesale power costs to NMISA load from merchant line (ISO-NE RPS Buildout Case) is estimated at $617 million over 20 years or about $30.8 million per year (or 3.9 cents per kwh).

As discussed in Section 4.1, given the socialization of transmission costs and the incentives of the other states/utilities in New England, there will likely be reliability transmission additions above the RSP Buildout regardless if the RPS Buildout occurs. Assuming the rest of the New England States build out transmission proportional to Maine (approximately $1.8 billion)(in addition to the ISO-NE 2012 RSP Case assumptions above), NMISA load would pay ***an additional*** $133.9 million over 20 years or $6.7 million per year (or 0.8 cents per kwh) in wholesale power supply cost shift as a result of the merchant line.

4.2.5. As stated in Section 4.1, it is important to emphasize that under the status quo, even though NMISA's wholesale power supply cost is less than ISO-NE's power supply cost, NMISA's cost is driven by and highly correlated with ISO-NE's power supply cost. This is because ISO-NE's Salisbury node (external node between ISO-NE and New Brunswick) is the liquid market pricing point for the New Brunswick marketplace. Therefore, market efficiency and/or cost reductions in ISO-NE also provide a lower power supply cost for NMISA customers in today's marketplace via a lower Salisbury nodal price. For example, if BW or

OW directly interconnects with ISO-NE as its own generation lead (i.e., not interconnected with NMTS) and its output results in a lower energy clearing price in ISO-NE, then this impact will be reflected in the Salisbury nodal price and ultimately the price paid by NMISA customers without incurring the risks and costs associated with joining ISO-NE.

4.2.6. If the MPC2012 interconnection does not proceed and market conditions change, then an alternative transmission connection, such as the long studied connection from Houlton to Haynesville, could be undertaken. NES believes that such a connection would qualify as PTF under the so-called "Bucksport Rule", which allows a Transmission Owner's principal interconnection to qualify as PTF as long as its system contains at least 25 MW of generation.

5.0 Conclusions

As required by NMISA market rules 8 and 9, and as described in Section 2 (Scope of Evaluation) of this report, NES addresses the following question(s)/issue(s) associated with the power market assessment:

1. Will the MPC2012 improve the efficiency of the Northern Maine Market?

    (a) As indicated in Section 4 of this report, all else equal, the economic impact of the MPC2012 under the Socialized Transmission Model and Merchant Transmission Model would be significantly adverse to northern Maine consumers.

    Under the Socialized Transmission Model the combination of increased transmission costs and wholesale power supply costs could be between $19.54/MWh and $51.66/MWh ($15.6 million to $41.2 million per year), possibly more (with inclusion of (1) additional buildout to meet RPS standards and/or (2) additional NE reliability transmission buildout projects), to the overall status quo cost to northern Maine customers.

    Under the Merchant Model the combination of reduced transmission costs and increased wholesale power supply costs could be a net cost of between $18.35/MWh and $37.72/MWh ($14.6 million to $30.1 million per year), possibly more (with inclusion of (1) additional buildout to meet RPS standards and/or (2) additional NE reliability transmission buildout projects), to the overall status quo cost to northern Maine customers.

    Even if one assumes that this wholesale power cost (excluding effects of transmission) shift is zero (unlikely, based upon history and return of Point Lepreau), the transmission cost shift is still very large (representing 59% to 85% of the total cost shift) and is very likely to occur.

(b) Although it is possible that the energy clearing price in ISO-NE will decrease due to improving power market competition, such as may occur with the addition of non-gas fueled generation, as discussed in Sections 4.1.4, 4.1.5, 4.2.4, and 4.2.5 of in this report, NMISA participants do not need to be participants in ISO-NE or have a direct transmission interconnection with ISO-NE to receive the benefits of decreasing energy prices in ISO-NE. NMISA's energy cost is highly correlated with ISO-NE's energy clearing price, and as such energy clearing price reductions in ISO-NE result in energy price reductions in NMISA.

(c) It also should be noted that any decision to join the ISO-NE market may carry with it future obligations related to investments made in the region where related costs are recovered or socialized through the participants. Even if these identified cost shifts are mitigated by ISO-NE, BW, OW or others, there is a significant risk that actual costs will be higher, and it may be difficult to withdraw and avoid such higher costs should they occur.

(d) Given the risks to NMISA participants associated with the Socialized Transmission Model (joining ISO-NE) and Merchant Transmission Model, (NMTS interconnection with ISO-NE) a logical approach would be for any new generation in northern Maine to directly connect to ISO-NE as a generation lead and not interconnect with the NMTS. Under this approach northern Maine customers (NMISA North and South Regions) will (1) avoid the current/projected power supply cost shift, (2) avoid the current/projected transmission cost shift, (3) avoid the risk of substantial transmission and administrative cost increases in ISO-NE (as discussed in this report), (4) likely continue to have lower costs than southern Maine in the foreseeable future, and (5) realize the benefits of lower energy prices in ISO-NE when lower cost resources are developed. In addition, this approach would provide significant flexibility for Maine's regulators and policy makers. If market conditions change in the future such that it becomes economic to interconnect without incurring significant cost risks to northern Maine customers, then the NMTS could interconnect to ISO-NE via an interconnection with the generation lead.

In the event that MPC2012 does not proceed with an interconnection with ISO-NE, the NMTS still maintains an option to interconnect with a much more modest transmission project, which very likely could qualify for inclusion in the regional ISO-NE transmission tariff.

APPENDIX A

SOCIALIZED TRANSMISSION MODEL

COST BENEFIT ASSESSMENT

NES conducted a cost benefit assessment of the transmission interconnection request from the NMTS to ISO-NE. NES assumed NMISA's participants become part of ISO-NE. The assessment was conducted on both the transmission cost impact and the wholesale power supply cost impact on NMISA's Northern and Southern Regions.

TRANSMISSION COST BENEFIT ASSESSMENT

The transmission assessment involved developing 20 year transmission cost projections for (1) MPS under status quo, (2) ISO-NE, (3) MPS joining ISO-NE, (4) EMEC under status quo, and (5) EMEC joining ISO-NE. NES determined the cost or benefits for NMISA's North Region by comparing the transmission cost projections for MPS Status Quo to MPS joining ISO-NE. For NMISA's South Region, NES compared the transmission costs of EMEC Status Quo to EMEC joining ISO-NE. The following discusses the approach and major assumptions for the transmission cost projections for scenarios 1 through 5 above.

MPS Stand Alone (Status Quo)

NES performed a high level 20 year annual transmission cost projection for Maine Public Service Company on a stand alone basis. MPS currently has about $29.2 million of gross transmission investment, and NES assumed $18.7 million of increased gross transmission investment from 2013 through 2018 (based upon the MPS transmission plan included in the 2012 NMISA 7 year outlook plus $2 million to upgrade the Tinker transformer) with transmission investment growing at 2.5% per year (assumed equal to annual depreciation) thereafter. NES also estimated an annual carrying cost of 15.73% of gross transmission investment in 2012, and assumed it remains at 15.73% thereafter. The annual carrying cost includes cost of capital, OM&G, property taxes, and other applicable costs. In addition, NES developed projections of additional transmission related costs (scheduling and dispatch, reactive voltage, customer and regulatory charges, and cancelled plant) based on MPS' current (2012) transmission tariff. NES assumed inflationary increases of 3% per year to these costs. Attachment 1 shows the MPS Status Quo transmission cost projection in detail.

ISO-NE Regional Network Service (RNS) and OATT Schedule 1

NES also performed 20 year projections of ISO-NE's RNS and OATT Schedule 1 costs under (1) an ISO-NE 2012 RSP Case [ISO-NE August 2012 Five Year RNS Forecast, and $348 million (includes AFUDC) of MPC2012], (2) an ISO-NE Renewable Portfolio Standards (RPS) Buildout Case [ISO-NE 2012 RSP Case plus transmission buildout to

accommodate renewable generation to meet the future 30% regional RPS], and (3) a New England/Maine Transmission Buildout Case [NE Buildout proportional to Maine (MPRP, NRI, DRP, Keene Road,…)]. These projections are necessary to estimate MPS' and other NMISA T&D's future transmission costs in the event they join ISO-NE.

Becoming a part of ISO-NE would allow MPS and other NMISA T&Ds to roll the PTF eligible portion of their transmission system into ISO-NE's Regional Network Service, which may help MPS socialize the cost associated with the Maine Power Connection 2012 project. However, MPS would be obligated to pay its share of ISO-NE's RNS costs. At the end of 2011 ISO-NE had about $7.0 billion of gross transmission investment with significant additions planned over the next several years.

In this assessment, the ISO-NE 2012 RSP Case assumed future gross transmission additions that are specified in the August 2012 ISO-NE Five Year RNS Forecast plus $348 million of MPC2012 (includes AFUDC) related transmission investments (any new northern Maine generation are assumed to have generator leads paid for by the generation project) which are assumed to be required to allow new northern Maine energy and capacity production to reach the energy marketplace south of Maine. This amounts to an additional investment in New England of about $7.0 billion.

For the second case (ISO-NE Renewable Portfolio Standards Buildout Case), NES assumed the ISO-NE 2012 RSP Case plus the estimated cost (by ISO-NE) of incremental transmission needed to accommodate additional renewable generation to meet the 30% RPS in the year 2020. Based upon the recent New England 2030 Power System Study which ISO-NE performed at the request of the New England Governors, this could require between $10 billion and $36 billion of additional transmission. NES assumed the midpoint of the estimated range, $23 billion (2009$).

The third case, New England/Maine Buildout Case, assumed other future New England reliability transmission investments are equal to the same proportional investment made in Maine (MPRP, NRI, DRP, Keene Road,…). This would result in an additional $10 billion of transmission investment (in addition to the ISO-NE 2012 RSP Case).

Subsequent to the initial buildouts as described above, NES assumed ISO-NE's gross transmission investment increases at a rate equal to annual depreciation, 2.5% per year. NES also estimated an annual carrying cost based on ISO-NE's August 2012 Five Year RNS Forecast, then remaining at 17.49% thereafter. As with MPS' Stand Alone assessment, the annual carrying cost includes cost of capital, OM&G, property taxes, and other applicable costs. For other RNS assumptions, NES utilized ISO-NE's 2011 RSP, ISO-NE's August 2012 Five Year RNS Forecast, 2012 CELT report, and ISO-NE's current tariff Schedule 1 for RNS. NES prepared a 20 year projection of ISO-NE's RNS rate for all three cases. Attachments 2 and 3 shows ISO-NE's RNS and OATT Schedule 1 projection detail for each of the ISO-NE 2012 RSP and Renewable Portfolio Standards Buildout Cases respectively.

MPS Joins ISO-NE (NMISA's North Region)

NES performed 20 year annual transmission cost projections (ISO-NE 2012 RSP Case, RPS Buildout Case, as well as a New England/Maine Buildout Case) for Maine Public Service (NMISA's North Region) under the scenario that MPS becomes a Transmission Owner participant in ISO-NE. NES assumed $348 million (includes AFUDC) of MPC2012 cost would be included in ISO-NE's regional transmission tariff (generator leads were assumed to be paid for by the generation project). Also, consistent with MPS' July 1, 2008 filing with the MPUC, NES assumed 76.9% of MPS' current and future transmission assets could be rolled into ISO-NE RNS, and incorporated that amount of RNS payments (or credits) with ISO-NE. In addition, NES estimated future ISO-NE OATT and NEPOOL costs (ISO-NE 2012 RSP Case, RPS Buildout Case, and New England/Maine Buildout Case). NES' annual projections were based on ISO-NE's current OATT and NEPOOL expenses, with annual inflationary increases of 3% per year (consistent with the MPS status Quo projection). Attachments 4 and 5 shows MPS' annual transmission cost projection detail if MPS joins ISO-NE under the ISO-NE 2012 RSP and RPS Buildout Cases respectively.

EMEC Status Quo and EMEC Joins ISO-NE (NMISA's South Region)

If MPS joins ISO-NE, NES assumed EMEC would also join ISO-NE. Please note it is unclear at this point whether EMEC could actually obtain the appropriate transmission rights and/or be able to receive roll-in treatment from ISO-NE. NES performed 20 year annual transmission cost projections for EMEC Status Quo, as well as EMEC Joins ISO-NE (ISO-NE 2012 RSP Case, RPS Buildout Case, and New England/Maine Buildout Case).

For this cost/benefit assessment, NES assumed EMEC's transmission costs include the New Brunswick Transmission Tariff and EMEC's transmission system, and 100% of the costs could be rolled-in to RNS. For NES' projection of transmission costs, we assumed EMEC and New Brunswick's current (2012) transmission tariff rates would increase 0.5% per year. Under the EMEC joins ISO-NE scenario, NES assumed ISO-NE's out service charge is waived. The other ISO-NE costs are consistent with the MPS joins ISO-NE scenarios (ISO-NE 2012 RSP Case, RPS Buildout Case, and New England/Maine Buildout Case). Attachment 6 shows the transmission cost projection details for EMEC Status Quo and EMEC joins ISO-NE under the ISO-NE 2012 Regional System Plan and Renewable Portfolio Standards Buildout Cases, respectfully.

TRANSMISSION COST/BENEFIT ASSESSMENT RESULTS

NMISA North Region

To determine the transmission cost or benefit to NMISA's North Region, NES compared the total annual transmission cost of the MPS Status Quo scenario with MPS joining ISO-NE. Based on NES' assessment, MPS joining ISO-NE would significantly increase the cost of transmission to customers in NMISA's North Region.

ISO-NE 2012 RSP Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $7.8 million in the first year, (b) $40.9 million over the first 5 years, (c) $81.9 million over the first 10 years, and (d) $164.2 million over a 20 year period (or an average of $8.2 million per year). The summary results are shown in Table 1 of the main body of this report.

RPS Buildout Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $11.9 million in the first year, (b) $104.0 million over the first 5 years, (c) $275.8 million over the first 10 years, and (d) $619.6 million over a 20 year period (or an average of $31.0 million per year). The summary results are shown in Table 2 of the main body of this report.

New England/Maine Buildout Case – Incremental (above RSP Case) Cost Impact: Assuming 2015 ISO-NE participation, the incremental cost of transmission would be (a) $0 in the first year, (b) $27.9 million over the first 5 years, (c) $84.5 million over the first 10 years, and (d) $197.6 million over a 20 year period (or an average of $9.9 million per year).

NMISA South Region

To determine the transmission cost or benefit to NMISA's South Region, NES compared the total annual transmission cost of the EMEC Status Quo scenario with EMEC joining ISO-NE. Based on NES' assessment, EMEC joining ISO-NE would significantly increase the cost of transmission to customers in NMISA's South Region.

ISO-NE 2012 RSP Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $0.9 million in the first year, (b) $5.1 million over the first 5 years, (c) $10.3 million over the first 10 years, and (d) $20.3 million over a 20 year period (or an average of $1.0 million per year). The summary results are shown in Table 1 of the main body of this report.

RPS Buildout Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $1.4 million in the first year, (b) $13.0 million over the first 5 years, (c) $34.4 million over the first 10 years, and (d) $77.0 million over a 20 year period (or an average of $3.9 million per year). The summary results are shown in Table 2 of the main body of this report.

New England/Maine Buildout Case – Incremental (above RSP Case) Cost Impact: Assuming 2015 ISO-NE participation, the incremental cost of transmission would be (a) $0 in the first year, (b) $3.5 million over the first 5 years, (c) $10.5 million over the first 10 years, and (d) $24.6 million over a 20 year period (or an average of $1.2 million per year).

Total NMISA

Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of transmission to customers in NMISA.

ISO-NE 2012 RSP Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $8.7 million in the first year, (b) $46.0 million over the first 5 years, (c) $92.2 million over the first 10 years, and (d) $184.5 million over a 20 year period (or an average of $9.2 million per year). The summary results are shown in Table 1 of the main body of this report and Attachment 13.

RPS Buildout Case: Assuming 2015 ISO-NE participation, the cost of transmission would increase by (a) $13.3 million in the first year, (b) $117.0 million over the first 5 years, (c) $310.2 million over the first 10 years, and (d) $696.6 million over a 20 year period (or an average of $34.8 million per year). The summary results are shown in Table 2 of the main body of this report and Attachment 14.

New England/Maine Buildout Case – Incremental (above RSP Case) Cost Impact: Assuming 2015 ISO-NE participation, the incremental cost of transmission would be (a) $0 in the first year, (b) $31.3 million over the first 5 years, (c) $95.0 million over the first 10 years, and (d) $222.2 million over a 20 year period (or an average of $11.1 million per year **in addition to the ISO-NE 2012 RSP Case**). Attachment 15 shows the summary results for New England/Maine Buildout Case.

ADDITIONAL ISSUES TO CONSIDER

There are various cost risks for NMISA participants from MPS/EMEC joining ISO-NE which have not been incorporated into the Cost Benefit Assessment. These risks include (1) future RNS transmission additions in ISO-NE that are not addressed in this report, (2) potential Reliability Must Run (RMR) contracts and local network load reliability charges, and (3) ISO-NE tariff costs and NEPOOL expenses. Some of these risks could be substantial. For example, additional ISO-NE transmission investment of $1 billion with a carrying cost of 17.49% would result in an annual revenue requirement of about $174.9 million or $8.22/kw/yr. For NMISA participants, the additional cost would be about $1.2 million per year. As an example of potential RMR contract risks, in 2010 the State of Connecticut had fixed cost RMR contracts totaling $162 million annually or approximately $5/MWh, which was paid for by CT's network load in transmission rates. For NMISA participants, a similar RMR cost would be about $4.0 million per year.

WHOLESALE POWER SUPPLY MARKET COST BENEFIT

The wholesale power supply market assessment involved developing 20 year power supply cost projections for (1) MPS under status quo, (2) ISO-NE, (3) MPS joining ISO-NE, (4) EMEC under status quo, and (5) EMEC joining ISO-NE. To determine the cost or benefits for NMISA's North Region NES compared the wholesale power supply cost projections for MPS Status Quo to MPS joining ISO-NE. For NMISA's South Region NES compared the wholesale power supply costs from EMEC Status Quo to EMEC joining ISO-NE. The following discusses the approach and major assumptions for the wholesale power supply cost projections for scenarios 1 through 5 above.

MPS Status Quo

NES performed a 20 year annual power supply cost projection for NMISA's Northern Region under the status quo. A primary assumption is ISO-NE's external node with New Brunswick (Salisbury, formerly referred to as Keswick) sets the market energy price for the regional Maritime marketplace. Historically, energy flows primarily north to south into ISO-NE from the Maritimes (over MEPCO/NRI). NES developed its forecast of ISO-NE's energy price at MA Hub by utilizing the NYMEX/CME Group MA Hub forwards through 2016 (as of August 13, 2012 settle), and for 2017 and beyond by multiplying the 2016 implied heat rate (MA Hub DA LMP divided by NYMEX Henry Hub natural gas) by the forward NYMEX Henry Hub natural gas prices (as of August 13, 2012 settle)(refer to Attachment 7). To project the forward Salisbury market prices, NES then assumed the historical basis from MA Hub to Salisbury (refer to Attachment 8) adjusted in 2015 and beyond to reflect lower losses and congestion due to the regional transmission buildout.

NES also assumed the value of energy to a must run generator (hydro, wind…) located in the NMISA's territory is equal to the Salisbury node minus a portion (50%) of all costs for the generator to move its energy from NMISA through New Brunswick into ISO-NE. NES also developed a marginal cost forecast for each of the existing biomass plants in northern Maine (Fort Fairfield, Ashland, Sherman). NES assumed the Federal Wood Supplier Subsidy Program will remain in effect through 2015 and provides a subsidy equal to $10/ton. Ashland is assumed to be exported, when economic, from Northern Maine into ISO-NE in order to capture the Renewable Energy Credit (REC) value from southern Maine. In the event the biomass plants do not operate due to economics for five consecutive years, then NES assumed the plant was permanently decommissioned.

Consistent with historical practice, First Wind's Mars Hill project is also assumed to be exported from Northern Maine into ISO-NE in order to capture the REC value from Massachusetts. With the exception of Ashland and Mars Hill, generation located in northern Maine was assumed to be sold, if economic compared to Maritime energy at the Salisbury price, in northern Maine (to serve the load in northern Maine) at a price equal to the greater of (1) the Salisbury node (excluding any Massachusetts or Connecticut Renewable Energy Credit value) minus a portion (50%) of the netback costs or (2) $3/MWh greater than their marginal cost.

Any remaining energy requirements are assumed to be supplied from the surplus Maritime marketplace at the Salisbury node energy price. Maritime suppliers' surplus sales opportunity is selling into ISO-NE at the Salisbury nodal price, however Maritime suppliers will prefer selling in the Maritimes and northern Maine for various reasons, including reduced risk and administrative burdens.

Attachment 9 details the NMISA Northern Region load and generation resource assumptions. NES also assumed the current NB tariff rate for NMISA load serving operating reserves (escalated by 3% per year), NMISA capacity value equals 50% of ISO-NE's capacity cost through 2017 then ramping up to 100% in 2022, and a load

following cost adder of 3% of the usage weighted cost at the Salisbury energy price. Attachment 10 details the Status Quo wholesale power supply cost projection for NMISA's North Region.

MPS Joins ISO-NE

NES performed a 20 year annual wholesale power supply cost projection for NMISA's Northern Region if MPS becomes a Transmission Owner participant in ISO-NE. Under this scenario the load in NMISA's Northern Region would pay the Maine load zone price for energy, ISO-NE load serving costs (regulation, forward reserve market, capacity, NCPC/Uplift, GIS, ISO Sch 2, ISO Sch 3,…), and NEPOOL expenses. Historically, Maine Zone energy clearing prices have been at a substantial discount to Mass Hub. Given MPRP, other NE transmission investments, and new generation in northern Maine is intended to serve load south of Maine, NES assumes long term (2015 and beyond) Maine Zone energy prices will equal about 98% of the Hub, which is approximately the regional loss and non-congested price. NES projected ISO-NE's wholesale load serving costs by using (1) actual Maine 2011 load serving costs as specified in ISO-NE's 2011 Wholesale Cost Report (WCR), (2) 2012 ISO-NE Tariff revenue requirements, and/or (3) historical billing. For future years, NES incorporated known changes and/or a 3% annual inflationary cost increase. In addition, NES included a load following cost adder of 3% of the usage weighted cost at the Maine Zone energy price.

With respect to capacity, NES assumed the capacity rates cleared to-date in the Forward Capacity Market, $4.50/kw/mo in 2010/11, $3.60/kw/mo in 2011/12, $2.95/kw/mo in 2012/13, $2.95/kw/mo in 2013/14, $3.21/kw/mo in 2014/15, and $3.43/kw/mo in 2015/16 and then plus 3% per year until 2023/24 with the estimated cost of a new peaker ($11.81/kw/mo), escalated at 3% per year thereafter.

Attachment 11 details the Join ISO-NE wholesale power supply cost projection for NMISA's North Region.

EMEC Status Quo and EMEC Joins ISO-NE (NMISA's South Region)

NES performed a 20 year annual wholesale load serving cost projection for NMISA's South Region under both EMEC Status Quo and EMEC joins ISO-NE.

Under the Status Quo, NES' assumptions and approach are consistent with the MPS Status Quo scenario. In addition, there is currently not enough energy or capacity in EMEC's service territory (NMISA South) to serve its entire load. NES assumed the energy imported into EMEC is sourced from the energy surplus Maritime market at a price equal to the Salisbury node. NES also assumed the cost of capacity consistent with the MPS Status Quo scenario.

Under the Join ISO-NE scenario, NES assumed EMEC would have a virtual tie with ISO-NE through New Brunswick, and ISO-NE would waive any energy out service charges associated with serving EMEC (NMISA South) load. As with the North Region, NES assumed EMEC would pay the Maine Zone energy price and over the long term (2015 and beyond) ME Zone energy prices would equal about 98% of the Hub. NES'

assumptions surrounding the other wholesale load serving costs are consistent with the MPS joins ISO-NE scenario. Attachment 12 details both the Status Quo and Join ISO-NE wholesale power supply cost projection for NMISA's South Region.

WHOLESALE POWER SUPPLY COST/BENEFIT RESULTS

NMISA North Region

To determine the wholesale power supply market cost or benefit to NMISA's North Region, NES compared the total annual wholesale market costs of the MPS Status Quo scenario with MPS joining ISO-NE. Based on this assessment, MPS joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's North Region. Assuming 2015 ISO-NE participation, the cost of power supply would increase by (a) $5.4 million in the first year, (b) $28.3 million over the first 5 years, (c) $51.1 million over the first 10 years, and (d) $104.4 million over a 20 year period (or an average of $5.2 million per year). The summary results are shown in Table 3 of the main body of this report and in Attachment 11.

NMISA South Region

To determine the wholesale power supply market cost or benefit to NMISA's South Region, NES compared the total annual wholesale market costs of the EMEC Stand Alone scenario with EMEC joining ISO-NE. Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's South Region. Assuming 2015 ISO-NE participation, the cost of power supply would increase by (a) $1.0 million in the first year, (b) $5.3 million over the first 5 years, (c) $10.2 million over the first 10 years, and (d) $22.7 million over a 20 year period (or an average of $1.1 million per year). The summary results are shown in Table 3 of the main body of this report and in Attachment 12.

Total NMISA

Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA. Assuming 2015 ISO-NE participation, the cost of power supply would increase by (a) $6.4 million in the first year, (b) $33.6 million over the first 5 years, (c) $61.3 million over the first 10 years, and (d) $127.1 million over a 20 year period (or an average of $6.4 million per year). The summary results are shown in Table 3 of the main body of this report and Attachments 13 and 14.

ADDITIONAL ISSUES TO CONSIDER

As with Transmission, there are potential wholesale power cost risks associated with northern Maine joining ISO-NE that NES has not incorporated into this assessment. These risks include (1) increased price volatility and risk premium, (2) ISO-NE capacity costs, (3) increase in ISO-NE fees compared to NMISA, (4) AGC costs, and (5) increase in Maine and/or regional Reliability Must Run NCPC (Uplift) costs to maintain system

reliability, including the potential uplift due to substantial increases in wind generation in the northeast. For example, in a past wind RFP Hydro-Quebec assessed a balancing cost of $5/MWh to the wind generation. It is unclear whether HQ's balancing cost is driven by increased AGC requirements and/or Uplift. In any case Hydro-Quebec's generation portfolio makeup appears better equipped than ISO-NE's generation portfolio to balance the wind variance. Therefore, one would expect the balancing cost in ISO-NE to be higher than Hydro-Quebec. As another example of the potential impact of wind generation variability, in 2008 the unexpected loss of wind production amid changing weather was blamed, in part, for curtailment of electric service to industrial customers and real-time power prices hitting ERCOT's market cap of $2,250/MWh. If the balancing cost (AGC and uplift from unit posturing for reliability purposes) for new wind generation in northern Maine is $10/MWh, then the annual cost is approximately $8 million.

APPENDIX B

MERCHANT TRANSMISSION MODEL

COST BENEFIT ASSESSMENT

NES conducted a cost benefit assessment of the transmission interconnection request from the NMTS to ISO-NE under the assumption the interconnection is developed as a merchant transmission line. The assessment was conducted on both the transmission cost impact and the wholesale power supply cost impact on NMISA's Northern and Southern Regions.

TRANSMISSION COST BENEFIT ASSESSMENT

The transmission assessment involved developing 20 year transmission cost projections for (1) MPS under status quo, (2) MPS with merchant line, (3) EMEC under status quo, and (4) EMEC with merchant line. NES determined the cost or benefits for NMISA's North Region by comparing the transmission cost projections for MPS Status Quo to MPS with the merchant line. For NMISA's South Region, NES compared the transmission costs of EMEC Status Quo to EMEC with the merchant line. The following discusses the approach and major assumptions for the transmission cost projections for scenarios 1 through 4 above.

MPS Status Quo

NES performed a high level 20 year annual transmission cost projection for Maine Public Service Company under the Status Quo. The projection is identical to the one performed for the Socialized Transmission Model assessment, and the approach and major assumptions are described in Appendix A. Attachment 1 shows the MPS Status Quo transmission cost projection in detail.

MPS with Merchant Transmission Line (NMISA's North Region)

NES performed 20 year annual transmission cost projection for Maine Public Service with a Merchant Transmission Line interconnection between MPS and ISO-NE. The major assumptions are the same as the MPS Status Quo described above, with the exception of incremental energy and capacity exports from MPS from all the existing low cost generation in northern Maine (Tinker, Small Hydros, and ReEnergy Fort Fairfield, if economic) that have historically served northern Maine load. The incremental exports will provide additional revenue credits under MPS' OATT and formula tariff rate. Attachment 16 shows MPS' annual transmission cost projection detail if a merchant transmission line interconnects MPS to ISO-NE.

EMEC Status Quo and EMEC with Merchant Trans. Line (NMISA's South Region)

NES performed a high level 20 year annual transmission cost projection for EMEC under the Status Quo. The projection is identical to the one performed for the Socialized Transmission Model assessment, and the approach and major assumptions are described in Appendix A.

Given the Merchant Transmission Line only interconnects NMISA's Northern Region to ISO-NE, EMEC's projected transmission costs are only slightly lower with the Merchant Transmission Line due to increased Northern Region exports reduce EMEC's (Southern Region) share of NMISA administrative costs, Attachment 17 shows the EMEC Status Quo and EMEC merchant transmission line cost projections in detail.

TRANSMISSION COST/BENEFIT ASSESSMENT RESULTS

NMISA North Region

To determine the transmission cost or benefit to NMISA's North Region, NES compared the total annual transmission cost of the MPS Status Quo scenario with MPS with a Merchant Transmission Line interconnection to ISO-NE. Based on NES' assessment, the Merchant Transmission Line would reduce the cost of transmission to customers in NMISA's North Region. Assuming 2015 start date, the cost of transmission would be reduced by (a) $0.7 million in the first year, (b) $3.7 million over the first 5 years, (c) $7.3 million over the first 10 years, and (d) $15.1 million over a 20 year period (or an average of $0.8 million per year). The summary results are shown in Table 4 of the main body of this report.

NMISA South Region

To determine the transmission cost or benefit to NMISA's South Region, NES compared the total annual transmission costs of the EMEC Status Quo with EMEC with an MPS to ISO-NE merchant line. Assuming 2015 start date, the cost of transmission would be reduced by (a) $6 thousand in the first year, (b) $31 thousand over the first 5 years, (c) $67 thousand over the first 10 years, and (d) $154 thousand over a 20 year period (or an average of $8 thousand per year). The summary results are shown in Table 4 of the main body of this report.

Total NMISA

Based on this assessment, a merchant transmission line would reduce the cost of transmission to customers in NMISA. Assuming 2015 start date, the cost of transmission would be reduced by (a) $0.7 million in the first year, (b) $3.7 million over the first 5 years, (c) $7.4 million over the first 10 years, and (d) $15.3 million over a 20 year period (or an average of $0.8 million per year). The summary results are shown in Table 4 of the main body of this report and Attachments 24 and 25.

ADDITIONAL ISSUES TO CONSIDER

A high level economic evaluation raises significant questions as to whether such a "merchant" line is economically justified. For MPC2012 the total estimated cost is about $300 million (assuming two 345kv transmission lines from Houlton-Haynesville and/or Chester plus terminal equipment). Assuming a $348 million cost (with AFUDC), an 18% carrying charge, and 600 MW capacity, the cost of the "merchant" line access for the new wind generation project would be about $104/kw/yr (or about $36/MWh with a 33% capacity factor). For existing hydro/biomass generation, new wind generation, or new baseload generation north of Bridgewater in MPS' service territory, the transmission cost is assumed to be the MPS out-tariff plus MPC2012 (Houlton-Haynesville). With MPC2012 estimated costs of $348 million, 18% carrying charge, and 600 MW capacity, the MPC2012 cost would be about $104/kw/yr. MPS' outservice transmission charge is about $46/kw/yr. Therefore, the total transmission cost for these potential customers is about $150/kw/yr (or about $21/MWh for a baseload generator with an 80% capacity factor), which is significantly greater than $78/kw/yr cost of moving energy into ISO-NE through New Brunswick (MPS' $46/kw/yr, NB Power Transmission $32/kw/yr; average projected rates for 2015-2034).

WHOLESALE POWER SUPPLY MARKET COST BENEFIT

The wholesale power supply market assessment involved developing 20 year power supply cost projections for (1) MPS under status quo, (2) ISO-NE, (3) MPS with a merchant transmission line to ISO-NE, (4) EMEC under status quo, and (5) EMEC with a MPS to ISO-NE merchant transmission line. To determine the cost or benefits for NMISA's North Region NES compared the wholesale power supply cost projections for MPS Status Quo to MPS with a merchant transmission line. For NMISA's South Region NES compared the wholesale power supply costs from EMEC Status Quo to EMEC with a MPS to ISO-NE merchant transmission line. The following discusses the approach and major assumptions for the wholesale power supply cost projections for scenarios 1 through 5 above.

MPS Status Quo

NES performed a 20 year annual power supply cost projection for NMISA's Northern Region under the status quo. The projection is identical to the one performed for the Socialized Transmission Model assessment, and the approach and major assumptions are described in Appendix A. Attachment 10 shows the Status Quo wholesale power supply cost projection in detail for NMISA's Northern Region.

MPS with Merchant Transmission Line

NES performed a 20 year annual wholesale power supply cost projection for NMISA's Northern Region if MPS interconnects with ISO-NE via a merchant transmission line. Under this scenario it is assumed all the low cost generation (Tinker, Small Hydros, and ReEnergy Fort Fairfield, if economic) that historically served the load in northern Maine must make transmission commitments to export their energy and capacity into the higher

priced ISO-NE market via the MPS transmission system and the merchant transmission line. Given the commitments required, NES assumed northern Maine, Maritime and Quebec suppliers will price supply in northern Maine as a function of the cost of supply from ISO-NE. The new merchant transmission line interconnection point/node with ISO-NE will then become the liquid price point and resource to serve the load in NMISA's Northern Region. In addition, the merchant line interconnection point with ISO-NE is assumed to have the same Locational Marginal Price (LMP) as the Salisbury node. Therefore, the liquid price point for serving northern Maine consumers will be the new Salisbury energy price, capacity, ISO-NE export related fees (ancillaries, NCPC/Uplift, ISO Sch 2, ISO Sch 3,…), NEPOOL expenses, ISO-NE transmission outservice related costs, and MPC2012 transmission costs. Historically, Maine Zone and Salisbury energy clearing prices have been at substantial discount to Mass Hub. Given MPRP and other NE transmission investments south of Maine, NES assumes long term (2015 and beyond) Maine Zone energy prices will equal about 98% of the Hub, which is approximately the regional loss and non-congested price. The Salisbury nodal basis from the Hub will also increase accordingly. NES projected ISO-NE's energy, capacity, and export related costs by using (1) actual Maine 2011 load serving costs as specified in ISO-NE's 2011 Wholesale Cost Report (WCR), (2) 2012 ISO-NE Tariff revenue requirements, (3) historical billing and (4) ISO-NE transmission cost documents (2011 RSP, August 2012 Five Year RNS Forecast, New England 2030 Power System Study, 2010 Regional Energy Outlook, 2012 CELT Report,…). For future years, NES incorporated known changes and/or a 3% annual inflationary cost increase. In addition, NES included a load following cost adder of 3% of the usage weighted cost at the Salisbury energy price.

With respect to capacity, NES assumed the capacity rates cleared to-date in the Forward Capacity Market, $4.50/kw/mo in 2010/11, $3.60/kw/mo in 2011/12, $2.95/kw/mo in 2012/13, $2.95/kw/mo in 2013/14, $3.21/kw/mo in 2014/15, and $3.43/kw/mo in 2015/16 and then plus 3% per year until 2023/24 with the estimated cost of a new peaker ($11.81/kw/mo), escalated at 3% per year thereafter.

ISO-NE transmission outservice costs are included as one of the export fees charged by ISO-NE. Please note NES assumes suppliers serving northern Maine load from ISO-NE will become external network load/transmission customers of ISO-NE and thus pay ISO-NE's RNS rate. These costs are referred to herein as transmission outservice. With respect to ISO-NE transmission outservice related costs, NES performed 20 year projections of the three cases [ISO-NE 2012 RSP, RPS Buildout Case, New England/ Maine Buildout Case] detailed in Section 4.1 of the main body of the report (Socialized Transmission Model). The Merchant Transmission Model ISO-NE RNS projections differ only by excluding MPC2012 and MPS transmission costs from ISO-NE's RNS rate. However, it is assumed load in northern Maine will have to pay a portion of MPC2012 transmission cost to access the ISO-NE power supply market. Attachments 18 and 19 details the ISO-NE transmission cost projections for ISO-NE 2012 RSP and RPS Buildout Case accordingly.

NES assumes the supply to serve northern Maine load will be provided from the Maritime and/or Quebec marketplace at the MPC2012 node (assumed equal to Salisbury)

energy price plus 70% of the non-energy ISO-NE sourced cost (***including*** ISO-NE transmission outservice and MPC2012). This assumption reflects the potential for existing/new northern Maine renewable generation competition for this load as well as related required costs for back-up and ancillary services should that occur.

Attachments 20 and 21 details MPS (NMISA Northern Region) merchant line wholesale power supply cost projections for the ISO-NE 2012 RSP Case and RPS Buildout Case accordingly.

EMEC Status Quo and EMEC with MPS Merchant Line (NMISA's South Region)

NES performed a 20 year annual wholesale load serving cost projection for NMISA's South Region under both EMEC Status Quo and MPS merchant line interconnection with ISO-NE.

With respect to EMEC Status Quo, the projection is identical to the one performed for the Socialized Transmission Model assessment, and the approach and major assumptions are described in Appendix A. Attachment 22 shows the Status Quo wholesale power supply cost projection in detail for NMISA's Southern Region.

With respect to merchant line interconnection, NES assumed EMEC's load will be served by internal generation (on costs terms consistent with Status Quo) and the incremental generation will be provided by Maritime suppliers at a cost equal to Salisbury energy plus 70% of the non-energy cost from ISO-NE resources (same as the NMISA Northern Region). Attachment 23 details both the ISO-NE 2012 RSP Case and RPS Buildout Case wholesale power supply cost projection for NMISA's South Region.

WHOLESALE POWER SUPPLY COST/BENEFIT RESULTS

NMISA North Region

To determine the wholesale power supply market cost or benefit to NMISA's North Region, NES compared the total annual wholesale market costs of the MPS Status Quo scenario with the MPS merchant line interconnection with ISO-NE scenario. Based on this assessment, MPS merchant line with ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's North Region.

ISO-NE 2012 RSP Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $17.3 million in the first year, (b) $89.9 million over the first 5 years, (c) $168.8 million over the first 10 years, and (d) $303.6 million over a 20 year period (or an average of $15.2 million per year). The summary results are shown in Table 5 of the main body of this report.

RPS Buildout Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $20.1 million in the first year, (b) $132.1 million over the first 5 years, (c) $297.6 million over the first 10 years, and (d) $605.4 million over a 20

year period (or an average of $30.3 million per year). The summary results are shown in Table 6 of the main body of this report.

New England/Maine Buildout Case – Incremental (to RSP Case) Cost Impact: Assuming 2015 Merchant Interconnection Date, the incremental cost of power supply would be (a) $0.0 million in the first year, (b) $18.6 million over the first 5 years, (c) $56.1 million over the first 10 years, and (d) $130.9 million over a 20 year period (or an average of $6.6 million per year).

NMISA South Region

To determine the wholesale power supply market cost or benefit to NMISA's South Region, NES compared the total annual wholesale market costs of the EMEC Status Quo scenario with EMEC MPS merchant line interconnection with ISO-NE. Based on this assessment, a merchant line with ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's South Region.

ISO-NE 2012 RSP Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $0.2 million in the first year, (b) $1.3 million over the first 5 years, (c) $2.4 million over the first 10 years, and (d) $4.4 million over a 20 year period (or an average of $0.2 million per year). The summary results are shown in Table 5 of the main body of this report.

RPS Buildout Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $0.3 million in the first year, (b) $2.1 million over the first 5 years, (c) $5.0 million over the first 10 years, and (d) $11.3 million over a 20 year period (or an average of $0.6 million per year). The summary results are shown in Table 6 of the main body of this report.

New England/Maine Buildout Case – Incremental (to RSP Case) Cost Impact: Assuming 2015 Merchant Interconnection Date, the incremental cost of power supply would be (a) $0.0 million in the first year, (b) $0.4 million over the first 5 years, (c) $1.2 million over the first 10 years, and (d) $3.0 million over a 20 year period (or an average of $0.2 million per year).

Total NMISA

Based on this assessment, a merchant line interconnecting MPS with ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA.

ISO-NE 2012 RSP Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $17.6 million in the first year, (b) $91.1 million over the first 5 years, (c) $171.2 million over the first 10 years, and (d) $307.9 million over a 20 year period (or an average of $15.4 million per year). The summary results are shown in Table 5 of the main body of this report and in Attachment 24.

RPS Buildout Case: Assuming 2015 Merchant Interconnection Date, the cost of power supply would increase by (a) $20.4 million in the first year, (b) $134.2 million over the

first 5 years, (c) $302.6 million over the first 10 years, and (d) $616.7 million over a 20 year period (or an average of $30.8 million per year). The summary results are shown in Table 6 of the main body of this report and in Attachment 25.

New England/Maine Buildout Case – Incremental (to RSP Case) Cost Impact: Assuming 2015 Merchant Interconnection Date, the incremental cost of power supply would be (a) $0.0 million in the first year, (b) $19.0 million over the first 5 years, (c) $57.2 million over the first 10 years, and (d) $133.9 million over a 20 year period (or an average of $6.7 million per year **in addition to the ISO-NE 2012 RSP Case**). Attachment 26 shows the summary results for New England/Maine Buildout Case.

ADDITIONAL ISSUES TO CONSIDER

As with Socialized Model, there are potential wholesale power cost risks associated with Merchant Model that NES has not incorporated into this assessment. Given the Merchant model wholesale supply costs will be related to ISO-NE, these risks include the same risks outlined in the Socialized Model. These risks include (1) increased price volatility and risk premium, (2) ISO-NE capacity costs, (3) increase in ISO-NE fees, (4) AGC costs, and (5) increase in Maine and/or regional Reliability Must Run NCPC (Uplift) costs to maintain system reliability, including the potential uplift due to substantial increases in wind generation in the northeast.

ATTACHMENT 1

SOCIALIZED TRANSMISSION MODEL
and
MERCHANT TRANSMISSION MODEL

MPS Annual Transmission Cost Projection
Status Quo

ATTACHMENT 1

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Maine Public Service Company Annual Transmission Cost Projection - Status Quo
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**
MPS Gross Plant																					
MPS Planned Gross Plant Additions *		2,700	3,000	5,400	600																
Growth in Gross Plant																					
* Actual 2011 Gross Plant. Planned additions from MPS transmission plan inlcuded in NMISA 2012 7 Year Outlook plus $2 million Tinker Upgrade. Then 2.5% per year after 2018 which equals assumed depreciation.																					
MPS Gross Plant	2010	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838
MPS Gross Plant Additions	2011	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266
	2012	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045
	2013	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
	2014	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	2015	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
	2016		3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
	2017			5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400
	2018				600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
	2019					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022								0	0	0	0	0	0	0	0	0	0	0	0	0
	2023									0	0	0	0	0	0	0	0	0	0	0	0
	2024										0	0	0	0	0	0	0	0	0	0	0
	2025											0	0	0	0	0	0	0	0	0	0
	2026												0	0	0	0	0	0	0	0	0
	2027													0	0	0	0	0	0	0	0
	2028														0	0	0	0	0	0	0
	2029															0	0	0	0	0	0
	2030																0	0	0	0	0
	2031																	0	0	0	0
	2032																		0	0	0
	2033																			0	0
	2034																				0
Gross Plant Total		38,848	41,848	47,248	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848
Carrying Charge Rate (including OM&G, Property Taxes,…)		15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%
Transmission Investment Carry Cost ($K)		6,111	6,583	7,433	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2012 Tariff), 3%/yr	3.48	3.59	3.69	3.80	3.92	4.04	4.16	4.28	4.41	4.54	4.68	4.82	4.96	5.11	5.27	5.42	5.59	5.75	5.93	6.11
Reactive Supply and Voltage Control	Sch. 4 (2012 Tariff), 3%/yr	0.98	1.00	1.03	1.07	1.10	1.13	1.16	1.20	1.24	1.27	1.31	1.35	1.39	1.43	1.48	1.52	1.57	1.61	1.66	1.71
Customer Chg. (Sch. 1a)	MPS 2012 Tariff, 3%/yr	2.86	2.95	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73	3.84	3.96	4.08	4.20	4.33	4.46	4.59	4.73	4.87	5.01
Regulatory Chg. (Sch. 1b)	MPS 2012 Tariff, 3%/yr	0.47	0.48	0.50	0.51	0.53	0.54	0.56	0.58	0.59	0.61	0.63	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.80	0.82
Canc. Plant (Sch. 5)	MPS 2012 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		7.78	8.02	8.26	8.51	8.76	9.02	9.30	9.57	9.86	10.16	10.46	10.78	11.10	11.43	11.78	12.13	12.49	12.87	13.25	13.65
Other Transmssion Expenses ($/K)		798	826	855	885	916	948	982	1,016	1,052	1,089	1,127	1,167	1,208	1,250	1,294	1,340	1,387	1,435	1,486	1,538
Annual Revenue Requirement (excl. Wheeling) ($K)		6,909	7,409	8,288	8,412	8,443	8,475	8,509	8,543	8,579	8,616	8,654	8,694	8,735	8,777	8,821	8,867	8,914	8,963	9,013	9,065
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		67.41	71.93	80.06	80.85	80.75	80.65	80.57	80.49	80.43	80.37	80.33	80.29	80.27	80.26	80.26	80.27	80.30	80.34	80.39	80.45
Energy for Export from Northern Maine (MWh)		124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315
Ashland MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other exports MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill (to capture MA RECs) MWh		124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315
Previous Year Export Transmission Revenue ($K)		1,390	1,503	1,605	1,818	1,780	1,787	1,782	1,780	1,777	1,775	1,772	1,770	1,769	1,767	1,765	1,764	1,763	1,762	1,761	1,761
Through or Out Transmission Cost (Annual, $/kwyr)		50.29	53.70	60.85	59.56	59.81	59.62	59.56	59.46	59.39	59.31	59.25	59.18	59.13	59.07	59.03	58.99	58.96	58.93	58.91	58.90
Through or Out Transmission Cost (Hourly, $/MWh)		12.09	12.91	14.63	14.32	14.38	14.33	14.32	14.29	14.28	14.26	14.24	14.23	14.21	14.20	14.19	14.18	14.17	14.17	14.16	14.16
Transmission Revenue from Exports ($K)		1,503	1,605	1,818	1,780	1,787	1,782	1,780	1,777	1,775	1,772	1,770	1,769	1,767	1,765	1,764	1,763	1,762	1,761	1,761	1,760
Total Annual RR (after Wheeling Revenue Credit ($K))		5,519	5,906	6,683	6,594	6,663	6,688	6,727	6,763	6,802	6,841	6,882	6,923	6,966	7,010	7,056	7,103	7,151	7,201	7,252	7,305
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		53.85	57.34	64.55	63.38	63.73	63.65	63.70	63.73	63.77	63.82	63.88	63.94	64.02	64.10	64.20	64.30	64.42	64.54	64.68	64.83
NMISA Expenses (Entire NMISA)	NMISA 2012 Budget, 3% Esc.	327	337	348	358	369	381	392	404	417	430	443	456	470	485	500	515	531	547	564	581
MPS Status Quo - Annual Cost ($K)		5,846	6,243	7,030	6,952	7,033	7,069	7,120	7,168	7,219	7,271	7,325	7,380	7,437	7,495	7,556	7,618	7,682	7,748	7,816	7,886
MPS Load MW	NMISA 2012 7 Year Outlook	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1	112.7
Growth Factor: (2019-2034)	0.50%																				
MPS Load MW (12 CP) (Previous Year)		102.0	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MPS Status Quo - Annual Transmission Cost ($/kwyr)		57.04	60.61	67.91	66.82	67.26	67.27	67.42	67.54	67.68	67.83	67.99	68.16	68.34	68.54	68.75	68.97	69.20	69.45	69.71	69.98

ATTACHMENT 2

SOCIALIZED TRANSMISSION MODEL

ISO-NE Annual Transmission Cost Projection
2012 Regional System Plan (RSP) Case

ATTACHMENT 2

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model
ISO-NE Annual Transmission Cost Projection - ISO-NE 2012 RSP Case (ISO-NE 2012 Five Year RNS Forecast plus MPC2012)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (August 2012 RNS forecast)		1,330,000	1,246,000																		
New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection (MPC2012, $300 Million plus AFUDC)		348,000																			
Future Reliability Upgrades in Other States (Assumes NE Buildout Proportional to Maine)																					
Future Transmission Upgrades to Meet RPS Standards (ISO-NE New England 2030 Power System Study and 2010 Regional Electriciy Outlook)																					
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)		2,595	13	13	13																
MPS (PTF Qualified Portion, 76.9%)		29,874	2,307	4,153	461																
ISO-NE Gross Plant	2010	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600
ISO-NE Gross Plant Additions	2011	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000
	2012	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900
	2013	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000
	2014	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000
	2015	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469	1,710,469
	2016		1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320	1,248,320
	2017			4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166	4,166
	2018				475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475
	2019					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022								0	0	0	0	0	0	0	0	0	0	0	0	0
	2023									0	0	0	0	0	0	0	0	0	0	0	0
	2024										0	0	0	0	0	0	0	0	0	0	0
	2025											0	0	0	0	0	0	0	0	0	0
	2026												0	0	0	0	0	0	0	0	0
	2027													0	0	0	0	0	0	0	0
	2028														0	0	0	0	0	0	0
	2029															0	0	0	0	0	0
	2030																0	0	0	0	0
	2031																	0	0	0	0
	2032																		0	0	0
	2033																			0	0
	2034																				0
Gross Plant Additions Total		12,405,969	13,654,289	13,658,455	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930 22	13,658,930	13,658,930	13,658,930	13,658,930	13,658,930
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)		17.54%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%
Transmission Investment Carrying Cost ($K)		2,175,726	2,387,739	2,388,467	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550	2,388,550
ISO-NE Load MW (12 CP) (2012 ISO-NE RNS Forecast/ 2012 NMISA 7 Year Outlook Forecast)		20,290	20,392	20,494	20,596	20,699	20,803	20,907	21,011	21,116	21,222	21,328	21,435	21,542	21,650	21,758	21,867	21,976	22,086	22,196	22,307
Growth Factor (2017-2034) 0.50%																					
ISO-NE Load MW (12 CP) (Previous Year)		20,188	20,290	20,392	20,494	20,596	20,699	20,803	20,907	21,011	21,116	21,222	21,328	21,435	21,542	21,650	21,758	21,867	21,976	22,086	22,196
Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ISO-NE RNS Transmission Rate $/kwyr		107.77	117.68	117.13	116.55	115.97	115.39	114.82	114.25	113.68	113.11	112.55	111.99	111.43	110.88	110.33	109.78	109.23	108.69	108.15	107.61
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)		1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
Total ISO-NE Transmission Rate $/kwyr		109.71	119.67	119.18	118.66	118.14	117.63	117.13	116.62	116.13	115.63	115.15	114.67	114.19	113.72	113.25	112.79	112.33	111.88	111.44	111.00

ATTACHMENT 3

SOCIALIZED TRANSMISSION MODEL

ISO-NE Annual Transmission Cost Projection
Renewable Portfolio Standards (RPS) Case

ATTACHMENT 3

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model
ISO-NE Annual Transmission Cost Projection - Renewable Portfolio Standards (RPS) Buildout Case (ISO-NE 2012 RSP Case plus Transmission Buildout to Meet RPS)
August 17, 2012

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																				
ISO-NE Planned Gross Plant Additions (August 2012 RNS forecast)	1,330,000	1,246,000																		
New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																				
Proposed Northern Maine Interconnection (MPC2012, $300 Million plus AFUDC)	348,000																			
Future Reliability Upgrades in Other States (Assumes NE Buildout Proportional to Maine)																				
Future Transmission Upgrades to Meet RPS Standards (ISO-NE New England 2030 Power System Study and 2010 Regional Electriciy Outlook)	4,577,200	4,714,516	4,855,952	5,001,631	5,151,679	5,306,230														
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)	2,595	13	13	13																
MPS (PTF Qualified Portion, 76.9%)	29,874	2,307	4,153	461																
2010	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600
2011	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000
2012	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900
2013	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000
2014	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000
2015	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670	6,287,670
2016		5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837	5,962,837
2017			4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118	4,860,118
2018				5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105	5,002,105
2019					5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679
2020						5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230
2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022								0	0	0	0	0	0	0	0	0	0	0	0	0
2023									0	0	0	0	0	0	0	0	0	0	0	0
2024										0	0	0	0	0	0	0	0	0	0	0
2025											0	0	0	0	0	0	0	0	0	0
2026												0	0	0	0	0	0	0	0	0
2027													0	0	0	0	0	0	0	0
2028														0	0	0	0	0	0	0
2029															0	0	0	0	0	0
2030																0	0	0	0	0
2031																	0	0	0	0
2032																		0	0	0
2033																			0	0
2034																				0
Gross Plant Additions Total	16,983,170	22,946,006	27,806,124	32,808,229	37,959,909	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139	43,266,139
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated from ISO-NE RNS Forecast)	17.54%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%
Transmission Investment Carrying Cost ($K)	2,978,463	4,012,590	4,862,484	5,737,207	6,638,086	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991	7,565,991
ISO-NE Load MW (12 CP) (2012 ISO-NE RNS Forecast/ 2012 NMISA 7 Year Outlook Forecast)	20,290	20,392	20,494	20,596	20,699	20,803	20,907	21,011	21,116	21,222	21,328	21,435	21,542	21,650	21,758	21,867	21,976	22,086	22,196	22,307
Growth Factor (2017-2034) 0.50%																				
ISO-NE Load MW (12 CP) (Previous Year)	20,188	20,290	20,392	20,494	20,596	20,699	20,803	20,907	21,011	21,116	21,222	21,328	21,435	21,542	21,650	21,758	21,867	21,976	22,086	22,196
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ISO-NE RNS Transmission Rate $/kwyr	147.54	197.76	238.45	279.95	322.29	365.52	363.70	361.89	360.09	358.30	356.52	354.74	352.98	351.22	349.47	347.73	346.00	344.28	342.57	340.87
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)	1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
Total ISO-NE Transmission Rate $/kwyr	149.47	199.75	240.50	282.06	324.47	367.76	366.01	364.27	362.54	360.82	359.11	357.42	355.73	354.06	352.40	350.75	349.11	347.48	345.86	344.25

ATTACHMENT 4

SOCIALIZED TRANSMISSION MODEL

MPS Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2012 RSP Case)

ATTACHMENT 4

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model
Maine Public Service Company Annual Transmission Cost Projection - Joins ISO-NE (ISO-NE 2012 RSP Case)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**
MPS Gross Plant Total		38,848	41,848	47,248	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848
Carrying Charge Rate (including OM&G, Property Taxes,…)		15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%
Transmission Investment Carrying Cost ($K)		6,111	6,583	7,433	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		1,412	1,521	1,717	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		798	826	855	885	916	948	982	1,016	1,052	1,089	1,127	1,167	1,208	1,250	1,294	1,340	1,387	1,435	1,486	1,538
Total Local Transmission Costs ($K)		2,210	2,347	2,572	2,624	2,655	2,687	2,720	2,755	2,791	2,828	2,866	2,905	2,947	2,989	3,033	3,078	3,125	3,174	3,225	3,277
Assumed Percentage That Qualifies for PTF (MPC July 08 Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPS' PTF Annual Revenue Requirement ($K)		4,700	5,062	5,716	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788
Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MPS PTF Transmission Rate $/kwyr		46.08	49.39	55.49	55.91	55.64	55.36	55.08	54.81	54.54	54.27	54.00	53.73	53.46	53.19	52.93	52.67	52.40	52.14	51.88	51.63
MPS Load MW		102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1	112.7
Growth Factor: (2019-2034) 0.50%																					
MPS Load MW (12 CP) (Previous Year)		102.0	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		109.71	119.67	119.18	118.66	118.14	117.63	117.13	116.62	116.13	115.63	115.15	114.67	114.19	113.72	113.25	112.79	112.33	111.88	111.44	111.00
MPS RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		6,521	7,239	6,593	6,528	6,536	6,544	6,552	6,561	6,570	6,579	6,588	6,598	6,608	6,619	6,630	6,641	6,653	6,665	6,677	6,690
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2012 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	25	26	27	28	28	29	30	31	32	33	34	35	36	37	38	39	41	42	43	44
ISO Tariff Schedule 1 (System Control & Disp.)	2012 ISO Tariff, 3% Esc.	15	15	16	16	17	18	18	19	19	20	21	22	22	23	24	25	26	27	28	29
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2011 Tariff Rate, 3% Esc.	45	46	48	49	51	52	54	55	57	59	60	62	64	66	68	70	72	74	76	79
ISO Tariff Schedule 5 (NESCOE)	2012 ISO Tariff, 3% Esc.	11	11	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	18	19	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	33	34	35	36	37	38	39	41	42	43	44	46	47	49	50	51	53	55	56	58
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	56	58	59	61	63	65	67	69	71	73	75	77	80	82	85	87	90	92	95	98
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	19	19	20	20	21	22	22	23	24	24	25	26	27	27	28	29	30	31	32	33
Load Response Programs	Actual 2011, 3% Esc.	35	36	37	38	39	41	42	43	44	46	47	48	50	51	53	55	56	58	60	61
Demand Response Program	Actual 2011, 3% Esc.	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4
Total Other Expenses ($K)		241	249	256	264	272	280	289	297	306	316	325	335	345	356	363	374	385	397	409	421

MPS Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

MPS Annual Transmission Expenses ($K)																					
Local Transmission Expenses ($K)		2,210	2,347	2,572	2,624	2,655	2,687	2,720	2,755	2,791	2,828	2,866	2,905	2,947	2,989	3,033	3,078	3,125	3,174	3,225	3,277
PTF Transmission Expenses ($K)		11,188	12,265	12,276	12,284	12,292	12,300	12,308	12,316	12,325	12,334	12,344	12,353	12,364	12,374	12,385	12,396	12,408	12,420	12,432	12,445
Other Applicable ISO-NE/NEPOOL Expenses ($K)		241	249	256	264	272	280	289	297	306	316	325	335	345	356	363	374	385	397	409	421
Total Transmsission Costs ($K)		**13,639**	**14,860**	**15,104**	**15,172**	**15,218**	**15,267**	**15,317**	**15,369**	**15,422**	**15,478**	**15,535**	**15,594**	**15,655**	**15,719**	**15,781**	**15,848**	**15,918**	**15,991**	**16,066**	**16,143**
Total Transmission Costs ($/kwyr)		**133.07**	**144.27**	**145.90**	**145.83**	**145.55**	**145.28**	**145.04**	**144.80**	**144.58**	**144.38**	**144.19**	**144.02**	**143.87**	**143.74**	**143.58**	**143.48**	**143.40**	**143.33**	**143.29**	**143.27**
MPS Annual Transmission Costs (Stand Alone) ($K)		**5,846**	**6,243**	**7,030**	**6,952**	**7,033**	**7,069**	**7,120**	**7,168**	**7,219**	**7,271**	**7,325**	**7,380**	**7,437**	**7,495**	**7,556**	**7,618**	**7,682**	**7,748**	**7,816**	**7,886**
Annual MPS Transmission Cost/(Benefit) to Join ISO-NE ($K)		**7,793**	**8,617**	**8,074**	**8,220**	**8,186**	**8,198**	**8,197**	**8,201**	**8,203**	**8,207**	**8,210**	**8,214**	**8,219**	**8,224**	**8,225**	**8,231**	**8,237**	**8,243**	**8,250**	**8,257**

ATTACHMENT 5

SOCIALIZED TRANSMISSION MODEL

MPS Annual Transmission Cost Projection - Joins ISO-NE (RPS Buildout Case)

ATTACHMENT 5

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Socialized Transmission Line Model
Maine Public Service Company Annual Transmission Cost Projection - Joins ISO-NE (RPS Buildout Case)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K
MPS Gross Plant Total		38,848	41,848	47,248	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848
Carrying Charge Rate (including OM&G, Property Taxes,…)		15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%
Transmission Investment Carrying Cost ($K)		6,111	6,583	7,433	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		1,412	1,521	1,717	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		798	826	855	885	916	948	982	1,016	1,052	1,089	1,127	1,167	1,208	1,250	1,294	1,340	1,387	1,435	1,486	1,538
Total Local Transmission Costs ($K)		2,210	2,347	2,572	2,624	2,655	2,687	2,720	2,755	2,791	2,828	2,866	2,905	2,947	2,989	3,033	3,078	3,125	3,174	3,225	3,277
Assumed Percentage That Qualifies for PTF (MPC July 08 Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPS' PTF Annual Revenue Requirement		4,700	5,062	5,716	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788	5,788
Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MPS PTF Transmission Rate $/kwyr		46.08	49.39	55.49	55.91	55.64	55.36	55.08	54.81	54.54	54.27	54.00	53.73	53.46	53.19	52.93	52.67	52.40	52.14	51.88	51.63
MPS Load MW		102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1	112.7
Growth Factor: (2019-2034)	0.50%																				
MPS Load MW (12 CP) (Previous Year)		102.0	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		149.47	199.75	240.50	282.06	324.47	367.76	366.01	364.27	362.54	360.82	359.11	357.42	355.73	354.06	352.40	350.75	349.11	347.48	345.86	344.25
MPS RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		10,597	15,487	19,153	23,528	28,109	32,827	32,836	32,844	32,853	32,862	32,872	32,882	32,892	32,902	32,913	32,925	32,936	32,948	32,961	32,974
OTHER ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2012 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	25	26	27	28	28	29	30	31	32	33	34	35	36	37	38	39	41	42	43	44
ISO Tariff Schedule 1 (System Control & Disp.)	2012 ISO Tariff, 3% Esc.	15	15	16	16	17	18	18	19	19	20	21	22	22	23	24	25	26	27	28	29
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2011 Tariff Rate, 3% Esc.	45	46	48	49	51	52	54	55	57	59	60	62	64	66	68	70	72	74	76	79
ISO Tariff Schedule 5 (NESCOE)	2012 ISO Tariff, 3% Esc.	11	11	12	12	13	13	13	14	14	15	15	15	16	16	17	17	18	18	19	20
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	33	34	35	36	37	38	39	41	42	43	44	46	47	49	50	51	53	55	56	58
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	56	58	59	61	63	65	67	69	71	73	75	77	80	82	85	87	90	92	95	98
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	19	19	20	20	21	22	22	23	24	24	25	26	27	27	28	29	30	31	32	33
Load Response Programs	Actual 2011, 3% Esc.	35	36	37	38	39	41	42	43	44	46	47	48	50	51	53	55	56	58	60	61
Demand Response Program	Actual 2011, 3% Esc.	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4
Total Other Expenses ($K)		241	249	256	264	272	280	289	297	306	316	325	335	345	356	363	374	385	397	409	421

MPS Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)

MPS Annual Transmission Expenses ($K)																					
Local Transmission Expenses ($K)		2,210	2,347	2,572	2,624	2,655	2,687	2,720	2,755	2,791	2,828	2,866	2,905	2,947	2,989	3,033	3,078	3,125	3,174	3,225	3,277
PTF Transmission Expenses ($K)		15,243	20,473	24,773	29,199	33,757	38,452	38,461	38,469	38,478	38,487	38,497	38,506	38,516	38,527	38,538	38,549	38,561	38,573	38,585	38,598
Other Applicable ISO-NE/NEPOOL Expenses ($K)		241	249	256	264	272	280	289	297	306	316	325	335	345	356	363	374	385	397	409	421
Total Transmsission Costs ($K)		**17,694**	**23,068**	**27,601**	**32,087**	**36,684**	**41,420**	**41,470**	**41,521**	**41,575**	**41,630**	**41,688**	**41,747**	**41,808**	**41,872**	**41,933**	**42,001**	**42,071**	**42,144**	**42,219**	**42,296**
Total Transmission Costs ($/kwyr)		**172.64**	**223.95**	**266.62**	**308.41**	**350.85**	**394.17**	**392.68**	**391.21**	**389.77**	**388.35**	**386.95**	**385.57**	**384.21**	**382.88**	**381.54**	**380.25**	**378.99**	**377.76**	**376.55**	**375.36**
MPS Annual Transmission Costs (Stand Alone) ($K)		**5,846**	**6,243**	**7,030**	**6,952**	**7,033**	**7,069**	**7,120**	**7,168**	**7,219**	**7,271**	**7,325**	**7,380**	**7,437**	**7,495**	**7,556**	**7,618**	**7,682**	**7,748**	**7,816**	**7,886**
Annual MPS Transmission Cost/(Benefit) to Join ISO-NE ($K)		**11,848**	**16,825**	**20,571**	**25,135**	**29,651**	**34,351**	**34,350**	**34,354**	**34,356**	**34,360**	**34,363**	**34,367**	**34,372**	**34,376**	**34,378**	**34,383**	**34,389**	**34,396**	**34,403**	**34,410**

ATTACHMENT 6

SOCIALIZED TRANSMISSION MODEL

EMEC Status Quo and Joins ISO-NE
Annual Transmission Cost Projections
(ISO-NE 2012 RSP and RPS Buildout Cases)

ATTACHMENT 6

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Socialized Transmission Line Model
Eastern Maine Electric Cooperative (EMEC) Status Quo and Joins ISO-NE Annual Transmission Cost Projections
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
TRANSMISSION COSTS																					
Status Quo																					
EMEC Transmission																					
EMEC System ($/kwyr) (2012/13 Tariff Rate, 0.5% annual escalation)		5.28	5.31	5.34	5.36	5.39	5.42	5.44	5.47	5.50	5.52	5.55	5.58	5.61	5.64	5.66	5.69	5.72	5.75	5.78	5.81
NB System ($/kwyr) (2011 Firm Pt-to-Pt Tariff Rate, 0.5% annual esc., 100% Exch. Rate)		30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26	33.43	33.59
Total EMEC Transmission Cost ($/kwyr)		35.84	36.02	36.20	36.38	36.56	36.74	36.93	37.11	37.30	37.48	37.67	37.86	38.05	38.24	38.43	38.62	38.82	39.01	39.20	39.40
EMEC South NMISA Fee - T&D ($K)		41	42	43	44	46	47	49	50	52	53	55	57	58	60	62	64	66	68	70	72
Total EMEC South Transmission Cost ($K)		496	501	507	513	519	526	532	538	545	551	558	564	571	578	585	592	600	607	614	622
Total EMEC South Transmission Cost ($/kwyr)		39.03	39.29	39.56	39.82	40.09	40.37	40.64	40.92	41.21	41.49	41.78	42.08	42.37	42.67	42.98	43.29	43.60	43.91	44.23	44.56
ISO-NE 2012 RSP CASE (ISO-NE 2012 Five Year RNS Forecast, MPC2012)																					
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																					
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		109.71	119.67	119.18	118.66	118.14	117.63	117.13	116.62	116.13	115.63	115.15	114.67	114.19	113.72	113.25	112.79	112.33	111.88	111.44	111.00
EMEC Projected 12 CP (MW)		12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89	13.96
Prior Years EMEC 12 CP (MW)		12.64	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89
EMEC RNS Cost ($K)		1,393	1,527	1,529	1,530	1,530	1,531	1,532	1,534	1,535	1,536	1,537	1,538	1,539	1,541	1,542	1,543	1,545	1,546	1,548	1,550
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2012 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5
ISO Tariff Schedule 1 (System Control & Disp.)	2012 ISO Tariff, 3% Esc.	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2011 Tariff Rate, 3% Esc.	6	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	9	9	9	10
ISO Tariff Schedule 5 (NESCOE)	2012 ISO Tariff, 3% Esc.	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	7	7	7	8	8	8	8	9	9	9	9	10	10	10	10	11	11	11	12	12
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4
Load Response Programs	Actual 2011, 3% Esc.	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8
Demand Response Program	Actual 2011, 3% Esc.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
Total Other Expenses ($K)		30	31	32	33	34	35	36	37	38	39	40	41	43	44	45	46	47	49	50	52
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**1,423**	**1,558**	**1,560**	**1,562**	**1,564**	**1,566**	**1,568**	**1,570**	**1,572**	**1,575**	**1,577**	**1,580**	**1,582**	**1,585**	**1,587**	**1,590**	**1,592**	**1,595**	**1,598**	**1,601**
Total EMEC (South Region) Transmission Costs ($/kwyr)		112.06	122.08	121.65	121.19	120.74	120.29	119.85	119.42	118.99	118.57	118.16	117.75	117.35	116.95	116.53	116.15	115.78	115.42	115.06	114.71
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**927**	**1,057**	**1,053**	**1,049**	**1,045**	**1,041**	**1,036**	**1,032**	**1,028**	**1,024**	**1,019**	**1,015**	**1,011**	**1,006**	**1,002**	**997**	**993**	**988**	**984**	**979**
RPS BUILDOUT CASE - (2012 RSP Case plus Transmission Buildout to Meet Renewable Portfolio Standards (RPS))																					
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																					
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		149.47	199.75	240.50	282.06	324.47	367.76	366.01	364.27	362.54	360.82	359.11	357.42	355.73	354.06	352.40	350.75	349.11	347.48	345.86	344.25
EMEC Projected 12 CP (MW)		12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89	13.96
Prior Years EMEC 12 CP (MW)		12.64	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89
EMEC RNS Cost ($K)		1,898	2,549	3,085	3,636	4,203	4,788	4,789	4,790	4,791	4,792	4,793	4,795	4,796	4,797	4,798	4,800	4,801	4,803	4,804	4,806
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																					
NEPOOL Expenses	2012 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5
ISO Tariff Schedule 1 (System Control & Disp.)	2012 ISO Tariff, 3% Esc.	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2011 Tariff Rate, 3% Esc.	6	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	9	9	9	10
ISO Tariff Schedule 5 (NESCOE)	2012 ISO Tariff, 3% Esc.	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
OATT Schedule 2 - VAR	Actual 2011, 3% Esc.	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7
OATT Schedule 16 - Black Start	Actual 2011, 3% Esc.	7	7	7	8	8	8	8	9	9	9	9	10	10	10	10	11	11	11	12	12
OATT Schedule 19 - Special Const Resources	Actual 2011, 3% Esc.	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4
Load Response Programs	Actual 2011, 3% Esc.	4	4	5	5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	7	8
Demand Response Program	Actual 2011, 3% Esc.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
Total Other Expenses ($K)		30	31	32	33	34	35	36	37	38	39	40	41	43	44	45	47	48	49	51	52
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**1,928**	**2,580**	**3,116**	**3,668**	**4,237**	**4,822**	**4,825**	**4,827**	**4,829**	**4,831**	**4,833**	**4,836**	**4,838**	**4,841**	**4,844**	**4,846**	**4,849**	**4,852**	**4,855**	**4,858**
Total EMEC (South Region) Transmission Costs ($/kwyr)		151.82	202.16	242.97	284.59	327.06	370.42	368.73	367.06	365.40	363.75	362.12	360.50	358.89	357.30	355.72	354.15	352.59	351.05	349.52	348.01
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**1,432**	**2,078**	**2,609**	**3,155**	**3,717**	**4,297**	**4,293**	**4,289**	**4,284**	**4,280**	**4,276**	**4,271**	**4,267**	**4,263**	**4,258**	**4,254**	**4,250**	**4,245**	**4,241**	**4,236**

ATTACHMENT 7

SOCIALIZED TRANSMISSION MODEL

ISO-NE MA Hub Forward Energy Price Projection

ATTACHMENT 7

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
ISO-NE (MA Hub) Forward Energy Price Projection
August 17, 2012

Natural Gas (Henry Hub, August 13, 2012 NYMEX/CME close through 2024 then 2023/2024 escalation thereafter)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jan	4.31	4.51	4.71	4.95	5.22	5.51	5.83	6.17	6.48	6.78	7.09	7.42	7.76	8.12	8.49	8.89	9.30	9.73	10.17	10.64
Feb	4.28	4.48	4.68	4.93	5.20	5.49	5.81	6.14	6.45	6.75	7.07	7.39	7.74	8.10	8.47	8.87	9.28	9.71	10.16	10.64
Mar	4.20	4.40	4.60	4.85	5.12	5.41	5.73	6.06	6.37	6.67	6.99	7.32	7.66	8.02	8.40	8.79	9.21	9.64	10.10	10.57
Apr	3.97	4.18	4.38	4.62	4.90	5.19	5.53	5.82	6.09	6.37	6.67	6.97	7.29	7.63	7.98	8.35	8.73	9.13	9.55	9.99
May	3.99	4.19	4.40	4.64	4.92	5.21	5.56	5.82	6.08	6.36	6.65	6.96	7.28	7.61	7.96	8.33	8.72	9.12	9.54	9.98
Jun	4.02	4.22	4.42	4.67	4.95	5.24	5.59	5.85	6.12	6.40	6.69	7.00	7.32	7.65	8.00	8.37	8.75	9.15	9.57	10.01
Jul	4.06	4.26	4.47	4.72	5.00	5.29	5.63	5.90	6.17	6.45	6.74	7.05	7.37	7.70	8.05	8.42	8.80	9.20	9.62	10.05
Aug	4.08	4.28	4.49	4.74	5.02	5.31	5.65	5.94	6.21	6.49	6.79	7.09	7.41	7.75	8.10	8.46	8.84	9.24	9.66	10.09
Sep	4.08	4.28	4.49	4.74	5.02	5.31	5.66	5.95	6.23	6.51	6.80	7.11	7.43	7.76	8.11	8.47	8.85	9.25	9.67	10.10
Oct	4.12	4.32	4.53	4.78	5.06	5.35	5.70	6.01	6.29	6.57	6.87	7.17	7.49	7.82	8.17	8.54	8.92	9.31	9.73	10.16
Nov	4.21	4.41	4.64	4.89	5.17	5.47	5.81	6.13	6.42	6.70	7.00	7.31	7.64	7.98	8.33	8.70	9.09	9.49	9.91	10.35
Dec	4.41	4.61	4.85	5.11	5.40	5.71	6.05	6.36	6.65	6.93	7.23	7.54	7.86	8.20	8.55	8.92	9.30	9.70	10.12	10.55
Average	4.14	4.35	4.56	4.80	5.08	5.37	5.71	6.01	6.30	6.58	6.88	7.19	7.52	7.86	8.22	8.59	8.98	9.39	9.82	10.26

MA Hub Onpeak (August 13, 2012 NYMEX/CME Close through 2016, then 2016 Heat Rate and Natural Gas Forwards thereafter)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jan	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Feb	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Mar	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Apr	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
May	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Jun	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Jul	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Aug	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Sep	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Oct	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Nov	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Dec	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
Average	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67

MA Hub Offpeak (August 13, 2012 NYMEX/CME Close through 2016, then 2016 Heat Rate and Natural Gas Forwards thereafter)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jan	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Feb	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Mar	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Apr	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
May	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Jun	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Jul	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Aug	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Sep	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Oct	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Nov	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Dec	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Average	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14

MA Hub Around-the-Clock (August 13, 2012 NYMEX/CME Close through 2016, then 2016 Heat Rate and Natural Gas Forwards thereafter)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jan	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Feb	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Mar	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Apr	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
May	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Jun	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Jul	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Aug	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Sep	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Oct	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Nov	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Dec	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55
Average	42.33	43.43	45.52	48.01	50.78	53.70	57.10	60.08	62.94	65.80	68.78	71.90	75.17	78.58	82.14	85.87	89.77	93.84	98.10	102.55

ATTACHMENT 8

SOCIALIZED TRANSMISSION MODEL

Historical Regional Energy Prices

ATTACHMENT 8

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
Historical Northeast Regional Energy Clearing Prices
August 17, 2012

		ATC Salisbury	ATC ME Zone	ATC Hub	Onpeak Salisbury	Onpeak ME Zone	Onpeak Hub	Offpeak Salisbury	Offpeak ME Zone	Offpeak Hub	Hub Offpeak Perc of Onpeak
2008	January	76.07	78.60	83.99	86.62	89.23	95.83	66.60	69.06	73.37	76.6%
2008	February	68.41	71.62	75.33	75.82	79.97	84.74	61.49	63.83	66.56	78.5%
2008	March	72.44	74.08	78.20	78.35	80.35	85.37	67.56	68.91	72.28	84.7%
2008	April	79.69	83.61	90.08	87.33	92.16	100.80	72.38	75.45	79.83	79.2%
2008	May	91.00	92.45	99.43	103.10	104.20	114.73	81.04	82.77	86.83	75.7%
2008	June	100.85	102.78	109.32	114.10	116.76	127.00	89.26	90.55	93.85	73.9%
2008	July	97.33	103.56	111.02	110.93	121.57	132.10	85.12	87.38	92.09	69.7%
2008	August	65.82	67.42	70.92	71.54	73.51	78.16	61.11	62.40	64.96	83.1%
2008	September	62.93	63.34	65.68	68.27	68.70	72.04	58.26	58.66	60.11	83.4%
2008	October	59.01	59.72	60.18	64.08	64.82	66.44	54.05	54.73	54.07	81.4%
2008	November	56.51	56.88	61.13	62.89	63.09	68.69	51.84	52.33	55.60	80.9%
2008	December	57.25	57.56	59.76	61.33	61.59	64.24	53.59	53.93	55.73	86.8%
2008	Average	73.94	75.97	80.42	82.03	84.66	90.85	66.86	68.33	71.27	79.5%
2009	January	66.59	67.65	70.43	72.22	73.31	76.63	61.96	62.98	65.32	85.2%
2009	February	47.02	47.67	49.38	50.49	51.25	53.77	43.87	44.43	45.39	84.4%
2009	March	39.42	40.18	42.22	43.24	44.08	46.68	35.97	36.68	38.20	81.8%
2009	April	32.66	33.51	35.19	35.47	36.39	38.35	29.97	30.76	32.16	83.9%
2009	May	33.05	34.39	36.39	35.95	37.55	39.87	30.86	32.01	33.77	84.7%
2009	June	31.09	32.50	34.95	33.80	35.48	38.69	28.49	29.64	31.37	81.1%
2009	July	29.20	30.71	33.02	32.62	34.42	37.21	25.85	27.08	28.93	77.7%
2009	August	32.22	33.49	35.23	38.66	40.18	42.44	26.92	27.97	29.29	69.0%
2009	September	26.93	27.86	28.78	31.20	32.29	33.38	23.19	23.98	24.76	74.2%
2009	October	36.09	37.83	39.24	41.31	43.30	44.94	31.40	32.92	34.12	75.9%
2009	November	33.29	34.45	36.11	37.98	39.16	41.22	29.54	30.67	32.03	77.7%
2009	December	54.11	54.93	57.35	60.21	60.81	63.87	48.64	49.65	51.50	80.6%
2009	Average	38.47	39.60	41.52	42.76	44.02	46.42	34.72	35.73	37.24	79.7%
2010	January	58.34	58.94	61.07	64.02	64.66	67.12	54.06	54.61	56.51	84.2%
2010	February	48.71	49.82	52.36	53.31	54.55	57.42	44.53	45.52	47.77	83.2%
2010	March	34.77	36.09	38.07	38.36	39.82	41.99	31.25	32.43	34.22	81.5%
2010	April	31.71	33.24	37.19	35.42	37.23	41.92	28.16	29.42	32.66	77.9%
2010	May	38.33	39.90	44.11	42.26	44.30	50.70	35.36	36.57	39.13	77.2%
2010	June	46.05	46.76	48.49	52.83	53.57	55.86	39.57	40.24	41.45	74.2%
2010	July	56.03	58.24	61.05	71.74	74.84	78.24	43.10	44.57	46.89	59.9%
2010	August	50.04	51.51	53.55	62.33	64.29	66.66	39.01	40.03	41.78	62.7%
2010	September	44.23	44.95	45.12	53.06	53.84	53.94	36.51	37.17	37.40	69.3%
2010	October	34.46	35.24	35.97	38.79	39.94	40.95	30.90	31.37	31.88	77.9%
2010	November	41.73	42.54	44.08	45.26	46.37	48.28	38.63	39.19	40.40	83.7%
2010	December	61.39	62.80	65.28	68.34	70.01	73.17	54.59	55.75	57.57	78.7%
2010	Average	45.48	46.67	48.86	52.14	53.62	56.35	39.64	40.57	42.31	75.9%
2011	January	73.87	73.92	71.31	83.58	83.30	78.57	65.87	66.20	65.33	83.1%
2011	February	57.00	56.34	55.46	66.03	65.05	64.19	48.78	48.42	47.52	74.0%
2011	March	46.05	46.43	45.61	52.23	52.75	52.27	40.00	40.23	39.08	74.8%
2011	April	40.38	41.75	43.35	44.56	46.32	48.26	36.72	37.75	39.06	80.9%
2011	May	39.78	41.19	42.51	44.57	46.43	48.20	35.83	36.86	37.82	78.5%
2011	June	40.30	42.07	44.39	45.47	47.88	51.44	35.36	36.51	37.65	73.2%
2011	July	50.51	52.79	55.23	64.87	68.08	71.63	39.67	41.25	42.85	59.8%
2011	August	40.67	42.52	43.85	45.04	47.36	49.30	36.40	37.78	38.52	78.1%
2011	September	37.41	39.33	41.04	41.35	43.51	45.80	33.95	35.67	36.88	80.5%
2011	October	39.92	40.57	41.44	45.65	46.31	46.33	35.20	35.84	37.41	80.7%
2011	November	34.82	35.55	36.81	37.10	38.18	40.10	32.83	33.26	33.94	84.6%
2011	December	33.65	34.80	35.85	37.47	38.82	39.91	30.51	31.48	32.51	81.5%
2011	Average	44.53	45.61	46.40	50.66	52.00	53.00	39.26	40.10	40.71	77.5%
2010 thru 2011 Avg		45.01	46.14	47.63	51.40	52.81	54.68	39.45	40.34	41.51	
Basis to Hub		94.5%	96.9%		94.0%	96.6%		95.0%	97.2%		
2008 thru 2011 Avg		50.61	51.96	54.30	56.90	58.57	61.66	45.12	46.19	47.88	
Basis to Hub		93.2%	95.7%		92.3%	95.0%		94.2%	96.5%		

ATTACHMENT 9

SOCIALIZED TRANSMISSION MODEL

NMISA Load and Generation Assumptions
North Region

ATTACHMENT 9

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
NMISA Load and Generation Assumptions - Northern Region
August 17, 2012

Year	NMISA North & South Energy MWh	Northern % of Load	NMISA North Energy MWh	Peak MW		Tinker Hydro	Caribou Hydro	Squa Pan Hydro	Boralex Fort Fairfield	Boralex Ashland	Boralex Sherman	Evergreen Wind (MH)	Caribou Steam	Tinker Diesel	Caribou Diesel	Flo's Inn Diesel	Loring Diesel	Total	% of Load Served by In Region Generation
					MW ==>	34.6	0.9	1.4	33	37	19	42	23	1	7	4.2	5.1	208.2	
					Assumed CF (when operating)==>	48%	61%	8%	0%	0%	0%	34%	0%	0%	0%	0%	0%	46%	
2015	760,023	88.98%	676,241	119		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2016	763,823	88.98%	679,622	120		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2017	767,642	88.98%	683,020	120		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2018	771,481	88.98%	686,436	121		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2019	775,338	88.98%	689,868	121		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2020	779,215	88.98%	693,317	122		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2021	783,111	88.98%	696,784	123		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2022	787,026	88.98%	700,268	123		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	22%
2023	790,961	88.98%	703,769	124		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2024	794,916	88.98%	707,288	124		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2025	798,891	88.98%	710,824	125		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2026	802,885	88.98%	714,378	126		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2027	806,900	88.98%	717,950	126		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2028	810,934	88.98%	721,540	127		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2029	814,989	88.98%	725,148	128		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2030	819,064	88.98%	728,773	128		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2031	823,159	88.98%	732,417	129		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2032	827,275	88.98%	736,079	129		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	21%
2033	831,411	88.98%	739,760	130		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	20%
2034	835,568	88.98%	743,459	131		145,161	4,827	1,042	-	-	-	124,315	-	-	-	-	-	275,344	20%

Note: When economic, Boralex Ashland and Evergreen Wind are assumed to export out of Northern Maine to capture the value of southern New England RECs.

ATTACHMENT 10

SOCIALIZED TRANSMISSION MODEL

MPS Status Quo Power Supply Cost Projection
NMISA North

ATTACHMENT 10

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
MPS Status Quo Power Supply Cost Projection – NMISA North
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ISO-NE MA Hub Forward	Onpeak	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
ISO-NE MA Hub Forward	Offpeak	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Salisbury Basis	Onpeak	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%
Salisbury Basis	Offpeak	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%
(Salisbury/Keswick basis based on (1) historical 2008-11 and (2) reduced losses starting 2014 as a result of regionwide transmission additions).																					
Salisbury Node Forward	Onpeak	46.35	47.48	49.77	52.49	55.52	58.71	62.43	65.69	68.81	71.93	75.20	78.61	82.18	85.91	89.81	93.88	98.14	102.60	107.25	112.12
Salisbury Node Forward	Offpeak	35.18	36.16	37.90	39.97	42.28	44.71	47.54	50.02	52.40	54.78	57.26	59.86	62.58	65.42	68.39	71.49	74.73	78.13	81.67	85.38
Salisbury Node Forward	Around-The-Clock (ATC)	40.43	41.48	43.48	45.86	48.50	51.29	54.53	57.38	60.11	62.84	65.69	68.67	71.79	75.05	78.45	82.01	85.74	89.63	93.69	97.95
NET BACK TO NMISA (North Region) - ATC																					
ISO Tariff Schedule 2 (EAS) (Adjusted for Losses)		0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48	0.50
NB Transmission Losses (3.3%)		1.30	1.34	1.40	1.48	1.56	1.65	1.76	1.85	1.94	2.03	2.12	2.21	2.31	2.42	2.53	2.64	2.76	2.89	3.02	3.16
NB Trans Tariff (2011 Tariff, 80% CF, 0.5%/yr esc., 100% exch rate)		4.36	4.38	4.40	4.43	4.45	4.47	4.49	4.52	4.54	4.56	4.58	4.61	4.63	4.65	4.68	4.70	4.72	4.75	4.77	4.79
MPS Transmission Losses (2.3%)		0.93	0.96	1.00	1.06	1.12	1.18	1.26	1.32	1.38	1.45	1.51	1.58	1.65	1.73	1.81	1.89	1.97	2.06	2.16	2.26
MPS Tariff ($/MWh) (Projected Annual Rate @ 80% CF)		7.18	7.66	8.68	8.50	8.53	8.51	8.50	8.49	8.47	8.46	8.45	8.44	8.44	8.43	8.42	8.42	8.41	8.41	8.41	8.40
NMISA Tariff ($/MWh)		0.97	0.99	1.02	1.04	1.07	1.10	1.13	1.16	1.18	1.22	1.25	1.28	1.31	1.34	1.38	1.41	1.45	1.49	1.52	1.56
Total Netback		15.02	15.62	16.81	16.81	17.05	17.24	17.47	17.68	17.88	18.08	18.29	18.52	18.75	18.99	19.24	19.50	19.78	20.06	20.36	20.67
Status Quo Netback Energy Opportunity - ATC (Northern Region)		25.40	25.86	26.67	29.04	31.45	34.05	37.07	39.71	42.24	44.76	47.40	50.16	53.04	56.06	59.21	62.51	65.96	69.56	73.33	77.27
Assumed Split of Netback Costs with Northern Maine Consumers		50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Eff. Rate Charged to Northern Maine Consumers - ATC (Northern Region)		32.92	33.67	35.08	37.45	39.98	42.67	45.80	48.54	51.18	53.80	56.55	59.42	62.42	65.55	68.83	72.26	75.85	79.60	83.51	87.61
Status Quo Must Run Northern Region Netback MWh		151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029
Fort Fairfield Marginal Cost ($/MWh)		66.03	66.90	67.78	68.69	69.61	70.55	71.51	72.49	73.50	74.52	75.57	76.64	77.73	78.85	79.99	81.15	82.34	83.56	84.80	86.07
Eff, Rate for Fort Fairfield ($/MWh) (At least $3/MWh over MC)		69.03	69.90	70.78	71.69	72.61	73.55	74.51	75.49	76.50	77.52	78.57	79.64	80.73	81.85	82.99	84.15	85.34	86.56	87.80	89.07
Fort Fairfield Generation (MWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ashland Marginal Cost ($/MWh)		66.03	66.90	67.78	68.69	69.61	70.55	71.51	72.49	73.50	74.52	75.57	76.64	77.73	78.85	79.99	81.15	82.34	83.56	84.80	86.07
Effective Rate for Ashland ($/MWh) (At least $3/MWh over MC)		69.03	69.90	70.78	71.69	72.61	73.55	74.51	75.49	76.50	77.52	78.57	79.64	80.73	81.85	82.99	84.15	85.34	86.56	87.80	89.07
Ashland Generation (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherman Marginal Cost ($/MWh)		76.02	77.06	78.12	79.21	80.32	81.45	82.61	83.79	85.00	86.24	87.51	88.80	90.12	91.47	92.86	94.27	95.71	97.19	98.70	100.25
Effective Rate for Sherman ($/MWh) (At least $3/MWh over MC)		79.02	80.06	81.12	82.21	83.32	84.45	85.61	86.79	88.00	89.24	90.51	91.80	93.12	94.47	95.86	97.27	98.71	100.19	101.70	103.25
Sherman Generation (MWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Status Quo Wholesale Energy Cost (Northern Region) ($/MWh)		32.92	33.67	35.08	37.45	39.98	42.67	45.80	48.54	51.18	53.80	56.55	59.42	62.42	65.55	68.83	72.26	75.85	79.60	83.51	87.61
NMISA Northern Region (Avg ATC Generation MW)		17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
NMISA Northern Region Load																					
Onpeak Avg MW		87	88	88	88	89	89	90	90	91	91	92	92	92	93	93	94	94	95	95	96
Offpeak Avg MW		68	69	69	69	70	70	71	71	71	72	72	72	73	73	73	74	74	74	75	75
ATC Avg MW		77	78	78	78	79	79	80	80	80	81	81	82	82	82	83	83	84	84	84	85
NB Control Area Generation Purchases																					
NMISA Northern Region Load - Onpeak Avg MW		70	70	71	71	72	72	72	73	73	74	74	75	75	76	76	77	77	78	78	78
NMISA Northern Region Load - Offpeak Avg MW		51	52	52	52	53	53	53	54	54	54	55	55	55	56	56	57	57	57	58	58
NMISA Northern Region Load - ATC Avg MW		60	60	61	61	62	62	62	63	63	63	64	64	65	65	66	66	66	67	67	68
Status Quo Wholesale Energy Cost (NB Control Area) ($/MWh)		41.29	42.35	44.40	46.82	49.52	52.37	55.68	58.58	61.37	64.15	67.06	70.11	73.28	76.61	80.08	83.71	87.51	91.48	95.63	99.97
NMISA Northern Region Wholesale Energy Cost ($/MWh)																					
Northern Region Generation		32.92	33.67	35.08	37.45	39.98	42.67	45.80	48.54	51.18	53.80	56.55	59.42	62.42	65.55	68.83	72.26	75.85	79.60	83.51	87.61
NB Control Area Generation (Salisbury)		41.29	42.35	44.40	46.82	49.52	52.37	55.68	58.58	61.37	64.15	67.06	70.11	73.28	76.61	80.08	83.71	87.51	91.48	95.63	99.97
Load Following Premium (3% of Salisbury, Load Weighted)		1.23	1.26	1.33	1.40	1.48	1.56	1.66	1.75	1.83	1.92	2.00	2.09	2.19	2.29	2.39	2.50	2.61	2.73	2.86	2.99
Percent of Load Served by Northern Region		22%	22%	22%	22%	22%	22%	22%	22%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	20%	20%
Percent of Load Served by NB Control Area		78%	78%	78%	78%	78%	78%	78%	78%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	80%	80%
NMISA Northern Region Energy Cost ($/MWh)		40.65	41.69	43.66	46.16	48.91	51.82	55.20	58.17	61.02	63.86	66.83	69.94	73.19	76.58	80.13	83.84	87.72	91.77	96.01	100.44
Assumed NB Control Area Capacity Value (% of ISO-NE)		50%	50%	50%	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Status Quo Capacity Cost ($/kw-mo)		1.48	1.60	1.67	2.09	2.53	3.01	3.53	4.10	7.37	11.93	12.23	12.54	12.85	13.17	13.50	13.84	14.18	14.54	14.90	15.27
Capacity Cost ($/MWh)(64.92% LF per NMISA 7 Year Outlook)		3.13	3.36	3.53	4.41	5.35	6.33	7.45	8.65	15.56	25.11	25.81	26.45	27.11	27.71	28.49	29.20	29.93	30.68	31.44	32.23
NMISA Northern Region Energy Cost and Capacity Cost ($/MWh)		43.79	45.05	47.19	50.56	54.26	58.15	62.65	66.82	76.58	88.97	92.64	96.39	100.30	104.30	108.62	113.04	117.65	122.45	127.46	132.67
Other Wholesale Load Serving Costs																					
Reserves ($/MWh) (2012 NB Tariff, plus 3% per year, 100% Exchange Rate)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Fees ($/MWh) (inlcuded in Northern Region Trans)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total Other Wholesale Costs ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	1.00	1.02	1.05
Total Stand Alone Wholesale Power Supply Costs ($/MWh)		44.42	45.71	47.87	51.25	54.96	58.88	63.39	67.59	77.36	89.78	93.47	97.24	101.17	105.19	109.54	113.98	118.62	123.45	128.48	133.72
NMISA North Region Load (MWh)		676,241	679,622	683,020	686,436	689,868	693,317	696,784	700,268	703,769	707,288	710,824	714,378	717,950	721,540	725,148	728,773	732,417	736,079	739,760	743,459
North Region Stand Alone Wholesale Power Supply Costs ($K)		30,041	31,063	32,693	35,183	37,918	40,823	44,172	47,329	54,446	63,497	66,439	69,467	72,638	75,902	79,431	83,069	86,878	90,866	95,043	99,417

ATTACHMENT 11

SOCIALIZED TRANSMISSION MODEL

MPS Joins ISO-NE Power Supply Cost Projection
NMISA North

ATTACHMENT 11

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
MPS Joins ISO-NE Power Supply Cost Projection – NMISA North
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MA Hub	Onpeak	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
MA Hub	Offpeak	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
ME Zone Basis	Onpeak	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
ME Zone Basis	Offpeak	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
(ME Zone basis percentage Based on CME/NYMEX Forwards through 2013 then increases as a result of assumed reduction in losses and congestion that may result from regional transmission additions)																					
ME Zone	Onpeak	47.67	48.83	51.19	53.99	57.10	60.39	64.21	67.56	70.78	73.99	77.34	80.85	84.52	88.36	92.37	96.56	100.94	105.52	110.31	115.32
ME Zone	Offpeak	36.00	37.00	38.78	40.90	43.26	45.75	48.64	51.18	53.62	56.05	58.59	61.25	64.03	66.94	69.98	73.15	76.47	79.94	83.57	87.36
Historical NMISA Energy Usage	Onpeak	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%
Historical NMISA Energy Usage	Offpeak	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%
Load Following Premium (3% of ME Zone, Load Weighted)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
ME Zone Energy Usage Weighted Energy Cost		43.45	44.57	46.72	49.28	52.12	55.11	58.60	61.66	64.60	67.53	70.59	73.79	77.14	80.64	84.30	88.13	92.13	96.31	100.68	105.25
Other Wholesale Load Serving Costs																					
Capacity ($/kw-mo) (Cleared thru 15/16, then Floor thru 22/23, then estimated new peaker cost)		2.97	3.20	3.35	3.48	3.62	3.76	3.92	4.10	7.37	11.93	12.23	12.54	12.85	13.17	13.50	13.84	14.18	14.54	14.90	15.27
Capacity ($/MWh) (64.92% Load Factor per actual NMISA 2011)		6.27	6.73	7.06	7.34	7.64	7.92	8.28	8.65	15.56	25.11	25.81	26.45	27.11	27.71	28.49	29.20	29.93	30.59	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC/RMR	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other (Inad./Emer.En, RT Reserve)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.43)	(0.44)	(0.46)	(0.48)	(0.51)	(0.54)	(0.57)	(0.60)	(0.63)	(0.66)	(0.69)	(0.72)	(0.76)	(0.79)	(0.83)	(0.86)	(0.90)	(0.94)	(0.99)	(1.03)
NEPOOL Expenses	Included in Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Total Other Wholesale Power Supply Costs ($/MWh)		9.00	9.55	9.96	10.32	10.69	11.05	11.48	11.94	18.94	28.58	29.37	30.11	30.87	31.57	32.45	33.27	34.10	34.88	35.84	36.75
Total Join ISO-NE Wholesale Power Supply Costs ($/MWh)		**52.45**	**54.12**	**56.69**	**59.59**	**62.80**	**66.16**	**70.08**	**73.60**	**83.53**	**96.10**	**99.96**	**103.90**	**108.01**	**112.22**	**116.75**	**121.39**	**126.23**	**131.19**	**136.52**	**142.00**
Total NMISA North Region Wholesale Power Supply Costs ($K)		**35,471**	**36,782**	**38,717**	**40,908**	**43,327**	**45,871**	**48,831**	**51,540**	**58,788**	**67,973**	**71,054**	**74,227**	**77,548**	**80,968**	**84,661**	**88,469**	**92,454**	**96,565**	**100,995**	**105,569**
STATUS QUO vs JOIN ISO-NE																					
Status Quo Wholesale Power Supply Costs ($/MWh)		44.42	45.71	47.87	51.25	54.96	58.88	63.39	67.59	77.36	89.78	93.47	97.24	101.17	105.19	109.54	113.98	118.62	123.45	128.48	133.72
Join ISO-NE Wholesale Power Supply Costs ($/MWh)		52.45	54.12	56.69	59.59	62.80	66.16	70.08	73.60	83.53	96.10	99.96	103.90	108.01	112.22	116.75	121.39	126.23	131.19	136.52	142.00
Wholesale Market Costs (Benefits) for Joining ISO-NE ($/MWh)		8.03	8.42	8.82	8.34	7.84	7.28	6.69	6.01	6.17	6.33	6.49	6.66	6.84	7.02	7.21	7.41	7.61	7.74	8.05	8.27
NMISA Northern Region Load (MWh)		676,241	679,622	683,020	686,436	689,868	693,317	696,784	700,268	703,769	707,288	710,824	714,378	717,950	721,540	725,148	728,773	732,417	736,079	739,760	743,459
NMISA Northern Region Wholesale Market Costs (Benefits) ($K)		5,430	5,719	6,024	5,725	5,410	5,048	4,659	4,212	4,342	4,476	4,615	4,759	4,910	5,067	5,230	5,400	5,577	5,699	5,952	6,152

ATTACHMENT 12

SOCIALIZED TRANSMISSION MODEL

EMEC Status Quo and Joins ISO-NE
Power Supply Cost Projection
NMISA South

ATTACHMENT 12

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Cost/Benefit Assessment
Socialized Transmission Line Model
Eastern Maine Electric Cooperative (EMEC/NMISA South) Status Quo and Join ISONE Power Supply Cost Projection
August 17, 2012

WHOLESALE POWER SUPPLY COST

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo																					
Salisbury Node Forward	Onpeak	46.35	47.48	49.77	52.49	55.52	58.71	62.43	65.69	68.81	71.93	75.20	78.61	82.18	85.91	89.81	93.88	98.14	102.60	107.25	112.12
Salisbury Node Forward	Offpeak	35.18	36.16	37.90	39.97	42.28	44.71	47.54	50.02	52.40	54.78	57.26	59.86	62.58	65.42	68.39	71.49	74.73	78.13	81.67	85.38
Salisbury Node Forward	ATC	40.43	41.48	43.48	45.86	48.50	51.29	54.53	57.38	60.11	62.84	65.69	68.67	71.79	75.05	78.45	82.01	85.74	89.63	93.69	97.95
NET BACK TO NMISA ($/MWH) (South Region)																					
ISO Tariff Schedule 2 (EAS) (Adjusted for Losses)		0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49
NB Transmission Losses (3.3%)		1.36	1.39	1.46	1.54	1.63	1.72	1.83	1.93	2.02	2.11	2.21	2.31	2.41	2.52	2.64	2.76	2.88	3.01	3.15	3.29
NB Transmission Tariff (2011 Tariff Rate @ 80% CF, 0.5%/yr esc., 100% exchange rate)		4.36	4.38	4.40	4.43	4.45	4.47	4.49	4.52	4.54	4.56	4.58	4.61	4.63	4.65	4.68	4.70	4.72	4.75	4.77	4.79
EMEC Transmission Losses (1.83%)		0.74	0.76	0.80	0.84	0.89	0.94	1.00	1.05	1.10	1.15	1.20	1.26	1.31	1.37	1.44	1.50	1.57	1.64	1.71	1.79
EMEC Tariff ($/MWh) (2012/13 Tariff, non-firm hourly rate, 0.5% annual esc.)		0.88	0.89	0.89	0.90	0.90	0.91	0.91	0.92	0.92	0.92	0.93	0.93	0.94	0.94	0.95	0.95	0.96	0.96	0.97	0.97
NMISA Tariff ($/MWh)		0.97	0.99	1.02	1.04	1.07	1.10	1.13	1.16	1.18	1.22	1.25	1.28	1.31	1.34	1.38	1.41	1.45	1.49	1.52	1.56
Total Netback		8.59	8.71	8.87	9.05	9.25	9.46	9.70	9.91	10.12	10.33	10.55	10.77	11.01	11.25	10.12	10.35	10.58	10.83	11.08	11.34
Status Quo Netback Energy Opportunity - ATC (Southern Region)		31.83	32.77	34.61	36.80	39.25	41.83	44.84	47.47	50.00	52.51	55.15	57.90	60.78	63.80	68.33	71.67	75.15	78.80	82.62	86.60
Assumed Split of Netback Costs with EMEC Consumers		50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Eff. Rate Charged to EMEC Consumers - ATC (Southern Region)		36.13	37.12	39.05	41.33	43.87	46.56	49.69	52.43	55.05	57.68	60.42	63.29	66.29	69.42	73.39	76.84	80.45	84.21	88.16	92.28
Status Quo Must Run Northern Region Netback (MWh)		72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029
NMISA Southern Region Generation (Avg ATC MW)		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NMISA Southern Region Load																					
Onpeak Avg MW		11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12
Offpeak Avg MW		9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
ATC Avg MW		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	11
NB Control Area Generation Purchases																					
NMISA Northern Region Load - Onpeak Avg MW		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4
NMISA Northern Region Load - Offpeak Avg MW		0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NMISA Northern Region Load - ATC Avg MW		1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Status Quo Wholesale Energy Cost (NB Control Area) ($/MWh)		45.12	46.10	48.19	50.69	53.48	56.42	59.86	62.85	65.71	68.56	71.54	74.65	77.91	81.31	84.87	88.59	92.48	96.55	100.80	105.24
NMISA Southern Region Wholesale Energy Cost ($/MWh)																					
Southern Region Generation		36.13	37.12	39.05	41.33	43.87	46.56	49.69	52.43	55.05	57.68	60.42	63.29	66.29	69.42	73.39	76.84	80.45	84.21	88.16	92.28
NB Control Area Generation (Salisbury)		45.12	46.10	48.19	50.69	53.48	56.42	59.86	62.85	65.71	68.56	71.54	74.65	77.91	81.31	84.87	88.59	92.48	96.55	100.80	105.24
Load Following Premium (3% of Salisbury, Load Weighted)		1.23	1.26	1.33	1.40	1.48	1.56	1.66	1.75	1.83	1.92	2.00	2.09	2.19	2.29	2.39	2.50	2.61	2.73	2.86	2.99
Percent of Load Served by Southern Region Generation		86%	86%	85%	85%	84%	84%	83%	83%	83%	82%	82%	81%	81%	81%	80%	80%	79%	79%	79%	78%
Percent of Load Served by NB Control Area Generation		14%	14%	15%	15%	16%	16%	17%	17%	17%	18%	18%	19%	19%	19%	20%	20%	21%	21%	21%	22%
NMISA Southern Region Energy Cost ($/MWh)		38.63	39.69	41.73	44.16	46.86	49.72	53.03	55.95	58.74	61.53	64.45	67.50	70.69	74.02	78.06	81.72	85.54	89.54	93.72	98.09
Assumed NB Control Area Capacity Value (% of ISO-NE)		50%	50%	50%	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Capacity Cost ($/MWh)		3.13	3.36	3.53	4.41	5.35	6.33	7.45	8.65	15.56	25.11	25.81	26.45	27.11	27.71	28.49	29.20	29.93	30.68	31.44	32.23
NMISA Southern Region Energy and Capacity Cost ($/MWh)		41.76	43.05	45.26	48.57	52.21	56.05	60.48	64.60	74.30	86.64	90.25	93.95	97.80	101.74	106.55	110.92	115.47	120.22	125.16	130.32
Other Wholesale Load Serving Costs																					
Reserves (2012 NB Tariff)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Fees ($/MWh) (Incl. in Northern Region Trans)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total Other Wholesale Costs ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	1.00	1.02	1.05
Total Status Quo EMEC (South Region) Wholesale Power Supply Cost ($/MWh)		42.39	43.70	45.94	49.26	52.92	56.78	61.23	65.36	75.09	87.45	91.08	94.80	98.67	102.63	107.47	111.86	116.44	121.21	126.18	131.37
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																					
Weighted ME Zone Energy Price (Including Load Following Premium) ($/MWh)		43.45	44.57	46.72	49.28	52.12	55.11	58.60	61.66	64.60	67.53	70.59	73.79	77.14	80.64	84.30	88.13	92.13	96.31	100.68	105.25
Capacity ($/MWh)		6.27	6.73	7.06	7.34	7.64	7.92	8.28	8.65	15.56	25.11	25.81	26.45	27.11	27.71	28.49	29.20	29.93	30.59	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other Energy Obl (Inad/Em En, RT Res)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.43)	(0.44)	(0.46)	(0.48)	(0.51)	(0.54)	(0.57)	(0.60)	(0.63)	(0.66)	(0.69)	(0.72)	(0.76)	(0.79)	(0.83)	(0.86)	(0.90)	(0.94)	(0.99)	(1.03)
NEPOOL Expenses	Included in Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
NB Losses	3.3%	1.91	1.96	2.05	2.15	2.25	2.37	2.50	2.61	2.94	3.36	3.49	3.62	3.75	3.89	4.04	4.20	4.36	4.52	4.70	4.88
Total EMEC Join ISO-NE (South Region) Wholesale Power Supply Costs ($/MWh)		54.36	56.09	58.73	61.74	65.06	68.53	72.58	76.21	86.47	99.46	103.44	107.52	111.77	116.11	120.79	125.59	130.59	135.71	141.22	146.88
EMEC South Wholesale Pwr Supply Cost (Benefit) for Joining ISO-NE ($/MWh)		11.97	12.38	12.80	12.49	12.14	11.75	11.35	10.85	11.39	12.01	12.36	12.72	13.09	13.48	13.33	13.73	14.15	14.50	15.04	15.51
Total EMEC (South Region) Load (MWh)		84,061	84,481	84,903	85,328	85,755	86,183	86,614	87,047	87,483	87,920	88,360	88,801	89,245	89,692	90,140	90,591	91,044	91,499	91,956	92,416
Total EMEC (South Region) Wholesale Power Supply Cost (Benefit) ($K)		1,006	1,046	1,087	1,065	1,041	1,013	983	944	996	1,056	1,092	1,130	1,168	1,209	1,201	1,244	1,288	1,327	1,383	1,433

ATTACHMENT 13

SOCIALIZED TRANSMISSION MODEL

Summary
ISO-NE 2012 Regional System Plan (RSP) Case
Cost/Benefit Assessment

ATTACHMENT 13

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Socialized Transmission Line Model
ISO-NE 2012 Regional System Plan (RSP) Case
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	7,793	8,617	8,074	8,220	8,186	8,198	8,197	8,201	8,203	8,207	8,210	8,214	8,219	8,224	8,225	8,231	8,237	8,243	8,250	8,257
Southern Region	927	1,057	1,053	1,049	1,045	1,041	1,036	1,032	1,028	1,024	1,019	1,015	1,011	1,006	1,002	997	993	988	984	979
Total	8,720	9,673	9,126	9,268	9,230	9,238	9,234	9,233	9,231	9,230	9,230	9,229	9,230	9,230	9,227	9,228	9,229	9,231	9,234	9,237
Cumulative	8,720	18,394	27,520	36,789	46,019	55,258	64,491	73,724	82,955	92,186	101,415	110,645	119,874	129,104	138,331	147,558	156,788	166,019	175,253	184,490
Average	8,720	9,197	9,173	9,197	9,204	9,210	9,213	9,215	9,217	9,219	9,220	9,220	9,221	9,222	9,222	9,222	9,223	9,223	9,224	9,224
Wholesale Markets Cost ($K)																				
Northern Region	5,430	5,719	6,024	5,725	5,410	5,048	4,659	4,212	4,342	4,476	4,615	4,759	4,910	5,067	5,230	5,400	5,577	5,699	5,952	6,152
Southern Region	1,006	1,046	1,087	1,065	1,041	1,013	983	944	996	1,056	1,092	1,130	1,168	1,209	1,201	1,244	1,288	1,327	1,383	1,433
Total	6,436	6,765	7,111	6,791	6,451	6,061	5,642	5,156	5,338	5,532	5,707	5,889	6,078	6,275	6,431	6,644	6,865	7,026	7,335	7,585
Cumulative	6,436	13,201	20,312	27,103	33,553	39,614	45,256	50,412	55,750	61,282	66,989	72,878	78,956	85,232	91,663	98,306	105,171	112,197	119,532	127,117
Average	6,436	6,601	6,771	6,776	6,711	6,602	6,465	6,302	6,194	6,128	6,090	6,073	6,074	6,088	6,111	6,144	6,187	6,233	6,291	6,356
Total Cost (Benefit) ($K)																				
Northern Region	13,223	14,336	14,098	13,945	13,595	13,246	12,856	12,412	12,545	12,682	12,825	12,974	13,129	13,290	13,455	13,630	13,813	13,942	14,202	14,409
Southern Region	1,933	2,102	2,140	2,114	2,086	2,053	2,019	1,977	2,024	2,080	2,112	2,145	2,179	2,215	2,203	2,241	2,281	2,315	2,367	2,413
Total	15,156	16,438	16,237	16,059	15,681	15,299	14,876	14,389	14,569	14,762	14,937	15,118	15,308	15,505	15,658	15,871	16,094	16,257	16,569	16,822
Cumulative	15,156	31,595	47,832	63,891	79,572	94,872	109,748	124,136	138,706	153,468	168,405	183,523	198,831	214,336	229,994	245,865	261,959	278,216	294,785	311,607
Average	15,156	15,797	15,944	15,973	15,914	15,812	15,678	15,517	15,412	15,347	15,310	15,294	15,295	15,310	15,333	15,367	15,409	15,456	15,515	15,580
Transmission Cost ($/MWh)																				
Northern Region	11.52	12.68	11.82	11.97	11.87	11.82	11.76	11.71	11.66	11.60	11.55	11.50	11.45	11.40	11.34	11.29	11.25	11.20	11.15	11.11
Southern Region	11.03	12.51	12.40	12.29	12.18	12.07	11.97	11.86	11.75	11.64	11.54	11.43	11.33	11.22	11.11	11.01	10.90	10.80	10.70	10.60
Total	11.47	12.66	11.88	12.01	11.90	11.85	11.79	11.73	11.67	11.61	11.55	11.49	11.43	11.38	11.32	11.26	11.21	11.15	11.10	11.05
Cumulative	11.47	12.07	12.01	12.01	11.99	11.97	11.94	11.91	11.89	11.86	11.83	11.80	11.77	11.74	11.71	11.69	11.66	11.63	11.60	11.57
Wholesale Markets Cost ($/MWh)																				
Northern Region	8.03	8.42	8.82	8.34	7.84	7.28	6.69	6.01	6.17	6.33	6.49	6.66	6.84	7.02	7.21	7.41	7.61	7.74	8.05	8.27
Southern Region	11.97	12.38	12.80	12.49	12.14	11.75	11.35	10.85	11.39	12.01	12.36	12.72	13.09	13.48	13.33	13.73	14.15	14.50	15.04	15.51
Total	8.47	8.85	9.26	8.80	8.32	7.78	7.20	6.55	6.75	6.96	7.14	7.33	7.53	7.74	7.89	8.11	8.34	8.49	8.82	9.07
Cumulative	8.47	8.66	8.86	8.85	8.74	8.58	8.38	8.15	7.99	7.88	7.81	7.77	7.75	7.75	7.76	7.79	7.82	7.86	7.91	7.97
Total Cost (Benefit) ($/MWh)																				
Northern Region	19.55	21.09	20.64	20.31	19.71	19.11	18.45	17.72	17.83	17.93	18.04	18.16	18.29	18.42	18.55	18.70	18.86	18.94	19.20	19.38
Southern Region	23.00	24.89	25.20	24.78	24.32	23.82	23.31	22.71	23.14	23.66	23.90	24.15	24.42	24.70	24.44	24.74	25.05	25.30	25.74	26.11
Total	19.93	21.51	21.14	20.81	20.22	19.63	18.99	18.28	18.41	18.56	18.69	18.82	18.96	19.11	19.21	19.37	19.54	19.64	19.92	20.12
Cumulative	19.93	20.73	20.87	20.86	20.73	20.55	20.32	20.06	19.88	19.74	19.64	19.58	19.53	19.50	19.48	19.47	19.48	19.49	19.51	19.54

ATTACHMENT 14

SOCIALIZED TRANSMISSION MODEL

Summary
Renewable Portfolio Standards (RPS) Buildout Case
Cost/Benefit Assessment

ATTACHMENT 14

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Socialized Transmission Line Model
Renewable Portfolio Standards Case (ISO-NE 2012 RSP Case plus RPS Transmission Buildout)
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	11,848	16,825	20,571	25,135	29,651	34,351	34,350	34,354	34,356	34,360	34,363	34,367	34,372	34,376	34,378	34,383	34,389	34,396	34,403	34,410
Southern Region	1,432	2,078	2,609	3,155	3,717	4,297	4,293	4,289	4,284	4,280	4,276	4,271	4,267	4,263	4,258	4,254	4,250	4,245	4,241	4,236
Total	13,280	18,903	23,180	28,290	33,369	38,648	38,643	38,642	38,641	38,640	38,639	38,639	38,639	38,639	38,636	38,637	38,639	38,641	38,644	38,647
Cumulative	13,280	32,183	55,363	83,653	117,022	155,669	194,312	232,954	271,595	310,234	348,873	387,512	426,151	464,790	503,426	542,064	580,703	619,344	657,988	696,634
Average	13,280	16,092	18,454	20,913	23,404	25,945	27,759	29,119	30,177	31,023	31,716	32,293	32,781	33,199	33,562	33,879	34,159	34,408	34,631	34,832
Wholesale Markets Cost ($K)																				
Northern Region	5,430	5,719	6,024	5,725	5,410	5,048	4,659	4,212	4,342	4,476	4,615	4,759	4,910	5,067	5,230	5,400	5,577	5,699	5,952	6,152
Southern Region	1,006	1,046	1,087	1,065	1,041	1,013	983	944	996	1,056	1,092	1,130	1,168	1,209	1,201	1,244	1,288	1,327	1,383	1,433
Total	6,436	6,765	7,111	6,791	6,451	6,061	5,642	5,156	5,338	5,532	5,707	5,889	6,078	6,275	6,431	6,644	6,865	7,026	7,335	7,585
Cumulative	6,436	13,201	20,312	27,103	33,553	39,614	45,256	50,412	55,750	61,282	66,989	72,878	78,956	85,232	91,663	98,306	105,171	112,197	119,532	127,117
Average	6,436	6,601	6,771	6,776	6,711	6,602	6,465	6,302	6,194	6,128	6,090	6,073	6,074	6,088	6,111	6,144	6,187	6,233	6,291	6,356
Total Cost (Benefit) ($K)																				
Northern Region	17,278	22,544	26,595	30,860	35,061	39,399	39,009	38,565	38,698	38,835	38,978	39,127	39,282	39,443	39,608	39,783	39,966	40,095	40,355	40,562
Southern Region	2,438	3,124	3,696	4,220	4,759	5,310	5,276	5,233	5,281	5,336	5,368	5,401	5,436	5,471	5,460	5,498	5,538	5,572	5,624	5,670
Total	19,716	25,668	30,290	35,080	39,820	44,708	44,285	43,798	43,979	44,171	44,346	44,528	44,717	44,915	45,067	45,281	45,504	45,667	45,979	46,232
Cumulative	19,716	45,384	75,675	110,755	150,575	195,284	239,569	283,367	327,345	371,517	415,863	460,390	505,107	550,022	595,089	640,370	685,874	731,541	777,520	823,751
Average	19,716	22,692	25,225	27,689	30,115	32,547	34,224	35,421	36,372	37,152	37,806	38,366	38,854	39,287	39,673	40,023	40,346	40,641	40,922	41,188
Transmission Cost ($/MWh)																				
Northern Region	17.52	24.76	30.12	36.62	42.98	49.55	49.30	49.06	48.82	48.58	48.34	48.11	47.87	47.64	47.41	47.18	46.95	46.73	46.51	46.28
Southern Region	17.04	24.60	30.73	36.97	43.35	49.86	49.56	49.27	48.97	48.68	48.39	48.10	47.81	47.53	47.24	46.96	46.68	46.40	46.12	45.84
Total	17.47	24.74	30.18	36.66	43.02	49.58	49.33	49.08	48.83	48.59	48.35	48.11	47.87	47.63	47.39	47.16	46.92	46.69	46.46	46.23
Cumulative	17.47	21.12	24.16	27.31	30.49	33.71	35.98	37.65	38.92	39.91	40.70	41.33	41.85	42.28	42.63	42.93	43.17	43.38	43.55	43.69
Wholesale Markets Cost ($/MWh)																				
Northern Region	8.03	8.42	8.82	8.34	7.84	7.28	6.69	6.01	6.17	6.33	6.49	6.66	6.84	7.02	7.21	7.41	7.61	7.74	8.05	8.27
Southern Region	11.97	12.38	12.80	12.49	12.14	11.75	11.35	10.85	11.39	12.01	12.36	12.72	13.09	13.48	13.33	13.73	14.15	14.50	15.04	15.51
Total	8.47	8.85	9.26	8.80	8.32	7.78	7.20	6.55	6.75	6.96	7.14	7.33	7.53	7.74	7.89	8.11	8.34	8.49	8.82	9.07
Cumulative	8.47	8.66	8.86	8.85	8.74	8.58	8.38	8.15	7.99	7.88	7.81	7.77	7.75	7.75	7.76	7.79	7.82	7.86	7.91	7.97
Total Cost (Benefit) ($/MWh)																				
Northern Region	25.55	33.17	38.94	44.96	50.82	56.83	55.98	55.07	54.99	54.91	54.83	54.77	54.71	54.67	54.62	54.59	54.57	54.47	54.55	54.56
Southern Region	29.01	36.98	43.53	49.46	55.49	61.61	60.91	60.12	60.36	60.70	60.75	60.82	60.91	61.00	60.57	60.69	60.83	60.90	61.16	61.35
Total	25.93	33.59	39.44	45.45	51.34	57.36	56.53	55.63	55.58	55.55	55.49	55.44	55.40	55.37	55.28	55.26	55.26	55.18	55.28	55.31
Cumulative	25.93	29.78	33.02	36.16	39.23	42.29	44.36	45.80	46.91	47.79	48.51	49.11	49.61	50.03	50.40	50.71	50.99	51.24	51.46	51.66

ATTACHMENT 15

SOCIALIZED TRANSMISSION MODEL

Summary
New England/Maine Buildout Case
(NE buildout proportional to Maine)
Cost/Benefit Assessment

ATTACHMENT 15

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Socialized Transmission Line Model
New England/Maine Buildout Case (ISO-NE 2012 RSP Case plus NE pro-rata Buildout)
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	7,793	11,322	13,565	16,580	19,502	19,514	19,514	19,517	19,520	19,523	19,527	19,531	19,535	19,540	19,542	19,547	19,553	19,560	19,567	19,574
Southern Region	927	1,393	1,737	2,090	2,454	2,450	2,445	2,441	2,437	2,433	2,428	2,424	2,420	2,416	2,411	2,407	2,402	2,398	2,393	2,389
Total	8,720	12,715	15,301	18,670	21,956	21,964	21,959	21,958	21,957	21,956	21,955	21,955	21,955	21,956	21,953	21,954	21,955	21,957	21,960	21,963
Cumulative	8,720	21,435	36,737	55,407	77,363	99,327	121,286	143,245	165,202	187,158	209,113	231,068	253,023	274,979	296,932	318,886	340,841	362,799	384,759	406,722
Average	8,720	10,718	12,246	13,852	15,473	16,555	17,327	17,906	18,356	18,716	19,010	19,256	19,463	19,641	19,795	19,930	20,049	20,155	20,250	20,336
Wholesale Markets Cost ($K)																				
Northern Region	5,430	5,719	6,024	5,725	5,410	5,048	4,659	4,212	4,342	4,476	4,615	4,759	4,910	5,067	5,230	5,400	5,577	5,699	5,952	6,152
Southern Region	1,006	1,046	1,087	1,065	1,041	1,013	983	944	996	1,056	1,092	1,130	1,168	1,209	1,201	1,244	1,288	1,327	1,383	1,433
Total	6,436	6,765	7,111	6,791	6,451	6,061	5,642	5,156	5,338	5,532	5,707	5,889	6,078	6,275	6,431	6,644	6,865	7,026	7,335	7,585
Cumulative	6,436	13,201	20,312	27,103	33,553	39,614	45,256	50,412	55,750	61,282	66,989	72,878	78,956	85,232	91,663	98,306	105,171	112,197	119,532	127,117
Average	6,436	6,601	6,771	6,776	6,711	6,602	6,465	6,302	6,194	6,128	6,090	6,073	6,074	6,088	6,111	6,144	6,187	6,233	6,291	6,356
Total Cost (Benefit) ($K)																				
Northern Region	13,223	17,041	19,589	22,306	24,912	24,563	24,173	23,729	23,862	23,999	24,141	24,290	24,445	24,607	24,771	24,947	25,130	25,259	25,519	25,726
Southern Region	1,933	2,439	2,823	3,155	3,495	3,462	3,428	3,386	3,433	3,489	3,521	3,554	3,588	3,624	3,612	3,651	3,691	3,725	3,776	3,822
Total	15,156	19,480	22,412	25,461	28,407	28,025	27,601	27,114	27,295	27,488	27,662	27,844	28,034	28,231	28,384	28,597	28,820	28,983	29,295	29,548
Cumulative	15,156	34,636	57,049	82,510	110,917	138,941	166,543	193,657	220,952	248,440	276,102	303,946	331,980	360,211	388,595	417,192	446,012	474,996	504,291	533,839
Average	15,156	17,318	19,016	20,627	22,183	23,157	23,792	24,207	24,550	24,844	25,100	25,329	25,537	25,729	25,906	26,075	26,236	26,389	26,542	26,692
Transmission Cost ($/MWh)																				
Northern Region	11.52	16.66	19.86	24.15	28.27	28.15	28.01	27.87	27.74	27.60	27.47	27.34	27.21	27.08	26.95	26.82	26.70	26.57	26.45	26.33
Southern Region	11.03	16.49	20.45	24.49	28.61	28.42	28.23	28.04	27.86	27.67	27.48	27.30	27.11	26.93	26.75	26.57	26.39	26.21	26.03	25.85
Total	11.47	16.64	19.93	24.19	28.31	28.18	28.03	27.89	27.75	27.61	27.47	27.34	27.20	27.06	26.93	26.79	26.66	26.53	26.40	26.28
Cumulative	11.47	14.07	16.03	18.09	20.16	21.51	22.46	23.15	23.67	24.08	24.39	24.65	24.85	25.01	25.15	25.25	25.34	25.41	25.47	25.51
Wholesale Markets Cost ($/MWh)																				
Northern Region	8.03	8.42	8.82	8.34	7.84	7.28	6.69	6.01	6.17	6.33	6.49	6.66	6.84	7.02	7.21	7.41	7.61	7.74	8.05	8.27
Southern Region	11.97	12.38	12.80	12.49	12.14	11.75	11.35	10.85	11.39	12.01	12.36	12.72	13.09	13.48	13.33	13.73	14.15	14.50	15.04	15.51
Total	8.47	8.85	9.26	8.80	8.32	7.78	7.20	6.55	6.75	6.96	7.14	7.33	7.53	7.74	7.89	8.11	8.34	8.49	8.82	9.07
Cumulative	8.47	8.66	8.86	8.85	8.74	8.58	8.38	8.15	7.99	7.88	7.81	7.77	7.75	7.75	7.76	7.79	7.82	7.86	7.91	7.97
Total Cost (Benefit) ($/MWh)																				
Northern Region	19.55	25.07	28.68	32.49	36.11	35.43	34.69	33.89	33.91	33.93	33.96	34.00	34.05	34.10	34.16	34.23	34.31	34.31	34.50	34.60
Southern Region	23.00	28.87	33.25	36.98	40.76	40.17	39.58	38.89	39.24	39.68	39.85	40.02	40.21	40.41	40.07	40.30	40.54	40.71	41.07	41.36
Total	19.93	25.49	29.19	32.99	36.62	35.95	35.23	34.44	34.50	34.57	34.61	34.67	34.73	34.80	34.81	34.90	35.00	35.02	35.22	35.35
Cumulative	19.93	22.73	24.90	26.94	28.90	30.09	30.84	31.30	31.66	31.96	32.21	32.42	32.60	32.77	32.91	33.04	33.16	33.27	33.38	33.48

ATTACHMENT 16

MERCHANT TRANSMISSION MODEL

MPS Annual Transmission Cost Projection
Merchant Line Interconnection with ISO-NE

ATTACHMENT 16

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Merchant Transmission Line Model
Maine Public Service Company Annual Transmission Cost Projection - Merchant Transmission Line (MPS to ISO-NE)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**
MPS Gross Plant																					
MPS Planned Gross Plant Additions *		2,700	3,000	5,400	600																
Growth in Gross Plant																					
* Actual 2011 Gross Plant. Planned additions from MPS transmission plan inlcuded in NMISA 2012 7 Year Outlook plus $2 million Tinker Upgrade. Then 2.5% per year after 2018 which equals assumed depreciation.																					
MPS Gross Plant	2010	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838	23,838
MPS Gross Plant Additions	2011	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266	3,266
	2012	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045
	2013	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
	2014	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	2015	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
	2016		3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
	2017			5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400
	2018				600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
	2019					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022								0	0	0	0	0	0	0	0	0	0	0	0	0
	2023									0	0	0	0	0	0	0	0	0	0	0	0
	2024										0	0	0	0	0	0	0	0	0	0	0
	2025											0	0	0	0	0	0	0	0	0	0
	2026												0	0	0	0	0	0	0	0	0
	2027													0	0	0	0	0	0	0	0
	2028														0	0	0	0	0	0	0
	2029															0	0	0	0	0	0
	2030																0	0	0	0	0
	2031																	0	0	0	0
	2032																		0	0	0
	2033																			0	0
	2034																				0
Gross Plant Total		38,848	41,848	47,248	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848	47,848
Carrying Charge Rate (including OM&G, Property Taxes,…)**		15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%
** MPC CPCN Filing (July 1, 2008) - 2011 and thereafter																					
Transmission Investment Carry Cost ($K)		6,111	6,583	7,433	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527	7,527
OTHER TRANSMISSION EXPENSES ($/kwyr)																					
Scheduling Sys/Control and Dispatch	Sch. 3 (2012 Tariff), 3%/yr	3.48	3.59	3.69	3.80	3.92	4.04	4.16	4.28	4.41	4.54	4.68	4.82	4.96	5.11	5.27	5.42	5.59	5.75	5.93	6.11
Reactive Supply and Voltage Control	Sch. 4 (2012 Tariff), 3%/yr	0.98	1.00	1.03	1.07	1.10	1.13	1.16	1.20	1.24	1.27	1.31	1.35	1.39	1.43	1.48	1.52	1.57	1.61	1.66	1.71
Customer Chg. (Sch. 1a)	MPS 2012 Tariff, 3%/yr	2.86	2.95	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73	3.84	3.96	4.08	4.20	4.33	4.46	4.59	4.73	4.87	5.01
Regulatory Chg. (Sch. 1b)	MPS 2012 Tariff, 3%/yr	0.47	0.48	0.50	0.51	0.53	0.54	0.56	0.58	0.59	0.61	0.63	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.80	0.82
Canc. Plant (Sch. 5)	MPS 2012 Tariff	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		7.78	8.02	8.26	8.51	8.76	9.02	9.30	9.57	9.86	10.16	10.46	10.78	11.10	11.43	11.78	12.13	12.49	12.87	13.25	13.65
Other Transmssion Expenses ($/K)		798	826	855	885	916	948	982	1,016	1,052	1,089	1,127	1,167	1,208	1,250	1,294	1,340	1,387	1,435	1,486	1,538
Annual Revenue Requirement (excl. Wheeling) ($K)		6,909	7,409	8,288	8,412	8,443	8,475	8,509	8,543	8,579	8,616	8,654	8,694	8,735	8,777	8,821	8,867	8,914	8,963	9,013	9,065
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		67.41	71.93	80.06	80.85	80.75	80.65	80.57	80.49	80.43	80.37	80.33	80.29	80.27	80.26	80.26	80.27	80.30	80.34	80.39	80.45
Energy for Export from Northern Maine (MWh)		275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344	275,344
Ashland MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ashland MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fort Fairfield MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fort Fairfield MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mars Hill MWh		124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315	124,315
Tinker and Small Hydro MWh		151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029	151,029
New Wind MWh																					
Previous Year Export Transmission Revenue ($K)		2,605	2,541	2,884	3,206	3,056	3,147	3,085	3,121	3,095	3,109	3,098	3,103	3,099	3,100	3,099	3,100	3,100	3,101	3,102	3,104
Through or Out Transmission Cost (Annual, $/kwyr)		38.38	43.58	48.43	46.16	47.55	46.61	47.15	46.76	46.97	46.81	46.88	46.82	46.84	46.82	46.83	46.84	46.85	46.87	46.89	46.92
Through or Out Transmission Cost (Hourly, $/MWh)		9.23	10.48	11.64	11.10	11.43	11.20	11.33	11.24	11.29	11.25	11.27	11.25	11.26	11.25	11.26	11.26	11.26	11.27	11.27	11.28
Transmission Revenue from Exports ($K)		2,541	2,884	3,206	3,056	3,147	3,085	3,121	3,095	3,109	3,098	3,103	3,099	3,100	3,099	3,100	3,100	3,101	3,102	3,104	3,106
Levelized RR (to smooth out the transmission rate it is assumed the RR will ultimately be allocated proportional to internal load and energy export)																					
Internal Load ($K)		5,151	5,522	6,164	6,270	6,310	6,352	6,394	6,437	6,482	6,528	6,576	6,625	6,675	6,727	6,780	6,835	6,892	6,950	7,010	7,072
Energy Export ($K)		1,758	1,887	2,123	2,142	2,133	2,124	2,115	2,106	2,097	2,088	2,078	2,069	2,060	2,051	2,041	2,032	2,022	2,012	2,003	1,993
Total Annual RR (after Wheeling Revenue Credit ($K))		4,304	4,868	5,403	5,206	5,388	5,328	5,424	5,422	5,484	5,507	5,556	5,591	5,636	5,677	5,722	5,767	5,814	5,861	5,911	5,961
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		42.00	47.26	52.19	50.04	51.53	50.71	51.36	51.09	51.41	51.37	51.57	51.64	51.80	51.91	52.06	52.21	52.37	52.54	52.72	52.91
NMISA Expenses (Entire NMISA)	NMISA 2012 Budget, 3% Esc.	280	288	297	307	316	326	336	347	358	369	381	393	405	417	431	444	458	472	487	502
MPS (Merchant Line) - Annual Cost ($K)		7,189	7,697	8,585	8,719	8,759	8,802	8,845	8,890	8,937	8,985	9,035	9,086	9,140	9,195	9,252	9,311	9,372	9,435	9,500	9,567
MPS Load MW	NMISA 2012 7 Year Outlook	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1	112.7
Northern Region Load MWh	NMISA 2012 7 Year Outlook	676,241	679,622	683,020	686,436	689,868	693,317	696,784	700,268	703,769	707,288	710,824	714,378	717,950	721,540	725,148	728,773	732,417	736,079	739,760	743,459
Growth Factor: (2019-2034)	0.50%																				
MPS Load MW (12 CP) (Previous Year)		102.0	102.5	103.0	103.5	104.0	104.6	105.1	105.6	106.1	106.7	107.2	107.7	108.3	108.8	109.4	109.9	110.5	111.0	111.6	112.1
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MPS (Merchant Line) - Annual Transmission Cost ($/kwyr)		50.26	53.61	59.55	60.27	60.35	60.44	60.54	60.65	60.77	60.90	61.04	61.18	61.34	61.51	61.69	61.88	62.08	62.30	62.52	62.76

ATTACHMENT 17

MERCHANT TRANSMISSION MODEL

EMEC Status Quo and Merchant Line Transmission Cost Projection

ATTACHMENT 17

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Merchant Transmission Line Model
Eastern Maine Electric Cooperative (EMEC) Status Quo and Merchant Line (MPS to ISO-NE) Transmission Cost Projections
August 17, 2012

Merchant Transmission Line Model **TRANSMISSION COSTS**	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo Projection																				
EMEC Transmission																				
EMEC System ($/kwyr) (2012/13 Tariff Rate, 0.5% annual escalation)	5.28	5.31	5.34	5.36	5.39	5.42	5.44	5.47	5.50	5.52	5.55	5.58	5.61	5.64	5.66	5.69	5.72	5.75	5.78	5.81
NB System ($/kwyr) (2011 Firm Pt-to-Pt Tariff Rate, 0.5% annual esc., 100% Exch. Rate)	30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26	33.43	33.59
Total EMEC Transmission Cost ($/kwyr)	35.84	36.02	36.20	36.38	36.56	36.74	36.93	37.11	37.30	37.48	37.67	37.86	38.05	38.24	38.43	38.62	38.82	39.01	39.20	39.40
EMEC South NMISA Fee - T&D ($K)	41	42	43	44	46	47	49	50	52	53	55	57	58	60	62	64	66	68	70	72
EMEC Projected 12 CP (MW)	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89	13.96
Prior Years EMEC 12 CP (MW)	12.64	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89
Total EMEC South Transmission Cost ($K)	496	501	507	513	519	526	532	538	545	551	558	564	571	578	585	592	600	607	614	622
Total EMEC South Transmission Cost ($/kwyr)	39.03	39.29	39.56	39.82	40.09	40.37	40.64	40.92	41.21	41.49	41.78	42.08	42.37	42.67	42.98	43.29	43.60	43.91	44.23	44.56
EMEC - Merchant Line Projection																				
EMEC Transmission																				
EMEC System ($/kwyr) (2012/13 Tariff Rate, 0.5% annual escalation)	5.28	5.31	5.34	5.36	5.39	5.42	5.44	5.47	5.50	5.52	5.55	5.58	5.61	5.64	5.66	5.69	5.72	5.75	5.78	5.81
NB System ($/kwyr) (2011 Firm Pt-to-Pt Tariff Rate, 0.5% annual esc., 100% Exch. Rate)	30.56	30.71	30.86	31.02	31.17	31.33	31.48	31.64	31.80	31.96	32.12	32.28	32.44	32.60	32.77	32.93	33.09	33.26	33.43	33.59
Total EMEC Transmission Cost ($/kwyr)	35.84	36.02	36.20	36.38	36.56	36.74	36.93	37.11	37.30	37.48	37.67	37.86	38.05	38.24	38.43	38.62	38.82	39.01	39.20	39.40
EMEC South NMISA Fee - T&D ($K)	35	36	37	38	39	40	42	43	44	46	47	49	50	52	53	55	57	59	60	62
EMEC Projected 12 CP (MW)	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89	13.96
Prior Years EMEC 12 CP (MW)	12.64	12.70	12.76	12.83	12.89	12.95	13.02	13.08	13.15	13.22	13.28	13.35	13.41	13.48	13.55	13.62	13.68	13.75	13.82	13.89
Total EMEC South Transmission Cost ($K)	490	495	501	507	513	519	525	531	537	544	550	556	563	570	577	584	591	598	605	612
Total EMEC South Transmission Cost ($/kwyr)	38.57	38.82	39.07	39.33	39.59	39.85	40.11	40.38	40.65	40.93	41.20	41.48	41.77	42.06	42.35	42.64	42.94	43.24	43.55	43.86
Transmission Cost/(Benefit) $K	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(10)	(10)

ATTACHMENT 18

MERCHANT TRANSMISSION MODEL

ISO-NE Annual Transmission Cost Projection
2012 Regional System Plan (RSP) Case

ATTACHMENT 18

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Merchant Transmission Line Model
ISO-NE Annual Transmission Cost Projection - ISO-NE 2012 RSP Case (ISO-NE August 2012 Five Year RNS Forecast)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (Aug 2012 Five Year RNS Forecast)		1,330,000	1,246,000																		
New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection (MPC2012, $300 Million plus AFUDC)																					
Future Reliability Upgrades in Other States (Assumes NE Buildout Proportional to Maine)																					
Future Transmission Upgrades to Meet RPS Standards (ISO-NE New England 2030 Power System Study and 2010 Regional Electriciy Outlook)																					
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)																					
MPS (PTF Qualified Portion, 76.9%)																					
ISO-NE Gross Plant	2010	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600
ISO-NE Gross Plant Additions	2011	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000
	2012	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900
	2013	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000
	2014	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000
	2015	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000	1,330,000
	2016		1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000	1,246,000
	2017			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2018				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2019					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2020						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022								0	0	0	0	0	0	0	0	0	0	0	0	0
	2023									0	0	0	0	0	0	0	0	0	0	0	0
	2024										0	0	0	0	0	0	0	0	0	0	0
	2025											0	0	0	0	0	0	0	0	0	0
	2026												0	0	0	0	0	0	0	0	0
	2027													0	0	0	0	0	0	0	0
	2028														0	0	0	0	0	0	0
	2029															0	0	0	0	0	0
	2030																0	0	0	0	0
	2031																	0	0	0	0
	2032																		0	0	0
	2033																			0	0
	2034																				0
Gross Plant Additions Total		12,025,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500	13,271,500
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated based on ISO Forecasted RNS Rates)		17.54%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%
Transmission Investment Carrying Cost ($K)		2,109,000	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800	2,320,800
ISO-NE Load MW (12 CP) (2012 ISO-NE 5 Year RNS Forecast)		20,188	20,289	20,390	20,492	20,595	20,698	20,801	20,905	21,010	21,115	21,220	21,327	21,433	21,540	21,648	21,756	21,865	21,974	22,084	22,195
ISO-NE Load GWh (2012 ISO-NE CELT)		142,215	143,815	145,245	146,590	147,880	149,130	150,375	151,127	151,883	152,642	153,405	154,172	154,943	155,718	156,496	157,279	158,065	158,856	159,650	160,448
Growth Factor (2022-2034) 0.50%																					
ISO-NE Load MW (12 CP) (Previous Year)		20,188	20,188	20,289	20,390	20,492	20,595	20,698	20,801	20,905	21,010	21,115	21,220	21,327	21,433	21,540	21,648	21,756	21,865	21,974	22,084
Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ISO-NE RNS Transmission Rate $/kwyr		104.47	114.96	114.39	113.82	113.25	112.69	112.13	111.57	111.02	110.46	109.91	109.37	108.82	108.28	107.74	107.21	106.67	106.14	105.61	105.09
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)		1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
Total ISO-NE Transmission Rate $/kwyr		106.40	116.95	116.44	115.93	115.43	114.93	114.44	113.95	113.46	112.98	112.51	112.04	111.58	111.12	110.66	110.22	109.77	109.34	108.90	108.48
ISO-NE TOUT ($/MWh) (equal to ISO-NE network load cost)		14.83	16.14	15.98	15.83	15.69	15.56	15.43	15.36	15.28	15.20	15.13	15.05	14.98	14.90	14.83	14.76	14.68	14.61	14.54	14.46
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)		1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
OATT Sch. 1 ($/MWh, assume 68% LF)		0.32	0.33	0.34	0.35	0.37	0.38	0.39	0.40	0.41	0.42	0.44	0.45	0.46	0.48	0.49	0.51	0.52	0.54	0.55	0.57
ISO-NE Trans Out-service ($/MWh) (incl Sch. 1)		15.15	16.47	16.32	16.19	16.06	15.94	15.82	15.76	15.69	15.63	15.56	15.50	15.44	15.38	15.32	15.26	15.20	15.15	15.09	15.03

ATTACHMENT 19

MERCHANT TRANSMISSION MODEL

ISO-NE Annual Transmission Cost Projection
Renewable Portfolio Standards (RPS) Buildout Case

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Merchant Transmission Line Model
ISO-NE Annual Transmission Cost Projection - Regional Portfolio Standards (RPS) Buildout Case (ISO-NE 2012 RSP Case plus RPS Buildout)
August 17, 2012

Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Investments		**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (ISO-NE Aug 2012 RNS forecast)																					
ISO-NE Planned Gross Plant Additions (Aug 2012 Five Year RNS Forecast)		1,330,000	1,246,000																		
New Gross Plant Additions (assumed to equal depreciation at 2.5% per year)																					
Proposed Northern Maine Interconnection (MPC2012, $300 Million plus AFUDC)																					
Future Reliability Upgrades in Other States (Assumes ISO-NE Approved MPRP Cost Per State)																					
Future Transmission Upgrades to Meet RPS Standards (ISO-NE New England 2030 Power System Study and 2010 Regional Electriciy Outlook)		4,577,200	4,714,516	4,855,952	5,001,631	5,151,679	5,306,230														
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)																					
MPS (PTF Qualified Portion, 76.9%)																					
ISO-NE Gross Plant	2010	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600	6,237,600
ISO-NE Gross Plant Additions	2011	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000	429,000
	2012	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900	1,672,900
	2013	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000	1,172,000
	2014	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000	1,184,000
	2015	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200	5,907,200
	2016		5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516	5,960,516
	2017			4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952	4,855,952
	2018				5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631	5,001,631
	2019					5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679	5,151,679
	2020						5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230	5,306,230
	2021							0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2022								0	0	0	0	0	0	0	0	0	0	0	0	0
	2023									0	0	0	0	0	0	0	0	0	0	0	0
	2024										0	0	0	0	0	0	0	0	0	0	0
	2025											0	0	0	0	0	0	0	0	0	0
	2026												0	0	0	0	0	0	0	0	0
	2027													0	0	0	0	0	0	0	0
	2028														0	0	0	0	0	0	0
	2029															0	0	0	0	0	0
	2030																0	0	0	0	0
	2031																	0	0	0	0
	2032																		0	0	0
	2033																			0	0
	2034																				0
Gross Plant Additions Total		16,602,700	22,563,217	27,419,169	32,420,799	37,572,479	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709	42,878,709
Carrying Charge Rate (inc.OM&G, Taxes,…) (Estimated based on ISO Forecasted RNS Rates)		17.54%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%	17.49%
Transmission Investment Carrying Cost ($K)		2,911,737	3,945,652	4,794,817	5,669,456	6,570,336	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241	7,498,241
ISO-NE Load MW (12 CP) (2012 ISO-NE 5 Year RNS Forecast)		20,188	20,289	20,390	20,492	20,595	20,698	20,801	20,905	21,010	21,115	21,220	21,327	21,433	21,540	21,648	21,756	21,865	21,974	22,084	22,195
ISO-NE Load GWh (2012 ISO-NE CELT)		142,215	143,815	145,245	146,590	147,880	149,130	150,375	151,127	151,883	152,642	153,405	154,172	154,943	155,718	156,496	157,279	158,065	158,856	159,650	160,448
Growth Factor (2022-2034) 0.50%																					
ISO-NE Load MW (12 CP) (Previous Year)		20,188	20,188	20,289	20,390	20,492	20,595	20,698	20,801	20,905	21,010	21,115	21,220	21,327	21,433	21,540	21,648	21,756	21,865	21,974	22,084
Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ISO-NE RNS Transmission Rate $/kwyr		144.23	195.45	236.33	278.05	320.62	364.08	362.27	360.47	358.68	356.89	355.12	353.35	351.59	349.84	348.10	346.37	344.65	342.93	341.23	339.53
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)		1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
Total ISO-NE Transmission Rate $/kwyr		146.16	197.44	238.38	280.16	322.80	366.32	364.58	362.85	361.12	359.41	357.71	356.03	354.35	352.68	351.03	349.38	347.75	346.13	344.52	342.92
ISO-NE TOUT ($/MWh) (equal to ISO-NE network load cost)		20.47	27.44	33.01	38.68	44.43	50.28	49.86	49.62	49.37	49.12	48.88	48.64	48.39	48.15	47.91	47.67	47.44	47.20	46.97	46.73
OATT Schedule 1 (Act.12/13 Tariff Rate, 3% Esc.)		1.93	1.99	2.05	2.11	2.17	2.24	2.31	2.38	2.45	2.52	2.60	2.67	2.75	2.84	2.92	3.01	3.10	3.19	3.29	3.39
OATT Sch. 1 ($/MWh, assumes 68% LF)		0.32	0.33	0.34	0.35	0.37	0.38	0.39	0.40	0.41	0.42	0.44	0.45	0.46	0.48	0.49	0.51	0.52	0.54	0.55	0.57
ISO-NE Trans Out-service ($/MWh) (incl Sch. 1)		20.80	27.77	33.36	39.03	44.80	50.66	50.25	50.01	49.78	49.55	49.31	49.08	48.86	48.63	48.40	48.18	47.96	47.74	47.52	47.30

ATTACHMENT 20

MERCHANT TRANSMISSION MODEL

MPS Status Quo Power Supply Cost Projection
-Merchant Line-

NMISA North
ISO-NE 2012 Regional System Plan (RSP) Case

ATTACHMENT 20

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
Merchant Transmission Line Model
ISO-NE 2012 Regional System Plan (RPS) Case [ISO-NE 2012 Five Year RNS Forecast] Wholesale Power Supply Cost Projection – NMISA North
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MA Hub	Onpeak	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
MA Hub	Offpeak	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Salisbury Basis	Onpeak	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%
Salisbury Basis	Offpeak	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%
(Salisbury basis based on (1) historical 2008-11 and (2) reduced losses starting 2013 as a result of regionwide transmission additions).																					
Salisbury Node Forward	Onpeak	46.35	47.48	49.77	52.49	55.52	58.71	62.43	65.69	68.81	71.93	75.20	78.61	82.18	85.91	89.81	93.88	98.14	102.60	107.25	112.12
Salisbury Node Forward	Offpeak	35.18	36.16	37.90	39.97	42.28	44.71	47.54	50.02	52.40	54.78	57.26	59.86	62.58	65.42	68.39	71.49	74.73	78.13	81.67	85.38
Historical NMISA Energy Usage	Onpeak	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%
Historical NMISA Energy Usage	Offpeak	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%
Load Following Premium (3% of ME Zone, Load Weighted)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Salisbury Energy Usage Weighted Energy Cost		42.33	43.42	45.52	48.01	50.78	53.70	57.09	60.08	62.94	65.79	68.78	71.90	75.16	78.57	82.14	85.86	89.76	93.83	98.09	102.54
Other ISO-NE Wholesale Load Serving and Export Related Costs																					
Capacity ($/kw-mo) (Cleared thru 15/16, then Floor thru 22/23, then estimated new peaker cost)		2.97	3.20	3.35	3.48	3.62	3.76	3.92	4.10	7.37	11.93	12.23	12.54	12.85	13.17	13.50	13.84	14.18	14.54	14.90	15.27
Capacity ($/MWh) (64.92% Load Factor per actual NMISA 2011)		6.27	6.75	7.06	7.34	7.64	7.94	8.28	8.65	15.56	25.18	25.81	26.45	27.11	27.79	28.49	29.20	29.93	30.68	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC/RMR	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other (Inad./Emer.En, RT Reserve)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.41)	(0.43)	(0.45)	(0.47)	(0.50)	(0.53)	(0.56)	(0.59)	(0.62)	(0.64)	(0.67)	(0.70)	(0.74)	(0.77)	(0.80)	(0.84)	(0.88)	(0.92)	(0.96)	(1.00)
NEPOOL Expenses	(Actual 2011, ISO WCR, 3% Esc.)	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
ISO-NE Transmission Outservice (incl. Sch. 1)		15.15	16.47	16.32	16.19	16.06	15.94	15.82	15.76	15.69	15.63	15.56	15.50	15.44	15.38	15.32	15.26	15.20	15.15	15.09	15.03
MPC2012 Trans Service ($348M, 18% CC, 600 MW Firm Res.) ($/kwmo)		8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70
MPC2012 Transmission Service (avg. hourly rate, $/MWh)		11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92
Assumed MPC2012 Losses (%)		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
MPC2012 Losses ($/MWh)		2.36	2.45	2.52	2.60	2.69	2.79	2.90	3.00	3.29	3.67	3.78	3.89	4.01	4.14	4.27	4.40	4.54	4.69	4.84	5.00
Total Other ISO-NE Wholesale Power Supply Costs ($/MWh)		38.70	40.68	41.00	41.31	41.65	42.02	42.43	42.94	50.18	60.21	60.99	61.79	62.62	63.47	64.35	65.26	66.19	67.16	68.15	69.17
Assumed Charge for Supply from Maritime Marketplace (%)		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Assumed Charge for Supply from Maritime Marketplace ($/MWh)		27.09	28.48	28.70	28.92	29.16	29.41	29.70	30.06	35.12	42.14	42.69	43.25	43.83	44.43	45.05	45.68	46.34	47.01	47.70	48.42
NMISA Charges																					
Reserves ($/MWh) (2012 NB Tariff, plus 3% per year, 100% Exchange Rate)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Administation Fee ($/MWh)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total NMISA Charges ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	1.00	1.02	1.05
Total Wholesale Power Supply Costs ($/MWh)		**70.06**	**72.55**	**74.89**	**77.62**	**80.64**	**83.84**	**87.54**	**90.90**	**98.84**	**108.74**	**112.29**	**116.00**	**119.87**	**123.90**	**128.10**	**132.49**	**137.07**	**141.84**	**146.82**	**152.01**
Total NMISA North Region Wholesale Power Supply Costs ($K)		**47,376**	**49,309**	**51,154**	**53,279**	**55,632**	**58,125**	**60,999**	**63,653**	**69,563**	**76,912**	**79,822**	**82,869**	**86,058**	**89,397**	**92,894**	**96,555**	**100,389**	**104,404**	**108,609**	**113,014**

ATTACHMENT 21

MERCHANT TRANSMISSION MODEL

MPS Status Quo Power Supply Cost Projection
-Merchant Line-

NMISA North
Renewable Portfolio Standards (RPS) Buildout Case

ATTACHMENT 21

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
Merchant Transmission Line Model
Regional Portfolio Standard (RPS) Buildout Case Wholesale Power Supply Cost Projection – NMISA North
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MA Hub	Onpeak	48.64	49.83	52.24	55.09	58.27	61.62	65.52	68.94	72.22	75.50	78.92	82.50	86.25	90.16	94.25	98.53	103.00	107.68	112.56	117.67
MA Hub	Offpeak	36.73	37.75	39.57	41.74	44.14	46.68	49.63	52.23	54.71	57.19	59.79	62.50	65.34	68.30	71.40	74.64	78.03	81.57	85.27	89.14
Salisbury Basis	Onpeak	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%
Salisbury Basis	Offpeak	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%
(Salisbury basis based on (1) historical 2008-11 and (2) reduced losses starting 2013 as a result of regionwide transmission additions).																					
Salisbury Node Forward	Onpeak	46.35	47.48	49.77	52.49	55.52	58.71	62.43	65.69	68.81	71.93	75.20	78.61	82.18	85.91	89.81	93.88	98.14	102.60	107.25	112.12
Salisbury Node Forward	Offpeak	35.18	36.16	37.90	39.97	42.28	44.71	47.54	50.02	52.40	54.78	57.26	59.86	62.58	65.42	68.39	71.49	74.73	78.13	81.67	85.38
Historical NMISA Energy Usage	Onpeak	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%	53.02%
Historical NMISA Energy Usage	Offpeak	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%	46.98%
Load Following Premium (3% of ME Zone, Load Weighted)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Salisbury Energy Usage Weighted Energy Cost		42.33	43.42	45.52	48.01	50.78	53.70	57.09	60.08	62.94	65.79	68.78	71.90	75.16	78.57	82.14	85.86	89.76	93.83	98.09	102.54
Other ISO-NE Wholesale Load Serving and Export Related Costs																					
Capacity ($/kw-mo) (Cleared thru 15/16, then Floor thru 22/23, then estimated new peaker cost)		2.97	3.20	3.35	3.48	3.62	3.76	3.92	4.10	7.37	11.93	12.23	12.54	12.85	13.17	13.50	13.84	14.18	14.54	14.90	15.27
Capacity ($/MWh) (64.92% Load Factor per NMISA 2012 7 Yr Outlook)		6.27	6.75	7.06	7.34	7.64	7.94	8.28	8.65	15.56	25.18	25.81	26.45	27.11	27.79	28.49	29.20	29.93	30.68	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC/RMR	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other (Inad./Emer.En, RT Reserve)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.41)	(0.43)	(0.45)	(0.47)	(0.50)	(0.53)	(0.56)	(0.59)	(0.62)	(0.64)	(0.67)	(0.70)	(0.74)	(0.77)	(0.80)	(0.84)	(0.88)	(0.92)	(0.96)	(1.00)
NEPOOL Expenses	(Actual 2011, ISO WCR, 3% Esc.)	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Transmission Outservice (incl. Sch. 1)		20.80	27.77	33.36	39.03	44.80	50.66	50.25	50.01	49.78	49.55	49.31	49.08	48.86	48.63	48.40	48.18	47.96	47.74	47.52	47.30
MPC2012 Trans Service ($348M, 18% CC, 600 MW Firm Res.) ($/kwmo)		8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70
MPC2012 Transmission Service (avg. hourly rate, $/MWh)		11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92	11.92
Assumed MPC2012 Losses (%)		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
MPC2012 Losses ($/MWh)		2.53	2.79	3.03	3.29	3.55	3.83	3.93	4.03	4.32	4.69	4.79	4.90	5.02	5.13	5.26	5.39	5.52	5.67	5.81	5.97
Total Other ISO-NE Wholesale Power Supply Costs ($/MWh)		44.51	52.32	58.55	64.84	71.25	77.78	77.90	78.23	85.29	95.14	95.75	96.38	97.04	97.72	98.43	99.17	99.93	100.73	101.55	102.40
Assumed Charge for Supply from Maritime Marketplace (%)		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Assumed Charge for Supply from Maritime Marketplace ($/MWh)		31.16	36.62	40.98	45.39	49.88	54.44	54.53	54.76	59.70	66.60	67.02	67.47	67.93	68.40	68.90	69.42	69.95	70.51	71.09	71.68
NMISA Charges																					
Reserves ($/MWh) (2012 NB Tariff, plus 3% per year, 100% Exchange Rate)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Administation Fee ($/MWh)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total NMISA Charges ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	1.00	1.02	1.05
Total Join ISO-NE Wholesale Power Supply Costs ($/MWh)		**74.13**	**80.70**	**87.17**	**94.09**	**101.36**	**108.87**	**112.37**	**115.60**	**123.42**	**133.20**	**136.63**	**140.21**	**143.96**	**147.87**	**151.96**	**156.22**	**160.68**	**165.34**	**170.20**	**175.28**
Total NMISA North Region Wholesale Power Supply Costs ($K)		**50,128**	**54,845**	**59,542**	**64,584**	**69,926**	**75,480**	**78,296**	**80,950**	**86,860**	**94,209**	**97,119**	**100,166**	**103,355**	**106,695**	**110,191**	**113,852**	**117,686**	**121,701**	**125,907**	**130,311**

ATTACHMENT 22

MERCHANT TRANSMISSION MODEL

EMEC Status Quo Wholesale Power Supply Cost Projection

ATTACHMENT 22

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Cost/Benefit Assessment
Merchant Transmission Line Model
Eastern Maine Electric Cooperative (EMEC/NMISA South) Wholesale Power Supply Cost Projection
August 17, 2012

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WHOLESALE POWER SUPPLY COST																					
Status Quo Projection																					
Salisbury Node Forward	Onpeak	46.35	47.48	49.77	52.49	55.52	58.71	62.43	65.69	68.81	71.93	75.20	78.61	82.18	85.91	89.81	93.88	98.14	102.60	107.25	112.12
Salisbury Node Forward	Offpeak	35.18	36.16	37.90	39.97	42.28	44.71	47.54	50.02	52.40	54.78	57.26	59.86	62.58	65.42	68.39	71.49	74.73	78.13	81.67	85.38
Salisbury Node Forward	ATC	40.43	41.48	43.48	45.86	48.50	51.29	54.53	57.38	60.11	62.84	65.69	68.67	71.79	75.05	78.45	82.01	85.74	89.63	93.69	97.95
NET BACK TO NMISA ($/MWH) (South Region)																					
ISO Tariff Schedule 2 (EAS) (Adjusted for Losses)		0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48	0.50
NB Transmission Losses (3.3%)		1.36	1.39	1.46	1.54	1.63	1.72	1.83	1.93	2.02	2.11	2.21	2.31	2.41	2.52	2.64	2.76	2.88	3.01	3.15	3.29
NB Transmission Tariff (2011 Tariff Rate @ 80% CF, 0.5%/yr esc., 100% exchange rate)		4.36	4.38	4.40	4.43	4.45	4.47	4.49	4.52	4.54	4.56	4.58	4.61	4.63	4.65	4.68	4.70	4.72	4.75	4.77	4.79
EMEC Transmission Losses (1.83%)		0.74	0.76	0.80	0.84	0.89	0.94	1.00	1.05	1.10	1.15	1.20	1.26	1.31	1.37	1.44	1.50	1.57	1.64	1.71	1.79
EMEC Tariff ($/MWh) (2012/13 Tariff, non-firm hourly rate, 0.5% annual esc.)		0.89	0.89	0.90	0.90	0.91	0.91	0.92	0.92	0.92	0.93	0.93	0.94	0.94	0.95	0.95	0.96	0.96	0.97	0.97	0.98
NMISA Tariff ($/MWh)		0.97	0.99	1.02	1.04	1.07	1.10	1.13	1.16	1.18	1.22	1.25	1.28	1.31	1.34	1.38	1.41	1.45	1.49	1.52	1.56
Total Netback		8.60	8.71	8.88	9.06	9.26	9.47	9.70	9.92	10.13	10.33	10.55	10.78	11.01	11.25	10.13	10.35	10.59	10.83	11.09	11.35
Status Quo Netback Energy Opportunity - ATC (Southern Region)		31.83	32.77	34.60	36.80	39.24	41.82	44.83	47.47	49.99	52.51	55.14	57.90	60.78	63.79	68.33	71.66	75.15	78.79	82.61	86.60
Assumed Split of Netback Costs with EMEC Consumers		50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Eff. Rate Charged to EMEC Consumers - ATC (Southern Region)		36.13	37.12	39.04	41.33	43.87	46.56	49.68	52.42	55.05	57.67	60.42	63.28	66.28	69.42	73.39	76.84	80.44	84.21	88.15	92.27
Status Quo Must Run Northern Region Netback (MWh)		72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029	72,029
NMISA Southern Region Generation (Avg ATC MW)		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NMISA Southern Region Load																					
Onpeak Avg MW		11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12
Offpeak Avg MW		9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
ATC Avg MW		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	11
NB Control Area Generation Purchases																					
NMISA Northern Region Load - Onpeak Avg MW		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4
NMISA Northern Region Load - Offpeak Avg MW		0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NMISA Northern Region Load - ATC Avg MW		1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Status Quo Wholesale Energy Cost (NB Control Area) ($/MWh)		45.12	46.10	48.19	50.69	53.48	56.42	59.86	62.85	65.71	68.56	71.54	74.65	77.91	81.31	84.87	88.59	92.48	96.55	100.80	105.24
NMISA Southern Region Wholesale Energy Cost ($/MWh)																					
Southern Region Generation		36.13	37.12	39.04	41.33	43.87	46.56	49.68	52.42	55.05	57.67	60.42	63.28	66.28	69.42	73.39	76.84	80.44	84.21	88.15	92.27
NB Control Area Generation (Salisbury)		45.12	46.10	48.19	50.69	53.48	56.42	59.86	62.85	65.71	68.56	71.54	74.65	77.91	81.31	84.87	88.59	92.48	96.55	100.80	105.24
Load Following Premium (3% of Salisbury, Load Weighted)		1.23	1.26	1.33	1.40	1.48	1.56	1.66	1.75	1.83	1.92	2.00	2.09	2.19	2.29	2.39	2.50	2.61	2.73	2.86	2.99
Percent of Load Served by Southern Region Generation		86%	86%	85%	85%	84%	84%	83%	83%	83%	82%	82%	81%	81%	81%	80%	80%	79%	79%	79%	78%
Percent of Load Served by NB Control Area Generation		14%	14%	15%	15%	16%	16%	17%	17%	17%	18%	18%	19%	19%	19%	20%	20%	21%	21%	21%	22%
NMISA Southern Region Energy Cost ($/MWh)		38.62	39.68	41.73	44.16	46.86	49.71	53.03	55.94	58.74	61.53	64.44	67.49	70.68	74.02	78.06	81.72	85.54	89.54	93.72	98.09
Assumed NB Control Area Capacity Value (% of ISO-NE)		50%	50%	50%	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Capacity Cost ($/MWh)		3.13	3.37	3.53	4.41	5.35	6.35	7.45	8.65	15.56	25.18	25.81	26.45	27.11	27.79	28.49	29.20	29.93	30.68	31.44	32.23
NMISA Southern Region Energy and Capacity Cost ($/MWh)		41.76	43.06	45.26	48.56	52.21	56.06	60.48	64.60	74.30	86.70	90.25	93.95	97.80	101.81	106.54	110.91	115.47	120.21	125.16	130.32
Other NMISA Wholesale Load Serving Costs																					
Reserves (2010 NB Tariff)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Fees ($/MWh) (Incl. in Northern Region Trans)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total Other Wholesale Costs ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	0.99	1.02	1.05
Total Status Quo EMEC (South Region) Wholesale Power Supply Cost ($/MWh)		42.39	43.71	45.93	49.25	52.91	56.79	61.23	65.36	75.08	87.51	91.08	94.80	98.67	102.71	107.46	111.86	116.44	121.21	126.18	131.37

ATTACHMENT 23

MERCHANT TRANSMISSION MODEL

EMEC Merchant Transmission Line
Power Supply Cost Projection

NMISA South

ISO-NE 2012 RSP Case and RPS Buildout Case

ATTACHMENT 23

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Wholesale Power Supply Cost/Benefit Assessment
Merchant Transmission Line Model
Eastern Maine Electric Cooperative (EMEC/NMISA South) Merchant Line Wholesale Power Supply Cost Projections
August 17, 2012

WHOLESALE POWER SUPPLY COST

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
EMEC - Merchant Line Projection: ISO-NE 2012 RSP Case																					
Weighted Salisbury Energy Price (Including Load Following Premium) ($/MWh)		42.33	43.42	45.52	48.01	50.78	53.70	57.09	60.08	62.94	65.79	68.78	71.90	75.16	78.57	82.14	85.86	89.76	93.83	98.09	102.54
Other ISO-NE Export Related Costs (including Capacity)																					
Capacity ($/MWh)		6.27	6.75	7.06	7.34	7.64	7.94	8.28	8.65	15.56	25.18	25.81	26.45	27.11	27.79	28.49	29.20	29.93	30.68	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other Energy Obl (Inad/Em En, RT Res)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.41)	(0.43)	(0.45)	(0.47)	(0.50)	(0.53)	(0.56)	(0.59)	(0.62)	(0.64)	(0.67)	(0.70)	(0.74)	(0.77)	(0.80)	(0.84)	(0.88)	(0.92)	(0.96)	(1.00)
NEPOOL Expenses	Included in Transmission	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Transmission Outservice (including Schedule 1)		15.15	16.47	16.32	16.19	16.06	15.94	15.82	15.76	15.69	15.63	15.56	15.50	15.44	15.38	15.32	15.26	15.20	15.15	15.09	15.03
NB Tariff ($/MWh, assumes 64.92% load factor)		5.37	5.40	5.43	5.45	5.48	5.51	5.54	5.56	5.59	5.62	5.65	5.68	5.70	5.73	5.76	5.79	5.82	5.85	5.88	5.91
NB Transmission Losses	3.30%	2.38	2.48	2.56	2.65	2.75	2.86	2.98	3.09	3.42	3.83	3.95	4.08	4.21	4.35	4.49	4.64	4.80	4.96	5.13	5.30
Total Other ISO-NE Export Related Costs (including Capacity)		32.17	34.19	34.55	34.90	35.27	35.68	36.13	36.68	43.97	54.07	54.89	55.73	56.60	57.50	58.42	59.37	60.35	61.36	62.39	63.46
Assumed Charge for Supply from Maritime Marketplace (%)		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Assumed Charge for Supply from Maritime Marketplace ($/MWh)		22.52	23.93	24.18	24.43	24.69	24.97	25.29	25.67	30.78	37.85	38.42	39.01	39.62	40.25	40.89	41.56	42.24	42.95	43.67	44.42
Total Cost for Supply from Maritime Marketplace ($/MWh)		64.85	67.36	69.71	72.44	75.47	78.67	82.39	85.75	93.71	103.64	107.20	110.91	114.78	118.82	123.03	127.42	132.00	136.78	141.77	146.96
% of Load Served by Maritime Marketplace (%)		14%	14%	15%	15%	16%	16%	17%	17%	17%	18%	18%	19%	19%	19%	20%	20%	21%	21%	21%	22%
Southern Region Generation Cost ($/MWh)(detailed in status quo)		41.13	42.41	44.57	47.82	51.40	55.20	59.54	63.59	73.23	85.57	89.06	92.68	96.46	100.40	105.19	109.48	113.95	118.61	123.47	128.54
% of Generation from Southern Region		86%	86%	85%	85%	84%	84%	83%	83%	83%	82%	82%	81%	81%	81%	80%	80%	79%	79%	79%	78%
Other NMISA Wholesale Load Serving Costs																					
Reserves (2010 NB Tariff)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Fees ($/MWh) (Incl. in Northern Region Trans)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total Other NMISA Wholesale Costs ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	0.99	1.02	1.05
Total EMEC - Merchant Line (South Region) Wholesale Power Supply Costs ($/MWh)		45.10	46.67	48.98	52.28	55.89	59.71	64.07	68.12	77.58	89.60	93.19	96.93	100.82	104.87	109.65	114.05	118.65	123.43	128.41	133.60
EMEC South Wholesale Pwr Supply Cost (Benefit) for Merchant Line ($/MWh)		2.70	2.96	3.05	3.02	2.98	2.92	2.84	2.76	2.50	2.09	2.11	2.13	2.15	2.17	2.18	2.20	2.21	2.22	2.23	2.24
Total EMEC (South Region) Load (MWh)		84,061	84,481	84,903	85,328	85,755	86,183	86,614	87,047	87,483	87,920	88,360	88,801	89,245	89,692	90,140	90,591	91,044	91,499	91,956	92,416
Total EMEC (South Region) Wholesale Power Supply Cost (Benefit) ($K)		227	250	259	258	256	252	246	240	218	183	186	189	192	194	197	199	201	203	205	207
EMEC - Merchant Line Projection: RPS Buildout Case																					
Weighted Salisbury Energy Price (Including Load Following Premium) ($/MWh)		42.33	43.42	45.52	48.01	50.78	53.70	57.09	60.08	62.94	65.79	68.78	71.90	75.16	78.57	82.14	85.86	89.76	93.83	98.09	102.54
Other ISO-NE Export Related Costs (including Capacity)																					
Capacity ($/MWh)		6.27	6.75	7.06	7.34	7.64	7.94	8.28	8.65	15.56	25.18	25.81	26.45	27.11	27.79	28.49	29.20	29.93	30.68	31.44	32.23
Regulation	(Actual 2011, ISO WCR, 3% Esc.)	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Forward Reserve Mkt	(Actual 2011, ISO WCR, 3% Esc.)	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 2 (EAS)	(Actual 2012 RR, 50% to Load, 3% Esc.)	0.27	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.46	0.47
ISO Tariff Schedule 3 (RAS)	(Actual 2012 RR/Tariff, 3% Esc.)	0.39	0.40	0.41	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.56	0.57	0.59	0.61	0.63	0.65	0.66	0.68
NCPC	(Actual 2011, ISO WCR, 3% Esc.)	2.13	2.19	2.26	2.32	2.39	2.47	2.54	2.62	2.69	2.78	2.86	2.94	3.03	3.12	3.22	3.31	3.41	3.52	3.62	3.73
Other Energy Obl (Inad/Em En, RT Res)	(Actual 2011, ISO WCR, 3% Esc.)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08
Marginal Loss Revenue Fund	(Actual 2011 ISO WCR Percentage)	(0.41)	(0.43)	(0.45)	(0.47)	(0.50)	(0.53)	(0.56)	(0.59)	(0.62)	(0.64)	(0.67)	(0.70)	(0.74)	(0.77)	(0.80)	(0.84)	(0.88)	(0.92)	(0.96)	(1.00)
NEPOOL Expenses	Included in Transmission	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44
Generation Information System	(Actual 2012 RR/Tariff, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Transmission Outservice (including Schedule 1)		20.80	27.77	33.36	39.03	44.80	50.66	50.25	50.01	49.78	49.55	49.31	49.08	48.86	48.63	48.40	48.18	47.96	47.74	47.52	47.30
NB Tariff ($/MWh, assumes 64.92% load factor)		5.37	5.40	5.43	5.45	5.48	5.51	5.54	5.56	5.59	5.62	5.65	5.68	5.70	5.73	5.76	5.79	5.82	5.85	5.88	5.91
NB Transmission Losses	3.30%	2.57	2.85	3.12	3.40	3.70	4.00	4.11	4.22	4.54	4.95	5.06	5.19	5.31	5.44	5.58	5.73	5.88	6.03	6.20	6.37
Total Other ISO-NE Export Related Costs (including Capacity)		38.01	45.86	52.14	58.49	64.96	71.54	71.70	72.06	79.18	89.10	89.75	90.42	91.12	91.84	92.60	93.38	94.18	95.02	95.89	96.79
Assumed Charge for Supply from Maritime Marketplace (%)		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Assumed Charge for Supply from Maritime Marketplace ($/MWh)		26.60	32.10	36.50	40.95	45.47	50.08	50.19	50.45	55.43	62.37	62.83	63.30	63.78	64.29	64.82	65.36	65.93	66.52	67.12	67.75
Total Cost for Supply from Maritime Marketplace ($/MWh)		68.94	75.53	82.02	88.95	96.25	103.78	107.28	110.52	118.36	128.16	131.60	135.19	138.94	142.86	146.95	151.23	155.69	160.35	165.22	170.30
% of Load Served by Maritime Marketplace (%)		14%	14%	15%	15%	16%	16%	17%	17%	17%	18%	18%	19%	19%	19%	20%	20%	21%	21%	21%	22%
Southern Region Generation Cost ($/MWh)(detailed in status quo)		41.13	42.41	44.57	47.82	51.40	55.20	59.54	63.59	73.23	85.57	89.06	92.68	96.46	100.40	105.19	109.48	113.95	118.61	123.47	128.54
% of Generation from Southern Region		86%	86%	85%	85%	84%	84%	83%	83%	83%	82%	82%	81%	81%	81%	80%	80%	79%	79%	79%	78%
Other NMISA Wholesale Load Serving Costs																					
Reserves (2010 NB Tariff)																					
10 Minute Synchronous Req.	0.1 MW @ $1523.28/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $3272.64/mwyr, 3% Esc.	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18
30 Minute Non-Synch. Req.	6.2 MW @ $4054.56/mwyr, 3% Esc.	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
NMISA Fees ($/MWh) (Incl. in Northern Region Trans)		0.48	0.50	0.51	0.52	0.54	0.55	0.56	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76	0.78
Total Other NMISA Wholesale Costs ($/MWh)		0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.85	0.87	0.90	0.92	0.95	0.97	0.99	1.02	1.05
Total EMEC - Merchant Line (South Region) Wholesale Power Supply Costs ($/MWh)		45.67	47.85	50.82	54.80	59.16	63.77	68.19	72.32	81.87	93.96	97.63	101.45	105.41	109.54	114.39	118.87	123.53	128.38	133.43	138.69
EMEC South Wholesale Pwr Supply Cost (Benefit) for Merchant Line ($/MWh)		3.28	4.14	4.88	5.55	6.25	6.98	6.97	6.96	6.78	6.45	6.55	6.65	6.74	6.84	6.92	7.01	7.09	7.17	7.25	7.33
Total EMEC (South Region) Load (MWh)		84,061	84,481	84,903	85,328	85,755	86,183	86,614	87,047	87,483	87,920	88,360	88,801	89,245	89,692	90,140	90,591	91,044	91,499	91,956	92,416
Total EMEC (South Region) Wholesale Power Supply Cost (Benefit) ($K)		275	350	415	474	536	601	604	606	593	567	579	590	602	613	624	635	646	656	667	677

ATTACHMENT 24

MERCHANT TRANSMISSION MODEL

Summary
ISO-NE 2012 Regional System Plan (RSP) Case
Cost/Benefit Assessment

ATTACHMENT 24

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
ISO-NE 2012 Regional System Plan (RSP) Case [ISO-NE August 2012 Five Year RNS Forecast]
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	(695)	(721)	(866)	(681)	(722)	(717)	(726)	(731)	(737)	(743)	(749)	(755)	(762)	(769)	(776)	(783)	(790)	(798)	(806)	(814)
Southern Region	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(10)	(10)
Total	(701)	(728)	(872)	(688)	(729)	(724)	(733)	(738)	(744)	(750)	(757)	(763)	(770)	(777)	(784)	(792)	(799)	(807)	(815)	(824)
Cumulative	(701)	(1,429)	(2,301)	(2,989)	(3,718)	(4,442)	(5,174)	(5,912)	(6,656)	(7,406)	(8,163)	(8,926)	(9,696)	(10,473)	(11,257)	(12,049)	(12,848)	(13,655)	(14,470)	(15,294)
Average	(701)	(714)	(767)	(747)	(744)	(740)	(739)	(739)	(740)	(741)	(742)	(744)	(746)	(748)	(750)	(753)	(756)	(759)	(762)	(765)
Wholesale Markets Cost ($K)																				
Northern Region	17,335	18,240	18,461	18,096	17,715	17,290	16,826	16,324	15,117	13,366	13,383	13,401	13,421	13,441	13,463	13,486	13,511	13,538	13,566	13,597
Southern Region	227	250	259	258	256	252	246	240	218	183	186	189	192	194	197	199	201	203	205	207
Total	17,562	18,490	18,720	18,354	17,970	17,542	17,073	16,564	15,336	13,549	13,569	13,590	13,612	13,635	13,660	13,685	13,713	13,741	13,772	13,804
Cumulative	17,562	36,052	54,772	73,126	91,096	108,639	125,711	142,276	157,611	171,161	184,730	198,320	211,932	225,568	239,227	252,913	266,625	280,366	294,138	307,941
Average	17,562	18,026	18,257	18,281	18,219	18,106	17,959	17,784	17,512	17,116	16,794	16,527	16,302	16,112	15,948	15,807	15,684	15,576	15,481	15,397
Total Cost (Benefit) ($K)																				
Northern Region	16,640	17,518	17,595	17,415	16,993	16,573	16,101	15,594	14,381	12,623	12,634	12,646	12,659	12,672	12,687	12,704	12,721	12,740	12,761	12,783
Southern Region	221	244	253	252	249	245	239	233	211	176	179	181	184	186	188	190	192	194	196	197
Total	16,861	17,762	17,848	17,666	17,242	16,818	16,340	15,827	14,592	12,799	12,813	12,827	12,842	12,858	12,876	12,894	12,913	12,934	12,956	12,980
Cumulative	16,861	34,623	52,471	70,137	87,378	104,197	120,537	136,364	150,955	163,755	176,567	189,394	202,236	215,095	227,970	240,864	253,777	266,711	279,668	292,648
Average	16,861	17,312	17,490	17,534	17,476	17,366	17,220	17,045	16,773	16,375	16,052	15,783	15,557	15,364	15,198	15,054	14,928	14,817	14,719	14,632
Transmission Cost ($/MWh)																				
Northern Region	(1.03)	(1.06)	(1.27)	(0.99)	(1.05)	(1.03)	(1.04)	(1.04)	(1.05)	(1.05)	(1.05)	(1.06)	(1.06)	(1.07)	(1.07)	(1.07)	(1.08)	(1.08)	(1.09)	(1.09)
Southern Region	(0.07)	(0.07)	(0.07)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.11)
Total	(0.92)	(0.95)	(1.14)	(0.89)	(0.94)	(0.93)	(0.94)	(0.94)	(0.94)	(0.94)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.97)	(0.97)	(0.98)	(0.98)	(0.99)
Cumulative	(0.92)	(0.94)	(1.00)	(0.98)	(0.97)	(0.96)	(0.96)	(0.96)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.96)	(0.96)
Wholesale Markets Cost ($/MWh)																				
Northern Region	25.63	26.84	27.03	26.36	25.68	24.94	24.15	23.31	21.48	18.90	18.83	18.76	18.69	18.63	18.57	18.51	18.45	18.39	18.34	18.29
Southern Region	2.70	2.96	3.05	3.02	2.98	2.92	2.84	2.76	2.50	2.09	2.11	2.13	2.15	2.17	2.18	2.20	2.21	2.22	2.23	2.24
Total	23.10	24.20	24.38	23.78	23.17	22.50	21.79	21.04	19.38	17.04	16.98	16.92	16.86	16.81	16.75	16.70	16.65	16.60	16.56	16.51
Cumulative	23.10	23.66	23.90	23.87	23.73	23.53	23.28	22.99	22.58	22.02	21.55	21.15	20.81	20.52	20.26	20.03	19.82	19.64	19.47	19.31
Total Cost (Benefit) ($/MWh)																				
Northern Region	24.61	25.78	25.76	25.37	24.63	23.90	23.11	22.27	20.43	17.85	17.77	17.70	17.63	17.56	17.50	17.43	17.37	17.31	17.25	17.19
Southern Region	2.63	2.89	2.98	2.95	2.90	2.84	2.76	2.68	2.41	2.00	2.02	2.04	2.06	2.07	2.09	2.10	2.11	2.12	2.13	2.13
Total	22.18	23.25	23.24	22.89	22.23	21.58	20.86	20.10	18.44	16.10	16.03	15.97	15.91	15.85	15.79	15.74	15.68	15.63	15.58	15.53
Cumulative	22.18	22.72	22.90	22.90	22.76	22.57	22.32	22.04	21.63	21.07	20.60	20.20	19.86	19.57	19.31	19.08	18.87	18.68	18.51	18.35

ATTACHMENT 25

MERCHANT TRANSMISSION MODEL

Summary
Renewable Portfolio Standards (RPS) Buildout Case
Cost/Benefit Assessment

ATTACHMENT 25

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Merchant Transmission Line Model
Renewable Portfolio Standards (RPS) Buildout Case (ISO-NE 2012 RSP Case plus RPS Transmission Buildout)
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	(695)	(721)	(866)	(681)	(722)	(717)	(726)	(731)	(737)	(743)	(749)	(755)	(762)	(769)	(776)	(783)	(790)	(798)	(806)	(814)
Southern Region	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(10)	(10)
Total	(701)	(728)	(872)	(688)	(729)	(724)	(733)	(738)	(744)	(750)	(757)	(763)	(770)	(777)	(784)	(792)	(799)	(807)	(815)	(824)
Cumulative	(701)	(1,429)	(2,301)	(2,989)	(3,718)	(4,442)	(5,174)	(5,912)	(6,656)	(7,406)	(8,163)	(8,926)	(9,696)	(10,473)	(11,257)	(12,049)	(12,848)	(13,655)	(14,470)	(15,294)
Average	(701)	(714)	(767)	(747)	(744)	(740)	(739)	(739)	(740)	(741)	(742)	(744)	(746)	(748)	(750)	(753)	(756)	(759)	(762)	(765)
Wholesale Markets Cost ($K)																				
Northern Region	20,087	23,776	26,849	29,402	32,008	34,645	34,123	33,622	32,415	30,663	30,680	30,698	30,718	30,738	30,760	30,783	30,808	30,835	30,863	30,894
Southern Region	275	350	415	474	536	601	604	606	593	567	579	590	602	613	624	635	646	656	667	677
Total	20,362	24,126	27,264	29,875	32,544	35,246	34,727	34,228	33,008	31,230	31,259	31,289	31,319	31,351	31,384	31,419	31,454	31,491	31,530	31,571
Cumulative	20,362	44,488	71,752	101,627	134,171	169,418	204,145	238,372	271,380	302,610	333,869	365,158	396,478	427,829	459,213	490,632	522,086	553,577	585,108	616,678
Average	20,362	22,244	23,917	25,407	26,834	28,236	29,164	29,797	30,153	30,261	30,352	30,430	30,498	30,559	30,614	30,664	30,711	30,754	30,795	30,834
Total Cost (Benefit) ($K)																				
Northern Region	19,392	23,054	25,983	28,720	31,286	33,928	33,398	32,891	31,678	29,920	29,931	29,943	29,956	29,970	29,985	30,001	30,018	30,037	30,058	30,080
Southern Region	269	344	408	467	529	594	597	599	586	560	571	583	594	605	616	626	637	647	657	667
Total	19,661	23,398	26,391	29,188	31,815	34,522	33,994	33,490	32,264	30,480	30,502	30,526	30,549	30,574	30,600	30,627	30,655	30,684	30,715	30,747
Cumulative	19,661	43,059	69,451	98,638	130,454	164,976	198,970	232,460	264,724	295,204	325,707	356,232	386,782	417,356	447,956	478,583	509,238	539,922	570,637	601,385
Average	19,661	21,530	23,150	24,660	26,091	27,496	28,424	29,058	29,414	29,520	29,610	29,686	29,752	29,811	29,864	29,911	29,955	29,996	30,034	30,069
Transmission Cost ($/MWh)																				
Northern Region	(1.03)	(1.06)	(1.27)	(0.99)	(1.05)	(1.03)	(1.04)	(1.04)	(1.05)	(1.05)	(1.05)	(1.06)	(1.06)	(1.07)	(1.07)	(1.07)	(1.08)	(1.08)	(1.09)	(1.09)
Southern Region	(0.07)	(0.07)	(0.07)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.11)
Total	(0.92)	(0.95)	(1.14)	(0.89)	(0.94)	(0.93)	(0.94)	(0.94)	(0.94)	(0.94)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.97)	(0.97)	(0.98)	(0.98)	(0.99)
Cumulative	(0.92)	(0.94)	(1.00)	(0.98)	(0.97)	(0.96)	(0.96)	(0.96)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.96)	(0.96)
Wholesale Markets Cost ($/MWh)																				
Northern Region	29.70	34.98	39.31	42.83	46.40	49.97	48.97	48.01	46.06	43.35	43.16	42.97	42.79	42.60	42.42	42.24	42.06	41.89	41.72	41.55
Southern Region	3.28	4.14	4.88	5.55	6.25	6.98	6.97	6.96	6.78	6.45	6.55	6.65	6.74	6.84	6.92	7.01	7.09	7.17	7.25	7.33
Total	26.78	31.57	35.50	38.71	41.96	45.22	44.33	43.47	41.72	39.27	39.11	38.96	38.80	38.65	38.49	38.35	38.20	38.05	37.91	37.77
Cumulative	26.78	29.19	31.31	33.18	34.96	36.69	37.80	38.52	38.89	38.93	38.95	38.95	38.94	38.92	38.89	38.86	38.82	38.77	38.73	38.68
Total Cost (Benefit) ($/MWh)																				
Northern Region	28.68	33.92	38.04	41.84	45.35	48.94	47.93	46.97	45.01	42.30	42.11	41.91	41.72	41.54	41.35	41.17	40.99	40.81	40.63	40.46
Southern Region	3.21	4.07	4.81	5.48	6.17	6.90	6.89	6.88	6.70	6.37	6.46	6.56	6.65	6.74	6.83	6.91	6.99	7.07	7.15	7.22
Total	25.86	30.62	34.37	37.82	41.02	44.29	43.39	42.54	40.78	38.33	38.17	38.01	37.85	37.69	37.53	37.38	37.23	37.08	36.93	36.78
Cumulative	25.86	28.26	30.31	32.20	33.99	35.73	36.84	37.57	37.93	37.98	37.99	38.00	37.99	37.97	37.94	37.90	37.86	37.82	37.77	37.72

ATTACHMENT 26

MERCHANT TRANSMISSION MODEL

Summary
New England/Maine Buildout Case
(NE buildout proportional to Maine)
Cost/Benefit Assessment

ATTACHMENT 26

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection 2012 (MPC2012) Interconnection (NMISA to ISO-NE)
Merchant Transmission Line Model
New England/Maine Buildout Case (ISO-NE 2012 RSP Case plus NE pro-rata Buildout to Maine)
Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
August 17, 2012

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Transmission Cost ($K)																				
Northern Region	(695)	(721)	(866)	(681)	(722)	(717)	(726)	(731)	(737)	(743)	(749)	(755)	(762)	(769)	(776)	(783)	(790)	(798)	(806)	(814)
Southern Region	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(10)	(10)
Total	(701)	(728)	(872)	(688)	(729)	(724)	(733)	(738)	(744)	(750)	(757)	(763)	(770)	(777)	(784)	(792)	(799)	(807)	(815)	(824)
Cumulative	(701)	(1,429)	(2,301)	(2,989)	(3,718)	(4,442)	(5,174)	(5,912)	(6,656)	(7,406)	(8,163)	(8,926)	(9,696)	(10,473)	(11,257)	(12,049)	(12,848)	(13,655)	(14,470)	(15,294)
Average	(701)	(714)	(767)	(747)	(744)	(740)	(739)	(739)	(740)	(741)	(742)	(744)	(746)	(748)	(750)	(753)	(756)	(759)	(762)	(765)
Wholesale Markets Cost ($K)																				
Northern Region	17,335	20,064	22,147	23,684	25,250	24,800	24,311	23,809	22,602	20,850	20,868	20,886	20,905	20,926	20,948	20,971	20,996	21,023	21,051	21,081
Southern Region	227	283	327	365	403	403	401	398	381	349	356	363	369	375	382	388	394	399	405	410
Total	17,562	20,347	22,474	24,049	25,653	25,203	24,712	24,207	22,983	21,200	21,224	21,249	21,274	21,301	21,329	21,359	21,390	21,422	21,456	21,492
Cumulative	17,562	37,909	60,383	84,432	110,086	135,289	160,001	184,208	207,191	228,391	249,614	270,863	292,137	313,438	334,768	356,126	377,516	398,938	420,393	441,885
Average	17,562	18,955	20,128	21,108	22,017	22,548	22,857	23,026	23,021	22,839	22,692	22,572	22,472	22,388	22,318	22,258	22,207	22,163	22,126	22,094
Total Cost (Benefit) ($K)																				
Northern Region	16,640	19,343	21,281	23,003	24,528	24,083	23,585	23,078	21,865	20,108	20,119	20,131	20,143	20,157	20,172	20,188	20,206	20,225	20,245	20,268
Southern Region	221	277	321	358	397	396	394	391	373	342	348	355	361	367	373	379	385	390	395	401
Total	16,861	19,620	21,602	23,361	24,925	24,479	23,979	23,470	22,239	20,450	20,467	20,485	20,504	20,524	20,545	20,567	20,590	20,615	20,641	20,668
Cumulative	16,861	36,481	58,082	81,443	106,368	130,847	154,826	178,296	200,535	220,984	241,452	261,937	282,441	302,966	323,511	344,078	364,668	385,283	405,923	426,591
Average	16,861	18,240	19,361	20,361	21,274	21,808	22,118	22,287	22,282	22,098	21,950	21,828	21,726	21,640	21,567	21,505	21,451	21,405	21,364	21,330
Transmission Cost ($/MWh)																				
Northern Region	(1.03)	(1.06)	(1.27)	(0.99)	(1.05)	(1.03)	(1.04)	(1.04)	(1.05)	(1.05)	(1.05)	(1.06)	(1.06)	(1.07)	(1.07)	(1.07)	(1.08)	(1.08)	(1.09)	(1.09)
Southern Region	(0.07)	(0.07)	(0.07)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.11)
Total	(0.92)	(0.95)	(1.14)	(0.89)	(0.94)	(0.93)	(0.94)	(0.94)	(0.94)	(0.94)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.97)	(0.97)	(0.98)	(0.98)	(0.99)
Cumulative	(0.92)	(0.94)	(1.00)	(0.98)	(0.97)	(0.96)	(0.96)	(0.96)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.95)	(0.96)	(0.96)	(0.96)	(0.96)
Wholesale Markets Cost ($/MWh)																				
Northern Region	25.63	29.52	32.42	34.50	36.60	35.77	34.89	34.00	32.12	29.48	29.36	29.24	29.12	29.00	28.89	28.78	28.67	28.56	28.46	28.36
Southern Region	2.70	3.35	3.86	4.27	4.70	4.68	4.63	4.58	4.35	3.97	4.03	4.08	4.14	4.19	4.23	4.28	4.32	4.36	4.40	4.44
Total	23.10	26.63	29.27	31.16	33.07	32.33	31.54	30.75	29.05	26.66	26.56	26.46	26.36	26.26	26.16	26.07	25.98	25.88	25.80	25.71
Cumulative	23.10	24.88	26.35	27.57	28.68	29.30	29.63	29.77	29.69	29.38	29.12	28.89	28.69	28.51	28.35	28.20	28.07	27.94	27.82	27.71
Total Cost (Benefit) ($/MWh)																				
Northern Region	24.61	28.46	31.16	33.51	35.55	34.74	33.85	32.96	31.07	28.43	28.30	28.18	28.06	27.94	27.82	27.70	27.59	27.48	27.37	27.26
Southern Region	2.63	3.28	3.78	4.20	4.63	4.60	4.55	4.50	4.27	3.89	3.94	4.00	4.05	4.09	4.14	4.18	4.22	4.26	4.30	4.33
Total	22.18	25.68	28.13	30.27	32.14	31.40	30.61	29.81	28.11	25.72	25.61	25.51	25.40	25.30	25.20	25.10	25.00	24.91	24.82	24.73
Cumulative	22.18	23.94	25.35	26.59	27.71	28.34	28.67	28.81	28.74	28.43	28.17	27.94	27.74	27.56	27.40	27.25	27.11	26.99	26.87	26.75