2009 Strategic Resource Plan Refresh

A Supplement to the 2009 Strategic Resource Plan for the Entergy Utility System and the Entergy Operating Companies updating and extending coverage through 2029.

Prepared by System Planning & Operations

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Purpose of Refresh Supplement

Relationship to SRP Planning Process

In 2009, Entergy Services, Inc.'s ("ESI") System Planning and Operations ("SPO") group prepared a comprehensive Strategic Resource Plan ("SRP") for the Entergy System and Entergy Operating Companies. The SRP, which addressed resource needs over the 2009 – 2028 period, was approved by the Entergy Operating Committee. When the SPO presented the SRP to the Operating Companies and the Operating Committee, SPO indicated that it anticipated preparing a comprehensive revision to the SRP on a three-year cyclical basis. However, the SPO also informed the Operating Committee that it would monitor current developments and conditions and assess whether changes would warrant a comprehensive SRP update. Based on the review conducted in early 2010, the SPO determined that it would be reasonable to develop a supplement to the 2009 SRP in 2010 to refresh certain assumptions and extend coverage through 2029.

Elements of the SRP Refresh Supplement

In evaluating the need for and results of a supplement to refresh the key data inputs into the SRP, the SPO undertook the following steps:

1. Review key drivers of the SRP analysis;
2. Assess business environment (market and regulatory) changes since the 2009 SRP was prepared;
3. Assess implications of changes for current and future resource needs; and
4. Determine whether a more comprehensive SRP update is warranted.

Conclusions and Findings

Summary of Conclusions

1. A comprehensive update of the SRP is not required at this time.
2. The overall strategic recommendations set out in the 2009 SRP remain sound.
3. The overall long-term portfolio solution, which is unchanged from the conclusions reached in the 2009 SRP, requires a combination of:

- Investment in existing facilities that provide strategic long-term capabilities;
- Purchase from or acquisition of existing merchant capacity; and
- Development of new incremental resources in strategic locations.

Summary of Findings

1. Combined Cycle Gas Turbines ("CCGTs") continue to be an economically attractive alternative over a wide range of operating roles and input assumptions.

2. A reduction in forecasted long-term gas prices since the 2009 SRP has improved the economics of gas-fired alternatives relative to other technologies including solid fuel, nuclear, and renewable generation ("RG").

3. Lower long-term gas prices also change the relative economics of various gas-fired alternatives as among one another:

    - At current gas price projections, simple-cycle Combustion Turbines ("CTs") become competitive across a wider range of operation; and
    - The potential for plant betterment initiatives to provide an economic source of capacity from existing gas-fired units increases.

4. In the coming years, as the availability of existing merchant CCGT facilities from which the System can acquire incremental capacity declines, the incremental source of capacity likely will transition, at least in part, to resources developed by the System. Opportunity may exist to improve portfolio design through technology mix (CCGT vs. CT) or technology optimization (*e.g.*, load-following CCGT vs. base load CCGT).

5. Despite improvements in cost and/or performance, the cost of power from renewable generation alternatives continues to be above that of a CCGT given Reference Case assumptions.

6. SPO and Fossil Operations have continued to assess plant betterment opportunities to identify potential betterment candidates, assess economics of existing facilities relative to incremental generation alternatives, and develop recommended solutions that meet customer needs at a reasonable cost.

Re-Evaluation of 2009 Strategic Recommendations

SPO's review of the 2009 SRP indicates that the following strategic recommendations, which were adopted based on the conclusions set forth in the 2009 SRP, remain sound and do not need to be changed:

1. Focus on gas-fired CCGT capacity as the basic building block of the portfolio.

2. Pursue reasonable levels of economically attractive renewable generation.

   – In the near-term, expected to be primarily biomass.
   – About 700 MWs of Renewable Generation (spread across the 6 current Operating Companies) over the first ten years of the planning period.

3. Continue to monitor the economics of new nuclear and solid fuel, pursuing these options in the future if and when analyses warrant. Maintain readiness of new nuclear through spending levels consistent with results of on-going assessment.

4. Continue development of long term integrated planning efforts with Entergy's Transmission organization to identify portfolio solutions that best balance planning objectives. Planning efforts that have been implemented following the issuance of Federal Energy Regulatory Commission ("FERC") Order 717 may result in adjustment to timing and location of resource needs.

5. Pursue cost-effective Demand Side Management ("DSM") subject to appropriate regulatory approvals.

   – The Reference Planning Scenario includes assumptions about DSM consistent with results of the potential study developed by the independent consultant ICF International, estimated at about 729 MW by 2019 and 1,050 MW by 2029, adjusted for a reasonable implementation and approval timeline.

   – The level of DSM that will be implemented over the planning horizon will depend on a number of factors, including the level of DSM that the Operating Companies' retail regulators agree should be deployed and the implementation of appropriate regulatory review, approval, and cost recovery mechanisms that allow the Operating Companies a reasonable opportunity to recover the total costs associated with those programs.

SRP Action Plan

1. Continue to develop plans for continued reliable and economic operations of the Operating Companies post 2013.
2. Pursue closing of transactions selected in the 2009 Summer RFP.
3. Continue to monitor environmental regulation and incorporate into resource activities as appropriate.
4. RG RFP – Conduct Request for Proposals to solicit offers for renewable generation alternatives during 2010. The RFP will be designed to seek resources to address renewable energy objectives for Entergy Louisiana, LLC ("ELL") and Entergy Gulf States Louisiana, LLC ("EGSL"), consistent with a recent General Order from the Louisiana Public Service Commission.
5. Area Planning – Relying on the opportunity afforded by FERC Order 717, place enhanced focus on area planning processes. Complete integrated area plans for all planning regions during 2011.
6. Transmission Integration – Continue to enhance consideration of transmission within the SRP process.
7. Continue to monitor the economics of new nuclear and solid fuel and pursue these options in the future if and when analyses warrant. Maintain readiness of new nuclear through spending levels consistent with results of on-going assessment.

Note: Outcomes of the above action plan may dictate an update to Reference Planning Scenario, especially as it relates to the quantity, timeline and allocation of renewables.

2010 Regulatory Environment

EAI/EMI Standalone

EAI provided notice on December 19, 2005 pursuant to Section 1.01 of the System Agreement that it will withdraw from the System Agreement on December 18, 2013. EMI provided similar notice to the Operating Companies on November 8, 2007 that it plans to withdraw on November 7, 2015.

ESI continues to work with all Operating Companies to develop a proposed Successor Arrangement among all or some of the current Operating Companies that could be implemented to allow voluntary continued planning and operations as a unified system, while at the same time, ESI is helping each Operating Company prepare for the potential that a Successor Arrangement would not be in place by December 18, 2013 or November 7, 2015.

Successor to ICT Arrangements

At the behest of Federal and retail regulators, the Transmission Business Unit and SPO are involved in a study that will examine the costs and benefits of alternative future transmission operations regimes, including Regional Transmission Organization ("RTO") membership. This study is in progress, and no results of that study are available to consider within the context of a refreshed SRP. Any changes to the current Independent Coordinator of Transmission ("ICT") structure could have implications for the quantity and mix of resource requirements over the planning period. It is clear, however, that the current resources needs are sufficient to justify moving forward with the 2009 RFP selection regardless of what future transmission arrangements may be implemented.

Environmental Regulation Uncertainty

CO_2 Uncertainty

The issue of potential climate change associated with atmospheric greenhouse gases has continued to result in legislative and regulatory deliberations, but not resolution. While most policy experts continue to expect a mechanism to limit carbon emission for utility generation, the timing and scope of this mechanism remains unclear.

EPA Questions Arkansas CAVR State Implementation Plan

The Clean Air Visibility Rule ("CAVR") is expected to require the installation of scrubbers and related equipment at EAI's White Bluff coal-fired generating station. EAI sought a public interest finding from the Arkansas Public Service Commission ("APSC") for an Environmental Controls Project that would result in the installation of scrubbers at White Bluff. This project, and EAI's application with the APSC, has been suspended to allow time for the Arkansas Department of Environmental Quality ("ADEQ") to address concerns that the United States Environmental Protection Agency ("EPA") has raised with respect to the ADEQ's plan to meet CAVR requirements. It is expected that White Bluff will not be required to comply with the CAVR until five years after the Arkansas CAVR State Implementation Plan is approved. While the delay associated with the Environmental Controls Project preserves capital for now, it generates uncertainty regarding the long-term viability of the White Bluff facility. A smaller capital project to install environmental controls at EAI's Lake Catherine 4, which is subject the CAVR rules, also is on hold.

Other Environmental Regulation Uncertainty

A high level of uncertainty characterizes the current air regulatory context, with electric generators facing a wide range of new future requirements from EPA, Congress or both. New regulations for SO2 and NOx, have been proposed by EPA. New regulations on hazardous air pollutants ("HAP"s) including Mercury are expected. In addition, new regulations on water intake and waste management could drive significant expenditures at both coal and natural gas fired power plants, however, the largest burden is expected at coal fired facilities. While economics would likely drive most of facilities to comply rather than shut-down, that is before layering a CO2 cost compliance burden. The SRP Supplement Reference Planning Scenario does not contemplate any shut-down of operating company resources due to future environmental regulation; however, additional capital expenditures for environmental compliance are likely.

Support for Renewables

Federal Renewable Energy Standard

It is unclear if Congress will pass a Renewable Energy Standard ("RES") (which may also be referred to as a Renewable Portfolio Standard ("RPS")). Either term usually refers to a requirement that a specific percentage of annual energy used to meet ultimate customer load comes from a qualifying resource. The definition of what qualifies as renewable depends on the specific legislation. In some cases, demand side resources and nuclear additions or uprates may count toward meeting the RES. Although many states across the nation have state-level RES/PRS programs, Texas is the only state in which the Operating Companies do business currently with such a requirement, which means that at present only ETI is subject to one of these programs.

Jurisdictional Actions

In General Order R-28271, dated July 20, 2010, the Louisiana Public Service Commission ("LPSC") approved a pilot renewable resource program designed to provide the LPSC with more specific information regarding the availability and cost of renewable resources in Louisiana. The pilot program directs that LPSC-jurisdictional utilities (including EGSL and ELL) do the following:

1. Issue an, RFP seeking a prescribed level of renewable resources (≈ 240 MW between EGSL and ELL subject to finalization), with the LPSC retaining the right to deny certification of a contract for the purchase of power from a particular resource selected through the RFP;

2. Develop and issue a standard offer tariff to support up to 30 MW of small (less than 5 MW per project), developmental projects or, in the alternative, build three self-supply projects < 300 KW each in Louisiana.

In both instances, the LPSC has directed that the pilot programs include only renewable resources located within the State of Louisiana and that are defined as eligible under a to be issued LPSC General Order adopting the details of the renewable pilot.

ESI plans to issue an RFP later in 2010 on behalf of EGSL and ELL seeking up to 240 MW of renewable resources. ETI has determined it is more economic to purchase Renewable Energy Credits ("RECs"), and EAI, EMI and Entergy New Orleans, Inc. ("ENOI") have decided not to participate.

As will be discussed in more detail later in this supplement, without subsidies or RECs, renewable generation continues to have a cost premium compared to traditional resource alternatives, however, there are still compelling arguments for the System and the Operating Companies to pursue a limited amount of renewable resources at this time.

Key Drivers of SRP Analysis

Load Forecast

Recovery and Growth

In 2009, the Entergy Electric System peaked at 21,009 MW, a 1.1% decrease from the previous year, and total electric energy retail sales were 99,148 GWh, a 1.5% decrease from the previous year. These results are not weather normalized. Depressed retail sales and peaks primarily reflect the economic downturn. See Figure A-1 in the Appendix for historic utility operating data.

The updated Reference Case load forecast for the 2009 SRP Refresh Supplement projects a gradual recovery from the economic recession, followed by moderate growth in residential and commercial load. The industrial customer class, which has been more negatively affected by the economic recession, is expected to experience a slower rate of recovery. The economic recovery is reflected in an electric energy sales forecast slightly below the 2009 SRP forecast through 2018 and slightly above thereafter.

Hot weather in June 2009 provided an opportunity to calibrate the load forecast model's calculated peaks against actual peaks. The current load forecast model calculated a 2009 peak of 20,942 MW with an average System temperature of 98° F, which is a 0.3% variance from the actual peak, which occurred when the average System temperature was 98° F. With this calibration, the updated Reference Case forecasted peaks are above the 2009 SRP forecast in all years.

See Appendix Figure A-2 – Reference Case Total Sales & Firm Peak Load Forecast For the Six Company Utility.

Projected 10-year compound annual growth rates for Reference Case peak load and electric energy sales are unchanged from the 2009 SRP Update.

- Energy growth for the Entergy Operating Companies is expected to be 1.4% per year from 2010 to 2019 with about a 66% load factor. Electric sales growth over a 20-year period remains about 1.0 to 1.2% per year.

- The 10-year compound annual growth rate for peak load is expected to be 1.2%. The rate over the entire 20-year planning horizon has increased 0.1%.

Projected non-coincident firm peak loads by Operating Company, the coincident firm peaks for the Entergy System and the combination of the six Operating Companies are presented in the Appendix Figure A-3. Projected electric energy sales by Operating Company, for the Electric System, and for the combination of the six Operating Companies are found in Appendix Figure A-4. A graph visualizing the data of Appendix Figures A-3 and A-4 can be found in Appendix Figure A-2. The updated Reference Case load forecast for the 2009 SRP Supplement increases the generation resources needed to meet the peak load forecast by about 3%. This equates to an additional 600 MW after 10 years and an additional 800 MW after 20 years. While significant, this change is well bounded by the sensitivity cases outlined in the 2009 SRP Update to consider load uncertainties on long-term resource needs.

Natural Gas

Events Validate the Plan

In 2009, as measured by Platts Henry Hub day-ahead midpoint prices, natural gas prices fell from an average cash price of $5.25/MMBtu in January to a low of $2.90/MMBtu average during September. For the year, gas prices averaged $3.92/MMBtu, considerably below the 2009 SRP forecast of $6.04. While the price volatility was notable, 2009 was most remarkable as a year with strong domestic production in spite of falling gas prices and recession-weakened demand. Gas displacement of coal-fired generation provided some demand support, but the natural gas market was generally over supplied.

The lowered natural gas price forecast for the 2009 SRP Refresh Supplement reflects increased confidence in domestic non-conventional resources and the viability of technology innovations (horizontal drilling and fracking) to bring large volumes of low cost gas to market. Correspondingly, in the calculation of the expected case, the weight given to the Reference Case was increased from 60% to 65% and the weight for the Low Case was lowered from 30% to 25%. Appendix Figures A-5 and A-6 summarize the natural gas forecast in nominal and real dollars.

Many of the Entergy Operating Companies depend heavily on natural gas as a fuel for owned generation and wholesale purchases.

The lowered natural gas price forecast for the 2009 SRP Supplement

1. Reduces overall supply cost;

2. Improves the relative economics of gas-fired resource alternatives;

3. Enhances the selection of the CCGT as the basic portfolio building block;

4. Improves the relative economics of existing gas resources to new resources; and

5. Improves the relative performance of new CTs versus new CCGTs.

Wholesale Power Market

Power Prices Down from 2009 SRP

The methodology for developing the regional power price and heat rate forecast has remained the same, but changes to the underlying fundamentals have resulted in a significant drop in both actual and forecasted power prices. In 2009, gas prices at the Henry Hub dropped from their 2008 highs and "Into Entergy Region" power prices, being heavily tied to gas price, experienced a similar price decrease. Figure A-7 in the Appendix contains the historical average annual heat rate for 2009 and forecasted heat rate for the years 2010-2019.

Regional power demand also dropped in 2009 as a result of the economic recession, temporarily raising the Entergy region's reserve margin and lowering spot power prices. Recessionary impacts are generally temporary. In fact, 2010 year-over-year improvements in industrial demand are already apparent. Therefore, the 2009 impacts do not negate the Entergy System's need or desire for incremental long-term resources.

Regionally, a small number of projects that were already under construction before the drop in power demand are starting to come online. CLECO's 600 MW Rodemacher 3 circulating fluidized-bed unit fueled by petroleum coke began operation early in 2010, and the 665 MW Plum Point coal facility is expected online during summer 2010. However, these two resources are not available to meet the needs of the Entergy Operating Companies.

The current regional capacity surplus coupled with high capital requirements for new resources is likely to keep power plant development low, but potential environmental legislation could result in the addition of renewable or clean energy projects in the region.

Entergy region power prices are expected to rise as gas prices recover from their 2009 lows and as the capacity surplus gradually declines. Potential legislation on CO_2 could further raise power prices, especially during the off-peak hours when coal resources are often setting the marginal price.

Carbon Impacts on the SRP

The 2009 SRP Refresh has not incorporated any changes related to the impact of pending CO_2 legislation. If legislation is not passed this year, a start date after 2013 (the date assumed in the 2009 SRP) is likely. Nevertheless, future national carbon legislation is still likely and needed to send the proper price signal to all carbon emitters.

The Entergy System is presently evaluating its long-term point-of-view on carbon cost in light of the status of regulation. However, a new point-of-view is not anticipated to be available until sometime in 2011. During this interim resource evaluations may consider CO_2 assumptions that reflect best available information.

Generation Technology

2010 Technology Assessment Update

A reduction in forecasted long-term gas prices since the 2009 SRP has improved the economics of gas-fired alternatives relative to other technologies including solid fuel, nuclear, and renewable generation ("RG"). Since the 2009 SRP, the long-term point-of-view for Reference Case natural gas prices has declined ($1.69 per MMBtu levelized real 2009$s for 30 year period 2009-2038).

Lower long-term gas prices also change the relative economics of various gas-fired alternatives as among one another:

At current gas price projections, CTs become competitive across a wider range of operation; and the potential for plant betterment alternatives to provide an economic source of capacity increases.

In the coming years, as the availability of existing merchant CCGT facilities declines, the source of incremental capacity will transition to resources developed by or at the behest of one or more of the Operating Companies. Opportunity may exist to improve portfolio design through technology mix (CCGT vs. CT) or technology optimization (e.g., load-following CCGT vs. base load CCGT). The SPO is evaluating the incremental capital costs that may be required to ensure that the enhanced portfolio can supply the amount of flexible capability needed for reliable operations.

Capital cost for new CCGTs on a $/kW basis has increased about 20% or about $200/KW in 2009$s versus the POV in the 2009 SRP. This is partially driven by improved performance (slightly better heat rate of the newest class of turbines) and an expected higher cost for raw materials and other components in the Supply Chain. However, the capital cost increase is more than offset by the combination of better performance and lower expected natural gas prices when evaluating the life cycle revenue requirement of a typical CCGT.

Renewables continue to require a premium absent subsidies or government mandates. Since the 2009 SRP, SPO has developed a greater understanding of most renewable technologies especially biomass, wind, solar PV and geothermal. Refreshed installed capital cost estimates on a $/KW basis for new generation options are shown in Appendix A-8. SPO also developed a more rigorous biomass fuel forecast and examined how wind resource performance might improve if the resource was located in the Southwest Power Pool (SPP) region versus the Energy System region. From last year to this year, the potential capacity factor for SPP wind has been raised from 35% to 39%, but its capacity value has been lowered from 30% to 5%. The SPP RTO gives wind a 5% capacity value.

CTs may have a place in the portfolio. The potential advantages of CTs vis-à-vis CCGTs include lower installed capital cost, smaller footprint, quick-start-up, and shorter construction time. In addition, some CTs may be convertible to CCGTs through later additions of heat recovery steam generators, which provide an additional option value. Lower natural gas prices improve the CT value relative to CCGTs in low capacity load following roles. The SRP Refresh has not replaced any specific planned CCGT with a CT, but CTs will be considered on a case-by-case basis when new gas fired resources are needed in a peaking or load following situation.

New Build Bus Bar Costs (COD 2010-2019)

Figure A-9 in the Appendix provides the bus bar cost of various base load generation technologies currently available to the Entergy System. While some of the components have changed, the relative economics have not materially changed over the past year.

New Build Bus Bar Costs (For COD 2020-2029)

By 2020, it may be possible to utilize carbon capture and storage technology to reduce or eliminate the negative impacts of CO_2 emissions from coal plants. Figure A-10 in the Appendix still indicates that CCGTs provide lower levelized cost. This is driven by the higher capital and O&M cost needed to operate coal plants with carbon capture. The transportation and storage cost of the captured CO_2 is not considered. Nor is any economic benefit from the capture of CO_2.

The Green Spread

Without regulatory or tax-driven subsidies, the bus bar cost of renewables remains above that of conventional generation. Lower natural gas prices make it even harder for renewables to compete. Despite their higher cost, renewables in moderate quantities are beneficial to the System's portfolio because they improve fuel diversity and security, which lowers customer price risk. Furthermore, they have environmental and economic development benefits that indirectly benefit customers. See a bus bar cost comparison of renewables and CCGTs in Figure A-11 in the Appendix.

Demand-side Resources

Progressing Toward the Goal

From inception through 2009, utility-sponsored DSM programs have reduced the System peak by an estimated 80 MW. The Entergy Operating Companies are committed to pursuing cost-effective DSM; however, long term success requires consistent, sustained regulatory support and approval.

- Entergy Texas, Inc. ("ETI") has offered energy efficiency programs since 2002. ETI achieved stable program funding in its 2008 rate case which established a rider for recovery of program expenses. In addition, performance incentives are available if ETI surpasses its annual energy efficiency goal.

- Entergy Arkansas, Inc. ("EAI") is working towards transitioning from "Quick Start" programs implemented in 2008 and to more comprehensive programs. EAI has stable program cost recovery through an Energy Efficiency Cost Recovery Rider, while mechanisms to recover the lost contribution to fixed costs and shared savings or incentives remains under consideration by the APSC.

- Entergy New Orleans, Inc. ("ENOI") collaborated with community stakeholders to develop "Energy Smart" programs that begin in 2010. Annual funding was established in the settlement provisions of its 2008 rate case. ENOI received a matching Department of Energy stimulus grant to administer a Smart Grid pilot that will include a demand response program for low income customers. The pilot will begin in 2011.

- Entergy Louisiana, LLC ("ELL") and Entergy Gulf States Louisiana, L.L.C. ("EGSL") are participating in an LPSC docket to consider energy efficiency programs. In addition, a Smart Grid pilot program that includes demand response programs has been underway since 2008.

- Entergy Mississippi, Inc. ("EMI") is participating in an exploratory docket on energy efficiency at the Mississippi Public Service Commission ("MPSC"). EMI is also piloting a state-wide weatherization program with recovery of program costs through a rider.

No changes have been made to the level of DSM in the Reference Case Planning Scenario which includes 1,050 MW of peak reduction over the 20-year SRP planning horizon. The utility-sponsored DSM programs at ETI, EAI, and ENOI are generally on track to meet their proportional shares of the System-wide goal. The level of DSM that the System ultimately achieves depends on the level of DSM that the Operating Companies' retail regulators agree should be deployed and the implementation of cost recovery mechanisms to allow a reasonable opportunity to recover the costs associated with those programs.

Reference Planning Scenario

The major structure of the 2009 SRP Reference Planning Structure remains unchanged. Planning assumptions still maintain a CCGT centric portfolio transformation, with the same timetable and quantity of renewables coming into the portfolio.

Material changes from the 2009 SRP Reference Planning Scenario include:

1. Updated Load Forecast from FEA094 to FEA102.

2. Updated seasonal unit ratings from Summer 2008 to Summer 2010 ratings.

3. Changed Wind resource capacity value from 30% to 5% of total unit capacity (see Technology). A lower capacity value increases the cost of backup generation. The higher cost was incorporated into the bus-bar cost of wind resources in Figures A-11 in the Appendix.

4. Updated unit deactivation schedule to match more current information including the deactivation of Sterlington 6 beginning in 2010 due to unit inoperability and accelerated Lynch 3 deactivation from 2014 to 2012.

5. Increased the unit rating of future CCGTs from 500 MW to 600 MW based on improved performance from GE Model 5 versus Model 3 used in the 2009 SRP.

6. Accelerated EMI's 2016 CCGT resource to 2012.

7. Accelerated EAI's 2013 CCGT resource to 2012.

8. Accelerated ETI's 2014 CCGT resource to 2012.

In addition to the Reference Planning Scenario, the 2009 SRP also considered other planning scenarios. At this time those alternative scenarios are still valid and if refreshed would not change materially, therefore they have not been refreshed.

For specifics on the Reference Planning Scenario please see Figures A-12 through A-23 in the Appendix.

- Figure A-12 Summary of Reference Planning Scenario Resource Additions (2010 – 2019)
- Figure A-13 Summary of Reference Planning Scenario Resource Additions (2020 – 2029)
- Figure A-14 Summary of Reference Planning Scenario Portfolio Composition (Total 6-Company Utility Capacity)
- Figure A-15 EAI Load and Capability (MW) – Need to update due to Lynch 3 move to 2012
- Figure A-16 EMI Load and Capability (MW)
- Figure A-17 ELL Load and Capability (MW)
- Figure A-18 ENOI Load and Capability
- Figure A-19 EGSL Load and Capability
- Figure A-20 ETI Load and Capability
- Figure A-21 System Load and Capability
- Figure A-22 Utility Load and Capability
- Figure A-23 Potential Unit Deactivations

APPENDIX - SUPPORTING GRAPHICS AND DATA TABLES

Figure A-1 Historic Utility Operating Data

Non-Coincident Peak Load by Operating Company and System Coincident Peak (MW)

Entity / Reporting Level	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
EAI	5,145	5,533	5,207	5,099	5,223	5,072	5,273	5,238	5,297	5,080	4,701
EGSL	3,435	3,704	3,363	3,332	3,563	3,532	3,508	3,639	3,676	3,901	4,046
ELL	5,515	5,333	5,133	5,169	4,899	5,091	5,236	5,257	5,341	5,235	5,252
EMI	2,941	3,174	2,959	2,859	3,021	3,113	3,195	3,308	3,354	3,210	3,118
ENOI	1,255	1,276	1,161	1,162	1,188	1,210	1,254	788	904	882	998
ETI	3,205	3,338	3,143	3,185	3,248	3,512	3,434	3,571	3,711	3,176	3,246
Total System	20,664	22,052	20,315	20,419	20,162	21,174	21,391	20,887	22,001	21,241	21,009

Electric Energy Sales (Retail Sales) (GWh)

Entity / Reporting Level	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
EAI	18,664	19,333	19,377	19,600	19,650	19,735	21,005	21,331	21,371	21,038	19,926
EGSL	19,515	20,150	18,952	18,773	18,440	19,249	18,939	19,084	19,134	18,492	17,962
ELL	29,095	29,680	28,524	29,566	27,778	28,183	26,889	27,387	28,149	27,892	28,396
EMI	12,518	12,847	12,621	12,829	12,891	12,978	13,341	13,477	13,538	13,171	12,697
ENOI	5,895	5,880	5,597	5,875	5,844	6,055	4,712	3,759	4,299	4,483	4,721
ETI	14,833	15,325	14,885	14,987	15,366	16,026	14,979	15,383	15,521	15,533	15,446
Total System (1)	100,519	103,216	99,956	101,631	99,968	102,226	99,865	100,421	102,013	100,609	99,148

(1) Total System electric energy retail sales for 2005 and 2006 include ENOI which is generally disaggregated in public reports of utility operating data for these years.

Figure A-2 Reference Case Total Sales & Firm Peak Load Forecast for the Six Company Utility

Total Sales GWh; Firm Peaks MW

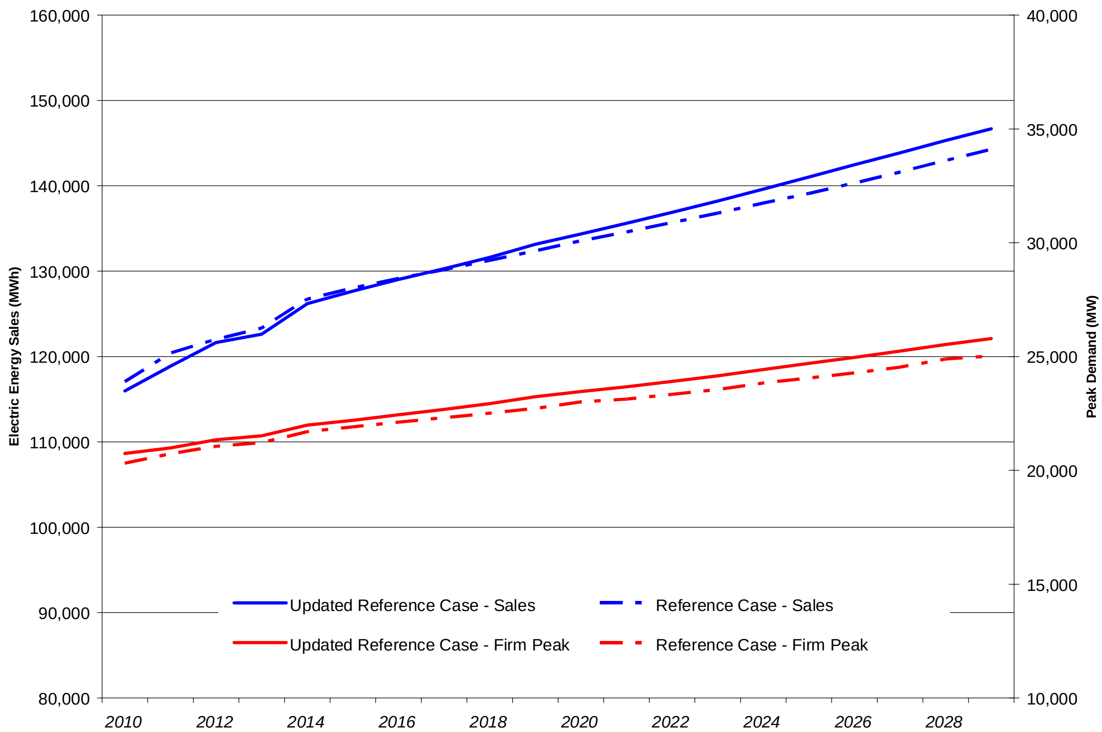


Figure A-3 Non-coincident Firm Peak Load (Reference Case Load Forecast 2010 – 2029)

(Firm MW)

Entity / Reporting Level	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EAI	4,573	4,653	4,695	4,716	5,046	5,100	5,150	5,199	5,253	5,332
EGSL	3,790	3,793	3,864	3,882	3,915	3,953	3,988	4,023	4,057	4,097
ELL	5,313	5,453	5,574	5,602	5,632	5,666	5,708	5,745	5,785	5,833
EMI	3,165	3,141	3,217	3,261	3,330	3,351	3,398	3,441	3,491	3,560
ENOI	966	974	979	990	990	996	1,006	1,012	1,019	1,026
ETI	3,562	3,638	3,757	3,824	3,869	3,934	4,006	4,074	4,140	4,208
System*	**20,741**	**20,984**	**21,345**	**21,518**	**16,946**	**17,099**	**13,915**	**14,061**	**14,209**	**14,364**
6 OpCos**	**20,741**	**20,984**	**21,345**	**21,518**	**21,986**	**22,196**	**22,442**	**22,680**	**22,932**	**23,236**

**System numbers reflect the coincident peak for six-company, five-company, or four-company System configuration consistent with the planning assumptions.*
*** "6 OpCos" numbers reflect the coincident peak for the combination of all six Operating Companies regardless of participation in the System Agreement.*

Entity / Reporting Level	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EAI	5,384	5,440	5,499	5,562	5,631	5,701	5,768	5,833	5,901	5,963
EGSL	4,127	4,157	4,187	4,222	4,257	4,293	4,332	4,371	4,408	4,442
ELL	5,864	5,894	5,921	5,958	5,995	6,032	6,067	6,105	6,132	6,178
EMI	3,609	3,662	3,718	3,773	3,836	3,899	3,964	4,029	4,097	4,163
ENOI	1,031	1,036	1,042	1,047	1,053	1,060	1,067	1,074	1,080	1,086
ETI	4,266	4,323	4,383	4,444	4,508	4,571	4,642	4,710	4,779	4,847
System*	**14,492**	**14,589**	**14,708**	**14,841**	**14,984**	**15,125**	**15,256**	**15,406**	**15,550**	**15,690**
6 OpCos**	**23,465**	**23,668**	**23,903**	**24,154**	**24,429**	**24,703**	**24,963**	**25,244**	**25,524**	**25,792**

**System numbers reflect the coincident peak for six-company, five-company, or four-company System configuration consistent with the planning assumptions.*
*** "6 OpCos" numbers reflect the coincident peak for the combination of all six Operating Companies regardless of participation in the System Agreement.*

Figure A-4 Electric Energy Total Sales (Reference Case Sales Forecast 2010 – 2029)

(GWh)

Entity / Reporting Level	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EAI	23,260	23,781	24,097	24,292	27,016	27,350	27,656	27,943	28,253	28,657
EGSL	21,461	21,695	21,964	22,091	22,239	22,433	22,609	22,781	22,952	23,131
ELL	32,645	34,175	35,167	35,268	35,409	35,722	35,971	36,195	36,424	36,688
EMI	14,576	14,859	15,212	15,449	15,656	15,919	16,148	16,362	16,592	16,915
ENOI	5,162	5,215	5,274	5,311	5,347	5,385	5,445	5,488	5,530	5,572
ETI	18,872	19,137	19,921	20,196	20,525	20,844	21,196	21,527	21,854	22,181
System*	**115,978**	**118,862**	**121,635**	**122,607**	**99,176**	**100,303**	**85,221**	**85,990**	**86,761**	**87,572**
6 OpCos**	**115,978**	**118,862**	**121,635**	**122,607**	**126,192**	**127,653**	**129,025**	**130,295**	**131,605**	**133,143**

**System numbers reflect six-company, five-company, or four-company System configuration consistent with the planning assumptions.*
*** "6 OpCos" numbers reflect the combination of all six Operating Companies regardless of participation in the System Agreement.*

Entity / Reporting Level	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EAI	28,958	29,282	29,621	29,973	30,337	30,713	31,053	31,388	31,724	32,050
EGSL	23,281	23,431	23,586	23,748	23,917	24,092	24,278	24,453	24,628	24,795
ELL	36,880	37,080	37,284	37,491	37,705	37,925	38,162	38,386	38,609	38,817
EMI	17,162	17,418	17,677	17,948	18,241	18,540	18,840	19,150	19,467	19,778
ENOI	5,607	5,642	5,676	5,712	5,748	5,787	5,830	5,869	5,908	5,944
ETI	22,466	22,751	23,047,	23,346	23,656	23,963	24,299	24,627	24,963	25,288
System*	**88,234**	**88,903**	**89,592**	**90,297**	**91,027**	**91,768**	**92,568**	**93,336**	**94,108**	**94,844**
6 OpCos**	**134,354**	**135,604**	**136,891**	**138,218**	**139,604**	**141,020**	**142,461**	**143,873**	**145,299**	**146,672**

**System numbers reflect six-company, five-company, or four-company System configuration consistent with the planning assumptions.*
*** "6 OpCos" numbers reflect the combination of all six Operating Companies regardless of participation in the System Agreement.*

Figure A-5 Nominal Natural Gas Price Forecast

(Nominal $/MMBtu)

	Weighting	2010	2015	2020	2025	2030
Reference	65%	4.75	6.72	7.92	9.19	10.66
High	10%	5.60	15.54	17.96	20.49	22.63
Low	25%	4.27	4.50	5.57	6.89	9.42
Expected		4.72	7.05	8.33	9.74	11.78

Figure A-6 Real Natural Gas Price Forecast

(Real 2009$/MMBtu)

	Weighting	2010	2015	2020	2025	2030
Reference	65%	4.71	6.09	6.50	6.84	7.18
High	10%	5.55	14.09	14.75	15.25	15.25
Low	25%	4.23	4.08	4.57	5.13	5.75
Expected		4.67	6.39	6.85	7.25	7.58

Figure A-7 Into Entergy Implied Heat Rate

	Implied Heat Rate [Btu/kWh]
2009 Actual	7,342
2010	8,540
2011	7,940
2012	7,827
2013	8,784
2014	8,928
2015	10,126
2016	10,282
2017	10,566
2018	11,017
2019	11,247
CAGR 2010-2019	**3.1%**

Source: 2009: Platts Day-Ahead Power (Into-Entergy) and Gas (Henry Hub midpoint), 2010 and after SPO Analysis

Figure A-8 Installed Capital Cost: New Build Options in the Entergy Retail Service Area (2010 – 2019 Timeframe)

(Installed Cost 2009$ per kW)

Technology	Fuel	20010 - 2019
Combined Cycle Gas Turbine (CCGT)	Natural Gas	$1,200
CCGT with Carbon Capture & Sequestration (CCS)	Natural Gas	NA
Circulating Fluidized Bed (CFB)	Coal	$3,300
CFB with CCS	Coal	NA
Combustion Turbine (CT)	Natural Gas	$900
Integrated Gasification Combined Cycle (IGCC)	Coal	$3,600
IGCC with CCS	Coal	NA
New Nuclear	Uranium	NA
Pulverized Coal	Coal	$3,000
Pulverized Coal with CCS	Coal	NA
Biomass	Agri / Forestry	$3,500
In-stream Hydro	NA	NA
Solar Photovoltaic	NA	$5,000
Wind On-shore	NA	$2,000
Wind On-shore Off-System*	NA	$2,500
Wind Offshore	NA	NA

***SPP Resource, includes $500/KW transmission investment**

Figure A-9 Levelized Cost of Current Baseload Alternatives

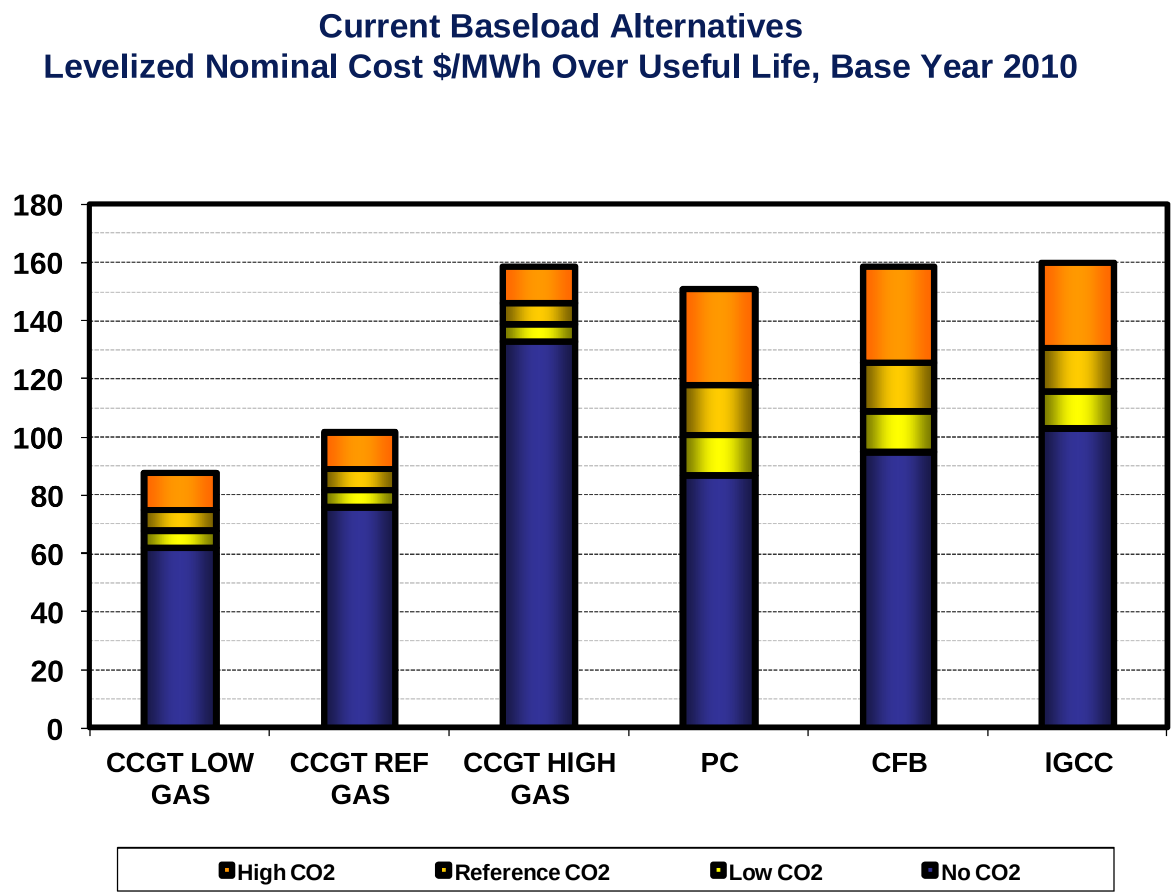


Figure A-10 Levelized Cost of Future Baseload Alternatives

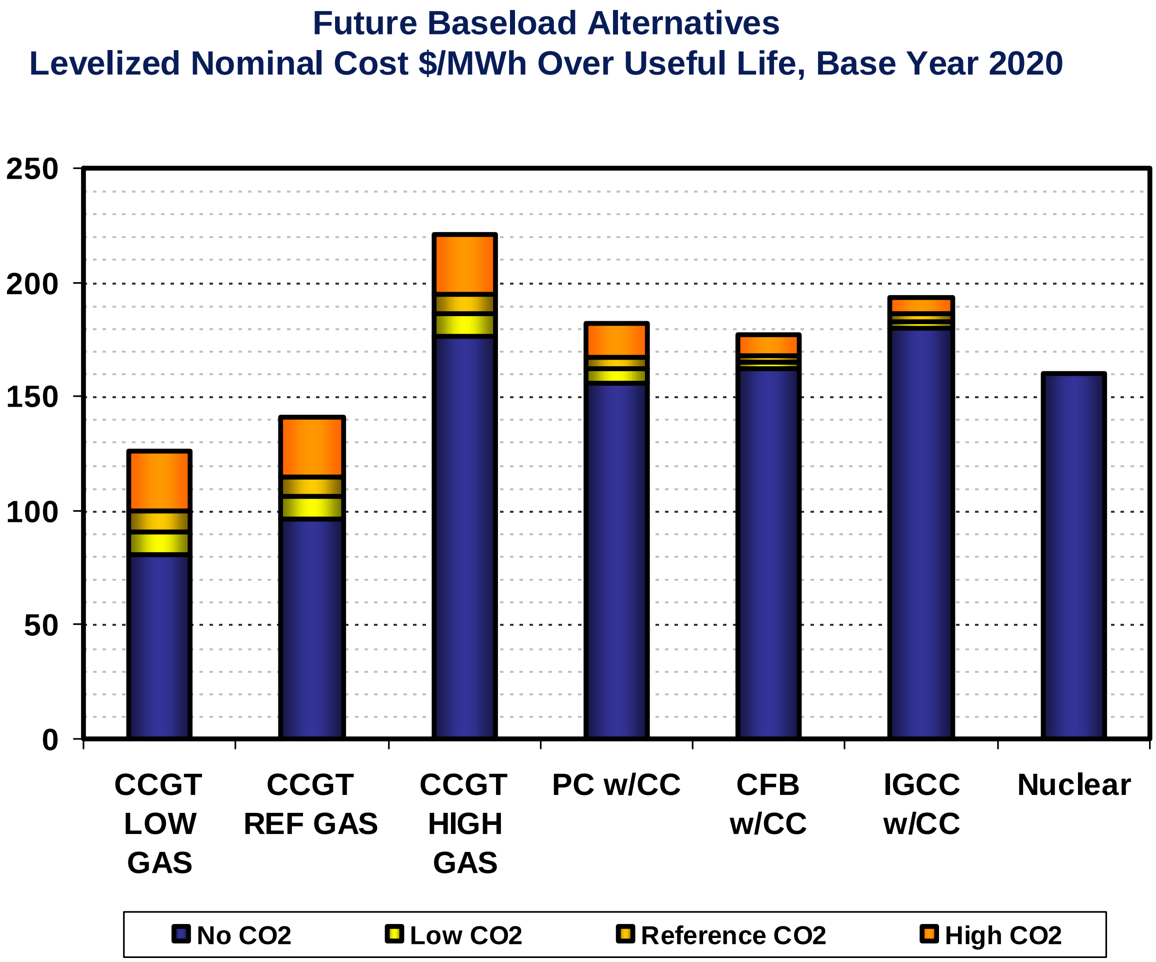
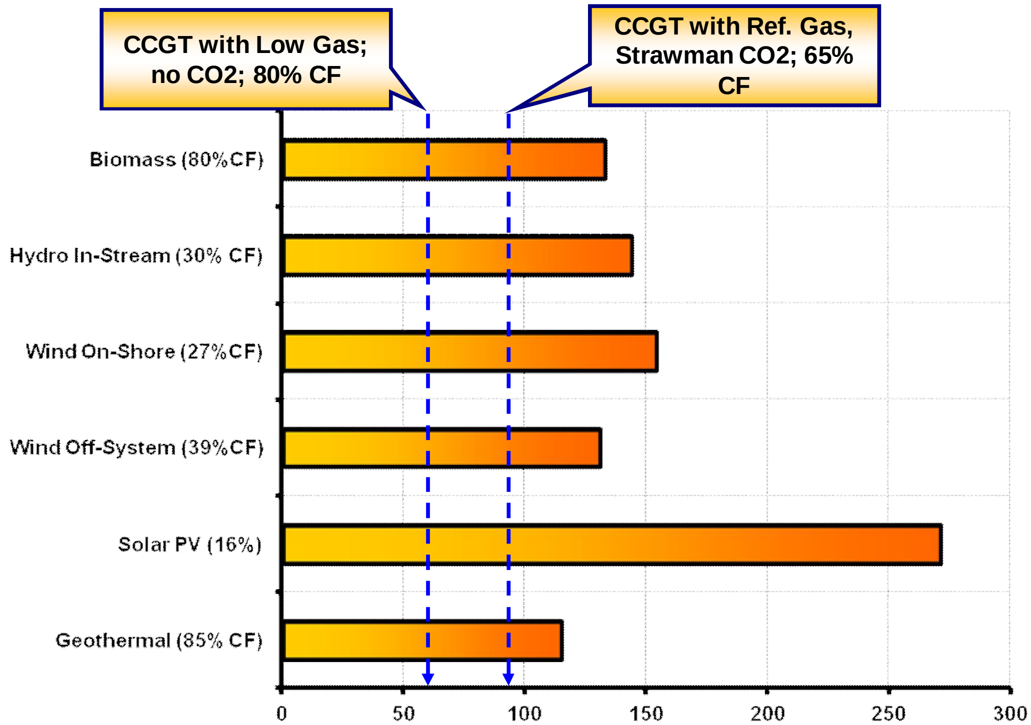


Figure A-11 Renewables Vs. CCGT Levelized Nominal Cost Comparison

Levelized Nominal Cost $/MWh Over Useful Life, Base Year 2010



<u>Assumptions</u>

- Off-System Wind assumes $500/kW generic off-system transmission adder.
- Resources are assumed to be located in or close to the Entergy utility service area. Off-System wind is assumed to be located in SPP.
- Costs do not include incentives or REC value.
- Wind and Solar costs include flexible cost and backup capacity cost.

Figure A-12 Summary of Reference Planning Scenario Resource Additions (2010 – 2019)

Resource Additions (2010-2019)			
COD	**Technology**	**Size (MW)**	**Operating Company**
2011	CCGT	580	EGSL & ELL
2012	Nuclear Uprate	160	EAI, ELL, EMI, & ENOI
	CCGT	600	EAI
	CCGT	600	EMI
	CCGT	600	ETI
2014	Biomass	100	EAI
	CCGT	600	EAI
2015	Biomass	100	EMI
	CCGT	600	ELL, ENOI
	Nuclear Uprate	125	ELL, ENOI, EGSL & ETI
	On-Shore Wind	50	EAI
2016	Biomass	100	ETI
	On-Shore Wind	50	EAI
2017	Biomass	100	EGSL
	On-Shore Wind	50	EAI
2018	Biomass	50	ELL
	Biomass	50	ENOI
	On-Shore Wind	50	EAI
	CCGT	600	ETI
2019	Biomass	100	ELL
	In-Stream Hydro	50	EMI
	CCGT	600	ETI
	2010 – 2019 Total	**5,915**	

Note: Renewable generation showed at gross capacity, not net capacity value

Figure A-13 Summary of Reference Planning Scenario Resource Additions (2020 – 2029)

Resource Additions (2020-2029)			
COD	**Technology**	**Size (MW)**	**Operating Company**
2020	Biomass	100	EAI
	In-Stream Hydro	50	EGSL
2021	Biomass	100	ETI
	In-Stream Hydro	50	ELL
	CCGT	600	EAI
2022	In-Stream Hydro	50	ELL
	Off-System Wind	100	ETI
	Off-System Wind	100	EMI
	Off-System Wind	50	EGSL
	CCGT	600	EGSL
2023	In-Stream Hydro	50	ELL
	Off-System Wind	150	ELL
	Off-System Wind	50	EGSL
	Off-System Wind	50	EMI
2024	CCGT	600	EGSL
	In-Stream Hydro	50	EMI
2025	CCGT	600	EMI
	CCGT	600	EMI
	CCGT	600	ETI
	In-Stream Hydro	50	EGSL
2026	In-Stream Hydro	50	EAI
	CCGT	600	EMI
	CCGT	600	ETI
2027	In-Stream Hydro	50	ETI
	CCGT	600	ENOI
2028	In-Stream Hydro	50	ENOI
	2020 – 2029 Total	**6,550**	
	2010 – 2029 Total	**12,465**	

Note: Renewable generation showed at gross capacity, not net capacity value

Figure A-14 Summary of Reference Planning Scenario Portfolio Composition (Total 6-Company Utility Capacity)

(GW)

	Year																			
Resource	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**
DSM	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1
Nuclear	5.1	5.1	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Coal	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Existing Hydro	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Existing Gas	11.8	11.8	11.2	11.0	10.9	10.9	10.8	10.0	9.4	8.9	8.9	8.5	8.2	7.8	7.4	6.3	5.7	5.2	5.2	5.2
Renewable Generation	-	-	-	-	0.1	0.2	0.3	0.4	0.5	0.7	0.8	1.0	1.0	1.1	1.2	1.2	1.3	1.3	1.4	1.4
CT / CCGT	4.1	4.1	5.9	5.9	6.5	7.1	7.1	7.1	7.7	8.3	8.3	8.9	9.5	9.5	10.1	11.9	13.1	13.7	13.7	13.7
Limited-Term Purchases	0.5	0.9	0.3	0.2	0.5	0.5	0.6	1.5	1.5	1.4	1.5	1.4	1.1	1.7	1.8	1.4	1.1	1.2	1.5	1.8
Total	24.1	24.6	25.4	25.2	26.1	27.0	27.2	27.5	27.7	28.0	28.3	28.6	28.8	29.2	29.6	29.8	30.3	30.5	30.8	31.1

Note: Renewable generation showed at gross capacity, not net capacity value

Figure A-15 EAI Load and Capability (MW)

EAI Load and Capability	EAI part of 6-OpCo System				EAI Stand-Alone Company															
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EAI LOAD																				
Firm Non-Coincident Peak	4,573	4,653	4,695	4,716	5,046	5,100	5,150	5,199	5,253	5,332	5,384	5,440	5,499	5,562	5,631	5,701	5,768	5,833	5,901	5,963
Reserve Margin (varies)	457	465	470	472	1,009	1,020	1,030	1,040	1,051	1,066	1,077	1,088	1,100	1,112	1,126	1,140	1,154	1,167	1,180	1,193
DSM Adjustment	(44)	(47)	(60)	(82)	(103)	(118)	(135)	(155)	(175)	(178)	(181)	(189)	(204)	(221)	(239)	(239)	(239)	(239)	(239)	(239)
TOTAL REQUIREMENT FOR FIRM LOAD	**4,987**	**5,071**	**5,105**	**5,105**	**5,952**	**6,002**	**6,045**	**6,084**	**6,128**	**6,221**	**6,280**	**6,339**	**6,395**	**6,454**	**6,518**	**6,602**	**6,682**	**6,760**	**6,841**	**6,916**
EAI RESOURCES																				
Total Owned Capacity	**5,192**	**5,192**	**4,948**	**4,760**	**4,637**	**4,113**	**4,092**	**4,092**	**4,092**	**4,092**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**	**4,036**
Contracted Purchases																				
Long Term Contracted Purchases	(199)	(199)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)	(207)
Limited Term Contracted Purchases	(304)	(335)	(345)	(345)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**(503)**	**(534)**	**(552)**	**(552)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**	**(207)**
Surplus/(Deficit) Before Planned Resources	**(298)**	**(413)**	**(709)**	**(896)**	**(1,522)**	**(2,096)**	**(2,159)**	**(2,199)**	**(2,243)**	**(2,335)**	**(2,450)**	**(2,509)**	**(2,566)**	**(2,624)**	**(2,689)**	**(2,773)**	**(2,852)**	**(2,930)**	**(3,012)**	**(3,086)**
Identified Planned Resources																				
Long Term Planned Resources	-	-	58	58	58	582	582	582	582	582	582	582	582	582	582	582	582	582	582	582
Limited Term Planned Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Identified Planned Resources	-	-	58	58	58	582	582	582	582	582	582	582	582	582	582	582	582	582	582	582
Surplus/(Deficit) incl. Identified Planned Resources	**(298)**	**(413)**	**(651)**	**(839)**	**(1,464)**	**(1,514)**	**(1,578)**	**(1,617)**	**(1,661)**	**(1,754)**	**(1,869)**	**(1,928)**	**(1,984)**	**(2,042)**	**(2,107)**	**(2,191)**	**(2,271)**	**(2,349)**	**(2,430)**	**(2,505)**
Other Planned Resources																				
Planned CCGT Additions	-	-	600	600	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Renewable Generation	-	-	-	-	100	103	105	108	110	110	210	210	210	210	210	210	260	260	260	260
Limited Term Generic Planned Purchases	-	122	-	-	200	300	300	400	400	500	500	-	-	100	100	200	300	300	400	500
Total Other Planned Resources	**-**	**122**	**600**	**600**	**1,500**	**1,603**	**1,605**	**1,708**	**1,710**	**1,810**	**1,910**	**2,010**	**2,010**	**2,110**	**2,110**	**2,210**	**2,360**	**2,360**	**2,460**	**2,560**
TOTAL RESOURCES	**4,689**	**4,780**	**5,054**	**4,866**	**5,988**	**6,091**	**6,072**	**6,175**	**6,177**	**6,277**	**6,321**	**6,421**	**6,421**	**6,521**	**6,521**	**6,621**	**6,771**	**6,771**	**6,871**	**6,971**
Surplus / (Deficit) incl. Planned Resources	**(298)**	**(291)**	**(51)**	**(239)**	**36**	**88**	**27**	**90**	**49**	**56**	**41**	**82**	**26**	**68**	**3**	**19**	**89**	**11**	**30**	**55**

Figure A-16 EMI Load and Capability (MW)

EMI Load and Capability	EMI part of 6-OpCo System				5-OpCo System (excludes EAI)		EMI Stand-Alone													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EMI LOAD																				
Firm Non-Coincident Peak	3,165	3,141	3,217	3,261	3,300	3,351	3,398	3,441	3,491	3,560	3,609	3,662	3,718	3,773	3,836	3,899	3,964	4,029	4,097	4,163
Reserve Margin (varies)	317	314	322	326	330	335	714	723	733	748	758	769	781	792	806	819	832	846	860	874
DSM Adjustment	-	(5)	(11)	(19)	(22)	(28)	(37)	(47)	(62)	(78)	(97)	(109)	(122)	(136)	(136)	(136)	(136)	(136)	(136)	(136)
TOTAL REQUIREMENT FOR FIRM LOAD	**3,482**	**3,450**	**3,527**	**3,568**	**3,609**	**3,658**	**4,074**	**4,116**	**4,162**	**4,230**	**4,271**	**4,323**	**4,376**	**4,430**	**4,505**	**4,581**	**4,661**	**4,739**	**4,822**	**4,901**
EMI RESOURCES																				
Total Owned Capacity	**3,600**	**3,600**	**3,423**	**3,423**	**3,423**	**3,423**	**3,353**	**3,353**	**3,353**	**3,144**	**3,144**	**3,144**	**3,144**	**3,144**	**3,144**	**1,968**	**1,968**	**1,968**	**1,968**	**1,968**
Contracted Purchases																				
Long Term Contracted Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Limited Term Contracted Purchases	181	160	163	163	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Total Contracted Purchases	**181**	**160**	**163**	**163**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**
Surplus/(Deficit) Before Planned Resources	**300**	**310**	**59**	**18**	**(101)**	**(151)**	**(637)**	**(679)**	**(725)**	**(1,002)**	**(1,043)**	**(1,095)**	**(1,148)**	**(1,202)**	**(1,277)**	**(2,529)**	**(2,608)**	**(2,687)**	**(2,770)**	**(2,849)**
Identified Planned Resources																				
Long Term Planned Resources	-	-	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Limited Term Planned Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Identified Planned Resources	-	-	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Surplus/(Deficit) incl. Identified Planned Resources	**300**	**310**	**111**	**71**	**(49)**	**(98)**	**(584)**	**(627)**	**(672)**	**(949)**	**(990)**	**(1,042)**	**(1,096)**	**(1,149)**	**(1,224)**	**(2,476)**	**(2,556)**	**(2,634)**	**(2,717)**	**(2,796)**
Other Planned Resources																				
Planned CCGT Additions	-	-	600	600	600	600	600	600	600	600	600	600	600	600	600	1,800	2,400	2,400	2,400	2,400
Renewable Generation	-	-	-	-	-	100	100	100	100	150	150	150	155	158	208	208	208	208	208	208
Limited Term Generic Planned Purchases	-	83	-	-	17	-	-	-	-	200	300	300	400	400	500	500	-	100	200	200
Total Other Planned Resources	**-**	**83**	**600**	**600**	**617**	**700**	**700**	**700**	**700**	**950**	**1,050**	**1,050**	**1,155**	**1,158**	**1,308**	**2,508**	**2,608**	**2,708**	**2,808**	**2,808**
TOTAL RESOURCES	**3,781**	**3,843**	**4,239**	**4,239**	**4,177**	**4,260**	**4,190**	**4,190**	**4,190**	**4,231**	**4,331**	**4,331**	**4,436**	**4,438**	**4,588**	**4,612**	**4,712**	**4,812**	**4,912**	**4,912**
Surplus / (Deficit) incl. Planned Resources	**300**	**393**	**711**	**671**	**569**	**602**	**116**	**73**	**28**	**1**	**60**	**8**	**59**	**9**	**83**	**31**	**52**	**73**	**91**	**11**

Figure A-17 ELL Load and Capability (MW)

ELL Load and Capability	6-OpCo System				5-OpCo System (excludes EAI)		4-OpCo System (excludes EAI & EMI)													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ELL LOAD																				
Firm Non-Coincident Peak	5,313	5,453	5,574	5,602	5,632	5,666	5,708	5,745	5,785	5,833	5,864	5,894	5,921	5,958	5,995	6,032	6,067	6,105	6,132	6,178
Reserve Margin (10%)	531	545	557	560	563	567	571	574	579	583	586	589	592	596	599	603	607	611	613	618
DSM Adjustment	-	(9)	(21)	(35)	(41)	(59)	(82)	(109)	(140)	(175)	(214)	(238)	(264)	(264)	(264)	(264)	(264)	(264)	(264)	(264)
TOTAL REQUIREMENT FOR FIRM LOAD	**5,845**	**5,989**	**6,111**	**6,127**	**6,154**	**6,174**	**6,197**	**6,210**	**6,224**	**6,242**	**6,236**	**6,245**	**6,250**	**6,290**	**6,330**	**6,371**	**6,410**	**6,452**	**6,482**	**6,532**
ELL RESOURCES																				
Total Owned Capacity	**5,307**	**5,307**	**5,307**	**5,307**	**5,307**	**5,307**	**5,307**	**5,307**	**5,182**	**4,944**	**4,944**	**4,944**	**4,944**	**4,534**	**4,534**	**4,534**	**4,012**	**4,012**	**4,012**	**4,012**
Contracted Purchases																				
Long Term Contracted Purchases	937	937	941	941	941	941	941	941	461	438	438	438	438	438	438	438	438	438	438	438
Limited Term Contracted Purchases	476	51	53	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**1,413**	**988**	**994**	**994**	**941**	**941**	**941**	**941**	**461**	**438**	**438**	**438**	**438**	**438**	**438**	**438**	**438**	**438**	**438**	**438**
Surplus/(Deficit) Before Planned Resources	**875**	**306**	**190**	**173**	**93**	**74**	**51**	**37**	**(581)**	**(860)**	**(855)**	**(864)**	**(868)**	**(1,319)**	**(1,359)**	**(1,400)**	**(1,961)**	**(2,003)**	**(2,032)**	**(2,082)**
Identified Planned Resources																				
Long Term Planned Resources	-	387	409	409	409	434	434	434	914	937	937	937	937	937	937	937	937	937	937	937
Limited Term Planned Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Identified Planned Resources	-	387	409	409	409	434	434	434	914	937	937	937	937	937	937	937	937	937	937	937
Surplus/(Deficit) incl. Identified Planned Resources	**875**	**693**	**599**	**582**	**502**	**508**	**485**	**471**	**333**	**77**	**83**	**73**	**69**	**(382)**	**(422)**	**(463)**	**(1,024)**	**(1,065)**	**(1,095)**	**(1,145)**
Other Planned Resources																				
Planned CCGT Additions	-	-	-	-	-	480	480	480	480	480	480	480	480	480	480	480	480	480	480	480
Renewable Generation	-	-	-	-	-	-	-	-	50	150	150	200	250	308	308	308	308	308	308	308
Limited Term Generic Planned Purchases	-	155	-	-	33	-	39	357	354	196	197	355	237	395	395	197	237	237	316	355
Total Other Planned Resources	-	155	-	-	33	480	519	837	884	826	827	1,035	967	1,182	1,182	985	1,024	1,024	1,103	1,143
TOTAL RESOURCES	**6,720**	**6,836**	**6,709**	**6,709**	**6,689**	**7,162**	**7,201**	**7,518**	**7,441**	**7,145**	**7,146**	**7,354**	**7,286**	**7,091**	**7,091**	**6,894**	**6,411**	**6,411**	**6,490**	**6,529**
Surplus / (Deficit) for 10% Reserve Margin	**875**	**847**	**599**	**582**	**535**	**988**	**1,004**	**1,308**	**1,217**	**903**	**910**	**1,109**	**1,036**	**801**	**761**	**522**	**1**	**(41)**	**8**	**(2)**

Figure A-18 ENOI Load and Capability

ENOI Load and Capability	6-OpCo System				5-OpCo System (excludes EAI)		4-OpCo System (excludes EAI & EMI)													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ENOI LOAD																				
Firm Non-Coincident Peak	966	974	979	990	990	996	1,006	1,012	1,019	1,026	1,031	1,036	1,042	1,047	1,053	1,060	1,067	1,074	1,080	1,086
Reserve Margin (10%)	97	97	98	99	99	100	101	101	102	103	103	104	104	105	105	106	107	107	108	109
DSM Adjustment	(3)	(5)	(7)	(9)	(13)	(17)	(22)	(28)	(34)	(38)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)
TOTAL REQUIREMENT FOR FIRM LOAD	**1,060**	**1,066**	**1,071**	**1,080**	**1,076**	**1,078**	**1,084**	**1,086**	**1,087**	**1,090**	**1,092**	**1,097**	**1,103**	**1,109**	**1,116**	**1,123**	**1,131**	**1,138**	**1,146**	**1,152**
ENOI RESOURCES																				
Total Owned Capacity	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**939**	**706**	**706**	**706**	**706**	**706**	**191**	**191**	**191**
Contracted Purchases																				
Long Term Contracted Resources	267	267	271	271	271	271	271	271	271	271	271	271	271	271	271	271	271	271	271	271
Limited Term Contracted Resources	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**274**	**267**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**	**271**
Surplus/(Deficit) Before Planned Resources	**153**	**141**	**140**	**131**	**135**	**132**	**127**	**125**	**124**	**121**	**119**	**113**	**(125)**	**(132)**	**(138)**	**(145)**	**(153)**	**(676)**	**(683)**	**(689)**
Identified Planned Resources																				
Long Term Planned Resources	-	-	27	27	27	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Limited Term Planned Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Identified Planned Resources	-	-	27	27	27	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Surplus/(Deficit) incl. Identified Planned Resources	**153**	**141**	**167**	**158**	**162**	**172**	**166**	**165**	**164**	**160**	**159**	**153**	**(86)**	**(92)**	**(99)**	**(105)**	**(114)**	**(636)**	**(643)**	**(650)**
Other Planned Resources																				
Planned CCGT Additions	-	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120	120	720	720	720
Renewable Generation	-	-	-	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	100	100
Limited Term Generic Planned Purchases	-	26	-	-	5	-	6	56	56	31	31	56	37	62	62	31	37	37	50	56
Total Other Planned Resources	**-**	**26**	**-**	**-**	**5**	**120**	**126**	**176**	**226**	**201**	**201**	**226**	**207**	**232**	**232**	**201**	**207**	**807**	**870**	**876**
TOTAL RESOURCES	**1,213**	**1,233**	**1,238**	**1,238**	**1,243**	**1,370**	**1,377**	**1,427**	**1,477**	**1,452**	**1,451**	**1,476**	**1,225**	**1,249**	**1,249**	**1,218**	**1,225**	**1,310**	**1,372**	**1,378**
Surplus / (Deficit) for 10% Reserve Margin	**153**	**167**	**167**	**158**	**168**	**292**	**293**	**341**	**390**	**362**	**360**	**379**	**121**	**140**	**133**	**96**	**94**	**171**	**226**	**226**

Figure A-19 EGSL Load and Capability

EGSL Load and Capability	6-OpCo System				5-OpCo System (excludes EAI)		4-OpCo System (excludes EAI & EMI)													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EGSL LOAD																				
Firm Non-Coincident Peak	3,790	3,793	3,864	3,882	3,915	3,953	3,988	4,023	4,057	4,097	4,127	4,157	4,187	4,222	4,257	4,293	4,332	4,371	4,408	4,442
Reserve Margin (10%)	379	379	386	388	391	395	399	402	406	410	413	416	419	422	426	429	433	437	441	444
DSM Adjustment	-	(5)	(12)	(21)	(29)	(40)	(53)	(69)	(88)	(108)	(131)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)	(143)
TOTAL REQUIREMENT FOR FIRM LOAD	**4,169**	**4,167**	**4,238**	**4,249**	**4,278**	**4,309**	**4,334**	**4,356**	**4,375**	**4,399**	**4,409**	**4,429**	**4,463**	**4,502**	**4,540**	**4,579**	**4,622**	**4,665**	**4,706**	**4,743**
EGSL RESOURCES																				
Total Owned Capacity	**3,614**	**3,614**	**3,527**	**3,527**	**3,527**	**3,527**	**3,527**	**3,056**	**2,798**	**2,798**	**2,798**	**2,554**	**2,554**	**2,554**	**2,330**	**2,330**	**2,330**	**2,330**	**2,330**	**2,330**
Contracted Purchases																				
Long Term Contracted Purchases	26	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-
Limited Term Contracted Purchases	923	586	104	104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**949**	**613**	**131**	**131**	**26**	**26**	**26**	**26**	**26**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Surplus/(Deficit) Before Planned Resources	**395**	**59**	**(581)**	**(592)**	**(724)**	**(756)**	**(781)**	**(1,273)**	**(1,551)**	**(1,601)**	**(1,611)**	**(1,875)**	**(1,909)**	**(1,948)**	**(2,210)**	**(2,250)**	**(2,293)**	**(2,336)**	**(2,376)**	**(2,414)**
Identified Planned Resources																				
Long Term Planned Resources	-	193	193	193	193	244	244	244	244	270	270	270	270	270	270	270	270	270	270	270
Limited Term Planned Resources	-	-	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485
Total Identified Planned Resources	-	193	678	678	678	729	729	729	729	755	755	755	755	755	755	755	755	755	755	755
Surplus/(Deficit) incl. Identified Planned Resources	**395**	**253**	**97**	**86**	**(46)**	**(27)**	**(52)**	**(544)**	**(823)**	**(846)**	**(856)**	**(1,120)**	**(1,154)**	**(1,193)**	**(1,455)**	**(1,495)**	**(1,538)**	**(1,581)**	**(1,621)**	**(1,659)**
Other Planned Resources																				
Planned CCGT Additions	-	-	-	-	-	-	-	-	-	-	-	-	600	600	1,200	1,200	1,200	1,200	1,200	1,200
Renewable Generation	-	-	-	-	-	-	-	100	100	100	150	150	153	155	155	205	205	205	205	205
Limited Term Generic Planned Purchases	-	111	-	-	23	-	28	244	244	136	135	244	162	271	271	135	162	162	217	244
Total Other Planned Resources	**-**	**111**	**-**	**-**	**23**	**-**	**28**	**344**	**344**	**236**	**285**	**394**	**915**	**1,026**	**1,626**	**1,540**	**1,567**	**1,567**	**1,622**	**1,649**
TOTAL RESOURCES	**4,564**	**4,531**	**4,336**	**4,336**	**4,254**	**4,282**	**4,309**	**4,155**	**3,897**	**3,789**	**3,838**	**3,703**	**4,224**	**4,335**	**4,710**	**4,625**	**4,652**	**4,652**	**4,706**	**4,733**
Surplus / (Deficit) for 10% Reserve Margin	**395**	**364**	**97**	**86**	**(23)**	**(27)**	**(24)**	**(201)**	**(479)**	**(610)**	**(571)**	**(727)**	**(239)**	**(167)**	**171**	**46**	**30**	**(13)**	**0**	**(10)**

Figure A-20 ETI Load and Capability

ETI Load and Capability	6-OpCo System				5-OpCo System (excludes EAI)		4-OpCo System (excludes EAI & EMI)													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ETI LOAD																				
Firm Non-Coincident Peak	3,562	3,638	3,757	3,824	3,869	3,934	4,006	4,074	4,140	4,208	4,266	4,323	4,383	4,444	4,508	4,571	4,642	4,710	4,779	4,847
Reserve Margin (10%)	356	364	376	382	387	393	401	407	414	421	427	432	438	444	451	457	464	471	478	485
DSM Adjustment	(30)	(47)	(53)	(62)	(75)	(89)	(105)	(126)	(147)	(151)	(160)	(176)	(192)	(209)	(225)	(225)	(225)	(225)	(225)	(225)
TOTAL REQUIREMENT FOR FIRM LOAD	**3,888**	**3,954**	**4,081**	**4,144**	**4,181**	**4,238**	**4,302**	**4,355**	**4,408**	**4,478**	**4,532**	**4,579**	**4,629**	**4,680**	**4,733**	**4,803**	**4,881**	**4,956**	**5,032**	**5,106**
ETI RESOURCES																				
Total Owned Capacity	**2,480**	**2,480**	**2,415**	**2,415**	**2,415**	**2,415**	**2,415**	**2,067**	**1,876**	**1,876**	**1,876**	**1,696**	**1,696**	**1,696**	**1,530**	**1,530**	**1,530**	**1,530**	**1,530**	**1,530**
Contracted Purchases																				
Long Term Contracted Purchases	170	320	320	320	320	320	320	320	320	300	300	-	-	-	-	-	-	-	-	-
Limited Term Contracted Purchases	462	352	355	255	146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**632**	**672**	**675**	**575**	**466**	**320**	**320**	**320**	**320**	**300**	**300**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Surplus/(Deficit) Before Planned Resources	**(776)**	**(803)**	**(990)**	**(1,154)**	**(1,300)**	**(1,504)**	**(1,567)**	**(1,968)**	**(2,212)**	**(2,302)**	**(2,356)**	**(2,883)**	**(2,933)**	**(2,984)**	**(3,203)**	**(3,273)**	**(3,351)**	**(3,426)**	**(3,502)**	**(3,576)**
Identified Planned Resources																				
Long Term Planned Resources	-	-	-	-	-	37	37	37	37	57	57	357	357	357	357	357	357	357	357	357
Limited Term Planned Resources	-	-	-	-	-	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Total Identified Planned Resources	-	-	-	-	-	183	183	183	183	203	203	503	503	503	503	503	503	503	503	503
Surplus/(Deficit) incl. Identified Planned Res	**(776)**	**(803)**	**(990)**	**(1,154)**	**(1,300)**	**(1,321)**	**(1,384)**	**(1,785)**	**(2,029)**	**(2,099)**	**(2,153)**	**(2,381)**	**(2,430)**	**(2,481)**	**(2,700)**	**(2,770)**	**(2,848)**	**(2,923)**	**(2,999)**	**(3,073)**
Other Planned Resources																				
Planned CCGT Additions	-	-	600	600	600	600	600	600	1,200	1,800	1,800	1,800	1,800	1,800	1,800	2,400	3,000	3,000	3,000	3,000
Renewable Generation	-	-	-	-	-	-	100	100	100	100	100	200	205	205	205	205	205	255	255	255
Limited Term Generic Planned Purchases	-	104	-	-	22	-	27	243	245	137	136	245	163	272	272	136	163	163	218	245
Total Other Planned Resources	**-**	**104**	**600**	**600**	**622**	**600**	**727**	**943**	**1,545**	**2,037**	**2,036**	**2,245**	**2,168**	**2,277**	**2,277**	**2,741**	**3,368**	**3,418**	**3,473**	**3,500**
TOTAL RESOURCES	**3,111**	**3,255**	**3,690**	**3,590**	**3,503**	**3,518**	**3,644**	**3,513**	**3,924**	**4,415**	**4,415**	**4,444**	**4,367**	**4,476**	**4,310**	**4,774**	**5,401**	**5,451**	**5,506**	**5,533**
Surplus / (Deficit) for 10% Reserve Margin	**(776)**	**(699)**	**(390)**	**(554)**	**(679)**	**(721)**	**(657)**	**(842)**	**(484)**	**(62)**	**(117)**	**(135)**	**(261)**	**(204)**	**(423)**	**(29)**	**521**	**495**	**474**	**427**

Figure A-21 System Load and Capability

System Load and Capability	6-OpCo System				5-OpCo System (excludes EAI)		4-OpCo System (excludes EAI & EMI)													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SYSTEM LOAD																				
Firm Coincident Peak	20,741	20,984	21,345	21,518	16,946	17,099	13,915	14,061	14,209	14,364	14,492	14,589	14,708	14,841	14,984	15,125	15,256	15,406	15,550	15,690
Reserve Margin (varies)	3,495	3,536	3,597	3,626	3,050	3,078	2,783	2,812	2,842	2,873	2,898	2,918	2,942	2,968	2,997	3,025	3,051	3,081	3,110	3,138
DSM Adjustment	(67)	(99)	(139)	(208)	(175)	(216)	(243)	(309)	(391)	(466)	(548)	(600)	(642)	(658)	(675)	(675)	(675)	(675)	(675)	(675)
Total Requirement for Firm Load	**24,169**	**24,420**	**24,802**	**24,936**	**19,820**	**19,961**	**16,455**	**16,564**	**16,660**	**16,771**	**16,842**	**16,907**	**17,008**	**17,151**	**17,306**	**17,476**	**17,633**	**17,813**	**17,985**	**18,153**
SYSTEM RESOURCES																				
Total Owned Capacity	**21,132**	**21,132**	**20,559**	**20,371**	**15,611**	**15,611**	**12,188**	**11,370**	**10,795**	**10,557**	**10,557**	**10,133**	**9,900**	**9,490**	**9,100**	**9,100**	**8,578**	**8,063**	**8,063**	**8,063**
Contracted Purchases																				
Long Term Contracted Purchases	1,201	1,351	1,351	1,351	1,558	1,558	1,558	1,558	1,078	1,009	1,009	709	709	709	709	709	709	709	709	709
Limited Term Contracted Purchases	1,745	815	330	230	230	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracted Purchases	**2,946**	**2,166**	**1,681**	**1,581**	**1,788**	**1,642**	**1,558**	**1,558**	**1,078**	**1,009**	**1,009**	**709**	**709**	**709**	**709**	**709**	**709**	**709**	**709**	**709**
Surplus/(Deficit) Before Planned Resources	**(90)**	**(1,122)**	**(2,562)**	**(2,983)**	**(2,421)**	**(2,708)**	**(2,709)**	**(3,636)**	**(4,788)**	**(5,206)**	**(5,277)**	**(6,065)**	**(6,399)**	**(6,952)**	**(7,497)**	**(7,667)**	**(8,346)**	**(9,041)**	**(9,213)**	**(9,381)**
Identified Planned Resources																				
Long Term Identified Resources	-	580	740	740	682	807	755	755	1,235	1,304	1,304	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604
Limited Term Identified Resources	-	-	485	485	485	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631
Total Identified Planned Resources	-	580	1,225	1,225	1,167	1,438	1,386	1,386	1,866	1,935	1,935	2,235	2,235	2,235	2,235	2,235	2,235	2,235	2,235	2,235
Surplus/(Deficit) incl. Identified Planned Resourc	**(90)**	**(542)**	**(1,337)**	**(1,758)**	**(1,254)**	**(1,270)**	**(1,324)**	**(2,250)**	**(2,922)**	**(3,271)**	**(3,342)**	**(3,830)**	**(4,165)**	**(4,718)**	**(5,263)**	**(5,432)**	**(6,112)**	**(6,807)**	**(6,979)**	**(7,147)**
Other Planned Resources																				
Planned CCGT Additions	-	-	1,800	1,800	1,200	1,800	1,200	1,200	1,800	2,400	2,400	2,400	3,000	3,000	3,600	4,200	4,800	5,400	5,400	5,400
Renewable Generation	-	-	-	-	-	100	100	200	300	400	450	600	658	718	718	768	768	818	868	868
Limited Term Generic Planned Purchases	-	600	-	-	100	-	100	900	900	500	500	900	600	1,000	1,000	500	600	600	800	900
Total Other Planned Resources	**-**	**600**	**1,800**	**1,800**	**1,300**	**1,900**	**1,400**	**2,300**	**3,000**	**3,300**	**3,350**	**3,900**	**4,258**	**4,718**	**5,318**	**5,468**	**6,168**	**6,818**	**7,068**	**7,168**
TOTAL RESOURCES	**24,078**	**24,478**	**25,265**	**24,977**	**19,866**	**20,591**	**16,531**	**16,613**	**16,738**	**16,800**	**16,850**	**16,976**	**17,101**	**17,151**	**17,361**	**17,511**	**17,689**	**17,824**	**18,074**	**18,174**
Surplus / (Deficit) incl. Generic Planned Resourc	**(90)**	**58**	**463**	**42**	**46**	**630**	**76**	**50**	**78**	**29**	**8**	**70**	**93**	**(0)**	**55**	**35**	**56**	**11**	**89**	**21**

Figure A-22 Utility Load and Capability

Utility Load and Capability	6-OpCo Utility				5-OpCo System + EAI standalone		4-OpCo System + EAI & EMI standalone													
(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
UTILITY LOAD																				
Firm Coincident Peak	20,741	20,984	21,345	21,518	21,986	22,199	22,463	22,701	22,953	23,257	23,485	23,691	23,925	24,176	24,451	24,725	24,988	25,268	25,548	25,816
Reserve Margin (varies)	3,495	3,536	3,597	3,626	4,059	4,098	4,526	4,575	4,626	4,687	4,733	4,775	4,822	4,873	4,929	4,984	5,037	5,094	5,150	5,205
DSM Adjustment	(67)	(99)	(139)	(208)	(278)	(334)	(415)	(511)	(628)	(722)	(825)	(897)	(968)	(1,015)	(1,050)	(1,050)	(1,050)	(1,050)	(1,050)	(1,050)
Total Requirement for Firm Load	**24,169**	**24,420**	**24,802**	**24,936**	**25,767**	**25,963**	**26,574**	**26,765**	**26,951**	**27,222**	**27,393**	**27,568**	**27,780**	**28,034**	**28,329**	**28,659**	**28,975**	**29,312**	**29,648**	**29,970**
UTILITY RESOURCES																				
Total Owned Capacity	**21,132**	**21,132**	**20,559**	**20,371**	**20,248**	**19,724**	**19,633**	**18,815**	**18,240**	**17,793**	**17,737**	**17,313**	**17,080**	**16,670**	**16,280**	**15,104**	**14,582**	**14,067**	**14,067**	**14,067**
Contracted Purchases																				
Long Term Contracted Purchases	1,201	1,351	1,351	1,351	1,351	1,351	1,351	1,351	871	802	802	502	502	502	502	502	502	502	502	502
Limited Term Contracted Purchases	1,745	815	330	230	230	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Total Contracted Purchases	**2,946**	**2,166**	**1,681**	**1,581**	**1,581**	**1,435**	**1,435**	**1,435**	**955**	**886**	**886**	**586**	**586**	**586**	**586**	**586**	**586**	**586**	**586**	**586**
Surplus/(Deficit) Before Planned Resources	**(90)**	**(1,122)**	**(2,562)**	**(2,983)**	**(3,938)**	**(4,804)**	**(5,506)**	**(6,514)**	**(7,755)**	**(8,542)**	**(8,770)**	**(9,669)**	**(10,113)**	**(10,778)**	**(11,463)**	**(12,969)**	**(13,807)**	**(14,659)**	**(14,995)**	**(15,317)**
Identified Planned Resources																				
Long Term Planned Resources	-	580	740	740	740	1,389	1,389	1,389	1,869	1,938	1,938	2,238	2,238	2,238	2,238	2,238	2,238	2,238	2,238	2,238
Limited Term Planned Purchases	-	-	485	485	485	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631
Total Identified Planned Resources	**-**	**580**	**1,225**	**1,225**	**1,225**	**2,020**	**2,020**	**2,020**	**2,500**	**2,569**	**2,569**	**2,869**	**2,869**	**2,869**	**2,869**	**2,869**	**2,869**	**2,869**	**2,869**	**2,869**
Surplus/(Deficit) incl. Identified Planned Resources	**(90)**	**(542)**	**(1,337)**	**(1,758)**	**(2,713)**	**(2,784)**	**(3,486)**	**(4,494)**	**(5,255)**	**(5,973)**	**(6,201)**	**(6,800)**	**(7,244)**	**(7,909)**	**(8,594)**	**(10,100)**	**(10,938)**	**(11,790)**	**(12,126)**	**(12,448)**
OtherPlanned Resources																				
Planned CCGT Additions	-	-	1,800	1,800	2,400	3,000	3,000	3,000	3,600	4,200	4,200	4,800	5,400	5,400	6,000	7,800	9,000	9,600	9,600	9,600
Renewable Generation	-	-	-	-	100	203	305	408	510	660	810	960	1,023	1,085	1,135	1,185	1,235	1,285	1,335	1,335
Generic Planned Purchases	-	600	-	-	300	300	400	1,300	1,300	1,200	1,300	1,200	1,000	1,500	1,600	1,200	900	1,000	1,400	1,600
Total Other Planned Resources	**-**	**600**	**1,800**	**1,800**	**2,800**	**3,503**	**3,705**	**4,708**	**5,410**	**6,060**	**6,310**	**6,960**	**7,423**	**7,985**	**8,735**	**10,185**	**11,135**	**11,885**	**12,335**	**12,535**
TOTAL RESOURCES	**24,078**	**24,478**	**25,265**	**24,977**	**25,854**	**26,682**	**26,793**	**26,978**	**27,105**	**27,308**	**27,502**	**27,728**	**27,958**	**28,110**	**28,470**	**28,744**	**29,172**	**29,407**	**29,857**	**30,057**
Surplus/(Deficit) After Planned Resources	**(90)**	**58**	**463**	**42**	**87**	**719**	**219**	**213**	**155**	**87**	**109**	**160**	**178**	**76**	**141**	**85**	**197**	**95**	**209**	**87**

Figure A-23 Potential Unit Deactivations

SRP Reference Planning Scenario Assumptions