Distributed Generation and Distribution Planning:
An Economic Analysis for the Massachusetts DG Collaborative

January 20, 2006

Prepared by Navigant Consulting, Inc.

under contract to the

Massachusetts Technology Collaborative

NAVIGANT CONSULTING

Each Massachusetts Electric Distribution Company provided details about a proposed distribution upgrade[1] and customer information for two locations within their distribution system.[2, 3]

Opportunity Name	Electric Distribution Company	Load Zone	Gas Distribution Company	Opportunity Type[4]	Date of Proposed Upgrade[5]	Current Rating (MW)	Traditional Solution Rating (MW)	Traditional Solution Cost	2006 Load (MW)	Average Annual Load Growth
NGRID Norwell	MECO	SEMA	Commonwealth Gas (NSTAR Gas)	New Substation Transformer, Growth	2009	28	50	$900,000	26.5	2.50%
NGRID Worcester	MECO	WCMA	Bay State Gas	New Substation Transformer, Contingency and Growth	2006	19.1	60	$2,100,000	23.2	1.40%
FG&E Lunenberg	FG&E	WCMA	Fitchburg Gas and Electric	Distribution Line Construction & Load Transfer, Contingency	2007	16.0	15.98	$603,000	15.6	2.96%
FG&E Leominster	FG&E	WCMA	Boston Gas (KeySpan)	Distribution Line Reconstruction, Condition	Est. 2006	N/A	N/A	$250,000	0.05	0.00%
NSTAR Woburn	BECO	NEMA	Boston Gas (KeySpan)	Transfer load to alternate circuit, Growth	2006	2	3	$60,000	2.1	1.00%
NSTAR Framingham	BECO	NEMA	Commonwealth Gas (NSTAR Gas)	Tie line, contingency	2007	121.6	126.6	$530,000	119.0	0.55%
WMECO Substation	WMECO	WCMA	None	New Substation Transformer, Projected Contingency Overload and Growth	2010	35.4	73.9	$2,300,000	34.1	1.12%
WMECO Circuit	WMECO	WCMA	None	New Distribution Circuit, Projected Contingency Overload, Reliability and Growth	2009	20.7	46.5	$500,000	19.3	2.36%

1. "Utility Distribution Planning Situations Analysis," March 9, 2005. Available at: http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab_2005Collab05_03_09_DP_UtilityList.xls
2. "Data from utilities on customer load in the 8 opportunity areas," Available at: http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab2005_2005-08-16_All-Customers-in-DG-situations_draft.xls
3. "These opportunities are examples of regions in the Company's distribution system that would face constraints in the future. The objective was for each Distribution Company to present two opportunities in order to capture a range of possible distribution planning scenarios that would help facilitate the discussion of the [Distribution Planning] Working Group." Massachusetts Distributed Generation Collaborative 2005 Annual Report. May 31, 2005. Available at: http://www.masstech.org/renewableenergy/public_policy/DG/2005_annualreport.htm
4. There are two general types of opportunities – contingency and growth. Contingency - new equipment is needed to provide back-up when an existing device fails or is unavailable. Growth - New equipment is needed when existing equipment is overloaded due to increased load growth.
5. This date corresponds to the first year of capacity shortfall after 2006.

The next distribution planning example presented was for substation in the Speen St. area of Framingham. Reliability for customers is currently maintained by the capability to transfer load between transformers at the substation; however, the capability to transfer load has been exhausted as a result of load growth. The traditional approach would be to add a new 13.8 kV tie line circuit between a nearby substation at an estimated cost of $530,000, which would access approximately 5 MW of additional capacity. The DG alternative would be to install approximately 5 MW of new capacity over the planning period.

3.4.1.4 Western Massachusetts Electric Company

WMECO presented a 90% residential circuit with potential contingency load, load growth, and reliability concerns. It is estimated that a new 23 kV circuit would be needed by 2009 to shift some of the existing load to the new circuit and improve reliability for all customers. The cost of adding the new circuit is estimated at $500,000. For a DG alternative 400 kW of DG would be required annually to meet contingency load requirements beginning in 2009.

The second scenario presented by WMECo was a substation that would require a new transformer as a result of contingency overload and load growth. The traditional approach would be to replace two 25 MVA transformers with two 47 MVA transformers to provide sufficient capacity for future load growth at a cost of $2,300,000. The DG alternative would be to add approximately 500 kW of DG annually beginning in 2009.

3.4.2 Discussion of Planning Opportunities

The Distribution Companies' identification and analysis of the planning opportunities were appreciated by all stakeholders. Their effort was a first step towards a comprehensive analysis of the benefits and costs of DG in distribution planning. Members of the DG Cluster and other stakeholders suggested that the technical analysis of planning opportunities be expanded to include other benefits and costs in addition to distribution infrastructure deferrals and lost revenues.

The Collaborative agreed that it is likely that distribution deferral would account for a small portion of the value of DG. Therefore, the discussion should go beyond "distribution deferral DG" and include the value that could be provided by "customer-driven DG". The stakeholders identified a partial list of benefits that should be considered in additional technical analysis to achieve a comparison of the benefits provided by DG versus traditional distribution planning. For example, in addition to the distribution system deferrals, there would simultaneously be a deferral of incremental generation and transmission assets from the use of DG. Other considerations are the environmental benefits that could be provided by combined heat and power because of higher fuel efficiency or by renewable DG. (Section 3.5.3 discusses the benefits and costs of DG in more detail.)

During the discussions of the planning opportunities it was also suggested that an important component of analyzing the role of DG in distribution planning would be to identify the customer base that would be impacted in order to evaluate whether any customers would install DG. The Distribution Companies indicated that large C&I customers would generally be interested in installing DG.

Assuming that the large C&I customers would be the most interested customers, it was suggested that an additional metric be included in the evaluation of planning opportunities to compare the geographic locations of large C&I customers who are considering DG with the locations of distribution company planning opportunities. It was noted that it could be difficult for the Collaborative to obtain the electrical

Customers	Type of Establishment (Based on SIC)	Number of Customers	Opportunity	SIC	Max Demand	Annual (kWh)	Electric Company	Load Zone	Electric Rate	Gas Company	Class *	Load Factor
Customer 1	3089 Plastics Products, Not Elsewhere Clas	1	WMECO Circuit	3089	3,885	24,569,745	**WME**	WCMA	T-2	NONE	C&I	0.722
Customer 2	3069 Fabricated Rubber Products, Not Elsev	1	WMECO Circuit	3069	1,114	6,694,199	**WME**	WCMA	T-2	NONE	C&I	0.686
Customer 3	2297 Non-woven Fabrics	1	WMECO Circuit	2297	601	1,870,644	**WME**	WCMA	T-2	NONE	C&I	0.355
Customer 4	2297 Non-woven Fabrics	1	WMECO Circuit	2297	427	932,975	**WME**	WCMA	T-2	NONE	C&I	0.249
Assumes "Medium C/I" are in the rate class G-2		30	WMECO Circuit	AAAA	**100.3**	**610,537**	**WME**	WCMA	G-2	NONE	C&I	0.695
Assumes "Small C/I" are in the rate class G-0		448	WMECO Circuit	AAAA	**7.45**	**35,356**	**WME**	WCMA	G-0	NONE	C&I	0.542
Assumes all "Residential" customers are in rate class R-1		5920	WMECO Circuit	AAAA	**1.6**	**7,910**	**WME**	WCMA	R-1	NONE	Residential	0.557

In the Active Utility scenario, DG could defer upgrades in many of the opportunities analyzed; there is a positive net NPV for several opportunities for one or more years.

Active Utility Scenario: Summary Table

Opportunity	T&D Solution				DG Additions			Net Savings (Cost)	
	Capacity Added (MW)	Date of Proposed Upgrade	Capital Cost	T&D NPV	Capacity Added (MW)	Capital Cost	DG NPV	Deferral Period (yrs)	Net NPV
NGRID Norwell	50.0	2009	$ 900,000	$ 122,830	2.5	$ 1,229,318	$ 119,407	1	$ 3,400
NGRID Worcester	60.0	2006	$ 2,100,000	$ 0	0	$ 0	$ 0	0	$ 0
FG&E Lunenberg	16.0	2007	$ 603,000	$ 186,123	1.0	$ 515,000	$ 136,325	2	$ 50,000
FG&E Leominster	N/A	2006	$ 250,000	$ 305,602	0.175	$ 95,000	$ 147,317	10+	$ 160,000
NSTAR Woburn	3.0	2006	$ 60,000	$ 9,133	0	$ 0	$ 8,630	2	$ 500
NSTAR Framingham	126.6	2007	$ 530,000	$ 0	0	$ 0	$ 0	0	$ 0
WMECO Substation	73.9	2010	$ 2,300,000	$ 1,397,758	2.0	$ 1,230,411	$ 494,714	6+	$ 900,000
WMECO Circuit	46.5	2009	$ 500,000	$ 129,164	1.0	$ 546,364	$ 109,343	2	$ 20,000

- The summary table presents the DG additions and economics for the deferral period. In the Appendix the results of the T&D Module and the DG Cost Module are presented for each opportunity.

Note: NCI made reasonable assumptions about DG unit sizes and the year DG units would be installed to meet capacity and reliability needs. A more refined set of DG solutions may increase the NPV for some opportunities. The amount of DG required for contingency upgrades could be less than that required for upgrades needed for normal overloads. NCI made the conservative assumption to model contingencies as normal overloads.

In the Active Utility scenario, DG could defer upgrades in many of the opportunities analyzed.

	Active Utility Scenario: Utility Ownership[1]			
	Deferral Period and Economics		Availability in the Last Year of the Deferral	
Opportunity	Deferral Period[2]	Net Savings (NPV)	Peak Load Availability[3]	Total Availability[4]
NGRID Norwell	1 yr	$3,400	0.99989	>0.99999
NGRID Worcester	0 yr	$0	N/A	N/A
FG&E Lunenberg	2 yr	$50,000	0.99932	>0.99999
FG&E Leominster	10+ yr	$160,000	0.99974	0.99994
NSTAR Woburn	2 yr	$500	0.99902	0.99999
NSTAR Framingham	0 yr	$0	N/A	N/A
WMECO Substation	6+ yr	$900,000	0.99896	0.99999
WMECO Circuit	2 yr	$20,000	0.99887	0.99996

1. NCI made reasonable assumptions about DG unit sizes and the year DG units would be installed to meet capacity and reliability needs. A more refined set of DG solutions may increase the NPV for some opportunities.
2. On an annual basis the cost of the DG solution is compared to the deferral savings. When the annual cost of the DG solution is greater than the annual savings of the T&D deferral, the deferral period ends. The DG solution must surpass the Peak Load Availability target of 0.999 in every year of the deferral.
3. Peak Load Availability = 1 - unserved energy at peak hour / peak load. This is a probabilistic calculation based on the historic availability of DG units.
4. Total Availability = 1 - total unserved energy / total load. This is a probabilistic calculation based on the historic availability of DG units.

The Active Utility results are presented using the charts and tables described below.

Provides details about the expected deferral period in the Active Utility scenario.

- The table provides the annual results of the DG Cost Module (DG Annual Cost) and the T&D Deferral Module (Deferral Savings).
- The Savings (Cost) column lists the net annual savings or cost of the DG solution.
- On an annual basis the cost of the DG solution is compared to the deferral savings. When the annual cost of the DG solution is greater than the annual savings of the T&D deferral, the deferral period ends. The end of the deferral period is denoted by the dashed line.
- The Peak Load Availability column demonstrates the DG solution can meet the Peak Load Availability target of 0.999.

Key Assumptions

- Lists the key assumptions for each opportunity.
- This includes aspects of the T&D solution, for example, the first year peak load and the system rating and the cost of the T&D solution.
- Also lists certain economic assumptions, for example, the cost of capital, inflation rate and the distribution O&M as a percent of capital costs.

WMECO Circuit – 2 year deferral

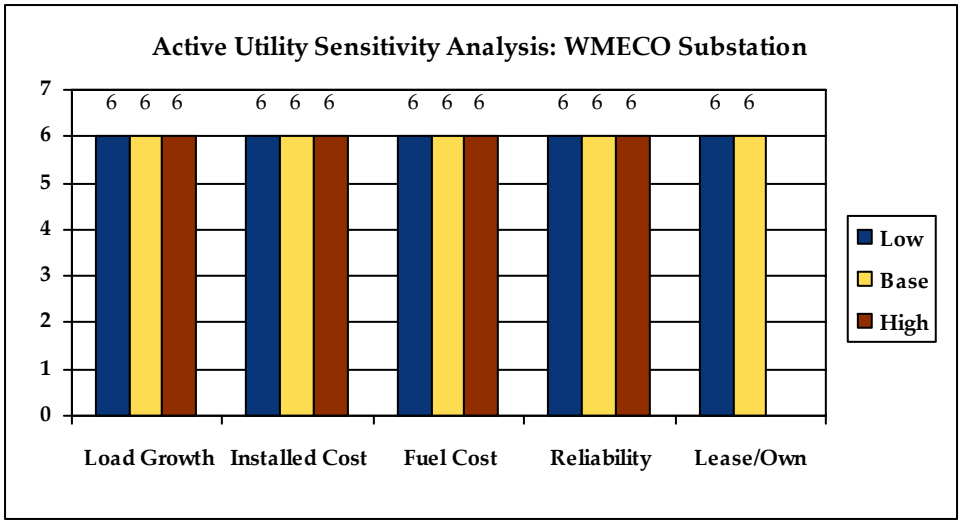
Opportunity: WMECO Circuit

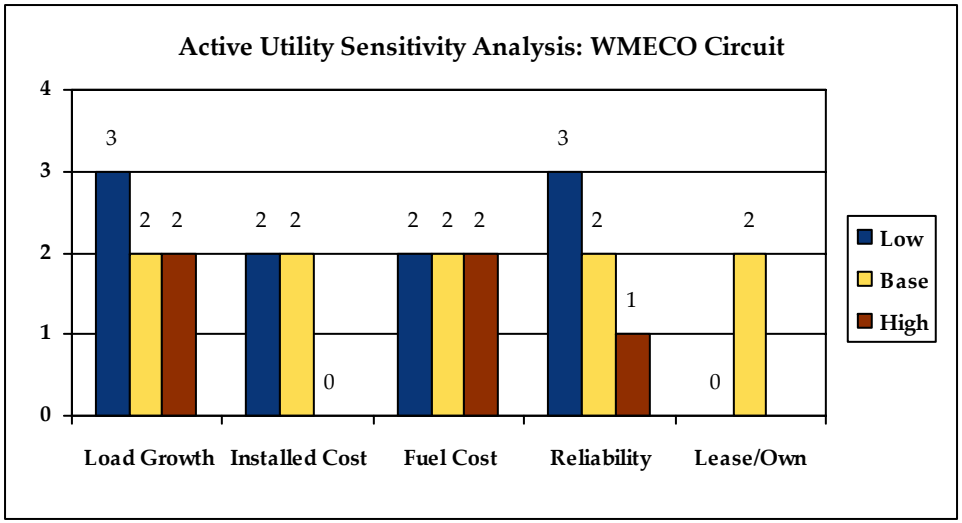
Year	DG Cap. Added (MW)	DG Capital Cost	DG Annual Cost	Deferral Savings	Savings (Cost)	Peak Ld Avail.
2006	0	$ -	$ -	$ -	$ -	1.0000
2007	0	$ -	$ -	$ -	$ -	1.0000
2008	0	$ -	$ -	$ -	$ -	1.0000
2009	1.0	$ 546,364	$ 75,424	$ 90,505	$ 15,082	0.9998
2010	0	$ -	$ 77,607	$ 90,156	$ 12,549	0.9989
2011	1.0	$ 579,637	$164,343	$ 91,806	$ (72,537)	0.9996
2012	1.0	$ 597,026	$254,847	$ 94,018	$ (160,829)	0.9999
2013	0	$ -	$266,663	$ 95,579	$ (171,084)	0.9993
2014	1.0	$ 633,385	$373,691	$ 99,678	$ (274,012)	0.9998
2015	0	$ -	$400,277	$ 103,465	$ (296,812)	0.9990

Key Assumptions	
Ownership	Utility
Number of DG Units	3.0
First Year Annual Peak Load (MW)	19.30
Existing System Rating	20.7
Cost of T&D Solution	$500,000
Max DG Capacity Added (kW)	7500
Inflation Rate	3.0%
Cost of Capital	0.078
Load Factor	72.9%
Distribution O&M as % of Cap Cost	1.5%
Avoided Losses	6.0%
Own/Lease	Own

The annual cost of the DG solution exceeds the annual deferral savings beginning in 2011

WMECO Opportunities





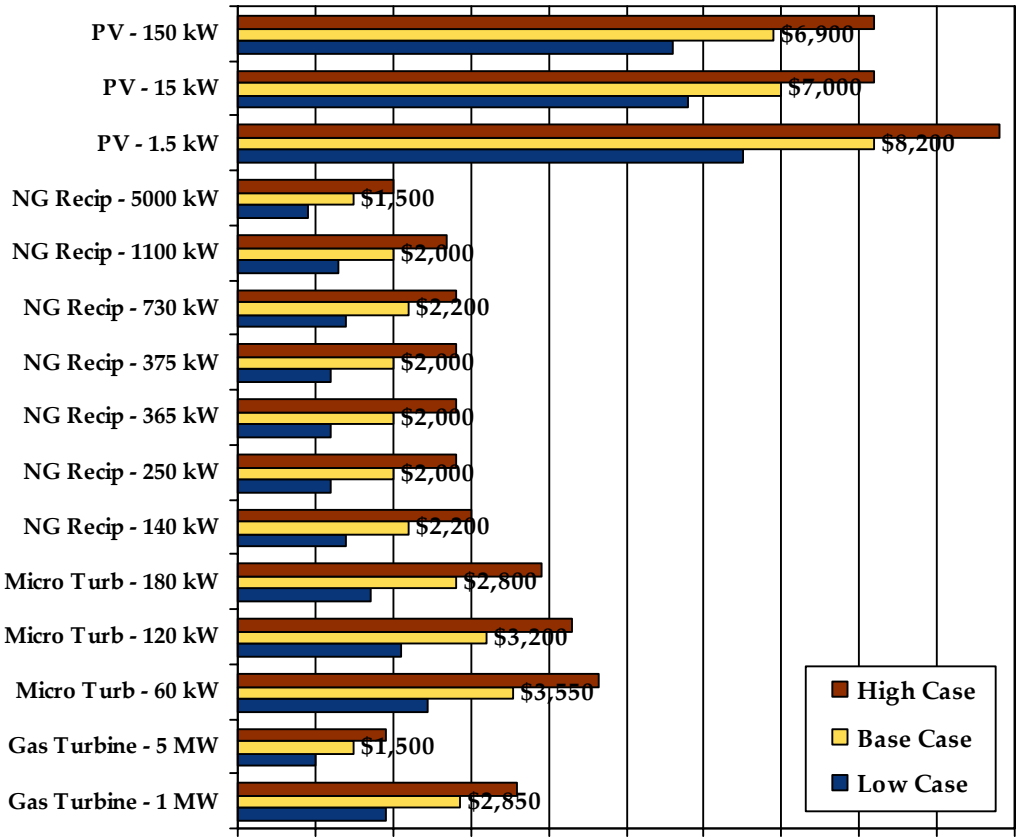
Variable	Low	Base	High
Load Growth	50%	100%	150%
Installed Cost	75%	100%	125%
Fuel Cost	75%	100%	125%
PLA Target	0.9900	0.9990	0.9999
Lease/Own	Lease		Own

- The WMECO Substation opportunity is a deferral candidate under all scenarios (i.e., addition of DG is robust as it achieves positive NPV for all sensitivity ranges)
- The WMECO Substation deferral begins in 2009 (first year of capacity deficit) and terminates in year 2015 (6 yrs); however, a longer deferral timeframe may be possible.
- The WMECO Circuit opportunity can be deferred a maximum of 3 years (low load growth) and a minimum 0 years (high DG capital cost, lease option or high reliability threshold)

NAVIGANT CONSULTING

DG systems installed costs for were estimated from publicly available data reported to the CEC and CPUC.

- Estimated installed costs for residential PV (1.5 kW) systems were derived from installed costs reported to California's Emerging Renewables Program.[1]
- Estimated installed costs for commercial PV (15 kW and 150 kW) systems were derived from installed costs reported to California's Self-Generation Incentive Program.[2]
- Estimated installed costs for CHP systems, natural gas recip. engines, microturbines and gas turbines, were derived from installed costs reported to California's Self-Generation Incentive Program.[2]



CEC: California Energy Commission; CPUC: California Public Utilities Commission

1. Data from the Emerging Renewables Program is available at: http://www.energy.ca.gov/renewables/emerging_renewables.html
   - Data Showing Completed Systems up to January 1, 2005. Updated: July 26, 2005.
   - Data Showing Approved and Completed Systems Since January 1, 2005. Updated: November 1, 2005.
2. Data from the Self-Generation Incentive Program is at: http://www.sdenergy.org/ContentPage.asp?ContentID=279&SectionID=276&SectionTarget=35
   - Statewide Self-Generation Incentive Program Data (updated November 2005).

The Status Quo results are presented using the charts and tables described below and on the following page.

DG and EE Installations in the Status Quo Scenario (Base Case)

- Compares the projected cumulative DG and EE investments by customers in the opportunity, as determined in the Market Adoption Module, with the forecasted distribution capacity shortfall.
- The data is presented for the Status Quo Base Case. The Base Case uses actual electric and gas tariffs for each electric/gas distribution company for January 1, 2005 to December 31, 2005 and installation costs reported to the California Energy Commission and the California Public Utilities Commission.
- The year of the proposed T&D upgrade is displayed on the chart.
- If the shortfall is less than the customer resources available in a given year after the proposed T&D upgrade, there may be sufficient capacity to meet the shortfall. To determine if the aggregate customer resources can meet the Peak Load Availability target the Reliability Module is utilized

1 Parameter Sensitivity Analysis of Cumulative DG Installations in 2015

- Provides the results of a sensitivity analysis of installed costs, electric supply costs and natural gas supply costs for 2015.
- These results can be compared to the chart to the left by dividing the value in this chart by 10 to determine annual installations.
- The assumptions for the Low, Base and High case installed costs are provided in the Approach and Assumptions section.
- The Base Case uses actual electric and gas tariffs for each electric/gas distribution company for January 1, 2005 to December 31, 2005 and installation costs reported to the California Energy Commission and the California Public Utilities Commission.
- Low Case: the electric and gas supply charges are reduced by 50% from the base case.
- High Case: electric and gas supply charges are increased by 50% from the base case.

Discussion:

- Describes the key findings as a result of the analysis, for example:
  - Number of years the distribution upgrade can be deferred
  - Sensitivity to installed costs
  - Sensitivity to electric supply costs
  - Sensitivity to natural gas supply costs

2 Parameter Sensitivity Analysis of Cumulative DG Installations in 2015

- Electric and gas prices are varied while installed costs are kept constant.
- The Low, Base and High Case utilize the same assumptions as above.
- The Base Case result which is incorporated in the chart in the upper left is circled for reference.
- These results can be compared to the chart in the upper left by dividing the value in the table by 10 to determine annual installations.

Status Quo template description, continued.

- The top three rows of the table specify the sensitivity case – either Low, Base, or High for installed costs, electric supply costs and natural gas supply costs; the Status Quo Base Case has been circled.
- The table presents the aggregated results of the Energy Cost Savings Module for each sensitivity case.
- The upper portion of the table lists the aggregate number of customers selecting a particular DG technology and size (boldface), and the average simple payback for the group of customers selecting the particular DG option. This information shows how customer behavior would change with different assumptions regarding installed casts, electric supply costs and natural gas costs.
- The lower portion of the table aggregates the customers into specific classes – large C&I, small and medium C&I, and residential.
- The total potential DG resource is reported by summing the kW of DG offering the best paybacks for the customers. Also, for each group of customers a weighted average simple payback is provided (it is weighted by the number of customers and the DG size).
- The last row provides the DG installations in 2015 for each sensitivity case as determined in the Market Penetration Module.

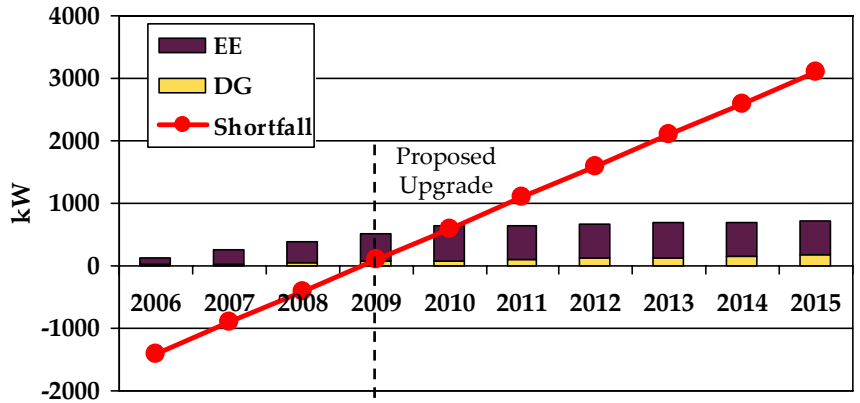
- The average annual electric and natural gas costs are reported for the Low, Base and High sensitivity cases for each class of customers.
- The average are determined after applying the appropriate electric and gas rate for each customer in the opportunity before DG was installed.

<u>Discussion</u>:

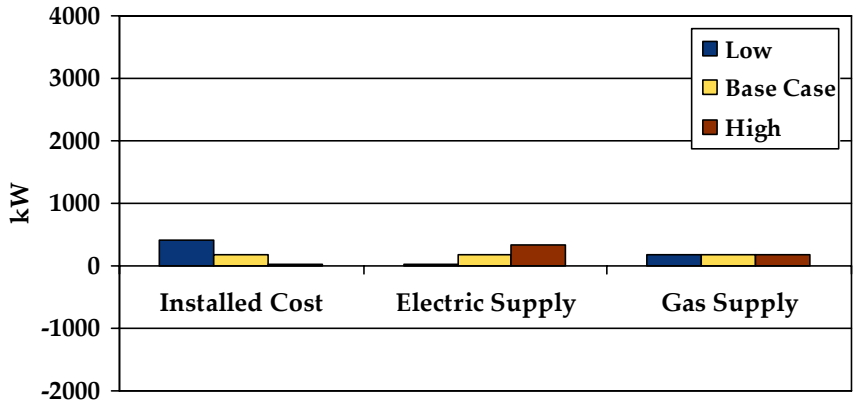
- Describes the key findings as a result of the analysis, for example:
  - — Customer behavior as a result of changing electric costs
  - — Customer behavior as a result of changing natural gas costs

In the Status Quo Base Case customer resources could defer the distribution upgrade at the WMECO Circuit opportunity for 1 year.

DG and EE Installations in the Status Quo Scenario (Base Case)



1 Parameter Sensitivity Analysis of Cumulative DG Installations in 2015



- The deferral in the WMECO Circuit opportunity is strongly dependent on assumptions regarding energy efficiency.
- There is no natural gas in this opportunity; therefore, paybacks for the large C&I customers are generally longer than in the opportunities served by natural gas and where the customers are good candidates for CHP.

2 Parameter Sensitivity Analysis of Cumulative DG Installations in 2015

		Electric Supply Costs		
		Low	Base Case	High
Gas Supply Costs	Low	37	170	321
	Base Case	37	170	321
	High	37	170	321

Base case installed costs, units kW

NAVIGANT CONSULTING

PV is the only DG technology option for all customers in the WMECO Circuit opportunity.

Gas Scenario	Low		Low		Low		Base		Base		Base		High		High		High		Base		Base	
Electric Scenario	Low		Base		High		Low		Base		High		Low		Base		High		Base		Base	
Installed Cost Scenario	Base		Base		Base		Base		Base		Base		Base		Base		Base		Low		High	
	Number of Customers and Average Simple Payback by DG Technology and Size:																					
PV - 150 kW	4	10.3	4	7.8	4	6.3	4	10.3	4	7.8	4	6.3	4	10.3	4	7.8	4	6.3	4	5.6	4	10.1
PV - 15 kW	96	10.9	96	8.2	96	6.5	96	10.9	96	8.2	96	6.5	96	10.9	96	8.2	96	6.5	96	6.0	96	10.3
PV - 1.5 kW	1480	22.1	1480	17.0	1480	13.8	1480	22.1	1480	17.0	1480	13.8	1480	22.1	1480	17.0	1480	13.8	1480	10.2	1480	24.9
	Potential DG (kW) and Average Simple Payback by Customer Class:																					
Large C&I	600	10.3	600	7.8	600	6.3	600	10.3	600	7.8	600	6.3	600	10.3	600	7.8	600	6.3	600	5.6	600	10.1
Small & Med C&I	1434	10.9	1434	8.2	1434	6.5	1434	10.9	1434	8.2	1434	6.5	1434	10.9	1434	8.2	1434	6.5	1434	6.0	1434	10.3
Residential	2220	22.1	2220	17.0	2220	13.8	2220	22.1	2220	17.0	2220	13.8	2220	22.1	2220	17.0	2220	13.8	2220	10.2	2220	24.9
All Customers	4254	16.6	4254	12.7	4254	10.3	4254	16.6	4254	12.7	4254	10.3	4254	16.6	4254	12.7	4254	10.3	4254	8.1	4254	17.9
Total DG in 2015 (kW)	37		170		321		37		170		321		37		170		321		416		34	

	Total Number of Customers	Average Electric Bill ($/kWh)			Average Gas Bill ($/MMBtu)		
		Low	Base	High	Low	Base	High
Large C&I	4	0.071	0.115	0.160	N/A	N/A	N/A
Med & Small C&I	478	0.062	0.106	0.151	N/A	N/A	N/A
Residential	5920	0.088	0.126	0.165	N/A	N/A	N/A

- The WMECO Substation serves an area where the large C&I customers make up 30% of energy load.
- PV is the only DG technology option because there is no natural gas service to these customers.

In the Active Customer scenario, customers are given incentives that vary depending on the cost of the upgrade and the size of the shortfall.

- Determine the NPV of the "deferral savings" in the Utility Distribution Deferral Module for the specific deferral period, either 2 or 3 years.
- A simplifying assumption was used that provided the entire value of the deferral to the DG Customer. While a sharing arrangement may be more appropriate. This approach helps to bracket the analysis.
- The capacity shortfall at the end of the deferral period (2 or 3 years) is multiplied by 1.5 to incent sufficient DG.
- The analysis assumes a kW cap on program incentives up 1.5 times the shortfall. Once the kW cap is reached incentives are removed and DG/EE/DR is installed at the rate determined in the Status Quo up to the capacity projected with the incentive payment.
- The incentive payment does not impact the customers' best DG technology and size identified in the Status Quo Scenario.
- To simplify the analysis, the incentive is a one-time incentive payment provided in the first year.
- The incentive is available equally for DG, EE and DR up until the kW cap.

Opportunity	2 yr Deferral ($/kW)	3 yr Deferral ($/kW)
NGRID Norwell	120	110
NGRID Worcester	100	140
FG&E Lunenberg	200	160
FG&E Leominster	1100	1600
NSTAR Woburn	180	200
NSTAR Framingham	76	64
WMECO Substation	520	480
WMECO Circuit	140	110

With an active program, DG[1] could defer upgrades for 2 or 3 years in several of the 8 opportunities.

Requirements for deferral are met within the deferral time period	Active Customer Scenario			
	2 yr Deferral Case		3 yr Deferral Case	
	Years DG/DR/EE[2] capacity is sufficient to meet shortfall	Years Peak Load Availability[3] is > 0.999	Years DG/DR/EE[2] capacity is sufficient to meet shortfall	Years Peak Load Availability[3] is > 0.999
NGRID Norwell	2 yrs	1 yr	2 yrs	1 yr
NGRID Worcester	0 yr	0 yr	0 yr	0 yr
FG&E Lunenberg	2 yrs	2 yrs	2 yrs	2 yr
FG&E Leominster	N/A	N/A	N/A	N/A
NSTAR Woburn	0 yr	0 yr	0 yr	0 yr
NSTAR Framingham	9+ yrs	9+ yrs	9+ yrs	9+ yrs
WMECO Substation	3 yrs	3 yrs	4 yrs	3 yrs
WMECO Circuit	2 yrs	2 yrs	2 yrs	2 yrs

Detailed results of the Active Customer scenario are presented for each opportunity in the Appendix.

1. Coupled with energy efficiency and demand response
2. A combined strategy of distributed generation, demand response and energy efficiency was analyzed. In no case would DG allow provide enough capacity to meet the shortfall.
3. Peak Load Availability = 1 - unserved energy at peak hour / peak load. This is a probabilistic calculation based on the historic availability of DG units. Utilities may require physical assurance to guarantee this level of peak load availability.

5 Appendix

- A Active Utility Results
- B Status Quo Results
- **C Active Customer Results**
- D Category A Benefits/Costs Examples
- E Dynamic Performance Issues
- F Bibliography

The Active Customer Scenario results are presented using the charts and tables described below.

DG, EE and DR in the Active Customer Scenario (2 year deferral)	DG, EE and DR in the Active Customer Scenario (3 year deferral)
• Presents a graph comparing the cumulative distributed generation (DG), cumulative energy efficiency (EE) and demand response (DR) activities by customers in the opportunity and the forecasted distribution capacity shortfall. • The customer data is presented for the Active Customer 2 year Case. This case utilizes the same base case assumptions in the Status Quo Scenario – actual electric and gas tariffs for each electric/gas distribution company for January 1, 2005 to December 31, 2005 and installation costs reported to the California Energy Commission and the California Public Utilities Commission. • The year of the proposed T&D upgrade is provided on the chart for reference. • If the shortfall is below the customer resources available in a given year after the proposed T&D upgrade, there is greater capacity than the size of the shortfall. To determine if the aggregate customer resources can meet the peak availability threshold the Reliability Module is utilized; the output is provided in the lower right.	• Presents a graph comparing the cumulative distributed generation (DG), cumulative energy efficiency (EE) and demand response (DR) activities by customers in the opportunity and the forecasted distribution capacity shortfall. • The customer data is presented for the Active Customer 2 year Case. This case utilizes the same base case assumptions in the Status Quo Scenario – actual electric and gas tariffs for each electric/gas distribution company for January 1, 2005 to December 31, 2005 and installation costs reported to the California Energy Commission and the California Public Utilities Commission. • The year of the proposed T&D upgrade is provided on the chart for reference. • If the shortfall is below the customer resources available in a given year after the proposed T&D upgrade, there is greater capacity than the size of the shortfall. To determine if the aggregate customer resource can meet the peak availability threshold the Reliability Module is utilized; the output is provided in the lower right

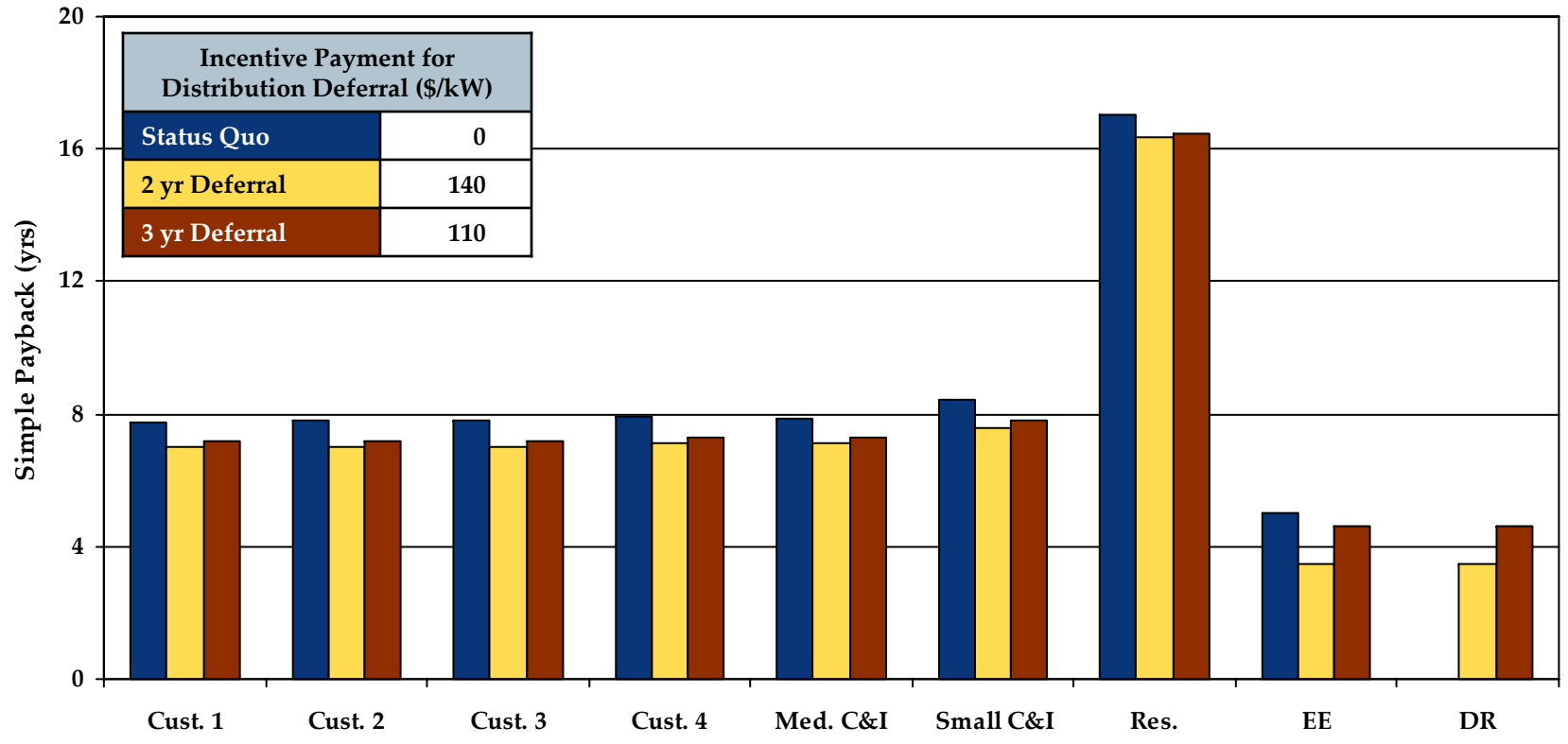
Discussion:

- Describes the key findings as a result of the analysis, for example:
  - Number of years the distribution upgrade can be deferred in the 2 year Active Customer case
  - Number of years the distribution upgrade can be deferred in the 3 year Active Customer case

• The table presents the net shortfall and peak load availability for the five years including the year the of the proposed upgrade
• If the customer resources are sufficient to meet the program's goal – 2 yr Active Customer Case, 2 yrs and 3 yr Active Customer Case, 3 yrs – the data is circled with a green box. If, however, the customer resources are not able to meet the shortfall the data is circled with a red box.

The incentive payment improves the weighted average customer payback by 0.7 yr in the 2 yr program and 0.6 yr in the 3 yr program.

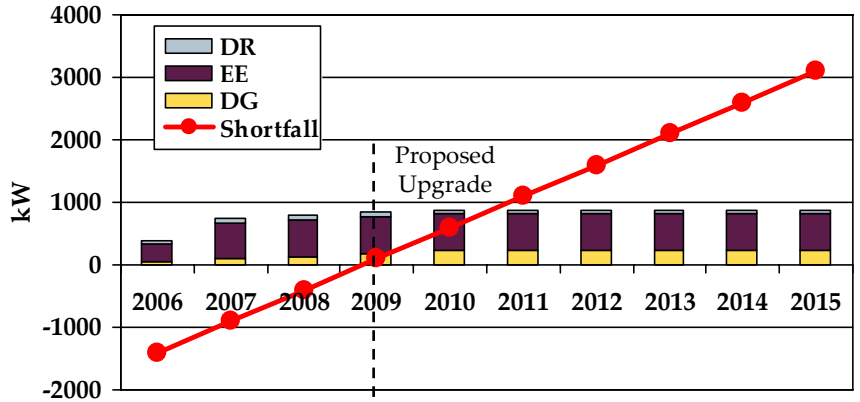
Impact of an Incentive Payment on Customer Payback – WMECO Circuit



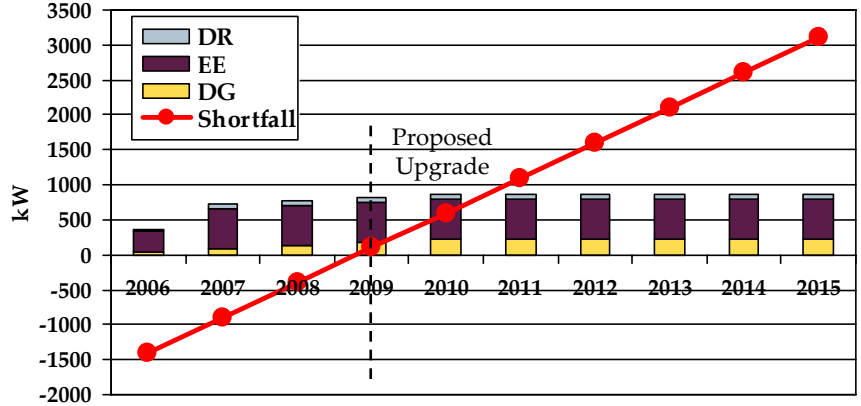
NAVIGANT CONSULTING

Customer-based DG/EE/DR resources are able to defer the distribution upgrade in the WMECO Circuit opportunity 2 yrs.

DG, EE and DR in the Active Customer Scenario (2 year deferral)



DG, EE and DR in the Active Customer Scenario (3 year deferral)



- The 2 yr deferral program would enable the deferral of the distribution investment for two years.
- The 3 yr deferral program would enable the deferral of the distribution investment for two years.

	2 year deferral		3 year deferral	
	Net Shortfall (kW)	Peak Load Availability	Net Shortfall (kW)	Peak Load Availability
2009	737	>0.9999	715	>0.9999
2010	283	0.9999	258	0.9999
2011	(217)	0.9808	(242)	0.9803
2012	(717)	0.9588	(742)	0.9583
2013	(1217)	0.9378	(1242)	0.9373

Next, the Category A Benefits/Costs are presented for a CHP and/or PV DG Owner in each of the remaining 6 opportunities.[1]

Opportunity	SIC	Classification	Peak Demand (kW)	Annual Energy (kWh)	DG Option
NGRID Norwell	**8211**	Colleges, Universities, and Professional Schools	222	654,900	150 kW PV
NGRID Worcester	**8361**	Residential Care	660	2,944,500	250 kW CHP NG recip
	2752	Commercial Printing	496	1,871,200	150 kW PV
FG&E Lunenberg	**8062**	Hospital	1,606	6,613,478	250 kW CHP NG recip
	5411	Grocery Store	609	2,539,846	150 kW PV
NSTAR Woburn	**8211**	Elementary School	449	702,600	150 kW PV
WMECO Substation	**4941**	Water Supply	410	1,861,101	150 kW PV
WMECO Circuit	**3089**	Plastic Products	3,885	24,569,745	150 kW PV

1. There is insufficient customer information to assess a DG option for the single customer in the FG&E Leominster opportunity.

NCI analyzed the Category A Benefits/Costs for a 150 kW PV installation in the WMECO Circuit opportunity.

Category A Benefit/Cost		DG Owner	Electric Distribution Company	Electric Transmission Provider	Other Electric Ratepayers	Gas Distribution Company	Environmental Stakeholders	Net
Total Electric Bill	DG Owner Electricity Bill: Transfer Payments	25,000	(8,400)	(7,600)	(13,000)	-	-	(11,000)
	Reduced Central Power Plant Fuel Consumption	100,000	-	-	-	-	-	100,000
	Avoided Central Power Plant Capacity	12,000	-	-	-	-	-	12,000
Total NG Bill	DG Owner Natural Gas Bill: Transfer Payments	-	-	-	-	-	-	-
	Increased DG Owner Natural Gas Consumption	-	-	-	-	-	-	-
State and Federal Incentives (NPV)		740,000	-	-	-	-	-	-
Renewable Energy Certificates		91,000	-	-	-	-	-	-
DG Equipment and Installation		(1,000,000)	-	-	-	-	-	(1,000,000)
Annual O&M Expenses for DG		(2,000)	-	-	-	-	-	(2,000)
Increased Reliability for DG Owner		-	-	-	-	-	-	-
Locational Installed Capacity (LICAP) Value		-	-	-	-	-	-	-
Deferred Distribution System Investment		-	3,300	-	-	-	-	3,300
Ancillary Services		-	-	-	-	-	-	-
Congestion Value		-	-	-	(2,800)	-	-	(2,800)
Emissions - CO2, NOx & SOx		-	-	-	-	-	15,000	15,000
Avoided Electric System Losses		-	-	-	17,000	-	900	18,000
Benefits Overhead		-	-	-	-	-	-	(110,000)
Sub-Total Category A*		**(61,000)**	**(5,100)**	**(7,600)**	**1,300**	**-**	**16,000**	**(1,000,000)**

* Including Category B benefits/costs for PV would provide additional net positive benefits.