TO: Scenario Task Force & SSC Members

FROM: SSC Modeling Working Group (MWG)

RE: MWG Recommendations for EE/DR/DG costs, integration costs for variable and thermal resources and nuclear uprate costs

DATE: August 31, 2011

Introduction

The Steering Stakeholder Committee (SSC) directed the Modeling Working Group (MWG) to develop high-level cost estimates associated with the assumptions defined in some of the futures and a few sensitivities to capture costs not accounted for in the MRN-NEEM modeling. These costs are associated with an increase of EE/DR/DG in Futures 4 and 8, nuclear uprate costs in Future 7, and an increase of intermittency penetration limit beyond 25% for variable energy resources in all futures except the BAU. Additionally, the SSC also agreed that the MWG may develop integration costs for other generation types, as appropriate.

The estimates provided below reflect a consensus view given the time and information available. Ranges were provided to reflect the uncertainty of the estimates. These assumptions and estimated costs have not been reviewed by the planning authorities or approved by the SSC. Consequently, these estimates should be used in the context of the stakeholder selection process for selecting the three scenarios to be further analyzed from a transmission perspective in Phase II. As such, these results only provide an order of magnitude of possible costs and are suited only for comparing futures rather, than predicating absolute costs.

Futures 4 and 8 Increase EE/DR/DG

Energy Efficiency. Many studies estimate Energy Efficiency (EE) potential based on the energy savings of electricity, natural gas, and other externalities. Only the electricity savings provide benefits to the electric system, although the savings from natural gas and other externalities are beneficial to the end-user. For the purposes of EIPC transmission planning, the MWG energy efficiency estimated costs included in the BAU and Futures 4 & 8 reflects only the costs associated with the electric savings.

The following figure illustrates the electric EE supply curves based on a Georgia Tech[1] study and a McKinsey[2] study. The original McKinsey curve contains 47 EE technologies consuming not only

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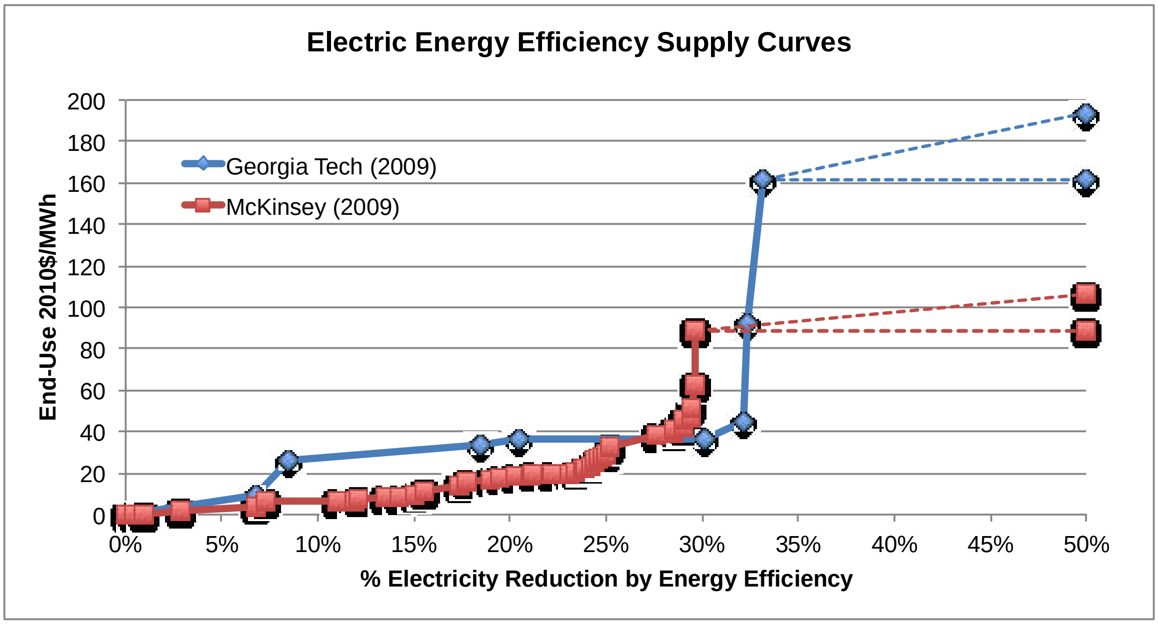
[1] Georgia Institute of Technology (2009), "Energy Efficiency in the South"

Georgia Tech study focused on the southern states located in the three census divisions of the West South Central, the East South Central, and the South Atlantic. The geographical scope of the study is not exactly consistent with that of the EIPC territory, but the states are major electricity consumers in the EIPC region. For that reason, the supply curve is assumed to represent the EE costs of the EIPC.
http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf

[2] McKinsey & Company (2009), "Unlocking Energy Efficiency in the U.S. Economy"

http://www.mckinsey.com/en/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx electricity but also natural gas and other energy sources. To create an EE supply curve solely for electricity demand, electric devices and relevant technologies such as building shell technologies are screened[3]. Georgia Tech analyzes energy efficiency from the policy perspective. Eight policy programs such as advanced appliance standards and incentives, retrofit and weatherization programs, and energy consumption monitoring systems are included in the scope.



McKinsey's electric EE supply curve shows a gradual increase until 28% of electricity reduction, and dramatically rises beyond the level. The levelized cost starts at $0/MWh and reaches $88.6/MWh at a 29.6% reduction in electricity consumption. Policy-based Georgia Tech's curve indicates more expensive electric EE prices including program administrative costs and monetary subsidies. According to Georgia Tech's curve, EE policy programs could save up to a 33.1% of electricity at $161.5/MWh. The range of the electric EE price is from $9.7 to $161.5 per MWh.

The cost beyond 29.6% (McKinsey) and 33.1% (Georgia Tech) are difficult to predict, although most agree that the cost of EE at higher reductions increases significantly. To bound this uncertainty, the MWG recommends maintaining the energy cost through the 50% reduction level, with an increase of 20% for a high range. The value of +20% was selected somewhat arbitrarily. Some stakeholders considered a 20% upper bound too conservative because of the rapid rise in costs between 30% and 35%. Others felt the rapid costs at the end were an artifact of the technologies or policies selected for the studies and should be discounted. To further

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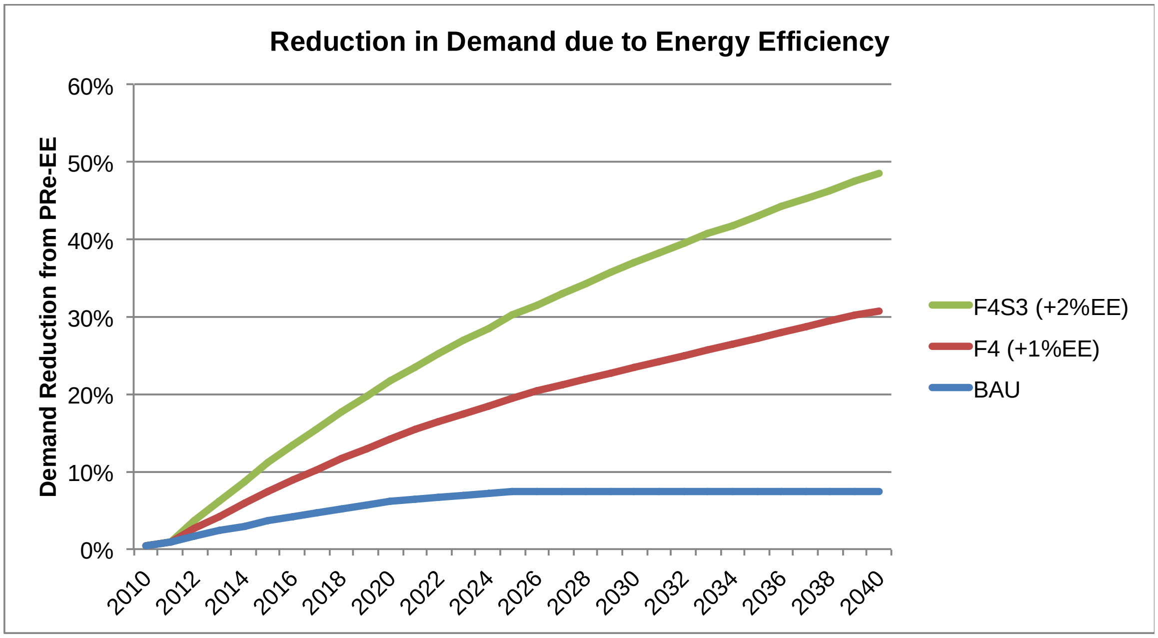
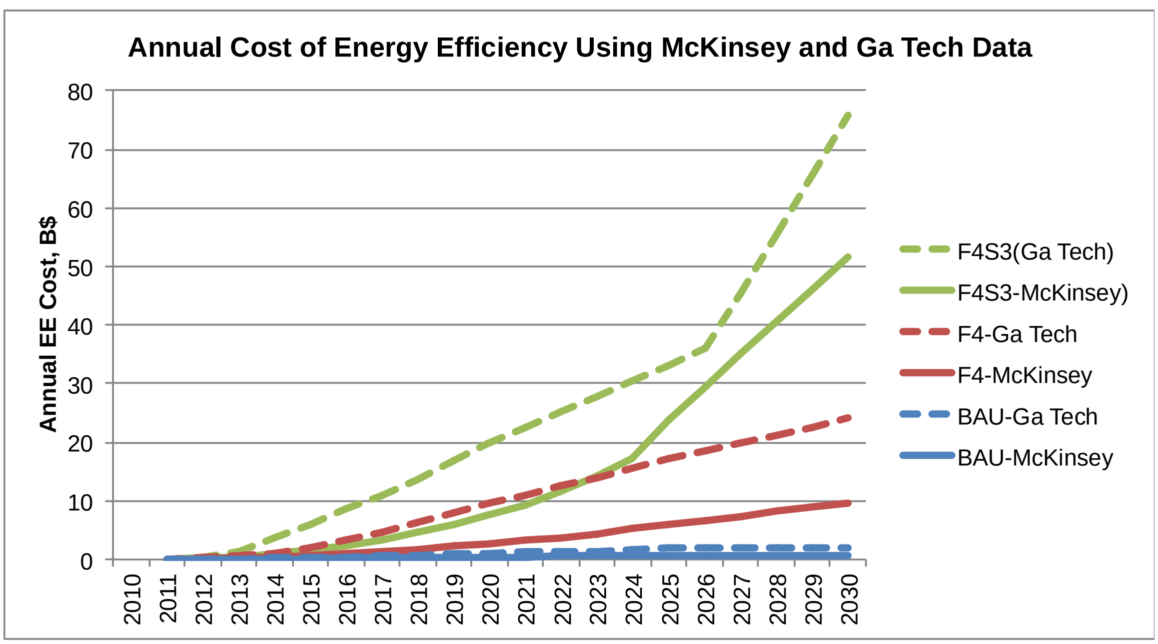
[3] A weighting factor of 0.24 which implies the ratio of cooling energy consumption to the total energy consumption was used to extract the portion of the contribution of building shell technologies to the electricity reduction.

explore the consequence, higher values for the increase by 50% reduction were analyzed as described below.

Using the derived (and incremental) electric EE supply curves, the total costs of energy efficiency of each scenario are computed. The annual reduction in electricity consumption is multiplied by the levelized cost corresponding to the amount of the reduction as a percentage.





The annual EE costs of F4 (red lines) gradually increase and reach $24 billion (Georgia Tech) and $9.7 billion (McKinsey) respectively. It is noticed that the annual cost curves under F4S3 are kinked between 2023 and 2027. The annual cost of F4S3 jumps from $35.9 billion to $45.2 billion between 2026 and 2027 with the Georgia Tech's supply curve. It rises from $17.3 billion to $23.7 billion between 2023 and 2034 with the McKinsey curve. The drastic increase in annual cost is caused by the dramatic increase in marginal EE price to reach the maximum achievable level of EE according to those studies (29-33%). The following table shows the Net Present Value (NPV) of total EE cost under each case.

It turns out that by 2030 so little of the electricity saved was beyond the peak points from the two supply curves that raising the supply curve values by 20% at 50% reduction had no effect on the BAU or F4 results and a negligible effect on the F4S3 case, as shown in the last line of the table. Raising the marginal cost to +50% raised the total NPV in scenario F4S3 by $2 to $4 billion, or an additional 1-2% of the total cost.

NPV (2015-2030) in Billions$	McKinsey	Georgia Tech	Average
BAU	$5.4	$13.6	$9.5
F4	$43.4	$125.9	$84.6
F4S3	$170.2	$289.7	$229.9
F4S3 (+20% marginal costs @ 50% electricity reduction)	$171.8	$290.4	$231.1

Demand Response (DR) costs

In order to estimate the cost of the Demand Response programs defined for the BAU, Future 4, Future 4S3, a model of demand response marginal costs per megawatt avoided was developed and applied to the megawatts of marginal peak load reductions achieved through demand response programs as forecast in the F4, F4S3, and BAU NEEM futures. (Future 8 scenarios should use the same costs as the Future 4 analyses.)

The model uses estimates of costs per customer ($/customer) for demand response programs from recent studies and divides these by calculations of the potential peak load reduction per customer (MW/customer) from FERC's National Assessment of Demand Response (NADR) model and FERC's 2011 survey of demand response and advanced metering to compute costs per megawatt potential peak load reduction ($/MW), i.e. costs per megawatt-avoided. These $/MW values are multiplied by the incremental peak load reductions per year through demand response that serve as inputs to the NEEM model's F4, F4S3, and BAU futures to produce costs of demand response programs per NEEM region per year; net present values of these costs are computed and displayed as the final results.

Sources from which $/customer estimates are borrowed or computed are shown below. The combination of FERC data with EIA data is abbreviated "FERC + EIA" and does not appear in this list because it is not a primary data source, but rather a synthesis of two primary data sources.

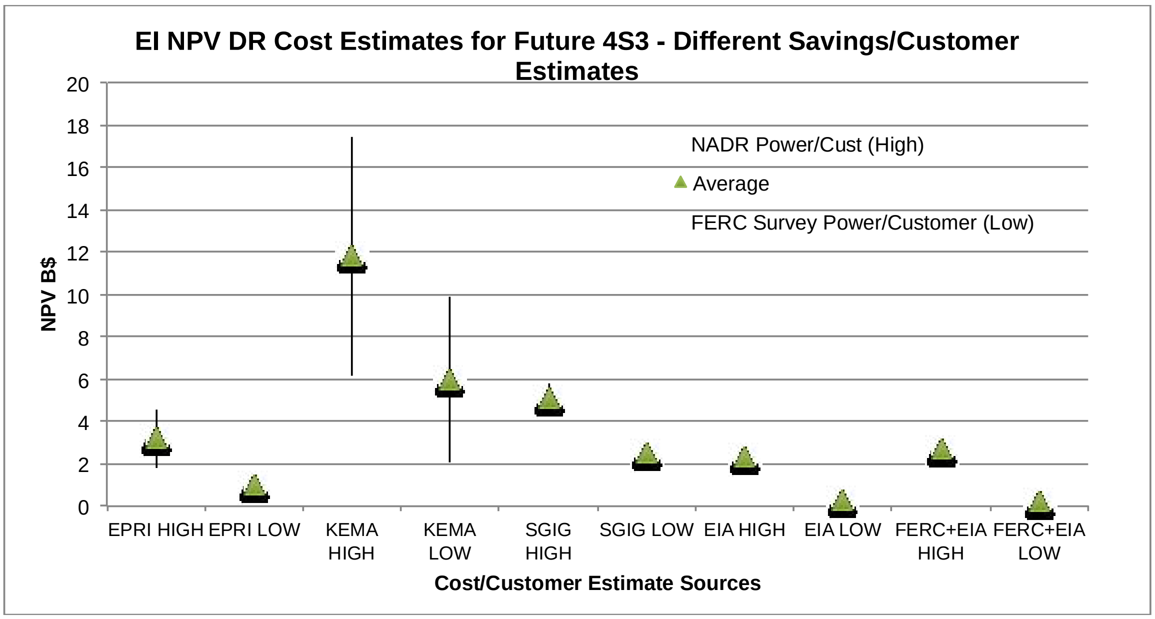
Data Sources Used

Source Author	Source Title (Year published)	Source URL (if applicable)	Abbreviation
Electric Power Research Institute	Estimating the Costs and Benefits of the Smart Grid (2011)	http://ipu.msu.edu/programs/MIGrid2011/presentations/pdfs/Reference%20Material%20%20Estimating%20the%20Costs%20and%20Benefits%20of%20the%20Smart%20Grid.pdf	EPRI
KEMA, Inc.	California solar initiative: For metering, monitoring and reporting market photovoltaic systems in California (2009)	http://www.energy.ca.gov/2009publications/CPUC-1000-2009-030/CPUC-1000-2009-030.pdf	KEMA
Department of Energy	Recovery act selections for smart grid investment grant awards by category (2010)	www.energy.gov/recovery/smartgrid_maps/SGIGSelections_Category.pdf	SGIG
Energy Information Administration	Form 861, File 3 (2009)	http://205.254.135.24/cneaf/electricity/page/eia861.html	EIA
Federal Energy Regulatory Commission	National Assessment of Demand Response (2009)	http://www.ferc.gov/industries/electric/indus-act/demand-response.asp	NADR
Federal Energy Regulatory Commission	Survey of Demand Response and Advanced Metering (2011)	http://www.ferc.gov/industries/electric/indus-act/demand-response.asp	FERC

Calculations or estimates for $/customer or MW/customer from these sources included an upper limit and a lower limit in all cases. In the results, the labels “HIGH” and “LOW” were attached to the abbreviations to distinguish whether a source’s upper limit or lower limit is used.

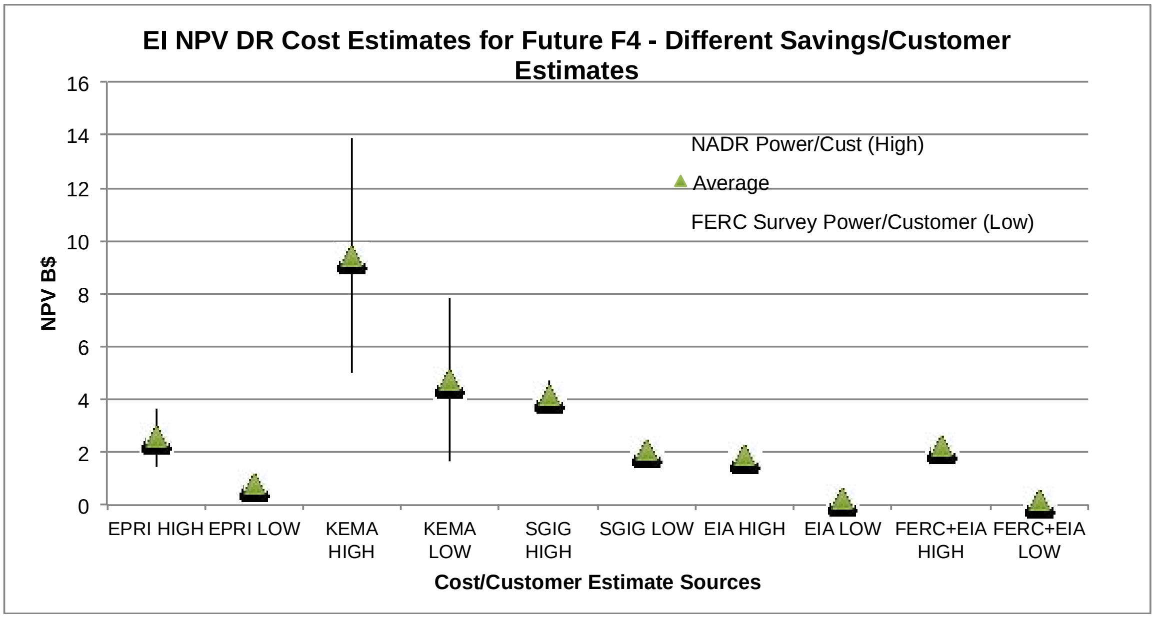
Model Results

In each of the following three pages, results from the various $/customer and MW/customer are reported for each NEEM future in the form of range bars. The top of each bar represents the result achieved using NADR, the bottom of each bar represents the result achieved using FERC 2011, and the green triangle in the center of each bar represents the average of the FERC result and the NADR result. A table displaying the corresponding values appears beneath each chart.



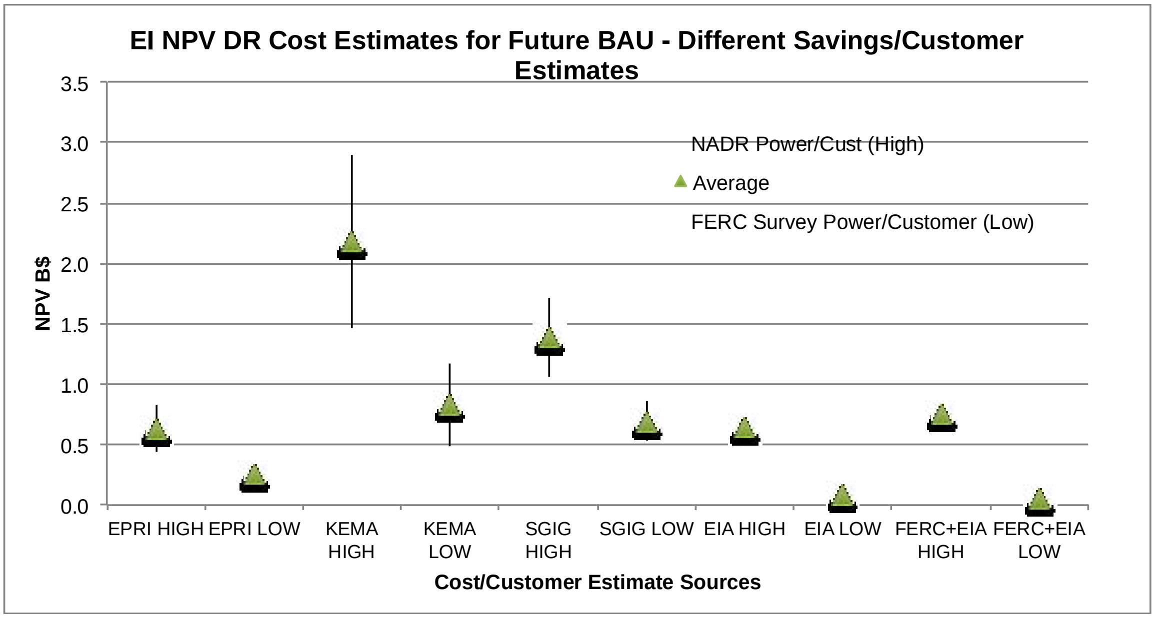
Results for Future 4 S3 ($Billion)

	NADR	FERC	Average
EPRI HIGH	4.6	1.8	3.2
EPRI LOW	1.2	0.8	1.0
KEMA HIGH	17.4	6.2	11.8
KEMA LOW	9.9	2.0	6.0
SGIG HIGH	5.8	4.4	5.1
SGIG LOW	2.9	2.2	2.6
EIA HIGH	2.1	2.6	2.3
EIA LOW	0.3	0.3	0.3
FERC+EIA HIGH	2.5	3.0	2.7
FERC+EIA LOW	0.2	0.2	0.2



Results for Future 4 ($Billion)

	NADR	FERC	Average
EPRI HIGH	3.6	1.5	2.6
EPRI LOW	1.0	0.6	0.8
KEMA HIGH	13.9	5.0	9.4
KEMA LOW	7.8	1.6	4.7
SGIG HIGH	4.7	3.5	4.1
SGIG LOW	2.4	1.8	2.1
EIA HIGH	1.7	2.1	1.9
EIA LOW	0.2	0.3	0.2
FERC+EIA HIGH	2.0	2.4	2.2
FERC+EIA LOW	0.1	0.2	0.1



Results for BAU ($Billion)

	NADR	FERC	Average
EPRI HIGH	0.8	0.4	0.6
EPRI LOW	0.3	0.2	0.3
KEMA HIGH	2.9	1.5	2.2
KEMA LOW	1.2	0.5	0.8
SGIG HIGH	1.7	1.1	1.4
SGIG LOW	0.9	0.5	0.7
EIA HIGH	0.7	0.6	0.6
EIA LOW	0.1	0.1	0.1
FERC+EIA HIGH	0.8	0.7	0.7
FERC+EIA LOW	0.0	0.0	0.0

Conclusions and Recommendations

The results for each scenario vary rather directly with the amount (MW) of demand response programs introduced under that scenario. F4S3 holds the largest DR Cost NPVs, F4 second largest, and BAU smallest.

The KEMA LOW estimates are recommended to the SSC/MWG on the grounds that they capture most of the other estimates; only KEMA HIGH exceeds the upper limit of KEMA LOW, and only EIA LOW and FERC + EIA LOW lie beneath the lower limit of KEMA LOW.

An alternative recommendation is EPRI HIGH, since the most recent estimates of capital costs related to demand response come from EPRI (see Table 1 for a link to the source document from EPRI).

Distributed Generation (DG) costs.

The distributed generation included in the BAU was based on the AEO 2011 forecast, some behind the meter some utility scale. For the aggressive renewable DG called for in Futures 4 & 8, an additional 2 times the BAU DG was included, all of which are behind the meter with photovoltaic (PV) systems. The estimated cost of the renewable distributed generation OVER 2015-2030 is $98B.[4]

The PV capital costs included in the AEO 2011 were for utility scale projects rather than the small scale systems. Consequently, the MWG had to deviate from the protocol of using AEO for capital costs. Instead, a Lawrence Berkeley National Laboratory[5] study was used and the capital costs were assumed to be the weighted average of the 2-5 kW and 5-10 kW systems to reflect the most likely sized systems to be installed to meet this aggressive goal. The learning rate assumptions (20% between 2011-2025, no change after 2020) are consistent with large solar and other technologies.

Future 7 Nuclear Uprate Costs

Both the BAU and Future 7 included nuclear uprate as part of their assumptions. The BAU assumed 1,538 MW and Future 7 assumed 8,687 MW. The costs of these uprates are not captured in the NEEM output. Consequently, the SSC directed the MWG to estimate the cost of the nuclear uprates based on $2,600/kW. The estimated costs for the nuclear uprates are $4.8B for the BAU and $27.4 B for Future 7.[6]

Thermal integration costs (Contingency reserves)

The cost information provided with the MRN-NEEM results does not incorporate the costs associated with maintaining contingency reserves needed to maintain power system reliability in the event of the sudden loss of a large generator. Contingency reserves are generally made up of fast-acting resources that are held 24/7/365 in case a large generator experiences a forced outage and goes offline. Because these costs are not being captured in the MRN-NEEM, and because the MWG recommends inclusion of integration costs for variable generation, including the integration costs of large nuclear, coal, and natural gas combined cycle units may allow greater comparability of costs among different cases.[7]

A 2003 study, Allocating Costs of Ancillary Services: Contingency Reserves and Regulation, suggests that costs of contingency reserves to accommodate the loss of the largest unit increases the operating costs and recommends a method that allocates based on its size and

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[4] Estimated cost was based on a fixed charge rate of 11.38% assuming 20-years of operation and discount rate of 5%.

[5] Tracking the Sun III, The installed Cost of Photovoltaics in the U.S. from 1998-2009, December 2010. http://eetd.lbl.gov/ea/emp/reports/lbnl-4121e.pdf

[6] Estimated costs were based on the same assumptions for new nuclear and include a 11.2% fixed charge rate assuming a 40-years of operation and a discount rate of 5%.

[7] Some stakeholders have suggested that only incremental costs should be considered rather than existing costs. Therefore, incremental costs of contingency reserve for new larger units is expected to be small. Thermal integration costs have been included because some stakeholders consider it inequitable to include total integration costs for VER and not for thermal generation.

forced outages to incentivize generators to maintain their units.[8],[9] The paper estimates, the average cost of contingency reserves across all generators was $2.0/MWh of load served. Therefore the recommendation is to apply a factor of $2/MWh in the BAU (Future 1). For other Futures, the rate should be adjusted according to the ratio:

$2/MWh * (% coal, nuclear, and combined cycle gas in study case/% coal, nuclear, and combined cycle in BAU)

Since there is some uncertainty about how the Kirby and Hirst costs compare to costs today for typical power systems in the Eastern Interconnection, and the likelihood that other integration costs are not being captured, a +/- 50% range should be added to the costs.

While these costs were developed to inform Phase I of this study, the MWG recommends that during Phase II the Planning Authorities add new transmission and generation units consistent with traditional planning methods that expands the system in a manner with lowest costs. This often results in adding new transmission and generation in such a manner that the largest single contingency remains unchanged, and therefore would avoid any incremental costs.

Variable Energy Resource (VER) integration costs

The SSC directed the MWG to quantify the operational costs of integrating wind/solar generation above a 25% penetration rate.[10] To be consistent with the other costs, the proposed approach, described below, is to apply an average integration cost to each kWh from VERs in the BAU and to all VERs above the BAU penetration limits in all other Futures. Combined, this will provide the total integration costs for each Future. These integration costs are a high-level estimate of operational costs only and do not include any interconnection costs.

There are a wide variety of studies that attempt to quantify the incremental operational costs of integrating large quantities of variable energy resources (VERs). The Eastern Wind Integration and Transmission Study (EWITS) is a particularly good choice for use in the EIPC context given that it is the study that most closely matches the geographic scope EIPC and because it is a relatively recent report. EWITS analyzes the operational impacts of high wind penetration scenarios that the SSC has directed the MWG to reflect in this cost analysis.[11]

A summary of recent wind integration studies is shown below.[12] It should be noted, however, that the studies represented in the figure cover a wide range of methodologies. Since it is not

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[8] http://www.consultkirby.com/files/Tm2003-152_Allocate_Res_Reg_Cost.pdf It should be noted that this study does not meet one of guidelines (i.e., current) for selecting references set by the MWG.

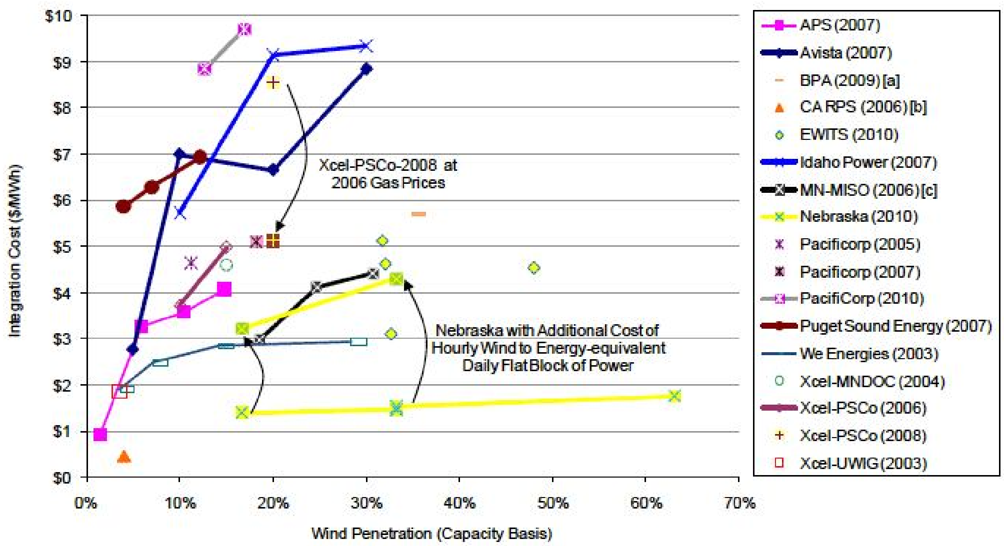
[9] Since 2003, regions have incorporated market mechanism such that generators capacity payments are established by their forced outages ($EFOR_d$) and are required to purchase energy in the real-time market to cover the energy loss from their outage. Essentially, adopting mechanism to address the concerns raised by Kirby and Hirst.

[10] See meeting summary of the March 2011 SSC meeting in Chicago, item 12 http://eipconline.com/uploads/SSC_meeting_Final_Summary_3_28-29_.pdf

[11] Eastern Wind Integration and Transmission Study http://www.nrel.gov/wind/systemsintegration/ewits.html

[12] from R. Wiser and M. Bolinger, "2010 Wind Technologies Market Report," U.S. Department of Energy June 2011. http://www1.eere.energy.gov/windandhydro/pdfs/51783.pdf , data available here http://eetd.lbl.gov/ea/EMS/reports/lbnl-4820e-data.xls Also, pages 38-93 of the following have a detailed summary of the wind integration studies completed as of mid-2009: http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf ; A

possible to normalize methodologies across a broad range of more narrowly focused studies, and because EWITS is a very recent report with closely matched geographic scope to EIPC, the proposed approach is to use the integration costs developed in EWITS as described above to provide one estimate of the costs for integrating VERs. This is also consistent with the guidance the MWG received from the EIPC planning authorities indicating that a generic interconnection-wide cost figure should be used rather than preparing regionally specific integration cost estimates.[13] Therefore, the EWITS study is the starting point of the high-level integration cost estimates.



[a] Costs in $/MWh assume 31% capacity factor.
[b] Costs represent 3-year average.
[c] Highest over 3-year evaluation period.

Sources: Acker (2007) [APS (2007)]; EnerNex Corp. (2007) [Avista (2007)]; BPA (2009); Shiu et al. (2006) [CA RPS (2006)]; EnerNex Corp (2010) [EWITS (2010)]; EnerNex Corp. and Idaho Power Co. (2007) [Idaho Power (2007)]; EnerNex Corp. and WindLogics Inc. (2006) [MN-MISO (2006)]; EnerNex et al. (2010) [Nebraska (2010)]; PacifiCorp (2005); PacifiCorp (2007); PacifiCorp (2010); Puget Sound Energy (2007); Electrotek Concepts, Inc. (2003) [We Energies (2003)]; EnerNex Corp. and WindLogics, Inc. (2004) [Xcel-MNDOC (2004)]; EnerNex Corp. (2006) [Xcel-PSCo (2006)]; EnerNex Corp. (2008) [Xcel-PSCo (2008)]; Brooks et al. (2003) [Xcel-UWIG (2003)]

Figure 1 Integration Costs at Various Levels of Wind Power Capacity Penetration (Wiser and Bolinger, 2011)

EWITS analyzed wind penetrations of 20-30% across the Eastern Interconnection. However, some of the runs in EIPC are in excess of this range (e.g. 40.6% in PJM-MISO for F2S12). A summary of the integration costs from EWITS is presented below in Figure 3. Of the four EWITS scenarios, Scenario 1 (the All-Onshore Scenario) appears to provide the best comparison to the types of results we are seeing in the Futures.[14] The distribution of wind generation at 20%

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more concise summary of many of these studies is available here: http://www.nrel.gov/wind/systemsintegration/pdfs/2008/parsons_wind_impacts_large_amounts.pdf

[13] MWG Call 7/20/2011

[14] Scenario 4 has the highest penetration rate investigated, but it includes 79 GW of offshore wind, which is far outside the range of offshore wind deployment we have seen in the SSC Futures. The average 2030 capacity of offshore wind in the 64 runs is 4.3 GW.

penetration in Scenario 1 is fairly comparable to many of the EWITS scenarios. The EWITS Scenario 1 integration cost is **$5.13/MWH (2009$).**

The MWG had extensive discussions on the appropriate adjustments to the EWITS Scenario 1 value for the higher penetration rates. For instance, the MWG agreed that since integration costs increase with penetration, the integration costs encountered in some of the EIPC futures and sensitivities might be higher than what is reflected in the analysis prepared in EWITS.

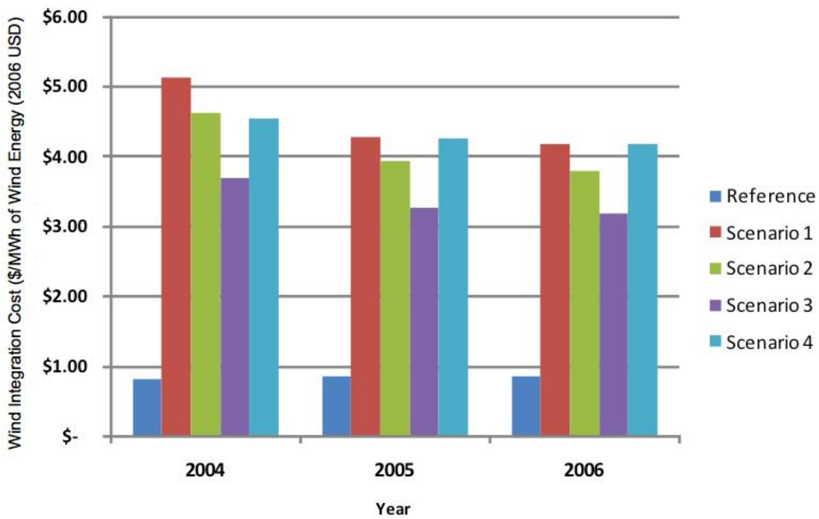

Figure 2 Wind Integration Costs from the Eastern Wind Integration and Transmission Study

On the other hand, EWITS does not take into account the full range of resources[15] that could be available by 2030 to facilitate VER integration. This could reduce the integration costs of wind and therefore the costs reported in EWITS could be overestimating the cost of reaching high VER penetrations. While EWITS does look at the impact of ATC on system flexibility, the impacts of dispatchable demand response (direct load control and the like), energy storage (both bulk and distributed storage), dynamic thermal line rating and other similar components of the flexibility supply curve[16] could enhance system flexibility in a significant way. This could substantially reduce the integration costs of wind and therefore the costs reported in EWITS could be overestimating the cost of reaching high VER penetrations by a significant margin.

Given the uncertainty of the future integration cost at higher penetrations, the MWG decided to bound the EWITS Scenario 1 costs by a minus 50% and plus 75% range.

Natural gas price assumptions are another important factor to consider when evaluating integration costs. Natural gas fired units (CT or CC) are the most likely generating resources that will be called on to compensate for the variable nature of wind. Therefore the EWITS VER integration costs should be adjusted to account for the differences between the EWITS natural

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[15] EWITS does look at the impact of ATC on system flexibility, the impacts of dispatchable demand response (direct load control and the like), energy storage (both bulk and distributed storage), dynamic thermal line rating and other similar components of the flexibility supply curve[1515] could enhance system flexibility in a significant way.

[16] The flexibility supply curve is a concept that describes the full range of options for integrating VERs as a function of cost http://www.nrel.gov/wind/systemsintegration/images/storage_graph.jpg

gas price forecast and that of the EIPC. A simple ratio between the average natural gas prices, normalized to 2010$ was used.

Based on the observations above, the MWG has proposed to adjust the EWITS Scenario 1 $5.13/MWh (2006$) with the following **equation.**

Integration Cost:

$$C_i = (\$5.13/\text{MWh} \bullet \pm 20\%) \bullet \delta_G \bullet 1.073 = \$3.139 \text{ to } 4.709/\text{MWh}$$

EWITS Integration Cost, Scenario 1, 20% Penetration, All-Onshore Gas = $8/MMBtu, 2006$

Adjustment to 35% Penetration

Dollar basis: 2010/2006 *

Gas Price Adjustment Factor, Future 2 Fixed Pipes Sensitivity (F2S11):

$$\delta_G = f \bullet (\$4.85/\text{mmBtu} / [\$8.00/\text{mmBtu} \bullet 1.073]) + (1-f) = 0.713$$

F2S11 Average EI Gas Price (2010$)

EWITS Gas Price (2006$)

Dollar basis: 2010/2006 *

f = fraction of C_i that scales with gas price P_{NG} (0.66 used here **)

The MWG recommends that the range to apply to these midpoint average cost estimates is negative 50% and positive 75%. Although there was agreement on the lower end range of 50%, the MWG chose 75% to represent the higher range as a compromise position between those who felt strongly that the value should be 100% and those who felt strongly that the appropriate upper range of uncertainty should be 50%.

Some felt the risk was similar for either higher or lower integration costs at high penetration levels. Others argued that several factors supported a higher upside risk, including the wide range of values seen in the studies reviewed, the fact that penetration of VERs exceeds 100% of load within NEEM regions in some Futures, the potential for higher gas prices than used as the basis for the adjustment, and the fact that the gas price adjustment formula does not have a risk premium associated with gas balancing. This makes the above example have a lower bound of $1.96/MWh and upper bound of $6.87/MWh. The base value remains at $3.92/MWh.

The NPV of the EI total integration cost for the F1S3 BAU case was $15 billion with a lower range (50%) of $7.5 Billion and an upper range (+75%) of $26.3 billion. The hardened Future 2 scenario had a cost of $34 billion ($17 to $60 billion). The highest cost was for the Future 2 with extra high gas prices at $53 billion ($26 to $93 billion).