San Diego Regional Energy Infrastructure Study

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Prepared for:

The County of San Diego
The San Diego Regional Energy Office
The City of San Diego
The Utility Consumers Action Network
The San Diego County Water Authority
The San Diego Association of Governments
And
The Port of San Diego

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3.3.3 Slack Capacity on the SDG&E and SoCalGas Systems ..............................10
3.4 Gas Utility System Planning Criteria.................................................................10
  3.4.1 Capacity Additions on the SDG&E System ...................................................11
  3.4.2 SoCalGas System Planning Criteria..............................................................13
  3.4.3 SoCalGas Capacity Additions........................................................................13
3.6 Other Regional Infrastructure Projects..............................................................14
  3.6.1 The North Baja Pipeline Project ....................................................................14
  3.6.2 LNG (Liquified Natural Gas) ..........................................................................15
  3.6.3 Underground Natural Gas Storage.................................................................17
3.7 Regulatory Proceedings and Issues......................................................................17
  3.7.1 The Role of the CPUC ...................................................................................17
  3.7.2 Core vs. Noncore Conflicts – What to Do......................................................18
  3.7.3 The Integration of SoCalGas and SDG&E Gas Operations .........................18
  3.7.4 The Peaking Tariff..........................................................................................18
3.8 Important Implications and Considerations for the Region...................................19
4 Electricity Demand, Supply, and Infrastructure........................................................1
4.1 Summary Findings................................................................................................1
  4.1.1 Short Term 2002–2006 ....................................................................................1
  4.1.2 Mid Term 2006–2010 .....................................................................................2
  4.1.3 Long Term Post 2010 ....................................................................................2
4.2 Electricity Demand and Consumption Trends and Forecasts..................................2
  4.2.1 Historical Energy Consumption ....................................................................2
  4.2.2 Per Capita Electricity Growth and Energy Intensity .......................................3
4.3 Electricity Supply: Generation and Transmission..................................................4
  4.3.1 Existing Generation Stock in San Diego County .............................................4
  4.3.2 New Generation Infrastructure .....................................................................7
4.4 San Diego County’s Electric Power Market........................................................9
  4.4.1 The Need for New Power Plants ..................................................................11
  4.4.2 Repowering Existing Power Plants...............................................................12
  4.4.3 New Power Plants in Baja California ...........................................................12
4.5 Electricity Transmission.......................................................................................12
  4.5.1 The Role of Transmission and Advantages and Disadvantages ....................12
  4.5.2 Transmission Issues .....................................................................................14
4.6 Other Issues Affecting Electricity Supply............................................................18
  4.6.1 Effects of State Executive, Legislative, Regulatory and Policy Decisions ..........18
  4.6.2 Federal Initiatives ..........................................................................................19
  4.6.3 Local Initiatives .............................................................................................20
5 Demand-Side Options: Energy Efficiency, Demand Response, Distributed Generation and Renewables ...............................................................1
5.1 DSM, DG and Renewable Opportunities: Summary of General Findings ..........1
  5.1.1 Energy Efficiency and Demand Response.....................................................1
  5.1.2 DG and Renewable Resources ......................................................................1
  5.1.3 Short Term (2002-2006) ..............................................................................2
  5.1.4 Mid Term (2006-2010) .................................................................................2
  5.1.5 Post-2010 Time Period ..................................................................................3
5.2 Background...........................................................................................................3
  5.2.1 Energy Efficiency ..........................................................................................3
  5.2.2 Public-Good Energy Efficiency Programs.....................................................4
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.2.3 Distributed Generation (DG) and Renewable Programs</td>
<td>4</td>
</tr>
<tr>
<td>5.3 Key Energy Efficiency and Demand Reduction Programs</td>
<td>5</td>
</tr>
<tr>
<td>5.3.1 Results: Market Impacts and Cost Effectiveness</td>
<td>8</td>
</tr>
<tr>
<td>5.3.2 Environmental Impacts</td>
<td>9</td>
</tr>
<tr>
<td>5.4 DG Technologies</td>
<td>10</td>
</tr>
<tr>
<td>5.4.1 DG Technology Comparison</td>
<td>10</td>
</tr>
<tr>
<td>5.4.2 Framework for Evaluating Role of DG</td>
<td>10</td>
</tr>
<tr>
<td>5.4.3 DG Applications</td>
<td>11</td>
</tr>
<tr>
<td>5.4.4 Customer-Based DG</td>
<td>11</td>
</tr>
<tr>
<td>5.4.5 System-Based DG</td>
<td>12</td>
</tr>
<tr>
<td>5.5 Distributed Generation Market Overview</td>
<td>12</td>
</tr>
<tr>
<td>5.5.1 Inventory of DG in San Diego Region</td>
<td>13</td>
</tr>
<tr>
<td>5.5.2 Landfill Gas</td>
<td>14</td>
</tr>
<tr>
<td>5.5.3 Hydro Power</td>
<td>16</td>
</tr>
<tr>
<td>5.5.4 Photovoltaics</td>
<td>16</td>
</tr>
<tr>
<td>5.6 Fuel Cells</td>
<td>18</td>
</tr>
<tr>
<td>5.7 Renewable Energy Technologies</td>
<td>19</td>
</tr>
<tr>
<td>5.7.1 Wind</td>
<td>19</td>
</tr>
<tr>
<td>5.7.2 Potential for Wind</td>
<td>20</td>
</tr>
<tr>
<td>5.7.3 Summary: Wind</td>
<td>20</td>
</tr>
<tr>
<td>5.8 Solar Water Heating</td>
<td>20</td>
</tr>
<tr>
<td>5.9 Geothermal</td>
<td>22</td>
</tr>
<tr>
<td>5.10 Effective Market Potential of DG in the San Diego Region</td>
<td>22</td>
</tr>
<tr>
<td>5.11 Potential Customer Benefits</td>
<td>23</td>
</tr>
<tr>
<td>5.12 Other Regional Benefits</td>
<td>24</td>
</tr>
<tr>
<td>5.13 Potential Utility Benefits</td>
<td>25</td>
</tr>
<tr>
<td>5.14 Economic Development Impacts of Energy Efficiency and Distributed</td>
<td>25</td>
</tr>
<tr>
<td>Generation</td>
<td>25</td>
</tr>
<tr>
<td>5.15 Potential Investment Impacts of Energy Efficiency, Demand Response</td>
<td>26</td>
</tr>
<tr>
<td>Distributed Generation on the Local Economy</td>
<td>26</td>
</tr>
<tr>
<td>5.16 Disadvantages of DG to the San Diego Region</td>
<td>27</td>
</tr>
<tr>
<td>5.16.1 Economics</td>
<td>28</td>
</tr>
<tr>
<td>5.16.2 Price of Energy</td>
<td>28</td>
</tr>
<tr>
<td>5.16.3 Regulatory Issues and Tariffs</td>
<td>29</td>
</tr>
<tr>
<td>5.16.4 Inability to Wheel Power Offsite</td>
<td>30</td>
</tr>
<tr>
<td>5.16.5 Interconnection</td>
<td>30</td>
</tr>
<tr>
<td>5.16.6 Net Metering</td>
<td>30</td>
</tr>
<tr>
<td>5.16.7 Tariffs</td>
<td>30</td>
</tr>
<tr>
<td>5.16.8 Departing Load Fee</td>
<td>31</td>
</tr>
<tr>
<td>5.16.9 Permitting</td>
<td>31</td>
</tr>
<tr>
<td>5.17 Air Permits</td>
<td>32</td>
</tr>
<tr>
<td>5.18 Local Building Permits</td>
<td>33</td>
</tr>
<tr>
<td>5.19 Role of Local Governments in Deploying DG</td>
<td>33</td>
</tr>
<tr>
<td>5.20 Streamline Permitting for DG</td>
<td>33</td>
</tr>
<tr>
<td>5.21 Identify and Address Barriers</td>
<td>34</td>
</tr>
<tr>
<td>5.22 DG Demonstration</td>
<td>34</td>
</tr>
<tr>
<td>5.23 Revenue Bonds to Procure DG</td>
<td>34</td>
</tr>
<tr>
<td>5.24 CA Power Authority</td>
<td>34</td>
</tr>
<tr>
<td>5.25 Recommended Actions for Promoting Energy Efficiency, Demand Response</td>
<td>34</td>
</tr>
<tr>
<td>and Expanding DG/Renewables</td>
<td>34</td>
</tr>
<tr>
<td>5.25.1 Energy Efficiency and Demand Response</td>
<td>34</td>
</tr>
</tbody>
</table>
6 Options and Scenario Analysis

6.1 Summary Findings of the Analysis
   6.1.1 Short Term (2002–2006)................................................................. 1
   6.1.2 Medium Term (2006–2010)............................................................. 2
   6.1.3 Long Term (2010 and Beyond)....................................................... 3

6.2 Background...................................................................................... 3

6.3 The Scenarios.................................................................................. 3

6.4 The Resource Balance: Supply and Demand Balance with Energy Efficiency and DG-Renewable Resource Options
   6.4.1 Caveats ....................................................................................... 6

6.5 Wholesale Electric Price Forecast
   6.5.1 Methodology and General Assumptions............................................ 12
   6.5.2 Long Run Marginal Cost (LRMC) of Electric Generating Capacity........ 13
   Other Assumptions ............................................................................... 14

6.6 Results.............................................................................................. 18
   6.6.1 Capacity Price Forecasts .............................................................. 18
   6.6.2 Energy Price Forecasts ................................................................. 20
   6.6.3 California Department of Water Resources (CDWR) Long-Term Power Contracts ......................................................... 21
   6.6.4 California Financial Investment Climate and Cost of Building Plants in San Diego County ......................................................... 21

7 Recommendations .............................................................................. 1
   7.1 Background .................................................................................. 1
   7.2 Considerations for Key Infrastructure Development ......................... 3
      7.2.1 Short Term (2002–2006) ............................................................... 3
      7.2.2 Mid Term (2006–2010) ................................................................. 4
      7.2.3 Long Term (Post 2010) ................................................................. 5

Appendix A: Contributors, Authors, and Acknowledgements .................... A-1

Appendix B: List of Acronyms Used in This Study .................................... B-1

Appendix C: Glossary of Terms Used in This Study ................................. C-1

Appendix D: Demand and Generation Scenarios and Forward Prices .......... D-1

Appendix E: Natural Gas System Data ..................................................... E-1

Appendix F: Power System Data ............................................................... F-1

Appendix G: COMPASS Modeling .......................................................... G-1

Appendix H. Addendum To Draft REIS Document Based on Public Comment ... H-1
List of Figures

2-1 Average Weekly Electricity Prices at Palo Verde................................................................. 2-2
2-2 SDG&E System Average Price – Pre-2000 Forecast Compared to Current Forecast................................................................. 2-3
2-3 Natural Gas Prices at the Permian Basin and the So. CA Border ........................................... 2-3
2-4 The Steady Decline of the Dow Jones Utility Average.............................................................. 2-4
2-5 Population, Housing, Employment, Electricity, and Natural Gas Consumption Growth Rates – Historical and Forecast........................................................................................................ 2-6
2-6 Per Capita Electricity Consumption.......................................................................................... 2-6
2-7 Electricity and Gas Energy Intensity........................................................................................ 2-7

3-1 Natural Gas Demand 5-Year Growth Rates ......................................................................... 3-3
3-2 Natural Gas Consumption....................................................................................................... 3-3
3-3 Natural Gas Consumption by Sector...................................................................................... 3-4
3-4 Natural Gas Consumption for Electric Generation, WSCC..................................................... 3-4
3-5 Natural Gas Price at the Basin.............................................................................................. 3-6
3-6 Natural Gas Storage Levels.................................................................................................... 3-6
3-7 San Diego Gas Supplies from Five Major Gas Basins............................................................ 3-7
3-8 Detailed Map of SDG&E Natural Gas Distribution System.................................................... 3-8
3-9 Map of the Baja Norte Pipeline............................................................................................ 3-15

4-1 Electricity Consumption......................................................................................................... 4-2
4-2 Electricity Demand by Sector............................................................................................... 4-3
4-3 Peak Electricity Demand by Sector........................................................................................ 4-4
4-4 Projected Cumulative Retirements of Generating Units in San Diego County .................. 4-5
4-5 Projected Cumulative Net Additions and Retirements of Generating Units in San Diego County ................................................................................................................................. 4-8
4-6 Projected New Plant Development in San Diego Region....................................................... 4-10

5-1 Peak Demand Contribution for Large Offices...................................................................... 5-3
5-2 Demand Impacts of Programs, 2006–2030........................................................................... 5-7
5-3 Energy Savings Impacts of Programs, 2006–2030............................................................... 5-8
5-4 Natural Gas Savings Impact of DSM Program Scenarios.................................................... 5-9
5-5 Wind Speeds By Location in San Diego County.................................................................. 5-19

6-1 Scenarios and Key Assumptions.......................................................................................... 6-3
6-2 WECC Region....................................................................................................................... 6-14
6-3 New Generating Projects in the WECC............................................................................... 6-16
6-4 Capacity Prices, 2002–2030............................................................................................... 6-18
6-5 Forward Energy Prices........................................................................................................ 6-20
List of Tables

2-1  Strengths, Weaknesses, Opportunities, and Threats for the San Diego Region .....2-17
3-1  Retail Natural Gas Price Estimates .................................................................3-5
3-2  Natural Gas Cost Component Range and Variability Factors ......................3-6
3-3  Slack Capacity Under Different Weather Scenarios Shows Adequate Backbone Transmission Capacity through 2006 ..................................................3-10
3-4  SDG&E Firm Service Day (FSD) Demand ......................................................3-11
3-5  SDG&E Potential Facility Expansion Projects .................................................3-12
3-6  Summary of Proposed Mexico LNG Facilities ...............................................3-16
4-1  New Generating Units Entering Service in 2001 ...............................................4-8
4-2  Constraints in Building New Power Plants in Southern California ..................4-9
5-1  Summary of Demand and Energy Impacts of Energy Efficiency and Demand Response Programs .................................................................5-6
5-2  Summary of DSM Program Life Cycle Costs and Impacts ............................5-7
5-3  Emission Impacts of Demand Response Programs .......................................5-10
5-4  Comparison of DG Technologies .................................................................5-11
5-5  DG Capacity in San Diego County ...............................................................5-13
5-6  CHP by Technology .......................................................................................5-13
5-7  Estimated Remaining CHP Potential in the C&I Market, San Diego ...............5-14
5-8  Existing Landfill and Wastewater Gas-Fired Generator ..................................5-15
5-9  Hydro Facilities in the San Diego Region ......................................................5-16
5-10 Estimates of Effective Incremental Market Potential for DG ..........................5-23
5-11 Summary of Economic Impacts of Demand Side and DG Options ...............5-26
6-1  Description of Demand and Supply Scenarios .............................................6-5
6-2  Supply/Demand Balance Assuming Optimistic Energy Efficiency and DG-Renewables, 2006–2030 .................................................................6-7
6-3  Supply/Demand Balance Assuming Worse Case Supply, Energy Efficiency, and DG-Renewables, 2006–2030 .................................................................6-7
6-4  Base Case Moderate Demand Growth and Optimistic Supply, 2002–2030 .......6-9
6-5  High Demand Growth and Worse Case Supply Scenario ............................6-10
6-6  High Demand Growth and Optimistic Supply, 2002–2030 ............................6-12
6-7  Natural Gas Prices Delivered to Electric Generating Units ............................6-15
6-8  Projected Full Load Heat Rates by Technology Projected to Be Achieved in the Period 2002–2030 .................................................................6-16
6-9  Installed Cost of Various Generation Technologies ........................................6-16
6-10 Forward Capacity Values ............................................................................6-19
6-11 Average Energy Price by Scenario .............................................................6-20
Executive Summary

Background

The goal of the San Diego Regional Energy Infrastructure Study ("Study") is to develop a fact-based foundation for assessing San Diego region’s electricity and natural gas needs through 2030. This is accomplished by identifying alternative resource development approaches to achieving the region’s energy vision and limiting the future risks that exist. The vision consists of ensuring long-term energy security, controlling cost and reliability, minimizing risk, and minimizing the impacts of energy production and use on the environment, which will contribute to a higher degree of sustainability and a higher quality of life. The Study provides an integrated and comprehensive inventory and evaluation of current and potential future energy supply and infrastructure required to meet the growing needs of the region through 2030. Key infrastructure and resource options include:

- Electric generation, transmission, and distribution
- Natural gas supply, transmission, and distribution
- Energy efficiency and demand response programs
- Distributed generation and renewable resources.

The Study was directed by the San Diego Regional Energy Office (SDREO), conducted by Science Applications International Corporation (SAIC), with funding and active participation of the City of San Diego, and the County of San Diego, the Port of San Diego, the San Diego Association of Governments (SANDAG), the San Diego County Water Authority, and the Utility Consumers Action Network (UCAN).

The objective of this Study is to provide the public and decision-makers with the necessary information to evaluate options and make choices for meeting future energy supply and demand of the region. These choices are difficult when the region cannot control the many decisions that are being made at the state and federal level, especially the degree to which a new, modified energy market will evolve.

The region has the opportunity to be more active in influencing forthcoming key decisions at state and federal levels regarding regional energy matters. Critical issues are facing the region in terms of developing a balanced portfolio of energy resources that recognizes the volatility of electricity and natural gas prices, the uncertainty surrounding the cost and availability of certain renewable technologies, the timing and availability of new transmission, addressing reliability issues, and evaluating important new generation assets or the repowering of these assets in the region. The goal should be to create hedges and options in the region by diversification of generation, transmission, demand response and energy efficiency resources. A strong commitment to cost-effective energy efficiency and renewable resource options is also needed.

There is also an important need to recognize the broader synergies with the Western power and natural gas markets, including Northern Baja California and neighboring counties. These areas face similar problems and working together to craft solutions can provide significant benefits.

The Problem

San Diego County is one of the top three residential electricity cost markets and in the top six commercial cost markets in the United States. The region also faces very high natural gas
transmission and city gate prices—often higher than other regions. Many factors drive these costs: regulation, market power, geography (i.e., terrain and land density), infrastructure performance, and other factors.

The region simply cannot afford the “business-as-usual,” ad-hoc approach to market and infrastructure planning. The high costs to consumers will continue to strain the economic vitality of the region. The region also cannot count on state and federal regulators to make decisions that are in the best interests of the region. Simply put, the region must become more engaged and involved in planning the region’s energy infrastructure.

The main focus of this report is to identify options that limit natural gas and electricity costs and market risk. A way to do this is to develop a comprehensive resource portfolio that takes into account price or market risk and flexibility. Active participation of the community and key stakeholders in defining, evaluating and selecting regional infrastructure projects for development is needed.

Project sponsors realize that the region cannot afford to be reactive in ensuring a sufficient supply of energy to meet the growing energy demand. New generation and transmission siting must consider other options and perspectives beyond the narrow and sometimes piecemeal considerations that are raised. A more comprehensive and inclusive public dialogue and involvement are needed in selecting major new regional energy infrastructure projects. In addition, the region has valuable assets of its own that could be drawn upon to help control risks and contribute to the County’s resource portfolio. These resources come from the San Diego County Water Authority, the Port of San Diego, the City of San Diego and County of San Diego, to name a few. Also, the many commercial and industrial customers who have existing supply resources can be drawn upon to contribute to the resource portfolio.

As a reaction to the recent market failure in California and the current industry restructuring, consumers are demanding that a greater range of options be considered, including non-traditional alternatives, particularly renewables. Consumers are also becoming more skeptical about market performance, government oversight and policymaking efficacy. Greater involvement and self-determination at the local level is viewed as a key to improving the quality and value of the energy infrastructure of the region.

The Key Questions

The key questions that this report addresses are:

- What is the expected supply/demand balance in the region through 2030?
- How adequate is currently planned generation and transmission capacity to meet these anticipated demands?
- What mix of resources is possible to cost-effectively meet demand requirements?
- What new transmission capacity is needed and when?
- To what degree are demand-side programs effective and what can be done to increase the public investment in demand-side strategies?
- Given the increasing dependence on natural gas, what renewable resource options are reasonable to pursue?

Key Findings

- Electricity demand is estimated to nearly double by 2030
- It is becoming more difficult to meet this growing demand with traditional grid-based generation and transmission infrastructure
- Energy efficiency and DG-renewables can be the difference between deficits and adequate supply to meet growth. Between 8 and 23 percent of new load growth can be met with energy efficiency and DG-renewables.
- A minimum of two 500-MW base generating plants are needed—more if the region does not pursue alternative energy sources
- Additional transmission is needed
- Sufficient local natural gas distribution system capacity exists for core customers
- Market power issues continue to exist and could worsen for natural gas capacity and supply
What types of risks will the region face in the years ahead and how can it minimize its exposure to these risks?

What organizational response is needed in the community from a public policy perspective to be more effective in ensuring its future energy security?

Current vs. Future State

In the past, the energy industry's large generation and transmission infrastructure was funded and developed on a cost-basis using a fixed rate-of-return on the capital base. It was planned, constructed and maintained by SDG&E with oversight by the state Public Utilities Commission. However, the state industry restructuring effort in 1996 made fundamental changes in how this was accomplished. SDG&E has indicated it no longer deems its role to be the regional energy planner, and the Public Utilities Commission's regulatory scope has been curtailed in lieu of market-based pricing. In light of the many uncertainties surrounding the future of energy markets and regulation, a new energy supply paradigm is required, one that achieves a more balanced portfolio of supply and demand resources including distributed energy options.

This study explores that new paradigm—one that balances demand-side efficiency, distributed generation and renewable resources that are much more attractive options as energy costs have soared. The level of cost-effective investment in these options can continue to increase as more innovative procurement and financing options are pursued. Under the state's new renewable portfolio standard, a growing amount of renewable resources will be required. This will be an opportunity for the San Diego region to increase the utilization of its indigenous renewable resources to create a form of "energy self-reliance" not seen before. The region has a tremendous opportunity to define its energy destiny that is harmonious, and not harmful, to the local economy, environment and consumer. The region can also decide to engage in a more participative, comprehensive planning process that is more flexible and will more readily adjust to changing external conditions, rather than relying only on large, capital-intensive solutions that have a significant lag time.

This study also assumes a competitive wholesale power market paradigm for wholesale supply, even though CDWR wholesale power is still above market prices. At the end of the contract period, prices should track wholesale market prices. The end result is an underestimation of wholesale prices and the consumer benefits of energy efficiency and demand response.

Summary of Major Findings

The major findings of the this study are as follows:

- Over the long-term, scenarios projecting low, medium and high natural gas and electric growth rates were defined. Electricity peak demand will nearly double, increasing by more than 4,000-MW by 2030. (Chapters 4, 6 and Appendix D)
- The region needs to develop a portfolio approach to balancing energy supply and demand options. Yet, there is no real institutional mechanism that exists to effectively accomplish this. (Chapters 4, 5, and 6)
  - The region needs to consider developing a balance of in-basin new generation and repowering of selected existing plants to meet future load growth requirements
  - The region needs additional transmission interconnection to the South (immediately), North (4-5 years), and East (in the 2020 time period and beyond)
  - The region can meet a significant proportion of its load growth through energy efficiency, demand response, distributed generation and renewable resources.
  - The region should recognize that renewables and some distributed resources are subject to technical and market risks that need to be taken into account.
  - The Otay Mesa plant is a strategic asset and the region should take the necessary action to ensure that this plant is built—and that maximum use of the asset in terms of total development potential is considered.
Existing power plants located in the South Bay and Carlsbad (Cabrillo) must be repowered as quickly as is feasible to maximize natural gas efficiency and supply potential.

- The region should consider the development of a joint energy development authority to ensure that a certain proportion of public and private energy assets are used to meet future energy requirements. These assets can also serve as a hedge against market volatility and dynamics that can lead to similar price shocks that were recently experienced in California and San Diego, in particular. Significant risks exist regarding the heavy dependency on natural gas for power and major direct uses. To some extent natural gas prices and future natural gas availability will drive the energy economy in the 2010–2030 time period. The region must actively consider these risks and attempt to develop the necessary hedges and options to control this risk. (Chapters 3 and 7)

- In the short term, natural gas supply is more than adequate to meet current and near-term core customer demand. (Chapter 3)
  - Longer-term, demand is expected to grow significantly as new natural gas-fueled power plants come online. Questions exist about how best to price EG natural gas.
  - The region needs to consider ways to increase competition and encourage cost reduction in California natural gas prices and also improve the management of within state natural gas transmission costs.
  - Growth in demand for natural gas will continue to accelerate as more power plants are built. The retirement of large existing plants in 10 to 20 years will further accelerate this growth. Gas production to supply these plants is expected to peak and then decline within the next 10 to 15 years, placing additional upward pressure on prices. Other than increased growth of renewables and demand reduction, importation of Liquid Natural Gas (LNG) provides the only suitable alternative.

- To meet future electricity requirements, a balance of in region new generation development, transmission expansion and energy efficiency, DG and renewables are needed. The region should work toward creating a balanced energy portfolio. (Chapter 5)
  - As many as three new 500-MW base power plants are required over the next 30 years, and new transmission will also be needed. Between now and 2010, at least two new generating plants are needed to replace the older plants that will be decommissioned.
  - Substantial renewable resources exist within the county and nearby. Over time, these resources can cost-effectively provide needed new energy supplies that will economically benefit the region.
  - Substantial economic value-added benefit exists from demand-side resource options including expanded efficiency and small-scale generation. The largest energy-saving measures include commercial lighting, commercial ventilation and air conditioning, time-of-use pricing and retrofit of existing buildings to current standards. A market-based demand response and conservation investment buy back program would encourage greater participation in these programs as would an emission offset credit program. This means a program that purchases conservation resources up to the short-run and/or long-run marginal costs of either the energy or emissions that are displaced.
  - Better incentives that encourage retrofit of existing buildings should be strongly considered, such as incentives for condition-of-sale provisions for residential property.
  - The region should recognize the valuable contribution that energy infrastructure resources in North Baja California provides and work toward achieving a satisfactory contribution to its

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1 This recommendation should be investigated and re-evaluated in light of the SDG&E new resource situation that includes the CDWR contracts and its own long-term supply situation.

2 Since this section was written, CDWR contracts, through CPUC actions, have been allocated to SDG&E and other utilities. SDG&E feels that these contracts will meet the energy needs of the county over the next 10 years. Project sponsors need to investigate this position as it moves forward in developing a regional energy strategy. See Addendum to this report for more information on this issue.
portfolio from this source—for both generation and renewable resources. A bi-national development framework and program should be encouraged.

- Additional transmission is needed. Short-term priorities include more transmission to the south and north. Eventually, additional transmission capacity to the east is needed in the post-2010 period.

**Economic Development Benefits**

This study found significant economic development returns are available from improved resource selection—as much as a 5-to-1 investment return from energy efficiency and small-scale distributed generation. For investing as much as $3.6 billion, the community could realize an economic benefit of $17.8 billion. Thousands of jobs would also be created in the community over the 30-year period. The region’s economy and energy services industry base is well positioned to take advantage of the growing demand for distributed generation and renewable resources.

**Implications for the Regional Energy Strategy**

A change is needed for future energy infrastructure planning in the region. This Study concludes that the region can become more self-reliant through better organization and utilization of county-wide talents and resources. The region needs to seriously consider creating a joint energy development authority that evaluates, recommends and co-invests in regional energy infrastructure projects. These projects could be either independently publicly supported or be joint ventures with private developers. The region needs to add more diversity to its resource base and work toward achieving a balanced resource portfolio. In addition, the broader implications of energy facility siting considering interrelationships of generation and transmission, achieving higher levels of system reliability and the benefits of avoiding both outages and excessive market prices are critical focus areas. Energy efficiency, demand response, renewables and distributed generation are critical “swing factor” resources that can have a tremendous impact in avoiding or delaying future capacity increases plus achieve market price stability.

**Future Options for Consideration**

- Better organization of public resources, including evaluating creation of a joint power agreement or power development authority to pursue a more aggressive regional energy investment strategy
- Strong endorsement for cost effective-to-high efficiency distributed generation and renewable investments
- Closely track federal/state energy policy and regulations, particularly FERC and the development of national energy policy. State PUC and CAISO proposed rules, pricing and cost allocations also should be closely tracked, and united positions on these issues formed.
- Capacity bidding and energy conservation investment markets
- More active lobbying in state and national regulatory and infrastructure issues
- Pursuit and selective implementation of time-of-use pricing and metering
- Better incentives for existing building upgrades
- Access to more diverse interstate markets and fuels for power generation
1 Introduction

1.1 Background

This 2030 Regional Energy Infrastructure Study ("Study") is designed to provide an integrated, comprehensive analysis of the supply and demand issues to form the basis of the most cost-effective electric and natural gas supply\(^1\) and distributed energy resource strategy with the goal of achieving a reliable and affordable energy future for the San Diego region.\(^2\) Over the past 2 years, the region has faced extremely high and volatile energy prices. Like the rest of the state, the region has fallen behind in the development of needed energy-related infrastructure and faces the need for substantial energy infrastructure investments.

This Study is a collaborative effort that has been conducted by Science Applications International Corporation (SAIC), under the direction of the San Diego Regional Energy Office. The Study was made possible by the funding and active participation of the City of San Diego (City), the County of San Diego (County), the San Diego County Water Authority (CWA), the San Diego Association of Governments (SANDAG), the Utility Consumers Action Network (UCAN), and the Port of San Diego (Port). SDG&E and other key stakeholders provided significant input, review, insights and valuable information to help identify and evaluate key infrastructure issues facing the San Diego region. This Study will be updated on an annual basis by the SDREO.

1.2 Regional Energy Infrastructure Study Goals

The goals of this study are the following:

1. To evaluate the relative attractiveness of new electricity and natural gas supply and demand management projects for meeting the region’s need for reliable and affordable energy resources.

2. To identify a more diversified energy supply and demand management portfolio, including the potential role for distributed generation and renewable resources.

3. To evaluate the potential role of local government agencies to collaborate in providing new energy supply and demand management projects that will enhance the region’s energy self-sufficiency and security and reduce future risk.

4. To evaluate the impacts and tradeoffs of these energy supply and demand options on the environment.

5. To consider the implications of the growing interdependence of San Diego and Baja California as an integrated bi-national energy supply and consumption region.

6. To evaluate supply and demand technologies and strategies from the standpoint of their ability to positively impact economic development and retain dollars in the region.

7. To evaluate energy resources that can enhance the region’s local control to meet future demand.

8. To identify major resource limitations that would significantly impact energy infrastructure development and the ability to meet regional energy needs.

9. Contribute to price stability and seek lower cost resources and options that help reduce upward price pressures for natural gas and electric supply and use.

\(^1\) This study addresses electricity and natural gas only. For the purpose of this study, the use of the term “energy” refers only to electric and natural gas use in the San Diego region. Transportation energy issues will be addressed in a future SDREO Study.

\(^2\) The “San Diego Region” for purposes of this study includes San Diego County and the Tijuana region of Northern Baja, Mexico.
1.3 Study Approach

The study approached electricity and natural gas issues from three perspectives:

1. **Supply/Demand** of the commodity itself
2. **Delivery/Capacity** of the infrastructure that serves San Diego natural gas and electric customers
3. **Pricing** of the commodity and its delivered cost to the customer.

The time-periods in which these areas are considered are:

1. **Short-term** (now to 2006)
2. **Mid-term** (2006 to 2010)
3. **Long-term** (post 2010).

The study involved a comprehensive review of data sources on regional economic and energy markets, a review of federal and state policies and programs, extensive modeling of electric and natural gas supply and demand options and a review of key natural gas infrastructure issues facing the region. This approach led to the identification of strategic and programmatic opportunities, options and recommendations. The conclusions reached in this study are intended to provide input into the development of a comprehensive Regional Energy Strategy (RES). This Strategy will be developed by the Regional Energy Policy Advisory Council (REPAC) involving the major energy stakeholders, as well as the public, to guide the region’s decisions on short-, mid-, and long-term energy initiatives.

The following activities were completed in the study:

- Extensive interviews and data collection from a variety of sources, ranging from project stakeholders to municipal agencies, community leaders, large commercial and industrial (C&I) end users, and other interested parties.
- Development of a set of scenario-based forecasts for natural gas and electricity, in addition to the modeling of power plant requirements of the Western States Coordinating Council (WSCC).
- Screening and evaluating the economic and system reliability impact of a diverse portfolio of energy efficiency, demand response, distributed generation and renewable resource investments and programs.
- Results of these analyses were used to identify and quantify the relative opportunities for energy infrastructure, end-use efficiency and distributed resource opportunities. This was accomplished through economic analyses that identified the avoided energy and capacity costs for electricity and estimated the unit energy supply curve cost for demand management options using net present value and levelized cost analysis.
- Ranking and prioritization of current and potential energy related projects was also developed for this study.

1.4 Organization of Report

Chapter 2 presents a situation analysis—which presents an assessment of the current energy environment of the region. Chapter 3 presents an analysis of gas supply and infrastructure issues and options. Chapter 4 presents a similar analysis for electricity issues and options. Chapter 5 discusses demand management issues and options, such as energy efficiency, demand response, distributed generation and renewable opportunities. Chapter 6 is an options and scenario analysis of balanced energy supply/demand to ensure adequate reserve margins and Chapter 7 presents a summary of key findings and implications.

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3 See http://www.sdenergy.org/planning/policy.html
2 Situation Assessment

2.1 Overview of the Region

2.1.1 Definition of the San Diego Region and the Changing Bi-national Energy Landscape

The San Diego region includes 18 local government jurisdictions within the County of San Diego. The San Diego region is unique compared to the rest of the state because of its proximity to Baja California, Mexico and their close integration with respect to trade flows, movement of people, and capital. Currently, there is a growing interdependency between San Diego County and Northern Baja California in terms of both the supply and demand of energy. Electric power transfers have taken place between California and Northern Baja California to some extent for more than 20 years and in the past few years, the bi-national supply and demand interdependencies have increased dramatically. Tremendous growth and unprecedented power plant development along the border in Mexico will continue to have a tremendous impact on the region’s energy supply and needs, as well as a potentially significant impact on the region’s environment. Additionally, while abundant renewable resources are located within the County, the available resources are much greater when the potential of surrounding counties and Baja California are considered. San Diego's economic and energy development future depends on bi-national as well as interregional cooperation and joint problem solving.

San Diego County experiences many unique challenges because of its “island-like” geographic situation, bounded by the Pacific Ocean to the west, the Laguna Mountains to the east, the Mexican border to the south and Camp Pendleton to the north. Because of this fact, there are significant supply issues and risks that the region is facing unless additional supply options are made available.

2.1.2 The Crisis of 2000-2001

In March 1998, the State of California implemented several fundamental changes to the structure of the electricity market to increase reliance on competitive market forces as a result of AB 1890, which was enacted as law 1996. Among other changes, the investor-owned utilities (IOU) were forced to sell their generation assets when the power market became unbundled. IOUs no longer would generate power, they would only deliver the power that they purchased. A majority of power purchases were made in the day-ahead market, which provided no long-term hedge against price volatility.

The opening of market trading created congestion and unnecessary cost increases. While San Diego and the rest of the State fared reasonably well for the first 2 years under regulated price caps, when the caps were lifted, prices steadily climbed as regulators were unable to react to suppliers and marketers who sought to maximize profits. Prior to 2000, while San Diego electric rates were higher than most regions of the country, they were the lowest electric rates in California, averaging about 9.7 cents per kilowatt-hour (kWh). As a result of industry restructuring, electric rates were expected to be
reduced by more than 10 percent. When price caps were lifted in 1999 in San Diego, retail prices soared nearly 50 percent. The average price continued to reach new heights during the winter of 2000–2001. At one point, the energy spot prices reached an all-time high of $1.50 per kWh while day-ahead prices exceeded $300 per megawatt-hour (MWh), as shown in Figure 2-1.⁸

![Figure 2-1: Average Weekly Electricity Prices at Palo Verde](image)

Rising electricity costs significantly added to the region’s costs for electricity, jumping from $1.7 billion in 1999 to more than $2.5 billion in 2001. Average electricity rates are anticipated to remain high levels through at least the end of this decade as shown in Figure 2-2.

Natural gas prices also began to rise in late 2000, particularly at the Southern California Border as shown in Figure 2-3. Before 2000 natural gas prices averaged about $2.50 per million British Thermal Units (Btus).⁹ In January 2001, gas prices climbed to close to $10 per million Btus with prices spiking above $50 in Southern California. As of May 2002, natural gas prices were near their 1998 average of $2.50.

This translated to a net additional cost of more than $2.5 billion for electricity and natural gas in 2000–2001. Through 2006, the estimated additional costs of electricity and natural gas for San Diego compared to historical prices are estimated to be more than $7.5 billion.

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⁸ California Power Exchange: http://www.calpx.org
⁹Todd Pedersen, California Energy Commission, Natural gas Price Data Files.
Figure 2-2: SDG&E System Average Price- Pre-2000 Forecast Compared to Current Forecast*

![Graph showing SDG&E System Average Price over years, comparing Current Forecast and Pre-2000 Forecast.]


Figure 2-3: Natural Gas Prices at the Permian Basin and the So. CA Border

![Graph showing natural gas prices at Permian Basin and So. CA Border over time.]

Source: Energy News Data

*These costs currently exclude the recently allocated CDWR contracts.
2.1.3 Uncertainty of Energy Supply to Support Economic Growth

San Diego’s economy and population expanded tremendously throughout the late 1990s. Likewise, so did its electricity and natural gas consumption. Despite this growth, power plant and transmission infrastructure development did not keep pace with load growth as utilities deferred infrastructure investment while anticipating industry restructuring for fear of new investments becoming “stranded,” meaning that they would not be able to recover full costs in the deregulated environment. Historically supply reserve margins\(^{10}\) were maintained at double-digit levels. During 2000–2001, reserve margins throughout California and the Western Systems Coordinating Council (WSCC) have steadily declined over time. In 2000–2001, California’s margins were frequently below 5 percent (which triggers a Stage 2 electrical emergency), and occasionally below 1.5 percent (which triggers a Stage 3 emergency and creates potential for rolling blackouts).

Subsequent to the bankruptcy of Enron and the revelation of the degree to which questionable trading and accounting practices have been used in the utility industry, valuations of energy companies have fallen tremendously. At the time of Enron’s bankruptcy, the aggregate exposure to Enron of all its counterparts was in excess of $6.3 billion.\(^{11}\) The day after Enron’s filing for bankruptcy, the market capitalization of the 10 most exposed firms dropped $4.2 billion, or an average of 10 percent. The slide in valuation of many of these companies has continued as is shown in Figure 2-4. As a result, the financial markets have tightened, restricting the ability for needed infrastructure development. Rating agencies are dictating the short and long-term strategies of many energy companies based on their level of debt/equity capital structure.\(^{12}\) It appears that the energy industry credit crisis will continue to be a primary driver of the availability of resources for at least the next few years.

Events of the recent past and the extreme uncertainty of the future suggest that the San Diego region and customers who depend on electricity and natural gas for their economic livelihood need to position themselves to be able to take positive steps to mitigate the effects of possible future energy market instability and volatility. It is tempting to assume that more natural gas-fired power plants and new transmission will help permanently solve the problems that exist. However, the continued patchwork and ad-hoc nature of generation, transmission and natural gas infrastructure development will likely lead to a sub-optimal balance of energy infrastructure development within the region. There is a need to take a more integrated approach to identify regional energy problems, investigate the options and trade-offs and reach regional consensus on what regional investment options should be made. A more balanced portfolio with greater local control will provide the region with a greater “hedge” against market imperfections and dysfunctions that can occur.

2.2 The Prognosis for 2002 and Beyond

The 2002 summer peak demand for SDG&E is expected to be 3,772 MW,\(^{13}\) assuming a 1-in-10 hot summer and a decrease in the voluntary consumer reductions experienced in 2001.\(^{14}\) Recent assessments indicate that there will likely be sufficient resources available in the next several years to

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\(^{10}\) Reserve margin is the percentage of extra generation capacity available and used by the system operator to adjust for fluctuations in load or other contingencies.


\(^{12}\) PUBLIC UTILITIES FORTNIGHTLY, July 15, 2002

\(^{13}\) While SDG&E electricity demand and consumption numbers are presented in this Study, San Diego County represents approximately 94 percent of the electrical consumption of SDG&E.

\(^{14}\) SDG&E forecasts as of October 2001.
meet state and local electricity peak loads and required operating reserves in the event of a hot summer. While these assessments assume the construction of new natural gas-fired and renewable resources that are expected to be online at specified periods, the outlook does not fully address the transmission problems of moving the electricity to the major load centers, including San Diego. Beyond 2002, the outlook also does not fully account for recent project cancellations and delays. Therefore, local area reliability issues will continue to be problematic in the near-term. Many financial and power analysts believe that California could face a significant power supply problem in 2004–2006 time period if the plants that were originally scheduled to be built in the state are not built soon. This is, in part, why the recent state contract renegotiation with Calpine Energy included an option for the State to intercede if Calpine’s best reasonable efforts do not result in the Otay Mesa Power Plant being built and operational by the end of 2004. The proposed Otay Mesa Power Plant will be discussed in more detail in Chapter 4.

The major risks that the region will be facing in so far as electric infrastructure is concerned are:

- Supply reliability from limited indigenous generation and transmission capacity into the region.
- Congestion and potentially higher transmission prices from importing power into the region as a result of locational marginal pricing (LMP).
- Inflated regional capacity values because of limited markets to sell “in-region” generation to the broader western market.
- Continued electric generation price volatility.

These and other issues must be addressed. The issues involve economics, finance, technology, and federal and state regulatory policy. The region must take on a greater role in framing these issues, proposing solutions, and be prepared to share in some of the investment. Key stakeholders in the region must be responsible for ensuring long-term goals are not sacrificed through short-term, reactionary fixes and incentives, which cannot be maintained and leave such policies open for criticism. Additionally, local stakeholders should be willing to share more responsibility in ensuring that the options and decisions proposed serve the broader public good—which may run counter to any one individual organization’s projects, values and strategic plans.

2.3 The Drivers of Energy Demand and the Need for Supply: The Region’s Demographics

2.3.1 Geography and Population

The County of San Diego, with a land area of 4,204 square miles, is the second largest county (by population) in California and the sixth largest county in the nation (by population). The 2000 census population of the County was 2,856,300 and it is projected to grow 38 percent to 3,948,300 by 2030.

From the 1980s to the 1990s, the rate of growth of population has diminished, while during the same time period, electricity consumption has grown by 29 percent (3-year rolling average rate of 3.4% per year), and natural gas consumption has grown by 36 percent (3-year rolling average annual growth rate of 2.9%). Figure 2-5 illustrates the trends in population, housing and employment versus electricity and natural gas consumption.

Figure 2-6 shows that per capita electricity consumption has been steadily increasing from 1990–2000. Then in 2001 with the electricity crisis, there was a significant drop in per capita consumption. It may take a few years for the older growth trends to resume.

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16 Congestion in the transmission system on critical paths prevents surplus electricity to flow to markets that have a deficit.
17 U.S. Census Bureau, 2000.
18 2030 Regionwide Forecast, SANDAG, March 2002.
Figure 2-5: Population, Housing, Employment, Electricity, and Natural Gas Consumption Growth Rates – Historical and Forecast

Source: SDREO

Figure 2-6: Per Capita Electricity Consumption (Indexed to 1990)

Source: SDREO
Tijuana is one of the fastest growing cities in Mexico, with a population more than 1 million. From 1980 to 1990, population grew by more than 60 percent and is projected to continue to grow at a similar rate until 2020, when the Tijuana population is projected to be larger than San Diego’s.

2.3.2 Economic Indicators: Employment, Gross Regional Product and Energy Intensity

San Diego’s gross regional product (GRP) is forecast to reach more than $125 billion in 2002, an increase of 6.5 percent more than an estimated $119 billion in 2001. Although the forecast for 2002 indicates a slower expansion rate, San Diego is expected to continue to experience strong economic growth.

2.3.3 Energy Intensity

Over the long-term, the region’s economy has become more efficient with respect to electricity and gas use, as measured by its energy intensity (the amount of Gross Regional Product produced per kWh or therm consumed) as shown in Figure 2-7. While it declined, then flattened in the 1990s (attributed to the waning economy and marginal improvements in energy efficiency during these years), it has improved significantly in the last 4 years, which is largely attributed to high growth of technology, tourist and service industry sectors combined with the high-degree of commercial conservation and energy efficiency that has been accomplished as a result of the energy crisis.

Figure 2-7: Electricity and Gas Energy Intensity (2000 dollars, Indexed to 1990)

The State of California as well as the U.S. Economy has been slowly recovering from a small economic downturn that started in 2001. Several economic studies have suggested that costs of the energy crisis, declining activities in the technology sector, a 20-percent fall in export demand, and the increased rate of unemployment have all contributed to declining demands for electricity in California.

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21 Inflation adjusted net increase of 1.8 percent.
in 2001. Recent economic statistics, however, indicate an increase in consumer spending, an increase in productivity, a reduction in business inventories, and an increase in business investment that will result in a recovery of demand. Many public and private studies have revised the near-term economic growth rate from less than one percent to about two and a half percent in 2002. It is most likely that the demand for electricity in California may increase in coming months because of a multiplier effect of the growing improvement in the general economic health of the State as well as the nation. This Study assumes that the significant reduction in energy demand that was experienced in 2001 due to the public’s response to the energy crisis will not fully be sustained in 2002. Psychological factors associated with potential summer blackouts are not expected in 2002, because of the improvements in the generation resource supply, moderation of prices and the significant reduction in visibility of the issue in the press.

2.3.4 Housing

Employment growth has been growing faster than population and housing, forcing people to live further inland and farther away from their jobs in San Diego County. In additional, most of the development is occurring further inland in hotter climate zones. The impacts on energy have been seen through these trends in the last 10 years. More (and larger) homes are being built inland in areas that require air-conditioning. Efforts to increase density and to promote re-development of urban areas should mitigate this trend somewhat. This reinforces the importance of fully integrating the Regional Energy Strategy with the region’s Regional Comprehensive Plan.22

2.3.5 Land Use, Economic Development and Energy Infrastructure Development

San Diego County has a very high quality of life and is an attractive location for technology-based industries. The development that has occurred to date has used virtually all of the available development areas along the coast. There will be a need to identify and hold valuable parcels of land for energy project development, including transmission right of way, co-location for more distributed resource development, and plant or facility siting that are close to transmission networks. For example, had the region worked cooperatively with Riverside County to “set aside” a transmission corridor in the early 1990’s, the subsequent development in that area may have taken into account a future significant infrastructure project mitigating the current challenges of siting the Valley-Rainbow Transmission Line (the proposed Valley-Rainbow Transmission Line is to be discussed in more detail in Chapter 4). For this reason, longer-term planning of energy infrastructure in the context of land-use planning is critical.

A key issue for this decade will be how the region helps influence a growth strategy that includes economic growth and sound planning for future energy infrastructure development.

2.4 Environmental Issues

2.4.1 Air Quality and Non-Attainment

San Diego County is in a non-attainment zone and all new major emission sources must be met with offsets from other sources in the county. San Diego Air Pollution Control District (APCD) Rule 20.3(d)(8) requires new stationary sources that will emit more than 50 tons per year of NOx and VOC to offset these emissions. The availability of NOx emission reduction credits (ERCs) is limited in San Diego, which is a significant barrier to the building of new power plants. Banked ERCs can be purchased or an interpollutant trade of VOC ERCs is allowed by Rule 20.3(d)(5)(vi).23

An offset market could be developed whereby future power plant developers would invest in other demand reduction opportunities in the county to create emission credits in order to use more combustible fuels, or power developers could co-invest in in-region efficiency and renewable efforts to create the offsets for power stations. For example, the Otay Mesa Power Plant that has been permitted for construction, created new ERCs by funding the conversion of diesel-powered trucks and

23 Sempra Energy has acquired emission credits for its proposed Palomar Generation Plant in Escondido through this mechanism.
boats with natural gas, thus creating Mobile Source Emission Credits (MSEC) through Rule 27. This strategy presents an opportunity for the region to continue to create more ERCs through continuing to repower vehicles while creating sorely needed ERCs and reducing the most significant emission source—vehicles.

In addition to emission issues, another primary concern relates to the siting of new plants, including peaking units. Power plants are not generally perceived as ideal neighbors and the transmission and distribution infrastructure required to support these plants create aesthetic and quality of life concerns with residents in the local community. Greater emphasis and incentive support associated with energy efficiency programs, consideration of wind energy, photovoltaics and load management can all help provide potential reductions in infrastructure cost, or at least defer expensive investments in new, larger fuel-burning facilities. However, while these options are generally less environmentally obtrusive than traditional power generation modes they typically have higher economic hurdles to overcome given the benefit cost analyses employed and typically exceed the short-term projections of market prices.

### 2.4.2 Water Quality and Availability

Power plants utilize less than one percent of the state’s water consumed. Increasingly, water constraints are affecting the siting and output of power plants, particularly in arid regions such as San Diego. To a large extent, power costs drive the supply cost of water due to pumping requirements to bring the water into San Diego County. Future new water sources, like desalination, will be energy intense processes that favor co-location to power plant development in order to be cost-effective. This, coupled with greater resistance to locating new energy facilities on the coast, increases the competition for water use. About 15,000 gallons of water per MWh is used by the new combined cycle gas plants being considered for San Diego County. This compares to more than double the rate for a central station boiler using once-through cooling. Water discharge from plants is a major concern due to both short and long-term impacts on ecosystems. Water-cooled power plants require National Pollution Discharge Elimination System (NPDES) permits to be renewed every 5 years by the Regional Water Quality Control Board. These issues are being raised regarding the future disposition of the South Bay Power Plant by the Environmental Health Coalition. The tradeoffs of air-cooling versus water cooling to reduce the water demand of electricity consumption will be discussed further in Chapter 4.

Section 316(b) of the Clean Water Act requires the Environmental Protection Agency (EPA) to ensure that the location, design, construction and capacity of cooling water intake structures for existing facilities with a design cooling water intake flow of 50 million gallons per day (MGD) or greater reflect the best technology available for minimizing adverse environmental impacts. On February 28, 2002, the EPA approved a proposed regulation that will establish location, design, construction and capacity standards for existing power plants that use the largest amounts of cooling water. The proposed regulation is designed to protect fish, shellfish and other aquatic life from being killed or injured by cooling water intake structures.

Earlier in 2001, EPA established standards for new facilities and manufacturers that withdraw more than two million gallons per day (MGD) from waters of the United States, if they use 25 percent or more of their intake water for cooling. New facilities with smaller cooling water intakes will still be regulated on a site-by-site basis. For facilities who choose certainty and fast permitting over greater flexibility, the rule sets standards to limit intake capacity and velocity. Facilities who locate where fisheries need additional protection must use special screens, nets or similar devices. Facilities

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24 The City of Carlsbad and the County Water Authority recently completed a feasibility study with Poseidon Resources Corporation for a 50-million-gallon-per-day desalination plant to be co-located at the Cabrillo Power Plant in Carlsbad. The energy demand for the plant would be approximately 35 MW, 1 percent of the entire region’s summer peak demand and by far the largest single facility demand in San Diego County.


26 Ibid.

27 http://www.epa.gov/ost/316b/ph2propfs.pdf
withdrawing less than 10 MGD are not required to reduce intake capacity, but must use special screens, nets or similar devices if they do not.28

2.5 Stakeholder Issues

At the beginning of this project, a series of interviews were conducted with key stakeholder groups and leaders of San Diego businesses, government and civic organizations to identify key concerns and perceived alternatives for the region to meet its future energy requirements. These opinions and assessments were considered in defining key regional issues and evaluating alternative infrastructure solutions for the region.

Some of the general areas of agreement among the stakeholders include the following:

- There is a leadership vacuum in the area of regional energy planning and coordination.
- Energy infrastructure investments in the region is often evaluated in a piecemeal and fragmented manner. Currently there is a need for a regional energy plan to better manage the dynamics of supply and demand.
- While the cost of energy is an important concern, the costs of failing to manage the system properly far outweigh the benefits.
- Greater sense of control and self-sufficiency is desired for meeting future energy requirements in the region.
- The region cannot rely solely on federal and state policies and assume that they will best serve the interests of the San Diego region.
- Conservation, load management, distributed generation and renewables should be an important part of the portfolio of solutions.
- Additional indigenous generation sources should be added to meet our needs and to reduce high-risk, over-dependency on imports external to the County.
- Redevelopment efforts should be used to enhance energy diversity and security. For example, new construction and redevelopment could be retrofitted with solar technologies to provide local supply and to reduce the burden on the energy infrastructure.
- Consideration for the environment should be a high priority, however, there is a concern for the restrictions air emission regulations place on the region’s ability to meet its energy needs.
- More public-involvement and transparency of options, costs, and tradeoffs are needed to evaluate major energy infrastructure projects.

There were also diverse opinions expressed about the following issues:

- Opinions are mixed on the type of market model that is best suited to the region’s needs. After the price shocks, market failures, and trading manipulations of the past 2 years, there is skepticism about how much of an open and competitive market there should be—recognizing the initial attempt was not successful. There is a strong tendency to support the return to traditional cost-based regulation. The current CDWR contracts and current regulatory directions for the restructuring of the gas industry suggest a trend toward cost based regulation is emerging—at least for some aspects of the electric and natural gas supply chain.
- The appropriate role for public agencies in planning and implementing the region’s energy future, including: full municipalization of systems within jurisdictions, community gas aggregation, ownership in generation assets, becoming more engaged in the implementation of public-good energy efficiency programs, and consideration of various Joint Power Agreements to promote regional alignment of strengths and assets (to be discussed more in Chapter 7).

28 http://www.epa.gov/ost/316b/316bph1fs.html
The tradeoffs associated with greater reliance on bi-national energy development projects. While many recognized development of supplies in Baja California as a positive means to meet demand, there is concern about dependency on energy projects in Baja California and the resulting environmental tradeoffs and compromises.

2.5.1 Key Stakeholders: Interests and Roles

The agencies that funded the study represent a broad cross-section of the region’s public interests. There are a number of other energy stakeholders that have considerable interests and leverage that could determine the makeup of the strategies and potential for future success. These organizations and other public, private, and government agencies and organizations are looking to this plan to provide the direction and leadership necessary to help define which path represents the best solution, given regional growth and energy market trends and local infrastructure conditions.

While the following list is not exhaustive, it highlights many of the strategic interests, roles and assets that will come into play and be described in more detail later in the study.

2.5.1.1 San Diego Regional Energy Office

SDREO performs a valuable function as the central clearinghouse for energy information for the region. Additionally, SDREO has an experienced staff with a growing role in designing and delivering energy programs in the region. The organization currently manages $17 million per year in funding for innovative energy programs, such as distributed generation, renewables, energy efficiency and demand response. SDREO will have an important role to play in delivering energy management services along with SDG&E, the City and County of San Diego and other agencies. SDREO’s charter is to serve the public-good in energy planning, program development and implementation. SDREO is empowered by SANDAG to develop and implement the Regional Energy Strategy.

For more information about SDREO, see http://www.sdenergy.org/.

2.5.1.2 Regional Energy Policy Advisory Council (REPAC)

REPAC is composed of voting members, and a number of advisory members. The voting members are appointed by their respective Boards or Councils representing the following organizations: County of San Diego, City of San Diego, SANDAG (North County Sub-region, North County Inland Sub-region, South County Sub-region, East County Sub-region), San Diego County Water Authority, San Diego Port District, SDREO, Utility Consumers Action Network (UCAN), Large Business Representative and Small Business Representative (both business representatives appointed by the San Diego Regional Chamber of Commerce). Advisory members include representatives of public and private entities that represent a broad cross-section of consumer and business interests, including, but not limited to: residential energy users, citizen interest groups, non-residential energy users, environmental groups, local governments, business representatives, economic development groups, Baja California representatives, energy service industries, transportation agencies, financial institutions, fuel and technology industries, educational institutions and local electric/gas utility.

Additional information about REPAC can be found at www.sdenergy.org/planning/repac.html.

2.5.1.3 County Water Authority (Water Authority)

Comments and concerns of the County Water Authority include the following:

- Concerned about electricity prices and grid stability due to the energy intensity of its operations and the potential impact of the cost of energy on consumer water bills.
- Interested in the role of the Water Authority in solving critical infrastructure challenges.
- During the height of the energy crisis, enabling legislation was approved by the state (SB 552) that allows the Water Authority to build power generation and provide the power to its...
constituency. Accordingly, the County Water Authority is now making a decision to build a 40-MW Olivenheim/Lake Hodges Pumped-Storage Project, which could be increased in size to provide 90 MW during peak periods.\textsuperscript{29}

- The Water Authority is considering other distributed generation projects to offset pump-station demand, such as the 4.5-MW Rancho Peñasquitos Pressure Control and Hydroelectric Facility.\textsuperscript{30}
- Potential for Federal tax savings if Water Authority builds infrastructure projects.
- Retains key competencies for planning and implementing critical utility infrastructure projects.
- Developing strategic water desalination projects\textsuperscript{31} that could enhance the value of future power plant siting.

For more information on the County Water Authority, see \url{http://www.sdcwa.org/}.

2.5.1.4 City of San Diego

Issues and concerns of the City of San Diego include the following:

- Strong commitment from Mayor, Council and staff to lead City toward greater “energy independence.”
- Large energy user and produces more than 14 MW through:
  - Digestester gas—4.57 MWs
  - Photovoltaic Systems that will produce more than 30 kW
  - SMML Hydro—1.3 MW
  - Evaluating new natural gas fired generation at nine locations
  - Privatized 10.2 MW of land fill gas and digester gas generation systems
  - Converting a 1,200-kW standby diesel generator to a dual fueled digester gas/diesel peaking unit
  - Has 2.2 MW of radio-dispatched, standby diesel generators that are setup to help avoid rolling blackouts
- Converting diesel trash trucks to LNG/diesel dual fuel.
- Dedicated and experienced energy staff to focus on energy policy and programs.
- Proven track record in energy efficiency implementation, including the completion of major energy efficiency upgrades in 65 existing facilities since 1995 resulting in annual energy savings of more than 45 million kWh.
- Completed traffic signal retrofits to high-energy efficiency LED bulbs in more than 1,400 traffic signals citywide reducing energy consumption by more than 12 million kWh per year.
- Sustainable Building Practices policy (900-14) establishes guidelines for efficient design in City buildings and provides streamlined permitting for private builders who exceed Title 24 by specified percentages.

\textsuperscript{29} More information can be found at \url{http://www.sdcwa.org/infra/cip.phtml#FEIR}
\textsuperscript{30} Conversation with the County Water Authority.
\textsuperscript{31} Currently evaluating the construction of a 50-million-gallon-per-day (MGD) facility at the Cabrillo Power Plant. The plant will have the ability to add an additional 50-MGD train in the future. If completed, the 100MGD facility could supply up to 17 percent of San Diego’s daily water supply.
The Purchase of Energy Efficient Products policy (900-18) establishes purchasing guidelines for City procurement, including purchasing Energy Star product when available.

More information on the City of San Diego Energy Program can be found at http://genesis.sanet.gov/infospc/templates/esd/index.jsp

2.5.1.5 County of San Diego

The County of San Diego in 2001 exceeded its ambitious targets for energy efficiency. It developed a Master Energy Plan that included recommendations for energy conservation, low-income assistance, development of a municipal utility district, the use of distributed generation technologies and a broad-based employee awareness program which resulted in the County reducing electricity consumption by more than 22 percent from July through September 2001. There is strong commitment from Board of Supervisors and staff to lead the County towards more public involvement in planning and control of energy infrastructure. Other noteworthy actions undertaken by the County include:

- Implemented demand-side management strategies including energy efficiency efforts that resulted in as much as a 50-percent energy use reduction over last year.
- Adopted “Green Building Policy” which provides a 7.5-percent permitting fee reduction and expedited plan checking/permitting for building projects that are built more energy efficiency than California’s strict building energy codes (Title 24) allows.
- The first regional jurisdiction to eliminate permitting fees for solar photovoltaic installations.

The County Board of Supervisors also serves as the San Diego Air Pollution Control District (APCD). The APCD Regional Air Quality Strategy, completed in August 2001, ensures air quality compliance through 2020. The plan does not specifically address energy infrastructure but does emphasize future reliance on new, clean technologies, especially for peaker units. The state has provided funds to help address and create an emissions credit bank, which is now depleted and needs to be replenished.

Looking toward 2020, the APCD does not endorse any specific energy mix but rather is a regulatory agency responsible for ensuring that energy sources comply with federal, state, and local standards for emissions of air pollutants using such tools as offset requirements, analyses, and permitting. State law and regulations require emission levels of smaller-scale, distributed generation systems units to meet the same criteria as central power plants by 2007. This is being enforced by the California Air Resources Board. The region also has a bi-national air quality alliance with Baja California that is supported by EPA, with a goal of increasing communication and planning in the broader regional context. 

More information on the County of San Diego or the Air Pollution Control District can be found at http://www.co.san-diego.ca.us/

2.5.1.6 Port of San Diego

The San Diego Unified Port District (Port) is a public benefit corporation established in 1962 by an act of the California State legislature and ratified by the voters of the five member cities of the Port. The enabling legislation and subsequent amendments conveyed certain tide and submerged lands within San Diego Bay and the oceanfront within the City of Imperial Beach to a unified Port administration to further the development of commerce, navigation, fisheries and recreation on behalf of the State of California, which owns the lands. The lands are conveyed to the Port as a trustee of the state.

The five member cities are Chula Vista, Coronado, Imperial Beach, National City and San Diego. The Port’s jurisdiction covers waterfront property within these cities and includes 2,795 acres of land and 3,034 acres of water.

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In 1999 the Port acquired the 690MW South Bay Power Plant (SBPP) from SDG&E and contracted with Duke Energy to manage and operate the 116-acre facility. In addition, the Port acquired from SDG&E a 33-acre site adjacent to the SBPP, site of the former LNG facility.

More information on the Port of San Diego can be found at http://www.portofsandiego.org/

2.5.1.7 San Diego Association of Governments (SANDAG)

SANDAG serves as the forum for decision-making on regional issues such as growth, transportation, land use, the economy, the environment, and criminal justice. SANDAG is governed by a Board of Directors composed of mayors, council members, and supervisors from each of the San Diego region's 19 local governments.

SANDAG's Regional Comprehensive Plan (RCP) is the region's growth management strategy that calls for an increase in the innovative mixed-use development already underway in the region's urban areas. Smart growth is the foundation for the RCP that is currently being prepared and is expected to be complete by the fall of 2003.

The Regional Comprehensive Plan will strengthen the integration of local and regional plans for land use, transportation systems, infrastructure needs, and public investments in a smart growth framework and in an interregional and international context. The regional plan will include elements such as transportation, housing, economic prosperity, open space, water supply and quality, air quality, energy, border issues, and urban design.

More information on the SANDAG can be found at http://www.sandag.org/.

2.5.1.8 Utility Consumers Action Network (UCAN)

Primary consumer advocate group in San Diego whose role is to represent the interests of residential and small business utility customers in the region. The organization is a major “watch dog” for consumer protection and prudent regulatory and utility policy for consumers. UCAN is very well networked in the state and it has a good grasp of energy policy and regulatory issues. It also has very good insights on the energy supply and demand issues in the County. Key issues raised by UCAN in the interviews were the following:

- The San Diego region is seriously disadvantaged by the absence of a regional energy plan or an entity accountable for implementing such a plan. There is a need to consider a strong role of energy efficiency, distributed generation and renewables and there is a large potential for these options over the Study period.
- Disjointed and questionable decisions are being made by the State and local utilities about long-term infrastructure investments that may disadvantage the San Diego region for decades to come.
- Additional bi-national solutions should be considered beyond the traditional supply-side and some growth cooperation.
- The economic development and employment impacts of emerging energy technologies in generation, energy efficiency and demand-side usage could contribute to San Diego's future economic prospects.

More information on UCAN can be found at http://www.ucan.org/

2.5.1.9 Other Regional Stakeholders of Note

**Sempra Energy**

- Owns both San Diego Gas and Electric Company and Southern California Gas Company, which is the largest natural gas distribution company in the United States.
Large enterprise-wide energy holding company, which including trading operations, power energy services and plant development.

- Strong commitment to developing supply resources in the region, with proposed power plants in San Diego (Escondido) and Baja California.
- Co-developed Baja Norte pipeline in northwestern Mexico.
- Potential developer of LNG facility in Baja California.

The two most visible Sempra affiliates that will affect San Diego County’s energy future are Sempra Energy Resources and Sempra Energy International. These two unregulated companies are rapidly establishing their presence in the region with several high-profile projects. The Baja Norte pipeline is the near-term project that is highly visible. Sempra Energy International has a 30-percent stake in that pipeline. One of the LNG plants being proposed in Mexico also has Sempra Energy International as a principal.

Sempra Energy Resources is a major contractor with the State of California for electric energy over the next decade. Sempra Energy Resources also has planned a 500-MW facility in Escondido, in northern San Diego County. Sempra Energy Resources has also announced a major interstate pipeline project for the Southwest.

**San Diego Gas & Electric**

- Owner and operator of electricity transmission, distribution and natural gas distribution infrastructure.
- Administers strategic energy efficiency programs and in the region.

**City of Chula Vista**

- One of the most proactive cities in the region in terms of energy programs.
- Adopted Carbon Dioxide (CO2) Reduction Plan in November 2000 with goal of reducing CO2 emissions in City operations by reducing fossil-energy consumption.
- Adopted a City Energy Plan to address long-term energy issues and protect Chula Vista constituents from unreliable energy supply and volatile prices. The Plan includes aggressive programs that address demand side management, energy efficient and renewable energy outreach programs for businesses and residents, energy acquisition, power generation and distributed energy resources and legislative actions.

**City of San Marcos**

Have formed a municipal utility to provide electric distribution and aggregate gas supply to businesses and citizens.

The City’s current Charter, approved by voters in 1994, allows the formation of a municipal utility. A municipal utility was formed in August 2000 and named the Discovery Valley Utility (DVU). The City has a power supply option from the Magnolia Power Plant, which is currently under development, to secure a low-cost supply of power in the future.33

**U.S. Navy Region Southwest**

As the largest energy consumer in the region, has implemented a comprehensive and aggressive energy management program that saved 14.7 MW, 57 million kWh and 1.7 million therms in fiscal year 2000–2001.

**Duke Energy**

Duke operates the South Bay Powerplant under contract to the Port of San Diego. Under this contract, Duke must find a suitable location for a replacement plant by 2006 and have a new plant

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33 City of San Marcos, Electric and Gas Utility Options Study, conducted by EES Consulting, February 2002
operational by December 31, 2009. Duke owns the air emission offset credits associated with the SDG&E sale of the SBPP, air credits arising from any improvements or modifications, and air credits resulting from the SBPP closure. If Duke proposes to sell or convey to any third party any portion of the air credits, Duke has agreed to offer the Port the right-of-first refusal (except in connection with the transfer of rights and interest with respect to a replacement generation plant, with the Port’s consent).

NRG/Dynegy

NRG/Dynegy own and operate the Cabrillo Powerplant located in Carlsbad and several peaking units throughout the County.

2.6 Challenges, Threats and Opportunities

Based on the above review of current external trends, policies, the prevailing energy supply landscape, and taking into account the insights gained from the key stakeholder interviews, the following section discusses the strengths, weaknesses, opportunities and threats for the San Diego region as outlined in the following table and addressed in this study (See Table 2-1).
<table>
<thead>
<tr>
<th>Issue</th>
<th>Challenge/Threat</th>
<th>Opportunity</th>
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| Planning | No comprehensive and integrated regional energy planning mechanisms now exist. This leads to reactive positions, suboptimal infrastructure and high risk from market volatility.  
A cohesive regional vision on the alternative and most preferable energy supply and demand options and infrastructure investment implications is missing.  
Cohesive and integrated regional energy policies and programs are lacking. There is considerable collaboration, but little in the way of organized processes for identifying issues, evaluating the issues, selecting a solution and implementing electricity and natural gas supply and demand programs.  
Current energy infrastructure decisions are evaluated in an isolated, fragmented manner—and often without public and community discussion. For example, electric transmission issues need to be evaluated in light of broader Southern California generation needs. The State of California has focused on short-term solutions, many with long-term implications (e.g., CDWR long-term contracts for supply). There is a need to start addressing regional energy supply/demand balancing issues and in light of evolving market design models.  
Evaluate hedges and options to market volatility  
The region being a major military center needs to diversify supply options, seeking both central generation based and distributed based resources. | Local city, county and regional governing bodies are currently highly sensitized and active in formulating policy and programs for energy efficiency and alternative resources. There is a need to solidify this activity into a robust regional energy strategy that looks comprehensively at the best integrated solutions for the region.  
Formulate a regional vision on energy strategies for supply development, distributed resources, demand reduction, energy conservation, use of existing renewable resources, energy storage systems and distributed generation options.  
Create a regional energy policy body and organize an active lobbying effort to better represent regional electricity and natural gas supply and demand policies, as the state is developing its own policy and programs. This process should also include SDG&E and other power development interests in the region including Mexico.  
Develop an energy strategy and plan that takes into account broad regional energy infrastructure solutions.  
The region needs to work to limit no more than one half of its electric and natural gas resource portfolio to market price volatility. This suggests a strong role for public-private partnerships in generation and transmission asset development and a strong role for conservation and renewable energy resources.  
Create a renewed energy conservation, distributed resource and load management ethic in the region to meet a substantial amount of new growth over the next 30 years from non-traditional supply sources. |
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<th>Issue</th>
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<td>Policy</td>
<td>Lack of coherent statewide natural gas and electricity policy and continued failure of state to address fundamental capacity and pricing issues in state.  Strong local government policy and regulation may be needed to influence regional growth and ensure that the building stock becomes very efficient.  A growing FERC role in the West is anticipated regarding market design and infrastructure development.</td>
<td>San Diego Region needs to seek control over its own energy destiny and not assume that Sacramento, San Francisco or Washington, D.C., have the best solution.  Great need to do policy papers and briefs on key regional infrastructure and regulatory initiatives like BCAP and GIR, and market, capacity credits and other critical regulatory initiatives.  The region needs to more closely track FERC rulemaking and evaluate potential FERC initiatives and how beneficial they are to San Diego County.</td>
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<tr>
<td>Organization</td>
<td>There is a significant amount of fragmentation and diverse opinion among state agencies. The region needs to be sure that local issues and concerns are adequately addressed in these deliberations. Currently, there is no coordinated regional effort to engage the many state and federal processes. Monitoring these proceedings will require dedicated resources and close coordination of effort among local agencies and stakeholders.  Given the growth in Northern Baja and Tijuana there is a risk for further environmental decay in the Imperial Valley and a risk to the quality of life for the entire region.  Future power plant development is at risk in the county and state unless the state implements policies and programs to continue to stimulate new plant development, along with conservation and renewable resources.</td>
<td>The region currently has a strong set of civic and business organizations and an active local government and interagency collaboration to pave the way for a strong regional energy policy and program.  The region needs to crystallize its view on energy supply and demand matters and work closely with state and federal policy makers to ensure that the “right” policies are being proposed that are beneficial to the San Diego region.  Identify and evaluate additional sources of regional power supply options, perhaps through a joint power authority (JPA) or through existing organizations such as the County Water Authority.  The region needs to gain the cooperation of Tijuana and other governmental entities in Northern Baja California regarding carefully planned energy strategy development and policies that use best available technology and also embrace a strong distributed and renewable energy future.  The policies of the CEC, CPUC and CAISO need to be closely scrutinized to ensure that an adequate supply of local generation occurs and is properly interacted with the larger WSCC market.  There is a need to ensure that local take away capacity is properly managed and costs controlled for natural gas. The closer natural gas infrastructure gets to local markets, the less competition and choice exists.</td>
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Table 2-1: Strengths, Weaknesses, Opportunities, and Threats for the San Diego Region (continued)

<table>
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<tr>
<th>Issue</th>
<th>Challenge/Threat</th>
<th>Opportunity</th>
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| Binational and Interregional | Quality of life and environment are at risk from significant new plant development in Northern Baja, Mexico. | A strong regional orientation that embraces Baja California as an integral part of planning for infrastructure development.  
Proximity to Mexico and its land resources and power development projects creates an opportunity to broaden power supply options—mutual dependency of energy infrastructure and supply investments is a benefit.  
Need to use U.S. trade and other foreign aid to encourage use of best available technology and energy efficiency and load management South of the Border. |
| Business and Industry      | Future job growth and overall community growth will be at risk if the past energy shocks continue in the future. In fact, the entire state is at risk. | The region enjoys a strong presence of innovative energy technology firms within the County (e.g., Solar Turbines, SAIC, SeaWest, AstroPower, Maxwell Technologies, Metallic Power, General Atomic, Cannon Power Corporation). These resources and additional energy-related businesses form a solid foundation for potential economic development opportunities surrounding emerging trends, such as distributed energy, energy storage and advanced energy generation.  
A robust, diversified, service economy with some significant manufacturing in traditional and computer electronic areas exists. |
| Economic Development       | Centralized energy systems create outflow of income and cost jobs versus more distributed energy technologies, which are more labor intensive. The region already has a strong energy technology base and this should be leveraged. | Local businesses that are not as significantly impacted by rising energy cost should be promoted.                                                                                                                                 |
| Environmental              | Emission ceilings have been reached and the region requires offsets for new, significant emissions. This will make future power plant development in the region very expensive.  
Some plants being developed in Mexico are not using best available technology. | Creation of air pollution offsets through implementation of energy efficiency, renewables and replacing polluting vehicles with cleaner, economically viable technologies. A bid and trading market could also be created. However, emission reductions may qualify only if they comply with EPA and APCD requirements. |
### Table 2-1: Strengths, Weaknesses, Opportunities, and Threats for the San Diego Region (continued)

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<tr>
<th>Issue</th>
<th>Challenge/Threat</th>
<th>Opportunity</th>
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<tbody>
<tr>
<td>Supply</td>
<td>Electrical and Gas system needs expansion to manage growth.</td>
<td>The region led the nation in the installation of cogeneration systems in the early 80’s prior to the technologies demise by restructured electric rates. The engineering and contracting knowledge is available in San Diego for accelerated development of small-scale, distributed generation.</td>
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<td></td>
<td>Lack of sufficient energy infrastructure investment in the County and limited transmission capability can create severe economic dislocation due to an outage of a major energy infrastructure facility.</td>
<td>SDG&amp;E has well defined interconnection requirements, and in recent years, has been cooperative towards interconnection requests.</td>
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<td>Trading and capacity risk must be controlled. This risk is now being addressed in the market model discussions of the state and FERC. The state needs to participate in this process.</td>
<td>There needs to be more infrastructure development in terms of both generation and transmission in the region.</td>
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<td>Capacity values being too high due to limited markets to sell the generation to unless additional transmission is built.</td>
<td>Need to secure a diverse portfolio of gas and electric options, including energy efficiency, demand response and renewables/DG.</td>
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<tr>
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<td></td>
<td>A public process is needed to help review and evaluate regional transmission investment requirements and options.</td>
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<tr>
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<td></td>
<td>Region needs additional transmission—the key question is when, where, and how best to develop it considering new generation options.</td>
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2.7 The Challenges of Market Design and Performance

The current market structure is being modified in order to ensure that adequate generation is available in a timely, efficient and sustainable manner. Although market design is largely out of the hands of San Diego, there may be an opportunity to influence the process to ensure future needs and interests are properly addressed. Further exploration is needed to determine the most effective capacity payment options, i.e., implementation of capacity surcharges tied to energy purchases, requiring loads to obtain reserve capacity, government intervention through purchase of facilities or contracts, or utility ownership of reserve capacity. California and San Diego County remain in a very serious supply and infrastructure situation. Also, FERC recently completed an audit of California-Independent System Operator (CAISO) activities and will soon decide on its independence and appropriate role in the market.

Several issues that remain include:

- It appears that California and the market are not building enough generating capacity. The boom/bust cycles in the power industry demonstrates that mixed markets and development paths are needed, and that close oversight of reserves is needed by Governments.
- The state lacks a capacity market that is sufficient and liquid—delays in forming a market for capacity may exist until late 2003-2004.
- Limited new transmission has been built in the state to alleviate congestion.

The CAISO and the Federal Energy Regulatory Commission (FERC) have been working on various proposals that would affect California’s future market design. The CAISO’s Market Design 2002 (MD02) is a proposal that attempts to address flaws in the current market structure. The goal is to improve reliability of the grid, establish better locational signals that encourage power plants to be built where they are needed most, to address congestion on the transmission system, and to give the ISO new market power mitigation tools.\textsuperscript{34}

It is not clear that the CAISO proposal for a standard market model will be accepted by FERC. FERC has made it clear that it is going to be a more active participant in monitoring and guiding California wholesale electric and infrastructure. While no formal decisions have yet been made, FERC is not satisfied with the progress California is making on infrastructure development. Greater FERC oversight and initiatives to better integrate California into the broader Western power market will likely occur. Should supplies not develop within the county and in the State, better integration into the Western Power Market could help moderate prices. Also, as FERC has noted, a stronger capacity market needs to be developed in California. In addition, a more dynamic and price responsive load management market is needed as is being used in other regions like the Northeast’s PJM pool—which is often viewed as a superior market model.

Flaws in market design and rules have been a major factor leading to excessively high prices for electricity. In addition, overzealous trading and gaming practices and the lack of regulatory scrutiny contributed to this issue. There appears to be excessive regulation affecting power plant development in the state, and there appears to be excessive reliance on traded wholesale power in the state. Until recently, FERC has not been vigilant in policing market performance. Now, with the new market design rules forthcoming, FERC wants to create a more standard model for market design vis à vis the creation of regional transmission organizations (RTOs). This will have a significant impact on the development of future markets.

Additional resources will be needed including the development of sufficient transmission and reserve capacity to move the power from the producing markets to consumers. In addition, more reserves are needed. Presently, the state has 7 percent or less reserve. Industry experts estimate that between 15-to 30-percent reserves are required to ensure reliability and stabilize prices. Moreover, FERC and

\textsuperscript{34} Source: http://www.caiso.com/docs/09003a6080/16/59/09003a60801659b5.pdf
the ISO are recognizing the value of creating economic and emergency capacity markets that should stimulate significant demand response programs and incentives to invest in distributed generation.\textsuperscript{35}

The State of California also has to realize the need to stimulate more in-state generation to avoid price volatility in the coming years. Currently, the investment community considers California high risk for the development of power plants and investments. Unless new initiatives and proposals from state and federal authorities improve current conditions, infrastructure development will remain difficult to accomplish. Also, the state needs to investigate ways to lower the overall cost of infrastructure development in the state. The cost of gas service in California is also very high, in spite of extensive CPUC regulation of intrastate gas movements.

A coherent market design will need to be advocated in multiple forums, including FERC, the CAISO, California Public Utilities Commission (CPUC), California Power Authority (CPA), and California Department of Water Resources (CDWR). New California laws will be needed to facilitate the new design and to replace the many short-term fixes that were legislated to handle immediate crises. While needed at the time, such approaches may be counter-productive in a redesigned market.

While the policy and market development activity is under way at the state and federal level, the region cannot afford to wait for the outcome. Serious consideration must be given to addressing the region’s own energy infrastructure development issues. In addition, the region has to take a careful look at its own infrastructure needs and what market models can best serve the region. This may include development of additional hedges or options given the market models being proposed. This does not imply that the region will ever be completely independent of the wholesale market, but the events of the past 2 years show that the risk of total reliance on an open market model without any buffer or options is an unnecessary risk that can be managed.

\textsuperscript{35} The ISO recently approved payments for load reduction in the summer of 2002 and has an Aggregated Distributed Generation Pilot Program (ADGPP) that will aggregate distributed generation units to allow the output to be sold into the market just like any other power source.
3 Natural Gas Demand, Supply and Infrastructure

3.1 Summary Findings

This chapter examines issues regarding the demand and supply of natural gas for the San Diego region. The western United States, and especially California, are undergoing a tremendous increase in demand for natural gas as plans unfold to build several thousand megawatts of new natural gas-fired electric generating capacity.\(^1\) This level of development raises questions about the ability of the region’s gas delivery system to meet this new demand without adverse consequences for existing natural gas consumers.

There are three main areas in the analysis of natural gas issues for the region:

1. **Supply/Demand** of the commodity itself
2. **Delivery/Capacity** of the infrastructure that serves San Diego gas customers
3. **Pricing** of the commodity and its delivered cost to the customer.

The significant gas issues facing the San Diego region are prioritized in this summary within three time-periods, with the main area indicated. Depending on the end-use customer’s perspective (or the utility’s, or other market participant’s), the overall importance of these summary findings will be different, e.g., core customers may consider long-term supply and price stability issues the most important for understandable reasons. The distinctions between residential and non-residential gas use, or “core and noncore use” of gas is where the most controversy has historically been in the three main areas analyzed. The simple fact is that it will continue to remain that way in the gas industry as long as these customers share this same commodity and same delivery system infrastructure. Within the long-term time frame of this study, the multitude of competing core/noncore gas interests are expected to remain in place.

3.1.1 Short-Term Findings (Now to 2006)

The most important findings that face the San Diego region in the short-term are:

- **Supply/Demand and Delivery/Capacity and Pricing**—A significant challenge will be resolving and managing the disparate gas interests of two primary gas customer classes, namely residential (core) and non-residential (noncore, especially major Electric Generators). This issue has been in place since the unbundling of gas began more than 15 years ago in California. These issues will increase in the future due to capacity and supply constraints and increased cost pressures.

- **Pricing**—Significant regulatory changes are currently underway as part of the implementation of the Gas Industry Restructuring (GIR) proceeding and delayed Biennial Cost Allocation Proceeding (BCAP) that will affect the manner in which gas transmission costs are set and services are provided by the gas utilities in southern California. Although temporarily delayed until 2003, potential BCAP issues such as a return to embedded-cost pricing, elimination of resource plans, required long-term (15-year) commitments by noncore customers, peaking tariffs, and incremental pricing for capacity expansions will most likely all be revisited and litigated. Adequate representation of San Diego gas customers is crucial to protect the interests of the region.

- **Delivery/Capacity**—There is sufficient regional natural gas transmission and distribution capacity to serve core customers for the next 10 to 20 years.

- **Delivery/Capacity**—The completion of the Baja Norte pipeline in Mexico within the year may help mitigate any capacity constraints on the SDG&E system. The degree to which this supply line will serve SDG&E gas load is uncertain.

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\(^1\) A total of 2,554 MW of new generation was added within the CAISO control area in 2001 and an additional 2,961 MW of generation is expected prior to June 2002. (CAISO 2002 Summer Assessment, Version 1.1, May 2002.)
Supply/Demand—Projected gas demand growth for electric generation (EG) is unclear, but may be as high as 60 percent of new gas growth. This also has significant implications on capacity and pricing.

3.1.2 Mid-Term Findings (2006–2010)

Supply/Demand—Expediting the re-powering or replacement of the two existing inefficient large generation plants in the region would increase the region’s gas efficiency dramatically, possibly delaying the need for capacity expansions. The South Bay plant is scheduled to be replaced by a state-of-the-art plant by 2009, but there appears to be little incentive for the owners of the Cabrillo Power Plant to improve its efficiency. Additionally, there are many other opportunities to implement natural gas efficiency measures, including water heater insulation blankets, commercial boiler tune-ups and replacements, solar hot water heating in domestic and commercial hot water systems and pool heating.

Supply/Demand—The construction of LNG plants in Mexico will potentially come on line during this period and the extent that they will provide gas supply or other services to SDG&E and its customers is an important issue for the region.

Delivery/Capacity—Near the end of the decade, capacity adequacy is less certain, however, it appears that SDG&E is prepared to respond to the expanding needs of the distribution system in a manner that would prevent curtailments and provide firm service. Non-core users, however, will have to pick up much of investment risk in the future.

3.1.3 Long-Term Findings (Post 2010)

Supply/Demand—A significant risk in the long-term is adequacy of gas supply. Natural gas production in the United States will likely peak between 2015 and 2020 leaving a power generation infrastructure that is dependent on a declining national resource.

Delivery/Capacity—In the period between 2010 and 2015, SDG&E gas infrastructure expansion will most likely be necessary. Of the potential pipeline expansion projects SDG&E has evaluated, one in particular stands out as the most beneficial to the region, the Rainbow to Santee 30-inch pipeline. This project would significantly improve system reliability, especially in time of emergencies or when other transmission lines are in need of maintenance. It is currently estimated to cost $90 million to construct, however it would add as much as 170 million cubic-feet per day (MMcfd) to the capacity of the system, approximately a thirty percent increase in system capacity.

3.2 Natural Gas Demand, Supply and Prices

3.2.1 Natural Gas Consumption and Growth

Figure 3-1 shows the historical 5-year growth rates for natural gas demand for San Diego for 1981 through 2001.

3.2.2 Natural Gas Demand Forecast

For the 2002–2006 time period, natural gas demand is projected to grow by between 1.5 and 2.5 percent per year. Growth rates for the region (including Baja California) will be much higher due to the high growth in Baja California, which is expected to be as much as 9 percent per year for the next 9 years. Beyond 2006, average growth rates of natural gas are expected to be about 1.2 to 1.6 percent per year. Natural gas will grow from 1,439 million therms (MMtherms) in 2001 to 1,600 MMtherms in 2006, and to 2,032 MMtherms in 2030 as shown in Figure 3-2.
Figure 3-1: Natural Gas Demand 5-Year Growth Rates

Figure 3-2: Natural Gas Consumption

Natural gas historical and projected consumption by sector is illustrated in Figure 3-3, which clearly shows that a) electric generation is likely to experience the future growth and be the most variable; and b) there is minimal variability in residential and commercial demand and the overall growth rates are more modest. Figure 3-4, which represents the recent historical natural gas demand for utility and non-utility generators also illustrates the volatility and high growth that is a result of power plant development.

Appendix E presents the historical and forecast natural gas consumption by scenario. Growth rates used through 2006 are 1.5, 2.0, and 2.5 percent for the low, medium and high scenarios, respectively. For years 2007 and beyond, growth rates used are 1.0, 1.2, and 1.6 percent for the low, medium and high scenarios, respectively. The primary driver for gas demand in the near-term is business growth as a result of the recovery from the economic recession, longer-term growth is driven primarily by power plant demand. While new electric generation plants brought on-line during this period will significantly increase demand, older plants that are repowered could produce a net reduction in demand due to higher plant efficiencies. Another driver for growth is the anticipated increase in the use of natural gas for cogeneration.
While residential use of natural gas may grow at a modest rate of about 0.5 percent, commercial and industrial uses are projected to grow at a much higher rate of 2.0 to 5.0 percent per year.\(^2\)

\(^2\) The 5\% growth rate is provided by SDG&E.
3.2.3 Natural Gas Prices

The California Public Utilities Commission (CPUC) regulates retail rates. Table 3-1 compares retail natural gas price increases by customer use. Residential customers pay the highest rates, followed by commercial and industrial customers.

Table 3-1: Retail Natural Gas Price Estimates ($2002/MM Btu)*

<table>
<thead>
<tr>
<th>Year</th>
<th>Core Residential</th>
<th>Core Commercial</th>
<th>Core Industrial</th>
<th>Non-Core Commercial</th>
<th>Non-Core Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>$9.66</td>
<td>$9.01</td>
<td>$7.07</td>
<td>$5.92</td>
<td>$5.92</td>
</tr>
<tr>
<td>2001</td>
<td>$10.36</td>
<td>$9.58</td>
<td>$7.64</td>
<td>$6.27</td>
<td>$6.27</td>
</tr>
<tr>
<td>2002**</td>
<td>$9.33</td>
<td>$8.59</td>
<td>$6.76</td>
<td>$5.46</td>
<td>$5.46</td>
</tr>
<tr>
<td>2003</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2004</td>
<td>$6.72</td>
<td>$6.01</td>
<td>$4.22</td>
<td>$3.06</td>
<td>$3.06</td>
</tr>
<tr>
<td>2005</td>
<td>$6.57</td>
<td>$5.89</td>
<td>$4.19</td>
<td>$3.11</td>
<td>$3.11</td>
</tr>
<tr>
<td>2006</td>
<td>$6.44</td>
<td>$5.79</td>
<td>$4.16</td>
<td>$3.13</td>
<td>$3.13</td>
</tr>
<tr>
<td>2007</td>
<td>$6.52</td>
<td>$5.86</td>
<td>$4.21</td>
<td>$3.19</td>
<td>$3.19</td>
</tr>
<tr>
<td>2008</td>
<td>$6.61</td>
<td>$5.94</td>
<td>$4.26</td>
<td>$3.25</td>
<td>$3.25</td>
</tr>
<tr>
<td>2009</td>
<td>$6.70</td>
<td>$6.02</td>
<td>$4.32</td>
<td>$3.30</td>
<td>$3.30</td>
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<tr>
<td>2010</td>
<td>$6.55</td>
<td>$5.89</td>
<td>$4.27</td>
<td>$3.31</td>
<td>$3.31</td>
</tr>
<tr>
<td>2011</td>
<td>$6.57</td>
<td>$5.92</td>
<td>$4.29</td>
<td>$3.36</td>
<td>$3.35</td>
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<tr>
<td>2012</td>
<td>$6.67</td>
<td>$6.01</td>
<td>$4.35</td>
<td>$3.42</td>
<td>$3.41</td>
</tr>
<tr>
<td>2013</td>
<td>$6.68</td>
<td>$6.03</td>
<td>$4.39</td>
<td>$3.49</td>
<td>$3.48</td>
</tr>
<tr>
<td>2014</td>
<td>$6.74</td>
<td>$6.09</td>
<td>$4.45</td>
<td>$3.55</td>
<td>$3.54</td>
</tr>
<tr>
<td>2015</td>
<td>$6.79</td>
<td>$6.13</td>
<td>$4.50</td>
<td>$3.61</td>
<td>$3.60</td>
</tr>
<tr>
<td>2016</td>
<td>$6.79</td>
<td>$6.15</td>
<td>$4.54</td>
<td>$3.65</td>
<td>$3.65</td>
</tr>
<tr>
<td>2017</td>
<td>$6.82</td>
<td>$6.20</td>
<td>$4.58</td>
<td>$3.71</td>
<td>$3.71</td>
</tr>
<tr>
<td>2018</td>
<td>$6.87</td>
<td>$6.23</td>
<td>$4.62</td>
<td>$3.78</td>
<td>$3.77</td>
</tr>
<tr>
<td>2019</td>
<td>$6.92</td>
<td>$6.28</td>
<td>$4.67</td>
<td>$3.83</td>
<td>$3.83</td>
</tr>
</tbody>
</table>

Source: SDG&E.

* 2003 price data not available for short-term forecast years. Only appears as long-term forecast.

** Source: CEC. Years 2000 to 2003 represent the short-term forecast and 2002 to 2019 represents the long-term price forecast.

Table 3-2 shows the various components and the sensitivities of the retail cost to price variations. These costs are for a typical electric generator in San Diego, core and other smaller customers pay much higher delivery costs on the two Sempra LDC systems. The data show that wellhead prices of natural gas and interstate pipeline charges are the two most expensive and volatile components of the natural gas supply chain.

Commodity gas prices are unregulated and in the long term are largely a function of national and international supply, which is a function of exploration, drilling and extraction. The amount of exploration and drilling is a function of price at the wellhead. Over the shorter term, commodity prices are a function of the relative level of storage, pipeline deliverability capacity, as well as weather effects. This relationship can be seen in Figures 3-5 and 3-6, which compare the Price of Natural Gas at the Permian Basin to Storage Levels over the same time period.
### Table 3-2: Natural Gas Cost Component Range and Variability Factors
(Typical Noncore Electric Generator Costs)

<table>
<thead>
<tr>
<th>Category</th>
<th>Current Cost $/Dth</th>
<th>Variability Percent (Forecast)</th>
<th>Variability Cost $/Dth</th>
<th>Variability Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply Basin Wellhead Cost (Southwest USA)</td>
<td>$2.50</td>
<td>-20 to +60</td>
<td>$2.00 to $4.00</td>
<td>Reserves/demand</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Production rates</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Drilling rig count</td>
</tr>
<tr>
<td>Interstate Pipeline Charges (Including third-party deliveries at California border)</td>
<td>$0.30</td>
<td>-50 to +10,000</td>
<td>$0.15 to $30.00</td>
<td>Total Capacity Demand</td>
</tr>
<tr>
<td>LDC Costs (Sempra Utilities)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission</td>
<td>$0.10</td>
<td>-10 to +100</td>
<td>$.09 to $.20</td>
<td>CPUC policies on cost</td>
</tr>
<tr>
<td>Storage/Balancing</td>
<td>$0.00</td>
<td>+100 total</td>
<td>$.00 to $.20</td>
<td>allocation/rates</td>
</tr>
<tr>
<td>Distribution/Customer Service</td>
<td>$0.05</td>
<td>-20 to +200</td>
<td>$.04 to $.15</td>
<td>Market Power</td>
</tr>
<tr>
<td>Other</td>
<td>$0.05</td>
<td>-20 to +300</td>
<td>$.04 to $.20</td>
<td>EG demand growth</td>
</tr>
<tr>
<td>Sub-Total</td>
<td>$0.20</td>
<td></td>
<td>$.17 to $.75</td>
<td></td>
</tr>
<tr>
<td>TOTAL Burner Tip Cost</td>
<td>$3.00</td>
<td>-22% to +1060%</td>
<td>$2.33 to $34.75</td>
<td></td>
</tr>
</tbody>
</table>

**Figure 3-5: Natural Gas Price at the Basin**

[Graph showing natural gas price at the basin from 2000 to 2002.]

Source: California Energy Markets

**Figure 3-6: Natural Gas Storage Levels**

[Graph showing natural gas storage levels from 2000 to 2002.]

Source: Energy Information Agency
Recent low gas prices can be attributed to current high levels of storage. Industry reports indicate that storage will reach full capacity long before the historical beginning of withdrawal season that starts in early November. As of July 19, there was 2,486 Bcf of working gas in storage in the U.S., 334 Bcf higher than at the same time last year and 364 Bcf above the 5-year average of 2,122 Bcf.³

### 3.3 The Natural Gas Supply Chain

SDG&E, an investor-owned utility, is the local distribution company (LDC) for natural gas in San Diego County with a gas customer base of over 775,000 natural gas meters. SDG&E receives gas service from the Southern California Gas Company (SoCalGas) on a wholesale customer basis. SoCalGas is wholly-owned by Sempra Energy, the same holding company that owns SDG&E, and is the largest gas distribution company in the United States. SDG&E, as well as SoCalGas, import gas that is produced at several major supply basins from Texas to Canada. Gas is shipped to receipt points that interconnect with major interstate pipelines as shown in Figure 3-7. The well-known Topock receipt point, for example, near Needles, California, is the location where the Transwestern and El Paso pipelines deliver gas to SoCalGas. Topock is also the point where PG&E receives gas as the Mohave Interstate pipeline continues into California. The Wheeler Ridge receipt point, near Bakersfield, is where SDG&E has contracted for deliveries of Canadian gas to be received into the SoCalGas system.

All shippers, including local distribution companies, large industrial customers, and energy marketers, purchase capacity on the interstate pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points. Shippers can elect to purchase firm capacity, which will be available under all but emergency circumstances, or non-firm capacity, which can be recalled at the discretion of the pipeline company to meet the needs of customers with firm capacity.

A map of the SDG&E system is presented as Figure 3-8. Another map of the SDG&E with interconnections to major transmission lines can be found in Appendix E.

It is important to recognize that the San Diego region is geographically located at the very end of the transmission pipeline network that brings natural gas from the producing basins in North America. Although the San Diego region has access to all these basins by interstate pipeline access, the final delivery into the SDG&E system is dependent on just one pipelineSoCalGas. This provides market power to that pipeline and places the San Diego region in a tenuous position with regard to its natural gas supply.

Figure 3-8: Detailed Map of SDG&E Natural Gas Distribution System
gas delivery options. For the first time in the region’s energy history, however, potential access to other gas supply sources (LNG) and alternative delivery options (Baja Norte) are on the horizon and are therefore significant to the San Diego region (these projects and their implications are discussed in Chapter 3.6).

3.3.1 SoCalGas System Descriptions and Capacities

SoCalGas has an extensive pipeline network that has 3,875 MMcf/d of firm receipt point capacity, including recently installed 375 MMcf/d of capacity. An additional 200 MMcf/d of interruptible capacity, along with 105 Bcf4 of gas storage in four fields, brings the total system capability to deliver up to 6,000 MMcf/d to SoCalGas customers. SoCalGas owns and operates four major underground gas storage fields in its service territory. There are no other gas storage providers in southern California.

The last major pipeline expansion on the SoCalGas system was the “Southern System Expansion,” as it was called, and it was completed around 1990. It was a major expansion of the large, backbone transmission lines coming in from the Southwest receipt points.

3.3.2 SDG&E System Description and Capacities

The SDG&E gas system is capable of delivering 600 MMcf/d in the summer and 620 MMcf/d the winter on a firm basis. The difference in summer and winter capacities is due to factors such as gas temperature, engine operating conditions, customer load profiles, and customer load locations. These two operating capacities include a reserve margin of 45 MMcf/d to account for various potential scenarios that could affect deliverability. Possible scenarios that could cause a reduction are lower Moreno suction pressure, Moreno or Rainbow compressor outages, or other system outages. The figure of 45 MMcf/d assumes any one of these could occur on a peak day. It is possible that deliveries could exceed the 620 MMcf/d under various conditions. Such a condition developed this past winter where the total SDG&E send-out was 639 MMcf/d for 1 day in January.

For the purposes of determining available capacity to meet customer elections for core and noncore firm service, the 620 MMcf/d Winter and 600 MMcf/d Summer figures will be used. Obviously, there will be times when interruptible service will be available to noncore customers. SDG&E’s interruptible customers have enjoyed a high level of service in spite of their interruptible status for many years due to SDG&E’s use of APD planning criteria (see Section 3.4). Prior to November 2000, SDG&E’s power plants had seen few curtailments in the past ten years. Most of these were in the winter months when core demand was highest and the resulting curtailment amounts were very insignificant. That was not the case in the late 1980s however, which preceded the installation of facilities required to meet growing core customer demand on both the SDG&E and SoCalGas systems.

The major pipeline facilities on the SDG&E system consist of a 30-inch diameter pipeline and a 16-inch diameter pipeline that extend south from the Rainbow meter station at the Riverside-San Diego county line. The 30-inch line veers west from Rainbow and continues south for about 50 miles to the Tecolote city-gate regulator station in Linda Vista. About 80% of the gas received at Rainbow is transported through this line. The 16-inch pipeline leaves Rainbow and heads due south again for about 50 miles and connects to the Mission city-gate regulator station.

These two local transmission pipelines are interconnected in two locations as they work their way south through the county. A 12-mile, 16-inch crosstie, half way down and again at the southern end a 4-mile, 30-inch pipeline connects them both. A 20-inch line connects at the southern crosstie and extends 7 miles to the Carlton Hills city-gate regulator station located in Santee. From Santee, a 36-inch line proceeds south about 30 miles to Otay Mesa at the southeast end of the SDG&E system. Four city-gate regulator stations feed high-pressure distribution networks from this line. Finally, a 4 mile, 30 inch line extends from the Harvest regulator station to the U.S./Mexico International border. These last few lines have been installed within the past 10 years.

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4 The firm withdrawal rate from storage is around 3,200 MMcf/d, with a maximum withdraw rate that exceeds 3,600 MMcf/d. 1,900 MMcf/d of withdrawal capacity is reserved for core customers.
A 12-inch-diameter line, commonly known as the “Coastline” extends 43 miles south from the San Onofre metering station near that San Diego/Orange County lines and continues to La Jolla. This line is owned and maintained by SoCalGas. The pipeline is interconnected at four locations along its path. This pipeline was the original pipeline serving San Diego and is more than 50 years old. It operates at a much lower pressure (and volume) than the other transmission lines serving SDG&E customers.

SDG&E also owns and operates a major compressor station at Moreno Valley, situated 33 miles north of the San Diego County line. SDG&E installed this compressor station in SoCalGas’ service territory to boost the pressure coming off of their major transmission line bringing in gas from the Southwestern gas basins. The Moreno station has increased its capacity over the years and now totals about 16,600 bhp. The Moreno station provides pressure to the SoCalGas lines 1027, 1028, and 6900 that comprise the Moreno-to-Rainbow transmission corridor. Line 6900 just last year completed the final phase of its 32-mile length, increasing the capacity into the SDG&E system by 70 MMcfd.

SDG&E’s pipeline expansions over the last decade have included its “Pipeline 2000” project. This project was a major transmission project on the SDG&E system that enhanced its deliveries to the southern part of its service territory, including potentially Baja California.

The only other compressor station SDG&E owns and operates is on the SDG&E system itself, and is located at Rainbow in Northern San Diego County. This station has a capacity of 3,080 installed brake horsepower and is used to pressurize the 16-inch line leaving the Rainbow station.

3.3.3 Slack Capacity on the SDG&E and SoCalGas Systems

Slack capacity is defined as the amount of unused firm transmission capacity, typically on an annual basis, divided by the amount of firm transmission capacity. It is expressed in a percentage. It is important to note that slack factor is calculated using annual average figures, not peak day. Table 3-3 shows the slack capacity on the SDG&E and SoCalGas systems. SDG&E has a slack factor of approximately 50 percent for transmission capacity on its system under nearly every scenario. Note this forecast is only through the year 2006.

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>SoCalGas</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Temperature, Normal Hydro</td>
<td>37%</td>
<td>49%</td>
</tr>
<tr>
<td>Average Temperature, Dry Hydro</td>
<td>31%</td>
<td>46%</td>
</tr>
<tr>
<td>Cold Temperature, Normal Hydro</td>
<td>33%</td>
<td>47%</td>
</tr>
<tr>
<td>Cold Temperature, Dry Hydro</td>
<td>28%</td>
<td>44%</td>
</tr>
<tr>
<td>Hot Temperature, Normal Hydro</td>
<td>38%</td>
<td>51%</td>
</tr>
<tr>
<td>Hot Temperature, Dry Hydro</td>
<td>33%</td>
<td>48%</td>
</tr>
</tbody>
</table>

Note: CPUC Calculations Based on Utility Forecasts of Natural Gas Demand, August–October 2001

3.4 Gas Utility System Planning Criteria

SDG&E performs analyses on potential facility expansions in the context of their BCAP Resource Plans. Currently, planning is done to meet, at a minimum, the core peak day demand for a 1-in-35-Year Recurrence Interval for a design Abnormal Peak Day (APD) condition. This 1-in-35-year criteria provides an optimal design that meets the CPUC standards of least cost planning, while providing an acceptable level of service to core customers. This APD condition is expected to occur once in every 35 years, or expressed in terms of probability, it has roughly a 3 percent chance of occurring in any

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5 SDG&E has noted that this level of service has historically provided an acceptable level of service to noncore customers as well.
given year. It represents an average daily temperature on the SDG&E system of 42 degrees, or a 23 heating degree day (HDD).

Recently, as part of a gas transmission Order Instituting Investigation (OII 00-11-002) filed with the CPUC, SDG&E has proposed a new approach in light of the difficult task of providing service for the anticipated growth in electric generation (EG) gas demand. This new proposal for their planning criteria is known as Firm Service Demand, or FSD. The FSD includes both core and non-core demand on a 21 HDD day, and is also thought of as having a 10-percent chance of occurring in any given year. In their 2002 BCAP application, SDG&E provided an indicative projection of EG throughput for Firm Service Demand (FSD) planning. This increased conservative planning criteria is in response to the growing uncertainty of EG customer firm service requirements. SDG&E’s latest forecast of gas demand under this condition is shown in Table 3-4. As illustrated, the current system capacity is exceeded by demand in the year 2008. Without further capacity expansions, SDG&E will not be able to meet the FSD planning criteria in 2008. This FSD planning criteria proposal by SDG&E has not yet been approved by the CPUC.

### Table 3-4. SDG&E Firm Service Day (FSD) Demand

<table>
<thead>
<tr>
<th>Year</th>
<th>Core (MMcfd)</th>
<th>Firm Noncore C&amp;I (MMcfd)</th>
<th>Firm EG (MMcfd)</th>
<th>Total (MMcfd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>380</td>
<td>63</td>
<td>37</td>
<td>480</td>
</tr>
<tr>
<td>2004</td>
<td>379</td>
<td>63</td>
<td>38</td>
<td>480</td>
</tr>
<tr>
<td>2005</td>
<td>379</td>
<td>63</td>
<td>67</td>
<td>509</td>
</tr>
<tr>
<td>2006</td>
<td>382</td>
<td>63</td>
<td>100</td>
<td>545</td>
</tr>
<tr>
<td>2007</td>
<td>387</td>
<td>63</td>
<td>136</td>
<td>586</td>
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<tr>
<td>2008*</td>
<td>393</td>
<td>63</td>
<td>170</td>
<td>626</td>
</tr>
<tr>
<td>2009</td>
<td>400</td>
<td>63</td>
<td>174</td>
<td>637</td>
</tr>
<tr>
<td>2010</td>
<td>407</td>
<td>63</td>
<td>177</td>
<td>647</td>
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<td>2011</td>
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<td>181</td>
<td>658</td>
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<td>2012</td>
<td>421</td>
<td>63</td>
<td>184</td>
<td>668</td>
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<tr>
<td>2013</td>
<td>427</td>
<td>63</td>
<td>188</td>
<td>678</td>
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<td>2014</td>
<td>434</td>
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<td>192</td>
<td>689</td>
</tr>
<tr>
<td>2015</td>
<td>440</td>
<td>63</td>
<td>196</td>
<td>699</td>
</tr>
<tr>
<td>2016</td>
<td>446</td>
<td>63</td>
<td>199</td>
<td>708</td>
</tr>
<tr>
<td>2017</td>
<td>452</td>
<td>64</td>
<td>203</td>
<td>719</td>
</tr>
</tbody>
</table>

*Available capacity is 600 MMcfd summer and 620 MMcfd winter on a firm basis.

The expansion of SDG&E gas transmission capacity is being addressed as part of the OII proceeding. During the winter of 2000–2001, SDG&E had to order gas curtailments of electric generators on its system. There were no curtailments during this past winter of 2001–2002, where even the CPUC predicted curtailments to occur on very cold days.

### 3.4.4 Capacity Additions on the SDG&E System

At this point on the SDG&E system, any significant increases in gas demand will necessitate increases in pipeline system capacities. Any new significant incremental non-core demand, such as the proposed Otay Mesa Power Plant, may not have a utility firm service option without system

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6 This OII proceeding is discussed in further detail in Appendix E.

7 SDG&E provides illustrated forecasts in some regulatory proceedings. SDG&E believes that large EG customers should provide SDG&E with their forecasted needs so that a system can be designed to meet their needs.

Available service options will vary depending on where the new load is located on the SDG&E system, e.g., new load on the northern end of the system can be accommodated more readily. Table 3-5 summarizes the potential facility expansions on the SDG&E system. Appendix E contains a more detailed description of these potential projects.

Table 3-5: SDG&E Potential Facility Expansion Projects

<table>
<thead>
<tr>
<th>Option</th>
<th>Facility - 50 MMcfd Options</th>
<th>Capacity (MMcfd)</th>
<th>Capital Cost ($MM)</th>
<th>O &amp; M Cost ($MM/year)</th>
<th>In Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Rainbow - Escondido Pipeline (23 miles)</td>
<td>45</td>
<td>$38</td>
<td>Minimal</td>
<td>2 - 3 years</td>
</tr>
<tr>
<td>2</td>
<td>Rainbow - Fallbrook Pipeline (15 miles)</td>
<td>50</td>
<td>$29</td>
<td>Minimal</td>
<td>3 - 4 years</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Option</th>
<th>Facility - 90 - 170 MMcfd Options</th>
<th>Capacity (MMcfd)</th>
<th>Capital Cost ($MM)</th>
<th>O &amp; M Cost ($MM/year)</th>
<th>In Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Rainbow - Escondido Pipeline (23 miles)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Escondido - Santee Pipeline (26 miles)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total: Rainbow o Santee Pipeline (49 miles)</td>
<td>150 - 170</td>
<td>$90</td>
<td>Minimal</td>
<td>3 - 4 years</td>
</tr>
<tr>
<td>2</td>
<td>Rainbow - Main Line Valve 7 Pipeline (25 miles)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Miramar - Santee Pipeline (7.5 miles)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total: Option 2</td>
<td>100 - 120</td>
<td>$62 - $67</td>
<td>Minimal</td>
<td>3 - 4 years</td>
</tr>
<tr>
<td>3</td>
<td>Carlsbad Compressor Station (17,000 HP) (17,000 HP)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Miramar - Santee Pipeline (7.5 miles)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total: Option 3</td>
<td>90 - 100</td>
<td>$49 - $54</td>
<td>Minimal</td>
<td>3 - 4 years</td>
</tr>
</tbody>
</table>

Project #1 (90–170 MMcfd option) described in Table 3-5 is the most likely project to be constructed on the SDG&E system to meet increasing demand. The total length of this pipeline would be 49 miles, extending to the existing 36-inch Pipeline 2000 in Santee. Essentially, this pipeline would complete a loop between the Rainbow Compressor station and the southern extreme of the SDG&E service territory. SDG&E personnel confirmed this project is ideal to significantly improve system reliability, especially in time of emergencies or when other transmission lines are in need of maintenance. The lead-time for this project is estimated at three to four years, with the southern portion being the most problematic since it goes through federal government property and various sensitive environmental zones. The cost of this entire project would be about $90 million and add 150 to 170 MMcfd to system capacity. Similar to Line 6900, this line could be built in phases, or increments, as demand increases over time.

SDG&E notes that if demand growth warrants more capacity, all the identified projects can be increased in size to 36-inch pipe to achieve additional capacity with an added cost of about $500,000 per mile. They also note that the estimates of lead-time and costs have been done on a very preliminary basis. Customer location is of course another factor, such as a major power plant siting.

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For example, a new 500-MW combined cycle power plant, with a 6,000 Btu/Kwhr heat rate, can create a maximum daily gas burn of 70 MMcfd, which would be over a ten percent increase in SDG&E’s capacity. As a comparison, the existing San Diego major power plants have heat rates of approximately 10,000 Btu/kwhr, much more inefficient due to their dated technology.
3.4.2 SoCalGas System Planning Criteria

SoCalGas recently stated their policy of maintaining a 15 to 20 percent excess backbone transmission capacity relative to best-estimate, normal weather forecasts. Any capacity expansions requested beyond the 20 percent will use incremental pricing based on long-term shipper commitments. Unlike SDG&E, SoCalGas is no longer required to submit Resource Plans in its BCAP proceedings. Natural gas transmission capacity can meet future demand on the SoCalGas system, although there are periods of high use. On an average daily basis there is sufficient capacity. However, there may be intermittent periods when capacity constraints may exist.

3.4.3 SoCalGas Capacity Additions

During the course of the SDG&E gas system investigation last year, SoCalGas announced they were proceeding with capacity expansions on their backbone transmission system totaling about 375 MMcfd, bringing the total take-away capacity to 3,875 MMcfd. This expansion has been installed. These capacity additions cost about $55 million, and it is anticipated SoCalGas will seek rolled-in rate treatment of these facilities. They have also proposed to increase storage capacity by about 14 Bcf.

3.5 Natural Gas Infrastructure Policy Issues – Who Should Plan and Pay for SDG&E Capacity Expansion?

A fundamental, and very controversial, pricing and resource economic issue is “Who is going to pay for any capacity expansions on the SDG&E system?” Just the annual facility costs that all customers pay on the SDG&E system alone are in the hundreds of millions of dollars, and new expansion facilities will be expensive as well. Those interstate pipelines have historically required long-term contractual commitments to justify the building of such a pipeline. SDG&E signed such a contract in the early 1990s to bring about 50 MMcfd of Canadian gas down through the PGT Expansion project being built. That gas is not delivered directly into the SDG&E system, however, and is actually delivered into the SoCalGas system at Wheeler Ridge in the northern part of their service territory. Those contract costs (along with the cost of gas) have been passed through to the SDG&E customers that have seen the benefit of that supply, namely the core customers.

Historically, this question of who pays for expansion fell squarely on the utility itself. SDG&E would propose the least cost expansion plan to the CPUC, and if approved, SDG&E would build the necessary facilities and recover the costs according to CPUC adopted rate design. Now the responsibility is that of the CPUC.

One important role of the CPUC was to question all aspects of these utility proposals, and decide whether to approve them or not. The forum in which this review was conducted was a General Rate Case (GRC). SDG&E has not had a GRC in nearly a decade (nor has SoCalGas for that matter). A GRC was an incredibly complicated, time-consuming proceeding that literally took years to file, litigate, brief, decide, and implement. It was extremely burdensome on the utility, the CPUC, and all other stakeholders in the process. Throughout the fifties and sixties many utilities, and SDG&E in particular, did not file a GRC: their rates in effect recovered all the facilities they had and any new ones being installed. Finally, SDG&E was forced to file a GRC in 1971, the first time in over a decade. During this time, facility costs were “rolled-in” to all customers’ rates.

As the seventies progressed, OPEC prices and other inflationary forces began to skyrocket, GRCs became a regularly scheduled item on the CPUC agenda, at one point happening every year – for every utility in the state. During this time, with fuel prices at their most volatile level, the utilities were continuously evaluated on their purchasing practices through the proceedings, which were called “Reasonableness Reviews,” which were oversight investigations that resulted in substantial disallowances of costs.

10 SoCalGas allocates nearly one and a half billion dollars a year in annual fixed gas facility costs, including a portion to SDG&E.
11 These matters are now addressed in the cost of service proceedings, which set rates and determines which customers should pay for expansion.
In the early 1990s, GRCs were eliminated with the advent of “Performance Based Ratemaking”, or PBR. Basically, what the initial PBR did was freeze the utility rate base (with a small annual escalation) and the utility would have to use its productivity and any other means to live with that amount. They could not come back to the CPUC and ask for more money in the traditional GRC model. One quid-pro-quo, of course, was that Reasonableness Reviews were eliminated. In addition, for the first time ever for a gas utility in the state, SDG&E could actually make a profit selling gas. Prior to that time, all gas costs were simply passed through to the customer. The same situation was created on the electric side, which reaped profits as well with SDG&E owning two major power plants. As long as the customers were receiving safe and reliable service, with the customers’ rates stabilized, the CPUC deferred from any micromanaging of the utilities infrastructure.

At the onset of PBR rate making, the CPUC did, however, promulgate a very clear policy toward any utility investment in gas infrastructure: any facility investments made for noncore customers would be done so at 100% of the utility shareholder’s risk. With the significant infrastructure improvements made by SoCalGas and SDG&E during the seventies (which were placed into rate base) and especially late eighties, no real infrastructure improvements were necessary during the nineties, until recently.

SDG&E’s and SoCalGas’ current PBRs are scheduled to expire within the next year (this is one reason cited by the ORA for a delay in the 2002 BCAPs). It is anticipated that both utilities will petition the CPUC to extend their PBR ratemaking structure. Assuming that the PBR structure will continue in its basic form, the ratemaking treatment for capacity expansions will most likely continue to remain as it is today, i.e., noncore customers will be subject to incremental ratemaking treatment.

After this understanding of how utility gas infrastructure regulation is now operating, and the utility risks and rewards in that regard, the answer to who should fund, develop and build gas infrastructure in the region can be answered in two parts:

1. The core customer will continue to pay for facility expansions on the same basis as it does today by including in rates the costs of any facilities necessary to satisfy the CPUC adopted planning criteria of 1-in-35 year Abnormal Peak Day demand. This policy is discussed fully elsewhere in this report, but the general consensus is that additional facilities to meet this criteria are not needed on the SDG&E system for several decades. When the time comes, SDG&E would propose the least cost expansion plan to the CPUC, and if approved, SDG&E would build the necessary facilities and recover the costs according to CPUC adopted rate design.

2. For the noncore, it is an entirely different situation, especially due to their interruptible status. Expanding current utility gas infrastructure capacity will most likely be driven by actions of the noncore customers on the system. As explained above, under the current regulatory structure, the state’s gas utilities have been more careful to invest in noncore gas infrastructure because of the cost recovery risk. Third party gas infrastructure development may occur, but will be done at the risk of those developers, which typically does not occur without substantial commitment from shippers (most likely that same utility noncore customer). To date, the region’s noncore customers have not been willing to make commitments necessary to expand gas infrastructure, whether utility or otherwise.

3.6 Other Regional Infrastructure Projects

3.6.1 The North Baja Pipeline Project

The 215-mile, $230 million North Baja Pipeline project (Baja Norte) is a joint effort of Sempra Energy, PG&E National Energy Group and Mexico’s Próxima Gas, S.A. de C.V. It originates in Ehrenburg, Arizona, near Blythe, California, traveling south into Mexico just East of Mexicali as shown in Figure

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12 SoCalGas, report SDG&E in comments on the draft REIS, “has always been willing to build for non-core contractual commitments. SoCalGas seeks contractual commitments so that those wanting the additions pay for them, and not saddle all other customers with the cost. SDG&E made a proposal for system investments, which was voted on November 21, 2002.
3-9. The pipeline then continues west along northern Mexico to Rosarito in Baja California, Mexico. Just south of the U.S.-Mexico border from Otay Mesa, Baja Norte will link with the existing pipeline that receives gas from SDG&E for delivery to Rosarito. The proposed capacity of the line is 500 MMcfd and is expected to be in service by September 2002.

In May 2001, Mexico’s Energy Regulatory Commission (CRE) issued Sempra Energy International a permit for construction of the 135-mile Mexico segment of the North Baja pipeline project. In October, PG&E National Energy Group (NEG) filed an application with FERC to build the 80-mile U.S. portion of the pipeline. In January this year, the FERC issued a certificate for construction and a Presidential permit authorizing the construction of the cross-border facilities.

The companies signed agreements for more than half of the pipeline’s 500 MMcfd capacity and discussions are continuing with other potential customers. NEG will direct the permitting and development of the U.S. leg of the pipeline, while Sempra Energy International will direct the permitting and development of the Mexico leg. The initial design calls for a 36-inch line for the first 12 miles, a 30-inch line for the rest, and one compressor station in Arizona.

When the pipeline becomes operational, the gas SDG&E is currently providing to the Rosarito Beach power plant will be available to serve SDG&E customers. Currently, that load has averaged between 30 and 60 MMcfd. Relieving SDG&E of this capacity commitment will be a direct benefit to customers on the SDG&E system. The Baja Norte pipeline does not increase supply diversity by providing access to any new natural gas producing basins. Baja Norte will receive gas from the El Paso system in Arizona and redeliver it to Baja California, therefore, Baja Norte will compete for gas pipeline capacity serving California via the El Paso pipeline. During the summer of 2000, the El Paso system was fully utilized serving California, and when Baja Norte becomes operational, removing up to 500 MMcfd from the El Paso system could potentially have a serious impact on California deliveries.

Finally, the Otay Mesa plant being constructed in Chula Vista has submitted an application to build a pipeline directly to the Baja Norte pipeline in Mexico. This pipeline would have a capacity of 110 MMcfd. It has received a Presidential permit from the FERC in July 2001. It is scheduled for completion in September 2002, coincident with the Baja Norte completion date.

3.6.2 LNG (Liquified Natural Gas)

When natural gas prices soared last year, several companies said they were looking at plans to import LNG.

Table 3-6 summarizes the five LNG projects that have been announced recently for the Northern Baja Mexico Region. Naturally, not all projects will be built. Since each one has its own set of unique obstacles to overcome, it is too speculative to determine which ones might actually be built. What is clear is that the capacity output of these plants is higher than the gas supply needs within Northern Mexico, at least for the next couple of decades. This implies that gas supply from these LNG plants could potentially serve customers in California.
LNG is kept at ultra-cold temperatures, which liquefies the gas for transport aboard special tankers, primarily sea-born, however truck transport is also possible. It begins as natural gas in its usual vapor form. A process cools the gas to minus -259º Fahrenheit, changing the gas into a liquid that is less than 1/600th of its original volume.

Table 3-6: Summary of Proposed Mexico LNG Facilities

<table>
<thead>
<tr>
<th>Company(s)</th>
<th>Terminal Location</th>
<th>LNG Source(s)</th>
<th>Capacity</th>
<th>Target Date</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chevron Texaco</td>
<td>TBD</td>
<td>Australia</td>
<td>500 MMcf/d</td>
<td>2006</td>
<td>Waiting for other deals to collapse before proceeding</td>
</tr>
<tr>
<td>Marathon Oil</td>
<td>Tijuana</td>
<td>Indonesia</td>
<td>750 MMcf/d</td>
<td>2005</td>
<td>Also 400 MW plant at site</td>
</tr>
<tr>
<td>Sempra – CMS</td>
<td>Bajamar (40 miles south)</td>
<td>Bolivia</td>
<td>1,000 MMcf/d</td>
<td>2005</td>
<td>Optioned 300 acres for $25 MM</td>
</tr>
</tbody>
</table>

LNG has averaged a 9-percent growth in the world market in 1999–2000. The Petroleum Economist estimates that an average conservative growth of 10 percent per year is possible. However, if all facilities are built globally, a 52-percent increase in liquefaction will occur between 2002 and 2005. U.S. imports of LNG increased by 29 percent over the first 6 months of 2000. A sophisticated set of transportation and short-and long-term LNG contracting schemes are expected. The Petroleum Economist also noted that there has been a 30-percent reduction in the capital cost of liquefaction plants. Further supply chain improvements are estimated to actually lower the overall costs of LNG by 15 to 20 percent.

LNG has recently become a more viable source of future natural gas supply because of the vast extent of world natural gas resources and the significant decline in LNG costs in all segments of the supply chain. If sufficient domestic LNG processing capacity existed, LNG imports could potentially play an important role in the U.S. gas market by dampening natural gas price extremes. LNG could quite easily become the “swing” supply that would moderate price increases by increasing spot cargos of LNG during periods of high prices and conversely moderate price declines by reducing spot cargos during periods of low prices.

The EIA projects LNG costs of about $3.80 per Mcf, which is comparable to the recent high natural gas prices. The construction costs for re-gasification terminals, such as those proposed in Mexico, have also seem similar decreases. The LNG trade is very capital intensive due to the requirement of significant facilities at both ends of the supply route and tankers to transport over long distances. More than 70 percent of the cost of re-gasified, delivered natural gas is made up of processing and transportation costs.

There is considerable uncertainty about the cost of constructing new LNG terminals. The capital costs for any project are site-specific, and can vary considerably, depending on the harbor’s characteristics, land costs, access to interstate transmission systems, and the degree of local opposition to the project. As reported in a San Diego Union Tribune article (March 4, 2002), there are already parties fighting the plans for terminals being proposed in Mexico, ranging from environmentalists, preservationists, politicians and other public interest groups.

The delivered cost of LNG to a re-gasification terminal, such as those being proposed in Mexico, depends on the world LNG market. With that, there exists the potential for a few large LNG producers to create a cartel similar to OPEC. This situation, at a minimum, creates price uncertainty.

LNG does have the potential to insulate the region from supply disruptions. But only if that supply has been contracted for delivery to San Diego—for use in San Diego. There is a very real possibility that
scenario might not occur. The gas could stay in Mexico; it could also be transported through San Diego County for use elsewhere in California. Under one potential scenario, in order for LNG delivered to Baja California to get to markets north of San Diego County, the SDG&E system flow would need to be reversed. The feasibility of this potential requirement has not yet been studied.

Regardless, having additional gas supplies available in the region can help SDG&E’s supply situation indirectly even if it is not contracted for delivery in San Diego. Additional supplies to other customers frees up supplies for San Diego.

3.6.3 Underground Natural Gas Storage

Natural gas storage is a means of insulating the region from gas supply disruptions. There are no on-system storage facilities on the SDG&E system, which is why SDG&E must size its transmission lines in order to meet peak day requirements. SDG&E contracts for all its storage needs from SoCalGas. SoCalGas is currently the only owner of storage facilities in southern California.

Traditional underground gas storage fields are not possible in the County due to the fact that there are no geological formations in which to develop such a facility.

At one point in the early 1980s, SDG&E owned and operated an LNG facility on its system for the purposes of providing gas storage. This plant was located at the southern portion of the South Bay Power Plant site in Chula Vista. The SDG&E LNG plant was eventually dismantled for various reasons, including the availability of more cost-effective storage services from SoCalGas.

SDG&E did have one other gas storage facility on its system, called the “Encanto holder,” it was simply a series of large gas pipes buried underground that the company would pack and draft at certain times when needed. This storage was severely limited in its capacity, and was essentially rendered obsolete with other transmission system enhancements. It was dismantled in the mid-1990s.

3.7 Regulatory Proceedings and Issues

3.7.1 The Role of the CPUC

SDG&E and SoCalGas are jurisdictional local distribution companies (LDC) regulated by the CPUC. They are also known as “Hinshaw pipelines,” which ensures that they will not be regulated by FERC. PG&E currently has the same status.

The CPUC sets the gas rates for SDG&E and SoCalGas. During the days of General Rate Cases, the Resource Plans were approved by the CPUC for the utilities to construct facilities necessary to meet the gas demands of their customers. As explained elsewhere in this report, GRCs are no longer conducted by the CPUC.

SoCalGas and SDG&E are currently in the midst of transitioning to a new gas ratemaking methodology. Since the beginning of regulatory control, the most common form of utility ratemaking was based on “embedded cost” determinations. In 1993, however, the CPUC adopted a form of “Long Run Marginal Cost” ratemaking, or LRMC.

LRMC ratemaking has now just about run its course. SoCalGas, in its next BCAP, will be transitioning its backbone transmission and storage system back to embedded cost ratemaking. The Gas Industry Restructuring (GIR) mandated this. In fact, most of the industry in California supported this return as well. PG&E’s transmission system had gone back to embedded cost principles with its Gas Accord years ago, and it was only natural that SoCalGas would follow. SoCalGas, along with SDG&E, has taken this transition one step further and recommended in their 2002 BCAP (now delayed) filings a complete return to embedded cost ratemaking for all their costs. It is anticipated this issue will return in their 2003 BCAP filings.

A return to embedded cost ratemaking should eliminate many of the issues that have been occurring in LRMC proceedings and provide a higher level of rate stability to all gas customers, at least for their fixed costs. The transition may be difficult, however.
3.7.2 Core vs. Noncore Conflicts – What to Do

Customer classes have not always seen eye-to-eye in basic functions of gas supply, transmission, distribution, storage, and of course pricing of these components. Because all these functions are basically still heavily regulated by the CPUC and FERC (except the commodity price of gas at the wellhead), the resolution of competing interests is a major purpose for CPUC proceedings such as BCAPs. BCAPs set the gas cost allocation for all ratepayers, including SDG&E as a wholesale customer of SoCalGas. Fundamentally it is a “zero sum game”, meaning that once the total revenue requirement of the utility has been set, the cost allocation methodology recovers those costs from all customers, with one customer class paying more if another pays less. Therein lies much of the controversy between customer classes in a BCAP proceeding.

Cost allocation of the utility’s fixed costs is probably the most important issue in a BCAP that sets all customers’ rates, but in recent years many other important policy issues have also been litigated in BCAPs. The managing of core interests is for the most part done by the LDC itself, such as SDG&E and SoCalGas, however this function continues to evolve and be influenced by organizations such as TURN and of course the Office of Ratepayer Advocates (ORA). Noncore customers have become very active in both the resolution and management of gas issues, as is evidenced by the high level of activity by electric generators in this area, as well as wholesale customers and other noncore customer classes.

The core and noncore classes will continue to compete for supply, pipeline capacity, reduced cost allocations, and other favorable gas services. It is entirely possible that there is common ground between these two customer classes on issues, such as keeping delivery costs fair and equitable, supply reliable and safe, establishing a market structure that encourages competition and fair play by the utilities and other market participants, as well as others. When that opportunity presents itself, parties should work together to achieve those objectives. When it does not, each party should be well represented to serve its best interests.

Appendix E contains brief summaries of the current gas regulatory proceedings at the CPUC that are of interest to the San Diego region.

3.7.3 The Integration of SoCalGas and SDG&E Gas Operations

SDG&E and SoCalGas have a rather unique relationship at the moment. They are affiliate companies under the same corporate umbrella. The merger of these two companies occurred just a few years ago. As part of the condition of the merger, it was agreed that the two companies would continue to operate as separate gas utilities. However, recent regulatory proceedings since the merger have made attempts to take precedence over the merger agreement. For example, the two utilities proposed to merge their gas purchasing functions into one organization and combine the respective core portfolios in the Portfolio Consolidation proceeding (A.01-01-021). The final CPUC decision deferred the consolidation of the two core portfolios, until CPUC investigations are completed.

The future of the relationship between SDG&E and SoCalGas will continue to evolve, with the current path seemingly headed towards an eventual merging of the two gas companies completely. Whether this is good or bad for San Diego gas consumers remains to be seen.

3.7.4 The Peaking Tariff

The so-called “peaking tariff” on the SoCalGas system has been in place for the past seven years, and even though recently modified, the tariff has essentially operated as an “anti-bypass poison pill” for any customers contemplating alternative gas service.

In the utilities’ defense of these peaking tariffs, their position is that customers that obtain service from other gas pipelines would end up using the utility gas system as a partial provider of gas services.
(presumably on a peak-only basis), leaving the captive customers subsidizing the partial bypass customers.

Since this peaking tariff has been in place, however, no alternative pipelines have been built in southern California. There has been no customer bypass of the SoCalGas system by any means: this tariff has never had a customer on it. The reason is the tariff would essentially have the customer pay for gas service twice: once to the alternate provider, and once again to SoCalGas (keeping the utility "whole" for any lost revenues). The result has been that gas pipeline competition has been kept out of southern California.

Now, however, with the Baja Norte pipeline nearing completion, there exists for the first time ever a potential bypass of gas service provided by SDG&E. Now the same situation could apply to SDG&E’s own customers. Explicitly pointing to the construction of the Baja Norte pipeline, SDG&E proposed in its 2002 BCAP that it also have a peaking tariff implemented on its system (this 2002 BCAP proceeding has been delayed until 2003, and whether SDG&E will pursue this proposal in that proceeding remains to be seen). Until this regulatory hurdle is overcome, gas supplies from Mexico may not be economically feasible for San Diego.\(^\text{14}\)

### 3.8 Important Implications and Considerations for the Region

Due to the extreme uncertainty of future growth of demand to support high growth of regional electric generation plants and longer-term dwindling supply, the region needs to continue to investigate and analyze opportunities for upstream diversification and delivery of natural gas supply, particularly deliveries directly into San Diego County. While the Baja Norte pipeline may help, it is limited to accessing supply from the Permian and San Juan basins only, and not larger supplies in the Rockies and Canada.

Additional issues and considerations include the following:

- There will be significant opportunities for the region to engage in the policy and decision-making process at the CPUC and CEC to evaluate and comment on capacity expansions for the SDG&E system in order to balance the gas demand needs and costs for all gas customers in San Diego against the regulatory, political, and environmental issues that facilitate or hinder gas infrastructure expansions.

- The region should strongly encourage the re-powering of two existing EG facilities to achieve higher natural gas efficiencies. Re-powering those two plants alone could significantly delay any gas system expansion projects required for existing gas customers. The capacity “freed up” could potentially be enough to completely absorb at least one other new power plant gas requirements.

- Currently, EGs in both SDG&E’s and SoCalGas’ service territories are served under the Sempra-wide EG rate tariff. This proposal was vigorously opposed by EGs in the SoCalGas service area because they opposed paying a subsidy to reduce the transportation rate to EGs in SDG&E. One result of this new rate design is that EGs in SDG&E’s area now have the same rate as Los Angeles power plants, rather than a much higher cost. This makes generation in San Diego cost competitive, and without it, these local plants would have a hard time competing for electric sales. If this CPUC policy changes, it could place these plants at sufficient risk.

- The integration of SDG&E into the SoCalGas system has advantages and disadvantages. Improved performance in productivity, performance based incentives and other observable management practices need to be made transparent to demonstrate the benefits from such actions. However, greater oversight is needed on proposed rate increases.

\(^\text{14}\) It should be noted that SDG&E’s opinion in commenting on the draft REIS is that the peaking tariff does not address supplies from Mexico. It has no effect on gas supplies delivered at the California border to the SDG&E system. Study sponsors were asked to compare the costs on Baja Norte with the SoCalGas system.
The potential for rapid development of LNG facilities and the potential of these facilities to serve San Diego County will present significant opportunities and challenges for the region. The region should closely monitor the progress of the proposed pipelines and LNG facilities and the potential of these facilities to serve San Diego County directly, including participating in any state or federal forums that set policy in this determination. If domestic supplies of natural gas start declining as expected in the next 15 years, LNG may be one of the few or only options available for additional supplies of natural gas.

The region should implement programs or other means to conserve gas usage by all customers and investigate federal, state, and local funding to facilitate such programs.

The potential for simultaneous price spikes in electricity and natural gas markets suggests that ownership of gas-fired resources alone may not provide much of a price hedge. The region should consider other resources such as renewables and energy efficiency.
4 Electricity Demand, Supply, and Infrastructure

4.1 Summary Findings

The Regional Energy Infrastructure Study (Study) reports the following key findings for electricity demand, supply and infrastructure:

4.1.1 Short Term 2002–2006

- The San Diego region will continue to be a high-cost electric market at least through 2006.
- Transmission capacity and import capability become important over the 2004–2010 time period. To avoid near-term imbalances the region needs 1 to 2 new generation plants, additional transmission, and increased energy efficiency. If these resources are not available, higher prices and load curtailments may occur.
- Unless the region pursues a strategy of diversifying its electric supply portfolio, including energy efficiency, demand response, distributed generation, renewables and additional transmission, the ability of the region to meet its needs in the longer-term will become increasingly difficult, particularly in the outer years.
- The recent economic downturn, low energy prices, the fallout from the collapse of Enron and the uncertain political and regulatory situation in California has significantly delayed the number of new power plants being built in California and San Diego County. There is high uncertainty surrounding new power plant development in the region.
- For a number of reasons, the region is not an attractive location for new plant development, even though the load growth exists and some new plants have been announced—it is highly uncertain if these plants will be built.
- New CAISO locational marginal pricing (LMP) transmission pricing and capacity reserve requirements for regional grid reliability suggest that the region is going to be more vulnerable to system constraints unless additional generation and transmission is added to the area.¹
- A number of needed transmission improvements are being made in the region. Because of reliability concerns and the fact that the region has only one major northern feeder into the region, it appears that additional transmission to the North is necessary. The line will be needed by 2005 unless the region takes positive action soon to ensure new generation or other alternatives are in place by that time.
- A broader regional energy infrastructure plan is needed. Currently, the planning of infrastructure project initiatives is too fragmented. Additionally, energy infrastructure planning should be a transparent process that is more accessible to the public.
- Load flow analysis is needed to evaluate the most optimal way to balance new transmission development and co-location of generation, not only for supply purposes but also for regional grid reliability.
- An energy development authority needs to track demand and renewable resources along with transmission as a basis of considering additional generation.
- In somewhat of a rebuttal to the findings of this report, SDG&E reports that the newly negotiated CDWR contracts coupled with SDG&E’s generation and long-term power purchases substantially meets all of the region’s energy needs, states SDG&E.² However, no evidence or even documentation was provided to reinforce this opinion. As part of the strategy development task, SDG&E and SDREO should work to verify this assertion.

¹ SDG&E commented in its evaluation of the draft REIS that LMP pricing of the capacity reserve requirements is not going to increase vulnerability over what it is now.
² From the draft to the final report, CDWR and the CPUC negotiated the capacity and cost allocations to the state’s three investor-owned utilities. When the local energy strategy is being developed, careful evaluation of these contracts is needed. They can have a major impact on local resource economics, reliability, and equity.
4.1.2 Mid Term 2006–2010

- Additional transmission to the north will be needed. At least one in region generation plant will also be needed.
- A much stronger contribution of DG and renewable energy resources is expected in this time frame.

4.1.3 Long Term Post 2010

- Substantial renewable resource imports are expected from eastern San Diego County and North Baja
- One-to-two additional power plants may be needed – with one each in the 2010 and post 2020 time period.
- The region should seriously consider an additional transmission line to Arizona for access to new capacity that is expected to be built there.

4.2 Electricity Demand and Consumption Trends and Forecasts

4.2.1 Historical Energy Consumption

Figure 4-1 presents the historical annual energy consumption for the San Diego region during the 1990–2001 period. The San Diego region consumed 17,632 gigawatt-hours (GWh) in 2001, down 4.3 percent from 2000.

This decrease in consumption was the result of the impact of higher prices, consumer conservation behavior and other factors such as increased use of small-scale, distributed generation. Historically, electricity consumption has grown an average of 3.1 percent per year. Peak demand for 2001 was about 3,200 MWs, down 18 percent from 2000, which represented the largest 1-year decline in demand in the last 50 years. Between 1988 and 2000, peak electric demand grew an average of 3.4 percent per year. Demand forecasts in recent years are lower than in the past for several reasons, including a more pessimistic economic outlook, higher electric rates, new conservation programs, long-term impacts of state-sponsored conservation efforts and new appliance efficiency standards. These estimates are likely conservative, as historical demand forecasts by SDG&E and the CEC have tended to under forecast demand by between 4 percent (during economic recession periods, like the early 1990s) and 21 percent (as was the case during the high economic growth during the late 1990s). Since the last forecasts accomplished by SDG&E in October 2001, electricity usage has rebounded significantly and it is expected that shorter-
term forecasts are indeed low, having been overly influenced by the extraordinary conservation efforts of 2001.\textsuperscript{8}

Demand for electricity is influenced by various economic and non-economic factors, and it is difficult to isolate the magnitude and timing of contribution by any one factor. All major energy related events, pronounced trends in economic conditions, temperature and change in consumers’ energy consumption behaviors, introduce a great deal of uncertainty in long-range load forecasts.

4.2.2 Per Capita Electricity Growth and Energy Intensity

Long-term electricity use trends are driven by many factors, the most significant being economic, population, commercial building and new housing. While population and housing growth has slowed from the 1980s to the 1990s by more than 60 percent, electricity demand growth has slowed by only 40 percent. This is due to a slight increase in per capita consumption over the longer-term. More electricity is being consumed per person in San Diego despite significant conservation efforts and advancements in technologies. The increased consumption per person is likely due to several factors, including the increase in use of computer electronics, building larger homes and more homes that are inland, which require air-conditioning. The most influential factors driving short-term electricity demand is the economy and the increased use of air-conditioning.

Figure 4-2 shows historical and projected electricity consumption by sector for the 1980–2010 period. The data show higher growth rates for the commercial segment, followed by residential. Flatter growth is shown for industrial, agricultural and other sales. For the year 2001, the relative shares in peak demand by sector, appear in Figure 4-3. The commercial market has the largest share of electric use (49 percent) followed by residential (35 percent). All other uses together total 19 percent.

\textsuperscript{8} SDG&E, Opening Brief of San Diego Gas & Electric Company (U 902-E) on the Need for The Valley-Rainbow Interconnect Project, July 12, 2002.
4.3 Electricity Supply: Generation and Transmission

4.3.1 Existing Generation Stock in San Diego County

Generation plants vary in size depending on their application and intended use. Currently, San Diego has a total on-system generation capacity of about 2,359 MWs, about 55 percent of the region’s summer peak demand. This capacity consists of 1,628-MW base-load plants. The remaining capacities are small and medium-sized peaking plants and on-site generators (excluding backup generation). All of this generation is not normally available since many of the generators are for emergency use and not available when needed. Available in County generation during peak period is approximately 64 percent of the region’s peak demand. A complete listing of all power plants located in San Diego larger than 100 kW can be found in Appendix F.

Cancellations of power plant proposals have become common. In light of this high degree of uncertainty, SDG&E is forced to plan for grid reliability improvements based on very conservative generation expansion assumptions because the utility must provide reliable service regardless of the uncertainties of the regulatory climate and capital markets for generation investment.

San Diego County has two major steam electric generating units and a number of smaller combustion turbine units, most of which were constructed between 1960 and 1978. Although these units have continued operation with modifications and upgrades, they are quickly nearing technological and economical obsolescence. A number of the least-efficient, must-run units have in the past operated at capacity factors in the 3 percent range and are needed to perform must-run duty 5 percent of the year. Must-run units are more expensive to operate and are only used as operating reserves during

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9 Exh. 101 (at p. 5). This appeared in the Valley Rainbow filing.
10 Exh. 5 (at p. II-16).
peak periods or in times of emergency backup. This is because the outage costs are much higher than the power generating cost.\textsuperscript{12}

The Cabrillo Power Plant\textsuperscript{13} in Carlsbad, owned jointly by NRG and Dynegy, has a capacity of 965 MWs. The South Bay Power Plant,\textsuperscript{14} located in Chula Vista is owned by the Port of San Diego, and operated by Duke Energy, has a capacity of 690 MWs. The design-life of the combustion turbines in San Diego County is approximately 35 years. Fossil-fired steam units such as South Bay and Cabrillo are designed to operate 40 to 50 years. Although many units outlive their design life, forced outage rates increase with time, leading to a higher likelihood that they will not be available when needed. This is why the County needs additional supply reserves that may be used should a major plant be taken out of service. These reserves can be provided by either in-region power plants or through existing or new transmission. CAISO grid reliability criterion requires that the system be able to serve the load even after the loss of the largest transmission line and the single largest generator. The load forecast used for analysis is based on a forecasted load that has only a 10% probability of being exceeded. Sufficient reserves are needed in the region to meet this situation. Some units may be retired or not operate due to economic or environmental issues, such as limitations on operating hours due to emissions. Therefore, the retirement of a significant amount (i.e., greater than 1,500 MWs) of the existing generation stock currently existing in San Diego County in the next 15 years could be expected. This planning assumption is reflected in the high growth scenario that is presented in Chapter 6.

Figure 4-4 presents the annual projected cumulative retirements of generating units in San Diego County. An estimated 67 MWs of older combustion turbine units are estimated to be removed from the region by 2003 because these plants are old, inefficient and beyond their useful economic life. All remaining units are RMR must run units.

\textbf{Figure 4-4: Projected Cumulative Retirements of Generating Units in San Diego County}\textsuperscript{15}

Based on currently available generation technology, plants such as South Bay or Cabrillo can be repowered and double or nearly triple their current capacity without increasing NOx.\textsuperscript{16} Additional potential benefits include increased local tax base, improved water use efficiency of up to 50-percent reduction per MW, improved visual attributes due to a smaller plant infrastructure and the creation of needed emission offsets to build additional capacity. The repowering or replacement of the South Bay Plant may allow for a dry cooling configuration, which would reduce its impacts on the San Diego Bay.

\textsuperscript{12} SDG&E adds that must run units are also needed to overcome transmission constraints and CAISO load balancing requirements. The lack of transmission in the region has led to a substantial number of must run units being located in the region.

\textsuperscript{13} The 5 Cabrillo Power Plant Units were placed in service 1954 (Unit 1), 1956 (Unit 2), 1958 (Unit 3), 1973 (Unit 4) and 1978 (Unit 5).

\textsuperscript{14} The 4 South Bay Power Plant Units were placed in service in 1960 (Unit 1), 1962 (Unit 2), 1964 (Unit 3) and 1971 (Unit 4).

\textsuperscript{15} California Energy Commission, 2001 Database of California Power Plants.

\textsuperscript{16} Additional NOx reductions have occurred at the South Bay Plant and, in the near term, additional reductions are planned at the Cabrillo Plant.
Additionally, air emission credits will need to be obtained since the air emission credits associated with the plant are owned by Duke Energy.

In the case of the South Bay Power Plant, should the replacement plant be constructed at a new site that is not in the vicinity of the existing site, costs to modify and/or move existing transmission infrastructure and to provide needed voltage support in the South County could well exceed $75 million. The additional costs that would be associated with the siting decision are the subject of an ongoing proceeding of the Port of San Diego.

San Diego County’s two existing steam-generating stations, Cabrillo (939 MW) and South Bay (690 MW) are approaching economic obsolescence. The Port of San Diego has made a commitment to replace South Bay with a new power plant by 2009. Duke Energy, under the terms and conditions of its existing agreement with the Port, is obligated to use commercially reasonable efforts to develop, finance, construct, and place into operation a new off-site replacement generation plant by 2009. Duke is currently conducting feasibility studies and siting activities for off-site facilities and has identified one potential north county site.

The City of Chula Vista in 2001 voted to recommend that Duke and the Port consider locating the new replacement plant on Chula Vista tidelands. On June 26, 2002 the Board of Port Commissioner’s voted to recommend that Port staff and Duke consider replacing the SBPP on the former 33-acre LNG site.

Upon termination of the operation of the SBPP, Duke is to begin performance of the decommissioning obligations that would return the 116 acre site to the Port provided the parties have received approval of the CAISO to commence decommissioning activities.

The Cabrillo Power Plant has had several emission controls improvements made to comply with air quality regulations, which has reduced its emissions by more than 50 percent. Without significant upgrades it is anticipated that both units will be shut down by the end of the decade. Until new combined cycle capacity is constructed in the region, these units will likely continue to be classified as must-run by the CAISO. 

SDG&E retains a 20-percent ownership of the San Onofre Nuclear Generating Station (SONGS), which is licensed to operate through 2022. The plant may be able to extend the license another 20 years if the plant’s owners apply to the Nuclear Regulatory Commission (NRC) for an extension of the license. If the plant life is extended, the potential costs to upgrade the plant to keep it running may be prohibitive. Unit 1 was shutdown in 1992 after 25 years of operation because the costs to upgrade the unit to current seismic standards and complete needed replacement of critical systems made the continued operation of the plant uneconomic. The remaining SONGS units operate under an “Incremental Cost Incentive Pricing (ICIP)” mechanism, which covers operational costs through December 31, 2003. After this time, SONGS will need to recover its costs in the market. To the extent that the market fails to cover the costs, a decision may be made to shutdown SONGS. A study was completed by the CAISO working with SCE and SDG&E to determine what would happen to the system if SONGS were to shut down after 2003. That study was not available to the authors of this Study. As a result of the failure of industry restructuring, SCE and SDG&E were ordered to operate SONGS for the benefit of ratepayers after 2003. Pursuant to that requirement, SCE's General Rate Case (currently before the CPUC) and SDG&E’s Cost of Service case (to be filed later this year) will ask the CPUC to return SONGS to traditional cost-of-service rate making beginning in 2004. This will replace the ICIP agreement relative the post-2003 time frame, and should ensure that the plant continues to operate at least for the foreseeable future.

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17 San Diego Air Pollution Control District.
18 CAISO must-run designation is required to ensure these plants are available for local reliability.
19 Unit 1 was a first generation Westinghouse design, while Units 2 and 3 are Combustion Engineering, Inc. designs. [http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/sanonofre.html](http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/sanonofre.html).
21 SDG&E.
If and when the remaining SONGS units are shut down, replacement generation plants equal to its capacity will need to be built in Southern California to provide for system stability. The total capacity that would need to be replaced is equivalent to that of three to four typical combined cycle plants being built today. Therefore, the loss of this generation capacity will be significant in terms of available supply and system stability. If it has not yet been completed, an evaluation of the costs of extending SONGS’ life should be completed by SCE and SDG&E in order to begin planning for replacing this capacity if the plants do not continue to operate.

SDG&E also retains long-term purchase power contracts with Portland General Electric for about 85 MWs delivered at the California – Oregon Border (“COB”) (which enters SDG&E’s system via Path 44 – the South of SONGS path) and Yuma Cogeneration Associates for 57 MWs delivered at North Gila Substation in Arizona (which enters SDG&E’s system via the 500-kV Southwest Power Link). All of these contracts are scheduled into SDG&E as imports over the ISO controlled grid and enter SDG&E’s service area at SONGS and Miguel.

4.3.2 New Generation Infrastructure

The first key issue facing California is the evaluation of whether or not there is significant new capacity being built and that it is available to meet future demand. The second key issue is whether or not this new capacity can be delivered to San Diego County and within the San Diego region. As the CEC noted in its 2002–2012 Electricity Outlook report, future load growth and generation supply are extremely uncertain, largely due to economic growth, weather and a tightening of the financial markets.

For the short-term, according to the CAISO, operating margins for the 2002 summer season are significantly higher than recent years. Barring extreme weather conditions and/or major generation or transmission outages, the CAISO anticipates there will be adequate resources available to meet the most likely operating scenario for forecasted 2002 summer peak demand and meet minimum operating reserve requirements. In addition, the CAISO anticipates that the transmission system will demonstrate adequate reliability performance during peak demand periods.

The WECC noted in its 2001–2002 annual report that 10,000 MW of new capacity was added in 2001. About sixty percent were combined cycle gas units. A total of 81,000 MW of new generation projects have been identified, of which, 28% are either in testing or under construction. Over 40,000 MW are estimated to be identified in the California/Mexico region. SAIC has completed a careful analysis of the WECC market and recently completed a new price forecast and model analysis. The Palo Verde region is going to be a large trading and generation location hub and North Baja could become a similar generation hub. This suggests that adequate transmission must be available in order to take advantage of this power.

For this reason, the region needs options it can exercise when supply provided by the market is uncertain. In this short timeframe, options are limited, but available. These options will be discussed in Chapters 5 and 6.

In 2001 and 2002 a total of 325 MWs of new CT were added. Table 4-1 lists the combustion turbines that became operational during 2001. These additions represent almost 2 years of load growth in the region.

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22 SDG&E.
23 Which is not to say there will not be electrical emergencies and possible rolling blackouts, as was the case on July 10, 2002 when the CAISO declared the years first Stage 2 and Stage 3 emergencies. During a stage 3 emergency, http://www.caiso.com/docs/2002/07/11/20020711300478205.pdf.
Table 4-1: New Generating Units Entering Service in 2001

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Developer</th>
<th>Maximum MW</th>
<th>Primary Fuel</th>
<th>Technology</th>
<th>Online Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lakespur</td>
<td>InterGen NA</td>
<td>90</td>
<td>Natural Gas</td>
<td>CT</td>
<td>7/2001</td>
</tr>
<tr>
<td>Chula Vista</td>
<td>RAMCO</td>
<td>42</td>
<td>Natural Gas</td>
<td>CT</td>
<td>7/2001</td>
</tr>
<tr>
<td>CalPeak Enterprise</td>
<td>CalPeak</td>
<td>49</td>
<td>Natural Gas</td>
<td>CT</td>
<td>9/2001</td>
</tr>
<tr>
<td>CalPeak Border</td>
<td>CalPeak</td>
<td>49</td>
<td>Natural Gas</td>
<td>CT</td>
<td>9/2001</td>
</tr>
<tr>
<td>CalPeak El Cajon</td>
<td>CalPeak</td>
<td>49</td>
<td>Natural Gas</td>
<td>CT</td>
<td>5/2002</td>
</tr>
<tr>
<td>Escondido Peaker</td>
<td>RAMCO</td>
<td>46</td>
<td>Natural Gas</td>
<td>CT</td>
<td>11/2001</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>280</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

While one large power plant is awaiting construction (Otay Mesa) and several plants are in the planning stages, all existing large non-nuclear generation plants will be retired by 2015 (or sooner), therefore, more than 1,600 MWs of generation will be required just to replace existing generation resources. Figure 4-5 illustrates the net additions to the San Diego County generation portfolio versus the retirements, based upon terminal retirement dates. As noted earlier, the state feels that there is sufficient capacity for 2002–2003 to meet peak load requirements. The supply deficit becomes more serious in 2004–2006. For this reason, the region needs to carefully evaluate the additional risks if the Otay Mesa Power Plant is not operational by 2004 along with additional transmission interconnection. Equally or even more important will be the degree to which the region implements more energy efficiency and distributed generation to mitigate or delay the need for this infrastructure.

Figure 4-5: Projected Cumulative Net Additions and Retirements of Generating Units in San Diego County

Many merchant developers of generating units have experienced financial crises recently. Calpine, a major developer of plants in California has announced a retrenchment in their development efforts. NRG/Dynegy, the owner of the Cabrillo Power Plant, has recently announced its parent corporation, Excel Energy, will purchase all outstanding equity. AES, another major developer, has also announced a significant reduction in capital spending and new development efforts. This leads to the conclusion that some projects that were announced in the last 2 years may not be completed.

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The reasons many of these projects will be cancelled include the following:

- Recent wholesale prices have been depressed due to the slow economy, improved hydro conditions and the addition of new plants in the region. These conditions have alleviated the price spikes that occurred last year and thus reduced the incentive to construct new assets.
- Many of the developers of merchant generation have experienced deteriorating financial conditions due to the fallout of the Enron and corporate accounting debacles.
- The State of California is in the process of renegotiating purchased power agreements signed last year creating price uncertainty for developers.

4.4 San Diego County’s Electric Power Market

San Diego County is not an attractive location for locating new power plants due to the lack of suitable sites away from populous areas, which results in increased costs and delays due to environmental concerns. Some of constraints of building new power plants are presented in Table 4-2.

Table 4-2. Constraints in Building New Power Plants in Southern California

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability and Cost of Water</td>
<td>Southern California and San Diego currently suffers from severe shortage of water. The relative cost of this commodity compared to other regions in the WSCC is high.</td>
</tr>
<tr>
<td>Availability and Cost of Coal</td>
<td>San Diego has no potential for the development lower-cost coal-fired generation. This technology requires a significant amount of water, a large site, and significant rail access for unit trains of coal. Furthermore, coal emits much higher levels of SO\textsubscript{X} and NO\textsubscript{X} and San Diego is distant from inexpensive sources of coal.</td>
</tr>
<tr>
<td>Availability and Cost of Natural Gas</td>
<td>San Diego has the most expensive natural gas in the WSCC.\textsuperscript{26} The state's two main gas supply basins are the Permian Basin and the San Juan Basin. The El Paso Pipeline Company does have major pipeline facilities tied to these basins. Inasmuch as this pipeline provides low cost natural gas in the Southwest, the cost to transport natural gas from the California border to San Diego is relatively high.</td>
</tr>
<tr>
<td>Regional Cost Levels</td>
<td>San Diego is a high-cost region to both construct and operate generating assets. In addition to the normal issues associated with regional cost differentials of electric generation, units in California must be able to generate electricity while emitting much lower levels of NO\textsubscript{X} and simultaneously using less water. Additionally, the financial community currently views California, in general, as an unfavorable investment climate for new plants due to the current CDWR long-term power contract commitments and regulatory uncertainty.</td>
</tr>
<tr>
<td>Availability of Suitable Generation Sites</td>
<td>There are very few suitable generating sites in San Diego given the limited amount of suitably zoned land. Coastal land is considered premium property and tends to be congested. Sites are generally limited to those near the intersection of natural gas supply and transmission access.</td>
</tr>
<tr>
<td>Cost to Transmit Power to Load Center</td>
<td>This is the one area where San Diego excels. This region is a major load center with relatively little indigenous generation resources.</td>
</tr>
</tbody>
</table>

\textsuperscript{26} SDG&E reports that transport gas from the California border is $.20 of a total $3.00/MMBTU cost.
A substantial number of new power plants and energy infrastructure projects are planned for the region. Figure 4-6 depicts the approximately 4,000 MWs of new plants expected between 2002 and 2004 in the California border region. Most of the new plants being added during 2001 and 2002 are combustion turbines, which dispatch at approximately $45/MWh. The annual capital cost of these units is $65/kW-yr. The average heat rate of these units is approximately 12,500 BTU/kWh; nearly 50 percent more inefficient than state-of-the-art combined cycle plants. The average unit cost for these plants is about double what the current market price is for power on the open market and the capital cost is close to the price point where significant numbers of consumers will participate in demand response programs (assuming that $75/Kw-yr is a price threshold where a significant proportion of the market is willing to participate).

Figure 4-6. Projected New Plant Development In the San Diego Region

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27 This study does not use a manufacturer’s heat rate but one that assumes ramp up, ambient temperatures, humidity and other operating conditions that can lower heat rates.
Units planned for 2004 are more speculative. Imports, long-term CDWR contracts and regional WECC prices may influence the use of these plants in the region.\textsuperscript{28} San Diego County will have to compete with plant development costs in other regions and also have to secure power contracts to mitigate the investment risk of the units.

Power plants under construction in Baja California appear to have a higher probability of being completed than new plants in San Diego County, due to lower cost of construction, greater political and regulatory support and less rigorous environmental requirements. While planned new generation capacity in Baja California is close to 1,900 MWs, much of this supply is intended to meet the growing needs of Mexico. The actual transmission capacity back across the U.S. border from Baja Norte into California is 800 MWs. There are approximately 500 MWs of potential transmission capacity additions being studied for power delivery from Baja California to California. However, while this capacity may increase supplies that could have an economic benefit, they do not necessarily improve reliability, since all the power would be imported through the Miguel Substation.\textsuperscript{29}

\subsection*{4.4.1 The Need for New Power Plants}

Increasing in-region electricity production is paramount to the regional goal of cost-effective and reliable energy supply. The only baseload generation projects anticipated for construction in the near future are the replacement of South Bay Power Plant, Calpine Energy’s Otay Mesa facility and possibly one or two other plants, including the proposed Sempra Energy Plant in Escondido and a proposed plant in the City of San Diego. The Otay Mesa Power Plant completed its certification process in 2001 and is awaiting secured financing by Calpine Energy. The plant is to be built on a 15-acre site in San Diego County, about 1.5 miles north of the U.S./Mexico border.\textsuperscript{30}

This facility is proposed to be a $300-million, 510-MW combined cycle plant. Although recent CDWR contract renegotiations with Calpine required “commercially reasonable efforts” for Otay Mesa to be on-line by December 31, 2004, there is no firm requirement that the plant be operational by this date. Calpine has a wide range of resources to draw upon to fulfill its contractual obligation to the State so it does not need to build Otay Mesa to fulfill this obligation. Moreover, Calpine’s obligation in the contract to use “commercially reasonable efforts” to construct Otay Mesa only means that Calpine will build Otay Mesa if it is profitable for Calpine to do so. There are provisions that would allow the State to step-in and build the power plant if necessary, however, whoever builds the Otay Mesa Plant, would need to contract for its output. This contracting would compete with existing CDWR power purchase contracts and may force SDG&E to sell power from existing CDWR contracts into the market at discounted rates.\textsuperscript{31} Thus, there is still significant uncertainty regarding if and when this plant will be built and operational. Additional information regarding the proposed Otay Mesa Power Plant can be found in Appendix D.

SDG&E has stated that a major question regarding Otay Mesa is that limited output from that unit will be needed because existing CDWR contracts satisfy the vast majority of its “net short requirements.” As such, SDG&E would be “in a situation of having capacity that is above and beyond the needs of San Diego, and the capacity would do nothing more than displace an existing generating unit.”\textsuperscript{32} Moreover, SDG&E notes that the renegotiated contract states that the “Delivery Point” for Calpine’s 1,000-MW obligation is “Any point or points designated by Seller on North Path 15, except as the Parties may otherwise agree,” but these scheduling points are remote from SDG&E’s service area. This is yet another factor that weighs against Calpine going forward with Otay Mesa. It should also be noted that CDWR’s ability to enter into a new supply contract to serve utility loads ends as of December 31, 2002.

\textsuperscript{28} Except Otay Mesa.

\textsuperscript{29} The California Independent System Operator (CAISO) is responsible for reliable operation of the transmission grid consistent with of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC).

\textsuperscript{30} http://www.energy.ca.gov/sitingcases/otaymesa/index.html

\textsuperscript{31} Conversation with SDG&E staff, July 2002.

\textsuperscript{32} SDG&E Valley-Rainbow Testimony to the CPUC, July 2002. However, if new, more efficient generation were added, it may offset an older inefficient unit and also postpone the development of a new unit that is not as far along in the permitting and project development process.
Two additional large-scale, baseload power plants that have been announced include a 500-MW plant in Escondido by Sempra Energy, and a 750-MW plant in eastern San Diego by ENPEX.\textsuperscript{33}

### 4.4.2 Repowering Existing Power Plants

Repowering Cabrillo Power Plant may include the following:

- Replacing the existing units to simple cycle or combined cycle gas units, which includes adding a gas turbine and in the case of a combined cycle unit a Heat Recovery Steam Generator (HRSG). The existing steam turbines may be used or replaced.\textsuperscript{34}
- A 10-percent or greater improvement in plant efficiency can occur.
- Repowered stations also include advanced emission control technology. Three of five boilers at Cabrillo are currently equipped with selective catalytic reduction (SCR). The remaining two boilers will be equipped with SCRs by the end of 2003.

### 4.4.3 New Power Plants in Baja California

There are three major power plants being built in Baja California, including the 750-MW Intergen plant (the La Rosita Power Project or LRPP), the 310-MW La Rosita Expansion Project (“LREP”) and the 600-MW Sempra Energy Resources plant in Mexicali (Mexico), which still leaves a substantial amount of proposed generation that may not be built.

### 4.5 Electricity Transmission

#### 4.5.1 The Role of Transmission and Advantages and Disadvantages

The second means to provide electricity supply to the region is through high-voltage transmission interconnection to broader energy markets. The State Legislature declared that "it is in the public interest to reconfigure and add transfer and replacement capacity to electric transmission facilities to facilitate competition in electric generation markets, ensure open, nondiscriminatory access to all buyers and sellers of electricity, to assure all buyers and sellers of electricity that they will receive comparable service, and to ensure continued reliability of the transmission grid."\textsuperscript{35}

The transmission grid provides for a number of functions. These functions include:

- Support wholesale market transactions and help stabilize electric prices
- Improve system reliability
- Create opportunities to site new electric generation
- Improve system stability and reliability
- Provide additional voltage support.

The chief advantages of adding new transmission are:

- Its ability to provide more access to diversified and potentially less expensive plants as opposed to building plants in San Diego County;
- Increase the number of sites where new generation units could be sited in San Diego County;
- Increase reliability though the addition of a new intertie;
- Increase fuel diversity by increasing the markets that San Diego County has access.

The disadvantages of new transmission are:

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\textsuperscript{33} ENPEX Corporation, located in San Diego, California, is a privately held owner and developer of energy related projects. It has joint ventured with major international energy corporations on a wide range of projects including oil and gas exploration and production, cogeneration and electric power generating projects and the development of advanced technology.

\textsuperscript{34} See “Repowering of Existing Power Station.” http://www.mhi.co.jp/pwer/e_power/product/boiler/repowering/

\textsuperscript{35} Subsection (k)(1) and (k)(2) of Section 1 of Senate Bill (“SB”) 1388.
New transmission is potentially very costly;

- Siting issues for new transmission lines are often complex due to the large number of parties that are affected by such projects (e.g., visual impacts, potential impacts on property values, concerns for the impacts of electric and magnetic fields (EMF))

- This capital cost is taxed for 30 or more years.

The taxing of new transmission is also viewed as a potential benefit to local governments where the line may pass through. Taxes will also apply to new generation stations. On an equivalent capacity cost basis (e.g., such as for a combined cycle gas turbine) new transmission is more costly than generation. However, combined cycle units using natural gas run the risk of price volatility. When one considers the reliability value and potential benefits in stabilizing prices and also comparisons to more expensive forms of generation and supply, transmission additions and upgrades can be very attractive. Increasingly, in congested areas like New York City or Seattle, distributed resources may be attractive alternatives to transmission upgrades, especially if the transmission is routed through dense corridors and in areas of aesthetic value. This suggests that resource investments do involve trade-offs and options. On some occasions, a broader portfolio perspective should be considered in evaluating different investment levels in resource options.

Currently, there are only two points of interconnection today between SDG&E’s service area and the external grid. These points are at the San Onofre Nuclear Generating Station (“SONGS”) switchyard in the northwest and the Miguel Substation in the south. The SONGS switchyard owns the north half of the switchyard and the four 230 kV lines to its service area. These four SCE lines comprise what is known as WSCC Path 43, or the “north of SONGS path.” SDG&E owns the south half of the switchyard and the 230 kV lines to its service area. These five SDG&E lines comprise what is known as WSCC Path 44, or the “south of SONGS path.” The Miguel Substation serves as the western terminus of SDG&E’s 500kV Southwest Power Link (“SWPL”) as well as the northern terminus of a 230 kV interconnection with Comision Federal de Electricidad’s (“CFE”) Tijuana Substation in Mexico. The Mexico CFE system is not expected to have surplus resources for supplying the San Diego area during the period studied, so the CFE system was assumed to have balanced load and resources. This assumption for CFE resulted in that system having no effect on the San Diego Reliability Must-Run (RMR) Study results. Historically, San Diego County has relied upon imports of electric power to meet about one half of the supply needs of the region (a higher percentage during the summer months, lower during the winter). SDG&E has an effective transmission import capability of 2,850 MWs south of SONGS. Each year, SDG&E proposes an updated 5-year Plan for upgrading existing and building new transmission capacity to the California System Operator (CAISO).

The southern California transmission grid suffers a north-south constraint at a key internal path within Northern California, known as Midway–Los Banos (Path 15) which transfers energy to the major load centers in Northern California. The limits on Path 15 are not expected to significantly change from last summer. In the north to south direction, the transmission limit on Path 15 is 1,275 MWs. In the south to north direction, the transmission limit on Path 15 is 3,950 MWs.

Significant transmission upgrades were implemented in 2000 and 2001 to raise both the SDG&E simultaneous Import Limit to 2,750/2,850 MWs and the non-simultaneous Import Limit (Path 44, South-of-Songs) to 2,200/2,500 MWs. With these higher simultaneous and non-simultaneous import capabilities, adequate imports can be handled during the projected peak for this area.

One new transmission upgrade scheduled for completion by June 2002, is the installation of a new 230/69 kV Transformer Bank at Sycamore Canyon substation. This project is expected to mitigate local SDG&E constraints based on the forecasted load levels.

37 SDG&E paid local generators approximately $40 million under RMR contracts in 2001 to ensure that this generation would be available to meet the reliability needs that could not be satisfied by transmission.
38 CAISO 2002 Summer Assessment.
As part of its 5-year plan, SDG&E has proposed building a new transmission line from the Valley Rainbow Substation in Northern San Diego County to the Valley Substation in Riverside County. SDG&E’s filing for certification at the CPUC states that the project is needed by 2005 to meet the statewide grid planning reliability criteria established by the CAISO. The CAISO governing board has previously approved the need for Valley Rainbow, or a project like Valley Rainbow. SDG&E believes that the consumers of San Diego will face a risk of outages that is unacceptable by the transmission reliability standards in 2005. A final decision on the project is expected from the CPUC later this year.

4.5.2 Transmission Issues

4.5.2.1 The Valley-Rainbow Interconnect

The $300 million Valley-Rainbow Interconnect Project will provide an interconnection between SDG&E’s existing 230-kilovolt (kV) transmission system at the proposed Rainbow Substation on Rainbow Heights Road near the unincorporated community of Rainbow in San Diego County, and Southern California Edison’s (SCE) existing 500-kV transmission system, at the Valley Substation on Menifee Road in the unincorporated community of Romoland in Riverside County.

The need for the Project arose out of recognition in the ISO’s 1999 transmission planning process that by 2004, SDG&E’s import capability would fail to meet the ISO’s Grid Planning Criteria. After determining that “all practical 230 kV alternatives of upgrading [SDG&E’s] system [had] been exhausted” in its 1999 grid assessment study, SDG&E, in conjunction with the ISO, Southern California Edison (“SCE”) and other ISO stakeholders conducted technical studies evaluating wires alternatives on the basis of project reliability, cost effectiveness and construction feasibility. These technical studies included several alternatives for 500 kV lines from SCE’s system to the proposed Rainbow Substation site in SDG&E’s system and also considered a second Southwest Power Link (SWPL) between SDG&E’s system and Arizona. The joint study concluded that a Valley-Rainbow 500-kV line is the “preferred alternative” based on cost, electrical performance, and ease of construction, among other factors. Based on its own consideration of these facts, the ISO Board first approved the Project in May 2000. Since then, the ISO Board has confirmed the need for the Project three additional times, most recently in March 2001.

The project reliability contribution to meet the ISO’s criterion that the transmission system be planned to meet projected load with the largest single transmission element and the largest single generator out of service (the “G-1, N-1” criterion). The Project accomplishes this objective by initially increasing the import capability of SDG&E’s system by 700 MWs, from 2,500 to 3,200 MWs. While this 700-MW increment in import capability meets SDG&E’s immediate reliability needs, the project

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39 Although restructuring of the electricity industry transferred responsibility for ensuring short- and long-term reliability away from electric utilities and regulatory bodies to the Independent System Operator and “various market-based mechanisms” (P.U. Code Section 334), the CAISO’s Federal Energy Regulatory Commission (FERC) approved tariff requires that “The ISO or the Participating TO [Transmission Owner], in coordination with the ISO and Market participants, through the coordinated planning processes of the WSCC and the RTGs [regional transmission groups], will identify the need for any transmission additions or upgrades required to ensure system reliability consistent with all Applicable Reliability Criteria.”


41 http://www.cpuc.ca.gov/environment/info/dudek/valleyrainbow/vicinity.jpg

42 Exh. 100 (at p. 10).

43 Exh. 100 (at 5/11/00 memo attachment at p. 4).

44 Specifically, the Valley Rainbow Interconnection Project consists of six major elements: (1) a 500 kV transmission line, (2) a new Rainbow substation, (3) modifications to the Valley substation, (4) an upgrade to the Talega – Escondido 230 kV line, (5) a rebuild of the 69 kV transmission line currently installed on one side of the Talega – Escondido 230 kV transmission line and (6) system voltage support. Exh. 100 (at p. 3). See also Exh. 1 (at pp. II-5 to II-6).

45 Exh. 100 (at p. 7 and attachment).

46 In its testimony, the ISO also refers to the G-1, N-1 criterion as the G-1/L-1 criterion. Exh. 101 (at p. 6).

47 See, e.g., Exh. 1 (at p. II-23).
also provides important going-forward options for further increases in import capacity through future modifications to substations and other upstream and downstream transmission facilities.\textsuperscript{48}

In a separate hearing the CEC updated major shortages of capacity during summer peak and the Commission noted that additional transmission would help reduce this risk by increasing the transfer capability into San Diego County by 26 percent from 2,850 to 3,600 MWs and potentially increasing the value of generating assets within the County by giving them access to markets external to the County. Additional hearings are rescheduled this year on the matter.

The cost of the Valley-Rainbow Project, or the annual revenue requirements required to be charged to consumers to support the installation cost of the project, is estimated by multiplying the total installed project cost by the fixed charge rate (currently 17.8 percent). The current installed cost estimate for the project is $341 million. The revenue requirement is $60.7 million and would include an allowance for operation and maintenance.

Over the next 30 years there will likely be major new transmission developments affecting the San Diego region that will involve projects beyond those that are now under consideration. The region needs more transmission access from the North, South and East. An additional 500-MW transmission line through Riverside County, to Devers or Valley, or a second 500-MW line following the right of way of SWPL are possibilities. In addition, private developers have proposed a new direct-current (DC) transmission line connecting Southern California to Wyoming or Utah, thereby creating access to low-cost coal generation. These new DC lines are likely to be costly—$1–2 billion for the entire project including the transmission lines and current conversion equipment. But, they can save a substantial amount of money through potentially lower fuel prices and reliability. There are growing advancements in high-temperature superconducting transmission lines and with DC transmission\textsuperscript{49}. DC transmission is very costly considering both the voltage conversion and the cost of the transmission line and right of way. This is why the more conventional DC transmission is limited to distances of more than 400 to 500 miles. DC has the benefits of lower line losses, better control over reactive power and the need for less spinning reserve. The San Diego region could possibly enter into a consortium of interests wanting to build a DC transmission line, if it makes economic sense. The actual markets where DC transmission will be used are very situational and speculative. It is also believed that more superconducting transmission will be used especially in dense markets, Breakthroughs will likely occur over the 30 year study period that will warrant serious consideration of DC and superconducting transmission. The actual economics will have to be evaluated when the right project opportunity is proposed, which is not well defined at the moment.

4.5.2.2 Planning for Transmission

The CAISO “G-1, N-1” Grid Planning Criteria require that the system be capable of meeting projected load under normal conditions with all facilities in service; that is the system should be capable of meeting peak load without resorting to involuntary load curtailments. In addition, CAISO Grid Planning Criteria require that the system be capable of meeting projected load under single contingencies with the largest single transmission element out of service and the largest generating unit out of service.

The critical G-1, N-1 contingency for which SDG&E is required to plan occurs for an outage of the largest generating unit in the SDG&E system (i.e., Encina Unit 5, which is 329 MW), followed by an outage of the most critical transmission line (i.e., the Imperial Valley – Miguel section of the SWPL). Under this condition, the only firm import path left into the service area is the interconnection at SONGS, which has an existing southbound rating of 2,500 MWs. This rating is what is called SDG&E’s non-simultaneous import limit (“NSIL”), which measures the ability to import power into SDG&E’s service area via the 230 kV tie with SCE’s system at SONGS during an outage of the SWPL. As previously discussed, construction of the Valley Rainbow Interconnect Project would initially increase SDG&E’s NSIL by 700 MWs from 2,500 to 3,200 MWs (with further increases possible in the

\textsuperscript{48} See, e.g., Exh. 5 (at p. I-6, pp. II-5–II-52), Tr. Vol. 4 (5/6) at pp. 380 (line 4) - 382 (line 5) (SDG&E – Avery) and Exh. 2 (App. A at p. 16 showing ultimate potential buildout of Rainbow Substation).

\textsuperscript{49} For a more detailed treatment of the state of DC transmission and the economics of DC transmission see: http://www.abb.com/hvdc.
future). Based on the methodology and criteria described above, SDG&E projects a G-1, N-1 deficiency of 81 MWs in the summer of 2005 rising quickly to 719 MWs in the summer of 2010.

The CAISO has developed a more stringent standard in the San Francisco Greater Bay Area. In the San Francisco Greater Bay Area, the CAISO Grid Planning Standards require that four generating units be removed from service along with the most critical single transmission line in assessing the need for further system upgrades. The more stringent standard for the San Francisco Greater Bay Area is necessary due to the large number of generating units in that area and the higher than normal outage rates of those units. The large number of units in the area increases the probability that at least one unit will be out of service, and in fact, in the San Francisco Greater Bay Area, historically there has been one or more units out of service more than 90 percent of the time.\(^{50}\)

The addition of Otay Mesa by itself could have the effect of deferring Valley Rainbow for several years (from 2005 to 2009) but only if construction of Otay Mesa (1) did not result in retirements or economic displacements of any existing facilities and (2) if the output of the plant was dispatchable to meet SDG&E’s local reliability needs at peak demand.

At one point, the CAISO was considering whether to conduct a competitive solicitation for non-wires alternatives to Valley Rainbow. The CAISO abandoned the idea,\(^{51}\) in part due to the staff concerns, including:\(^{52}\)

“Pitting generation against transmission challenged the notion of facilitating a competitive market. Staff felt that “While there certainly may be a place for “competition” between generation and transmission projects at a local level…any tangible short-term benefit resulting from a generation project deferring or displacing a larger regional transmission project is likely to be outweighed by the less tangible costs of reduced access and therefore less competition. Moreover, reliance on “market” generation to displace the need for critical regional transmission facilities will inevitably give rise to market power problems and the need to “negotiate” a deal with such generation on a long-term basis.” Although a non-wires project could potentially defer or displace the Valley-Rainbow project and result in a lower annual costs to consumers, the total net benefits were unclear. One potential project could possibly displace the Valley-Rainbow project, however, it would not increase supply in the San Diego area, because it displaces imports in the area, and would not add to the load serving capability in the area.”\(^{53}\)

SDG&E also contends that less new generation would be built if the Valley-Rainbow Transmission Interconnect is not built\(^{54}\) since the economic incentive for generation development will be limited “due to congestion constraints going north from SDG&E.”\(^{55}\) Conversations with Calpine Energy indicate that if and when the Valley Rainbow Transmission Line is built is not a criteria in deciding when to start and complete the construction of the approved Otay Mesa Power Plant. Although the ISO indicated that it had “not undertaken a formal analysis to estimate how likely or significant this impact would be,” the ISO further indicated that “it seems reasonable to expect that without adequate transmission infrastructure for exporting power of the San Diego area, some developers will choose not to proceed with proposed new projects in San Diego.”\(^{56}\)

SDG&E’s current northbound export capability is 720 MW. This figure is based on the approved WSCC rating of the North of SONGS Path (Path 43) and the current ownership shares in SONGS that
are delivered northward over Path 43. Construction of the Interconnect Project would more than double the existing northbound capability. This would translate into an additional 750 to 1,000 MWs of generation resources that could be exported from SDG&E and northern Mexico to meet California’s statewide resource requirements and enhance the regional and statewide grid. This increase in export capability would increase the net resources available to meet statewide resource requirements and reserve margins.  

Without Valley Rainbow, the generation development in these areas may be limited to about 1,000 to 1,400 MWs due to congestion constraints going north from SDG&E.  

An outage of the single interconnection at SONGS can leave SDG&E with a serious power shortage, such as that which occurred on February 27, 2002. If the Valley Rainbow Interconnect Project had been in operation at the time of this event, it would have prevented the need for firm load shedding of some 211,000 customers (approximately 300 MW) in SDG&E’s service area.  

The CAISO conducted a preliminary study of various alternative long-term transmission grid expansion concepts and evaluated how effectively each could mitigate this risk. All of the alternative expansion concepts assessed by the ISO for purposes of mitigating the risk of voltage collapse and line overloads included a Valley-Rainbow 500 kV line as a common building block. Even if other transmission reinforcements in the CAISO’s June 2000 report are not built, Valley Rainbow includes more than 1,100 megavar (“MVAR”) of voltage support apparatus that would significantly mitigate reliability risks in the Southern California grid in the absence of SONGS generator capacity by enhancing regional voltage stability. 

How the nation, state and region approach transmission planning needs to be totally rethought and redesigned. A priority area of endeavor by FERC is to use existing and new transmission infrastructure—through the management of large Regional Transmission Organizations (RTOs) to support the market function. Inadequate transmission capacity into an area results in potentially higher locally capacity prices, market power, increased unreliability and a need for voltage support. Additional transmission may also help diversify the fuel mix of future power supply. 

Current transmission planning can be improved. While yearly 5-year transmission plans are completed by SDG&E, they do tend to react to the location of planned generation. In turn, new plants are likely to be located near sufficient transmission. A planning of “convenience” occurs. This type of planning does not sometimes focus on what is best for markets, networks, and reliability. This is why FERC proposed rules and RMR units are used – to make up for gaps or resulting problems regarding network integrity in the future. A broader set of issues and concerns will be considered. 

What is needed is an advanced transmission planning study that looks at the county as a whole and attempts to optimize the location of new generation, distributed generation and other resources and also suggest which areas to target for improvement for the local network. New forms of optimization models are being created that improve load profiles for generation and demand side equipment. This should be done over the next two years, as issues regarding new plants and the need for new transmission projects get resolved. SDG&E and SDREO should consider jointly completing the study. 

Over the next 30 years additional technological improvements in transmission operation and control are likely to occur. There may a greater use of direct-current lines or the use of advanced technologies like high-temperature superconductors to improve current flow. In addition, there is also a growing role of merchant transmission investments.  FERC and U.S. DOE are interested in merchant transmission because it can introduce competition into what historically has been viewed as a natural monopoly.

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57 See generally Exh. 1 (at pp. II-10, II-11 and pp. II-20 to II-23) (as modified by Exh. 4) and Exh. 3 (e.g., Table 1).
58 Exh. 4 (at p. II-30).
59 Exh. 5 (at p. II-20).
60 CAISO, “San Onofre Nuclear Generating Station Operational Study – Phase 2 Report Transmission Plan of Service” (June 12, 2000).
61 Merchant transmission lines are built by investors and recover costs in the market, rather than through regulated transmission rates.
4.6 Other Issues Affecting Electricity Supply

There are additional regulatory and legislative issues that will impact the need for traditional grid-based power supply.

4.6.1 Effects of State Executive, Legislative, Regulatory and Policy Decisions

There are a number of ongoing federal, state policy and regulatory proceedings that will have an impact on the availability and price of electricity. On the electric side, the state needs to reach a consensus on the future market model—will the state continue to rely on market-based, competitive markets, or will the state move back to traditional cost-based, regulated markets. Utility ownership of generation assets, including distributed generation is also under consideration.

In addition, California needs to reach consensus on how to address regional transmission congestion and define the appropriate level of reserves beyond the required seven percent reserves to create stable electric prices. A more integrated approach is needed on plant siting and new transmission planning for both the California Independent System Operator (CAISO) and the Western States Coordinating Council. California drives much of the Western regional electric demand, but the probable and more attractive supply opportunities are in other WSCC states, which may provide more viable locations for new plant development although impending transmission constraints into the region have to also be considered. These factors affect local prices and reliability and hence, why a robust regional energy plan is necessary.

There are also local tariff constraints that inhibit local wheeling of distributed generation that also needs to be evaluated in light of the region's need for additional generating capacity in the region. Additional local generating supply in the county is possible if tariff provisions were to be modified. For example, the City of San Diego and the San Diego County Water Authority could potentially provide 50 MWs or more of generation through a combination of renewable and distributed generation resources that already exist or are being currently considered for development to meet internal needs. Other public and private entities, including several of the larger commercial and industrial firms as well as the military could potentially contribute significant generation resources to meet the need of external users if wheeling restrictions were modified or removed and if the business case could be justified.

Perhaps one of the biggest issues facing the state of California is the structure of the future market. Currently retail choice for CAISO-served customers have been eliminated with a few grand-fathered exceptions. In addition, the state legislature is starting to investigate new market models. It may take 2 to 3 years before consensus is reached on what the new market model should consist of. One important consideration for San Diego County is to encourage a large regional WSCC based wholesale market that offers day-ahead trades and also the possibility for bi-lateral power supply options. Local state utilities should be allowed to have generation assets for meeting local retail loads (even though functional separation would likely exist). The state needs to dramatically build its reserve margins up to 15 percent while carefully monitoring available import supplies of the surrounding states that make up the WECC. The 15 percent is not a mandatory reserve, but a commonly accepted estimate for minimum reserves for reliability and price stability.

Sufficient margins are important because in the electric utility business, there is little ability to store the commodity to be used when it is needed. Therefore high cost assets (generators) need to exist in order to provide the power at the time of peak usage. Consumers need to pay “rent” in order to have these assets available when they are needed. In the spot power market, this “rent” is paid via a “scarcity premium” that gets added to incremental costs when marketers price the output of their facilities.\textsuperscript{62} These bid adders or scarcity premiums can be quite large. During 2000, generators could price electricity at levels that were low enough not to cause voluntarily curtailment. Generators contend that they need to capture these high “scarcity premiums” when conditions allow them to do so in order to cover the many times during the lifetime of these assets when supply/demand is such that competition will result in very little (if any) “scarcity premium” in the pricing of the commodity.\textsuperscript{63}

\textsuperscript{62} Exh. 1, Ch. IV (at p. 3-2).
\textsuperscript{63} Id. (at pp. 3-2 to 3-3).
Critical regulatory and legislative issues that the region should closely monitor include:

- Whether or not California will adopt locational or zonal pricing to reflect regional transmission constraints;
- The role and impact of the California Power Authority and what it can do to help the City and County of San Diego leverage resources to implement the energy strategy;
- Future relationship of municipal generation assets and dispatch to CAISO power—this additional power to the market could help moderate prices;
- Potential joint investment action of municipals and authorities with private plant developers;
- New legislation regarding the role of IOUs in purchasing power and renewable portfolio standards. This may provide the region an opportunity to provide these additional renewable resource local.

4.6.2 Federal Initiatives

FERC Order 888 and recently affirmed by the U.S. Supreme Court gave FERC plenary authority over interstate transmission. In addition, the Supreme Court encouraged FERC to specify in more detail provisions in which it would investigate and correct bundled retail transmission discrimination. FERC has jurisdiction over retail bundled transmission where it believes some forms of discrimination exist. In addition, Order 888 ordered functional unbundling of generation and transmission costs. Also, in a separate working paper by FERC, “A Vision of the Future,” FERC endorsed the single tariff model for transmission and avoided the current practice of inflating transmission tariffs due to a “pancaking” of tariffs over different transmission lines. Order 888 also led to the creation of ISOs. However, this was a voluntary and extremely time-consuming process that was not progressing as much as FERC would like. This led to Order 2000.

FERC Order 2000 calls for the formation of large RTOs to coordinate markets and ensure the reliability of the nation’s transmission system. Regional characteristics of RTOs must demonstrate:

- Management independence of market participants
- The scope of RTO functions must be broad to sufficiently carry out their operations
- Each RTO must coordinate the security for the region and have excluding authority for maintaining short-term reliability of the grid it operates.

Future RTOs are expected to perform eight important functions:

1. Tariff administration and design
2. Congestion management
3. Parallel path flow
4. Ancillary services
5. Open Access Same Time Information System Administration (OASIS)
6. Market monitoring
7. Planning and expansion, and
8. Interregional Coordination.

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64 LMP pricing is a type of zonal or nodal pricing that charges variable fees based on day ahead and real time markets for power on a day ahead basis. Key cost components are the marginal nodal prices for the next increment of load at a given time (based on demand bids or supply offers), congestion and losses. For a more detailed discussion of LMP pricing, see: http://www.smd.iso-ne.com/cmsms/Standard_Market_Design/Frequently_Asked_Questions/Locational_Marginal_Pricing.html. Also see: http://www.pjm.com/lmp/docs1/control_page.html. Application of this type of pricing varies by RTO/ISO. The California is going to a form of locational or nodal pricing. FERC in the new market design wants to see more LMP pricing like PJM uses. It would be prudent for power system planners in California to assume that this form of congestion management and pricing will occur in the future.

65 SB 530 (Sher) would require utilities to increase the amount of renewables in their purchased power mix by one percent per year to achieve 20 percent renewables by 2015.

66 Pancaking refers to the layering of transmission costs of various transmission system owners.

FERC in 2001 began to use existing rules to implement this order. RTOs are expected to improve efficiency of grid operations and management, leading to a savings of from $1 to 10 billion annually.

At the Federal level there are a number of proceedings, past and future, that will have an impact on regional power supply. FERC is interested in its continued management of interstate wholesale electricity transactions. FERC also has responsibility for creating a standard regional market design. FERC also oversees the CAISO and will likely more closely observe its behavior in the implementation of the standard market design that will be released at the end of June 2002. FERC also has an interest in removing regional transmission congestion, improving regional transmission monitoring and control, and monitoring more closely market power and trading practices that may drive up wholesale power prices. FERC is also addressing the issue of siting and permitting new transmission right of way. Transmission costs less than 10 percent of the delivered price of electricity. It is also estimated that transmission saves consumers about $13 billion annually. In late July 2002, the standard market design was released and comments have been extended. The principle benefits of the “SMD” to San Diego County are more systemic and timely siting of transmission lines in adjacent states and more common market rules. Also, postage-stamp transmission pricing would be used vs. the current “pancake” pricing in the WSCC. This adds costs and restricts market dynamics.

Another key Federal activity for the Western states was the creation of Price Caps to control the extreme price volatility in the Western power markets. FERC Price Caps which set a ceiling of $90 per MWh for wholesale electricity sold through the CAISO will be increased to $250 in October 2002. This may lead to price stability and also help create additional value for demand reduction programs.

4.6.3 Local Initiatives

Perhaps one of the most significant initiatives is to issue local bonding to support the development of major new generation and transmission facilities. In addition, the County Water Authority, San Diego Port District and other municipalities can potentially expand their power development activities and organize major conservation and group renewable initiatives with other community organizations.

In addition, SDREO working with SANDAG and other public and private interests can spearhead a major conservation, distributed generation and renewable initiatives. Already SDREO has obtained more than $30 million to spearhead load monitoring, DG, and photovoltaic initiatives. The future over the next 30 years will require an eight-fold increase in combined conservation, demand response and distributed generation initiatives beyond what the market has already seen. These and other demand-side programs will be discussed in more detail in Chapter 5.

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68 U.S. DOE, National Transmission Grid Study (May 2002) p. xi.
5 Demand-Side Options: Energy Efficiency, Demand Response, Distributed Generation and Renewables

5.1 DSM, DG and Renewable Opportunities: Summary of General Findings

5.1.1 Energy Efficiency and Demand Response
The findings of the energy efficiency analysis are the following:

- Energy efficiency, demand response, distributed generation and renewables offer a significant hedge to volatile and rising energy prices and also contribute to achieving energy diversity.\(^1\) A substantial amount of cost-effective electricity energy and demand reduction savings is possible.

- Total cumulative peak demand savings cumulative through to 2030 are
  - 591 MW in low-impact case
  - 811 MW in medium-impact case
  - 1,111 MW in high-impact case

- The cumulative electric energy savings through 2030 are
  - 2,314 GWh in the low-impact case
  - 2,924 GWh in the medium-impact case
  - 3,775 GWh in the high-impact case

- Cost of energy efficiency and demand management
  - The cost per kW-year for the demand savings ranges from $17.28/kW-yr to $207.25/kW-yr. See glossary for kw-yr definition
  - The cost per kWh for electric energy savings ranges from 0.26 to 16.80 cents/kWh

- Natural gas savings from through 2030 range from 533 to 1,998 thousand MMBtu.

5.1.2 DG and Renewable Resources
The findings of the DG and renewable resource analysis are the following:

- Untapped supplies of wind resources exist in the Mountains and Desert Regions of San Diego County and significant wind and geothermal potential remain in adjacent counties and in Northern Baja California, limited primarily by sufficient transmission.

- Depending on the scenario, from 10- to 25-percent potential of DG and renewable resources exist. The actual potential depends on current and improved operating efficiencies of the technology, as well as electricity price and capital cost trends of the equipment. Approximately 2,150 to 3,260 MW of DG and renewable energy could be available between now and 2030.

- The legislature has passed a law that requires utilities to purchase one percent more renewables per year, up to 20-percent renewables by 2015.

- CHP, wind, PV and geothermal represent the largest distributed resources applications potential over the study period.

\(^1\) *Energy efficiency* is defined as a net reduction of energy required to meet a specific load. *Demand reduction* is a lowering of a portion of the load curve from the base load. *Demand response programs* include market driven and economy/emergency reductions in loads at specified time periods. *Demand-side management* is a term used to refer to the full set of efficiency, demand response and load reduction efforts by an individual customer, group of customers, utility initiated or third party. In modeling program cost effectiveness, programs were evaluated separately for their energy and demand impacts and energy and capacity values (or avoided costs) were used for each year of the analysis using the COMPASS model.
Wind and photovoltaics (PV) can constitute a substantial amount of renewable energy potential in the region with continued incentive support and innovative purchasing strategies such as aggregation in the near-term, followed by cost reductions through manufacturing improvements in the longer-term. Untapped opportunities exist to support indigenous renewables such as PV (e.g., SDREO/SDG&E-sponsored green power purchasing program to support renewables requirement similar to that which has been pursued at LADWP, SMUD and other metropolitan areas throughout the country). Future resource potential depends on capital cost reductions and incentives.

San Diego currently has 527 DG sites with a combined capacity of 372.3 MW—or 8 percent of current peak demand. Natural gas fueled combined heat and power (CHP) systems represent the largest percentage of DG capacity at 327 MW, followed by landfill gas (13.8 MW), hydro (9.8 MW) and photovoltaics (1.5 MW). 1 MW of PV produces about 200 KW per hour – annually, noted the City of San Diego, CA.

A stakeholder-based Distributed Generation Task Force was recently formed to a) assist in forming policy recommendations to support the Regional Energy Strategy, b) to evaluate and refine the findings of this study to develop future programs that maximize utilization of distributed generation and renewables public-good funding to achieve regional goals, c) review progress and incorporate findings and recommendations into an annual report to the public, and d) to develop and encourage financing mechanisms to assist in the development of DG.

5.1.3 Short Term (2002-2006)

- Energy efficiency, demand response, DG, and renewable resource acquisition plans need to be developed
- Aggressive monitoring and evaluation tools of measure performance are needed
- A collaborative strategy to merge energy efficiency with clean air, renewable and homeland security funds should be developed, because there are important synergies among these programs
- Packaged standardized solutions consisting of energy efficient, demand reduction, DG and renewable technologies should be developed and target marketed for selected business and institutional sectors
- An annual evaluation plan should be reported to the public on the performance of the region’s demand side and renewable efforts. Strong community feedback on the performance of programs should be reported. A formal cost-benefit report on the region’s energy efficiency, DG and renewable efforts should be reported to the public
- Energy efficiency programs should be tied to regional development efforts and economic development of new business and industries
- The region needs to communicate to businesses and energy companies the “option value” of energy efficiency, demand response, DG and other measures. A strong communication plan should be developed to provide the public and industry feedback on the relative success of programs and impact on alleviating additional supply requirements
- The region needs to consider the need for a DG portfolio in addition to a renewable portfolio that the state recently approved.
- CEC is responsible for setting building standards. The region should partner with the CEC to evaluate building standards to incorporate higher efficiency equipment.

5.1.4 Mid Term (2006-2010)

- Continue to monitor program performance and report results to the public
- Track economic development efforts and income to the community from the region’s jobs and businesses developed which program energy efficiency, renewable and DG options
- Work to change the portfolio of energy efficiency and DG options as avoided costs change and as new technologies are added
More target marketing of DG and other resources will be required. The regional energy development authority should consider additional financing opportunities for clean and green energy technologies.

Much more emphasis on demand response, automation, and dynamic or time-differentiated pricing may be necessary.

Demand responses tied to congestion and reliability issues may expand depending on load growth and congestion on the transmission system.

Increased automation of energy technologies with grid management may occur.

Expanded energy efficiency and demand response options in North Baja should be encouraged working in parallel with appropriate organizations to improve the emission impacts from the substantial electric generation that is expected.

5.1.5 Post-2010 Time Period

Significant expansion of wind and photovoltaic resources is expected during this period due to a reduction in capital cost and improved performance.

5.2 Background

5.2.1 Energy Efficiency

The San Diego region demonstrated in the summer of 2001 that as much as 2.2 percent or 81.7 MW of the region’s peak load requirements were met through pricing, customer education, and demand response programs. Figure 5-1 shows the major elements that comprise the peak demand for large commercial office buildings. The figure suggests that programs which target peak electric demand reduction (e.g., air-conditioning use, commercial lighting and other miscellaneous commercial loads) may be more cost effective because of the higher avoided costs that occur during the peak periods.

![Figure 5-1: Peak Demand Contribution for Large Offices](image)

Source: California Energy Commission.

Major questions that need to be addressed are:

- How much additional cost-effective demand reduction and energy efficiency potential remains in the county?
- What is the "optimal" investment level?
- Where should the resources be located?
This report provides answers to some of these questions. Additional research, analysis, community discussion, and public policy support will be needed to resolve selected issues. In the past, investment decisions in energy efficiency and demand reduction have been somewhat limited to CPUC proceedings and utility management. Potential opportunities include advanced pricing (time-of-use pricing and real-time pricing), automatic and/or web-based metering methods, and energy management and automation systems including smart appliances that can vary their coincident use based on market conditions, as well as many other conservation and demand reduction strategies. Many of these measures are currently supported by public-good funding.

The following approach was taken to estimate the potential for energy efficiency and demand response:

1. Review prior studies and reports on previous energy efficiency and demand response programs.
2. Identify and screen applicable programs and their success in other markets.
3. Identify key program data and assumptions for programs, including energy savings, expected customer acceptance, program costs, and market penetration.
4. Enter data into the COMPASS\(^2\) model for analysis.
5. Complete iterative analyses.

The result of the analysis provides SDREO with all the core data and results in a single relational database for future analysis. The benefit-cost analysis is consistent with the earlier developed California Standard Practice Methodology, and the assumptions, input data and program results from past year's programs can be used to update the modeling and analysis for year-to-year program planning.

### 5.2.2 Public-Good Energy Efficiency Programs

San Diego Gas & Electric and other third parties, like the San Diego Regional Energy Office and the City of San Diego, are currently offering a broad range of energy efficiency programs that provide incentives to encourage the purchase of energy efficient equipment and support practices for the design and construction of energy efficient buildings and homes. In September 2000, Governor Davis signed two bills—AB995 and SB1194—extending the systems benefits charge on electric distribution service to support these programs with $35 million in annual funding for energy efficiency programs through 2012.\(^3\) Currently, the CPUC is piloting the use of third parties to help implement energy efficiency and load management programs under AB 1890.

### 5.2.3 Distributed Generation (DG) and Renewable Programs

Grid-based power and centralized electric power plants will continue to be the major power supply source for the San Diego region in the foreseeable future. However, DG applications can complement central power by providing cost-effective incremental capacity to the utility grid or to an end user.

The Gas Research Institute (GRI) estimates that DG for systems of 25 MW and under will grow an average of 4 percent per year from 2001 to 2015.\(^4\)\(^5\) DOE/EIA projects that utility DG resources

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\(^2\) Comprehensive Planning and Analysis System, owned by Silicon Energy and licensed to SAIC for this project.

\(^3\) The CPUC is piloting and moving in the direction of allowing more non-utility administrators implementing energy efficiency and DG programs. SDREO is the major non-utility administrator of programs in the San Diego region.

\(^4\) [http://www.industrialcenter.org/consortia/distribgen.htm](http://www.industrialcenter.org/consortia/distribgen.htm). A wide variety of ranges in estimates are reported depending on the definition of technologies and markets. According to Resource Dynamics, there is a base of about 50 GW of smaller reciprocating engines. It is reported that less than 100 MW of capacity each year is sold by microturbines, fuel cells and other DG renewables. It is estimated that as much as 72 GW of DG may be added by 2010. See: [http://www.distributed-generation.com/market_forecasts.htm#Potential%20DG%20Market%20Size](http://www.distributed-generation.com/market_forecasts.htm#Potential%20DG%20Market%20Size).
between 2000 and 2020 will represent about 5 percent of total capacity or 19.1 GW of capacity added by 2020. DOE/EIA estimates that DG in buildings will grow from 8 billion kWh in 2000 to 27 billion kWh in 2020 for all fuel uses.\(^6\) Aggressive state and federal incentives offered for renewable and other clean DG resources are now supported by the State of California’s recently passed SB 532 that increases production of renewable energy from 12 percent of the state’s electric supply to 20 percent by 2010.

San Diego has 527 DG sites with a combined capacity of 372.3 MW—or about 8 percent of current peak demand. Combined heat and power (CHP) systems represent the largest percentage of DG capacity at 327 MW, followed by landfill gas (13.8 MW), hydro (9.8 MW) and photovoltaics (1.5 MW).

This study projects that a total of 2,200 to 3,200 MWs of DG and renewable capacity could be installed by 2030. This would represent approximately 30 percent of projected peak electrical demand for the region in 2030.\(^7\)

DG can also benefit electric utilities and ratepayers by avoiding or reducing the cost of transmission and distribution system improvements, avoiding congestion problems, adding voltage support, providing more efficient use of natural gas (through CHP), reducing peaking and base load generation development requirements, and provide additional generation without the capital cost being passed on to consumers. The individual customer could benefit from increased reliability, reduced peak demand and the ability to chose a power supply in the absence of direct access. Broader regional benefits from DG include: power supply diversity, increased in-region power supply, DG as a hedge against high grid-based power supply options, and energy security through enhanced "control" of supply and economic development.

Increased use of DG technologies in the region also has several potential disadvantages including the need for gas and T&D infrastructure upgrades, increased complexity of coordination of DG units for grid planning, inability of many DG technologies to dispatch power on demand and the potential of over reliance on natural gas.

Several economic, regulatory and institutional barriers exist that will influence the rate at which DG penetrates the San Diego region. Perhaps the most significant barrier to widespread deployment of DG is the high up-front capital cost of many technologies. While some DG technologies are very cost effective (e.g., CHP), others currently depend on government incentives (e.g. PV, wind, geothermal and natural gas DG, and some biogas DG). Regulatory barriers include tariff configuration, costly system exit fees and permitting processes, reasonable standby changes, predictable and reasonable prices for all of electricity sold to the grid, and better scheduling arrangements for excess power.

The extent to which DG contributes to the San Diego region’s energy future depends largely on the cost of energy, technological advances, the degree to which environmental externalities are valued (e.g., impact of emissions) and removal of critical barriers through regulatory and/or legislative decisions.

### 5.3 Key Energy Efficiency and Demand Reduction Programs

Key programs and technologies that can create significant energy and demand savings include:

- **Residential**
  - Retrofit program for existing homes\(^8\)

---

\(^6\) As SDG&E points out, this is a very ambitious estimate. Also, the cost and resource value of this estimate needs to be reviewed in light of the CDWR contracts and the CPUC promulgated cost allocations to customers. CPUC sanctioned customer exit fees also need to be considered.

\(^7\) Premium power uses, standby emergency generation and combined heat and power are assumed to be the largest uses for DG. GRI estimates that about 30 GW of natural gas fired DG will be on line by 2015. A vast majority of this will be gas turbine equipment.

\(^8\) DOE/EIA, See: http://www.eia.doe.gov/oiaf/speeches/dist_generation.html.
— Title 24 Plus for New Construction
— Photovoltaics for both new and existing homes
— Advanced metering and control (for larger users)
— Condition-of-building sale

• Commercial and industrial (C&I)
  — Demand Flexibility
  — High efficiency motors
  — High efficiency lighting
  — Retrofit Program
  — E2PRO: Energy and Environment Program.  

These programs were modeled for their energy and/or demand savings using the COMPASS model. The “value” of these programs is driven by the avoided energy and capacity costs, as well as the reduced transmission and distribution expenses. COMPASS models the impacts of each measure and rolls up the demand and energy savings, plus cost, into a bundled program. Appendix G presents this methodology in greater detail.

As shown in Table 5-1, three avoided cost scenarios were used. They were tied to the cost of natural gas, and the higher discount rate for building new plants in California. Each program was evaluated for cost-effectiveness from the program participant’s perspective, and from the total resource cost (TRC) perspective. Programs were valued for their demand and energy savings by individual measure. Multiple measures comprised bundled programs. Different ramp up rates and penetration levels were estimated by scenario. The lower the growth rate and avoided cost, the lower the penetration and ramp up rates. The higher the growth and marginal costs, the higher the penetration and ramp up rates.

The results of the analysis for these programs are summarized in Tables 5-1 and 5-2 and Figures 5-2 and 5-3.

### Table 5-1. Summary of Demand and Energy Impacts of Energy Efficiency and Demand Response Programs

<table>
<thead>
<tr>
<th>Conservation &amp; Load Mgmt</th>
<th>LOW</th>
<th>MEDIUM</th>
<th>HIGH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer Demand Impact, MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>110</td>
<td>145</td>
<td>194</td>
</tr>
<tr>
<td>2010</td>
<td>233</td>
<td>290</td>
<td>368</td>
</tr>
<tr>
<td>2020</td>
<td>414</td>
<td>553</td>
<td>745</td>
</tr>
<tr>
<td>2030</td>
<td>591</td>
<td>811</td>
<td>1,111</td>
</tr>
<tr>
<td>Energy Savings, GWH</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>373</td>
<td>538</td>
<td>771</td>
</tr>
<tr>
<td>2010</td>
<td>833</td>
<td>1,053</td>
<td>1,360</td>
</tr>
<tr>
<td>2020</td>
<td>1,704</td>
<td>2,117</td>
<td>2,696</td>
</tr>
<tr>
<td>2030</td>
<td>2,314</td>
<td>2,924</td>
<td>3,775</td>
</tr>
<tr>
<td>Gas Savings, thousand mmBtu</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>290</td>
<td>350</td>
<td>463</td>
</tr>
<tr>
<td>2010</td>
<td>566</td>
<td>723</td>
<td>1,128</td>
</tr>
<tr>
<td>2020</td>
<td>582</td>
<td>889</td>
<td>1,810</td>
</tr>
<tr>
<td>2030</td>
<td>533</td>
<td>904</td>
<td>1,998</td>
</tr>
</tbody>
</table>

Source: SAIC Analysis

---

8 Retrofit includes water heater blankets, night setback thermostats, insulating glass window replacements, and home insulation.

9 For a definition of the actual measures that are included in each of the programs, see Appendix C.
## Table 5-2. Summary of DSM Program Life Cycle Costs and Impacts

<table>
<thead>
<tr>
<th>Program</th>
<th>Program</th>
<th>Program Life Cycle Costs, ¢/kWh</th>
<th>Year 2030 Energy Savings GWh</th>
<th>Year 2030 Energy GWH Cumulative Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential Condition of Sale</td>
<td>RCS</td>
<td>-</td>
<td>359</td>
<td>359</td>
</tr>
<tr>
<td>C&amp;I Retrofit</td>
<td>CRT</td>
<td>0.26</td>
<td>1,401</td>
<td>1,760</td>
</tr>
<tr>
<td>C&amp;I E2 Program</td>
<td>CE2</td>
<td>0.30</td>
<td>547</td>
<td>2,307</td>
</tr>
<tr>
<td>Residential Retrofit</td>
<td>RRT</td>
<td>1.58</td>
<td>207</td>
<td>2,514</td>
</tr>
<tr>
<td>C&amp;I Demand Response</td>
<td>CDR</td>
<td>7.97</td>
<td>310</td>
<td>2,824</td>
</tr>
<tr>
<td>Residential Title 24 Plus</td>
<td>R24</td>
<td>9.50</td>
<td>34</td>
<td>2,858</td>
</tr>
<tr>
<td>Residential Advanced Metering</td>
<td>RAM</td>
<td>16.80</td>
<td>66</td>
<td>2,924</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Program</th>
<th>Program</th>
<th>Program Capital Costs, $/kW-Yr</th>
<th>Year 2030 Summer MW Savings</th>
<th>Year 2030 Summer MW Cumulative Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>C&amp;I E2 Program</td>
<td>CE2</td>
<td>17.28</td>
<td>93</td>
<td>93</td>
</tr>
<tr>
<td>C&amp;I Retrofit</td>
<td>CRT</td>
<td>18.01</td>
<td>174</td>
<td>267</td>
</tr>
<tr>
<td>Residential Condition of Sale</td>
<td>RCS</td>
<td>19.03</td>
<td>198</td>
<td>465</td>
</tr>
<tr>
<td>Residential Advanced Metering</td>
<td>RAM</td>
<td>121.23</td>
<td>91</td>
<td>556</td>
</tr>
<tr>
<td>C&amp;I Demand Response</td>
<td>CDR</td>
<td>133.20</td>
<td>185</td>
<td>741</td>
</tr>
<tr>
<td>Residential Title 24 Plus</td>
<td>R24</td>
<td>172.04</td>
<td>19</td>
<td>760</td>
</tr>
<tr>
<td>Residential Retrofit</td>
<td>RRT</td>
<td>207.25</td>
<td>51</td>
<td>811</td>
</tr>
</tbody>
</table>

Source: SAIC Analysis.

### Figure 5-2. Demand Impacts of Programs, 2006–2030 (in MW)

Source: SAIC Analysis.

---

10 See Appendix G for a review of the modeling and key assumptions, more detailed features of the program designs.
5.3.1 Results: Market Impacts and Cost Effectiveness

Figures 5-2 and 5-3 show the range of demand and energy savings by scenario, respectively. The demand impacts from the energy efficiency and demand response programs are:

- Savings in the low-high scenarios may range from 591 MW in the low case, to 811 in the medium case and 1,111 in the high case by 2030.
- Program energy savings range from 2,314 to 3,775 GWh by 2030. (See Table 5-1.)
- Residential and commercial photovoltaics and C&I retrofits provide the greatest savings (1,401 GWh) at cost ($0.26/kWh). See Table 5-2.
- All but three measures have low costs on a $/kW-yr basis.
- Nearly all DSM options are cost effective when compared to the total delivered cost of energy to customers, assuming average retail prices are from $.14 to $.17 per kWh.
- The programs vary in their ability to reduce demand and energy consumption. Some programs are stronger at energy savings and others are stronger performers for demand savings.
- The largest demand reduction programs, which contain multiple measures, include residential condition of sales, C&I retrofit, and C&I demand response.
- The programs with the largest energy savings in the Year 2030 are C&I retrofit, and C&I E-2 program.
- C&I programs offer the most significant energy savings at the lowest capital costs. This program should be the highest priority for implementation.
- Capital costs in present dollars for all program initiatives do not exceed $207.25/kW (Table 5-2).
Program expenditures range from $316 million to $850 million over the 30-year time period.\textsuperscript{11}

- Advanced Metering and Control for the residential market show very high energy life cycle costs because they save little energy and demand. This suggests narrowing the focus of program implementation for higher use customers.

- Residential Retrofit Program is also very cost effective from an energy savings standpoint.

The estimated savings from the natural gas demand management programs are as follows (See Figure 5-4):

- Natural gas savings show a net increase in the low DSM scenario due to higher incremental gas sales from DG. The medium scenario show incremental gas consumption even with off-setting incremental gas sales with conservation. In the aggressive, high DSM case, gas savings occur due to the cumulative gas savings potential over the extended time period. Conservation savings from growth exceed incremental DG sales.

- Approximately 1 Billion BTU of natural gas can be saved over the next 30 years in the high DSM scenario. This is a modest amount of gas due to the relatively low customer use of gas for residential and commercial applications. This is through more efficient buildings, furnaces, boilers, and hot water heaters. Increased pipe insulation, efficient dishwashers and flow restrictors also contribute.

\textbf{Figure 5-4. Natural Gas Savings Impact of DSM Program Scenarios}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure5-4}
\caption{Natural Gas Savings Impact of DSM Program Scenarios}
\end{figure}

Source: SAIC Analysis

\textbf{5.3.2 Environmental Impacts}

Table 5-3 lists the emissions impacts of the electric efficiency and demand response programs based on 1998 average emission levels.\textsuperscript{12}

\textsuperscript{11} At current expenditure levels, approximately $350 million in public funding will be expended through 2012 for energy efficiency programs in San Diego. If these programs are continued beyond 2012 at the same funding level, an additional $630 million will be available for energy efficiency through 2030. An additional $62 million in public incentive will be allocated through 2004 for self-generation.

\textsuperscript{12} Emissions reductions are estimated using the following: NOx: 7.0 lb/MWh; SO2: 7.9 lb/MWh; PM-10: 23.09 lb/MWh; CO2: 1,408 lb/MWh.
Table 5-3. Emission Impacts of Demand Response Programs

<table>
<thead>
<tr>
<th>Emissions Reduction, million lbs</th>
<th>Low</th>
<th>Medium</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year 2006</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>2.61</td>
<td>3.77</td>
<td>5.40</td>
</tr>
<tr>
<td>SO2</td>
<td>2.95</td>
<td>4.25</td>
<td>6.09</td>
</tr>
<tr>
<td>PM-10</td>
<td>8.61</td>
<td>12.42</td>
<td>17.80</td>
</tr>
<tr>
<td>CO2</td>
<td>526</td>
<td>758</td>
<td>1,086</td>
</tr>
<tr>
<td><strong>Year 2010</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>5.83</td>
<td>7.37</td>
<td>9.52</td>
</tr>
<tr>
<td>SO2</td>
<td>6.58</td>
<td>8.32</td>
<td>10.75</td>
</tr>
<tr>
<td>PM-10</td>
<td>19.23</td>
<td>24.31</td>
<td>31.40</td>
</tr>
<tr>
<td>CO2</td>
<td>1,173</td>
<td>1,482</td>
<td>1,915</td>
</tr>
<tr>
<td><strong>Year 2020</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>5.85</td>
<td>7.26</td>
<td>9.25</td>
</tr>
<tr>
<td>SO2</td>
<td>13.46</td>
<td>16.72</td>
<td>21.30</td>
</tr>
<tr>
<td>PM-10</td>
<td>39.35</td>
<td>48.88</td>
<td>62.25</td>
</tr>
<tr>
<td>CO2</td>
<td>2,399</td>
<td>2,981</td>
<td>3,796</td>
</tr>
<tr>
<td><strong>Year 2030</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>16.20</td>
<td>20.47</td>
<td>26.43</td>
</tr>
<tr>
<td>SO2</td>
<td>18.28</td>
<td>23.10</td>
<td>29.82</td>
</tr>
<tr>
<td>PM-10</td>
<td>53.43</td>
<td>67.52</td>
<td>87.16</td>
</tr>
<tr>
<td>CO2</td>
<td>3,258</td>
<td>4,117</td>
<td>5,315</td>
</tr>
</tbody>
</table>

5.4 DG Technologies

The CEC defines DG as “generation, storage, or demand-side management devices, measures, and/or technologies connected to the distribution level of the transportation and distribution grid, usually located at or near the intended place of use.”

The intention of this section is not to provide an exhaustive review of distributed generation technologies and assumes the reader has a working knowledge of the subject. Instead, this section focuses on evaluating the current status of DG in the region and the potential future role it might play in regional energy planning.

5.4.1 DG Technology Comparison

There are many DG technologies that vary by first cost, efficiency, capacity, operation and maintenance costs, fuel type and commercial availability. This section focuses on the possible role of microturbines, internal combustion engines, combined heat and power (CHP) applications, fuel cells, photovoltaics and other solar energy systems, wind, landfill gas, digester gas and geothermal power generation technologies to help meet the growing power needs of the San Diego region.

Table 5-4 compares various characteristics of selected DG technologies.

5.4.2 Framework for Evaluating Role of DG

Evaluating the role of DG technologies in the energy future of the San Diego region will involve many perspectives. Each perspective ascribes different values to DG. Considering and balancing these perspectives is essential in determining the value of DG for the region. Natural tensions will arise between individual customer perspective, which is more focused on immediate energy cost savings, versus a regional perspective, which may see DG as a means of providing energy market stability and broader societal benefits, such as supply diversity, control and security.
Table 5-4. Comparison of DG Technologies

<table>
<thead>
<tr>
<th>Factors</th>
<th>Microturbines</th>
<th>Combustion Turbines</th>
<th>Reciprocating Engines</th>
<th>Fuel Cell</th>
<th>Wind</th>
<th>Photovoltaics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost ($/kW)</td>
<td>$300–$1,000/kW</td>
<td>$300–$1,000/kW</td>
<td>$300–$900/kW</td>
<td>$5,500–$12,000/kW</td>
<td>$1,000/kW</td>
<td>$6,000–10,000/kW</td>
</tr>
<tr>
<td>Commercially Available</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Only PAFC*</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Size Range</td>
<td>30–500 kW</td>
<td>500 kW–25 MW</td>
<td>5 kW–7 MW</td>
<td>1 kW–10 MW</td>
<td>Several kW–5 MW</td>
<td>&lt;1 kW–1 MW+</td>
</tr>
<tr>
<td>Fuel</td>
<td>Natural gas, hydrogen, propane, diesel</td>
<td>Natural gas, liquid fuels</td>
<td>Natural gas, diesel, landfill gas, digester gas</td>
<td>Most Fuel Types</td>
<td>Wind</td>
<td>Sunlight</td>
</tr>
<tr>
<td>Efficiency</td>
<td>20–30% up to 85% in CHP</td>
<td>20–45% (primarily size dependent)</td>
<td>25–45%</td>
<td>30–60%</td>
<td>20–40%</td>
<td>5–15%</td>
</tr>
<tr>
<td>Emissions</td>
<td>Low (&lt;9–50 ppm) NOx</td>
<td>Very low when controls are used</td>
<td>Emission controls required for NOx and CO</td>
<td>Nearly zero emissions</td>
<td>No emissions</td>
<td>No emissions</td>
</tr>
<tr>
<td>Combined Heat and Power (Cogeneration)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Commercial Status</td>
<td>Small volume production</td>
<td>Widely available</td>
<td>Widely available</td>
<td>PAFC* Available</td>
<td>Widely available</td>
<td>Widely available</td>
</tr>
</tbody>
</table>

Source: California Energy Commission.

*PAFC denotes Phosphoric Acid Fuel Cell.

The following represents the various perspectives that should be considered when evaluating the role DG can play in the San Diego region's energy planning future.

- **Customer** (Commercial, Industrial, Residential) – Individual customers typically value energy cost savings, reliability, and control of supply, government incentives and environmental benefits.
- **Region** – From a regional perspective, the value of DG includes energy supply adequacy, control and security, energy planning flexibility, environmental benefits and economic development opportunities.
- **Utility** – DG represents a mechanism for utilities to mitigate system congestion, maintain T&D system efficiencies, and support stressed portions of the system (e.g., high demand at the end of a distribution line).

### 5.4.3 DG Applications

The varying perspectives outlined above will be driven by the range of DG applications relevant to each. Distributed generation technologies can be used in many different applications that can directly affect a customer site and more broadly affect the electrical transmission and distribution system.

### 5.4.4 Customer-Based DG

According to the California Energy Commission, the primary customer-based applications for DG include:

- **Combined Heat and Power (CHP)** – CHP, sometimes-called cogeneration, uses waste heat recovery equipment in conjunction with DG power generation equipment (e.g., reciprocating engines) to generate electrical and thermal energy.
engine, microturbine, fuel cell, etc) to capture and use waste heat. CHP applications vastly increase the efficiency of on-site power generation.

- **Power Quality/ Premium Power** – Commercial and industrial customers are using DG technologies to reduce frequency variations and to control voltage transients, surges, dips or other disruptions.
- **Peak Shaving** – DG can be used during peak demand times when electricity prices and demand charges are highest.
- **Low-Cost Energy** – DG can be used as baseload (primary) power source that is less expensive to produce locally than it is to purchase from the electric utility.
- **Stand Alone** – for energy needs in remote locations, DG that is isolated from the grid may be more economical than building new transmission and distribution infrastructure (although this Study does not specifically address stand-alone potential and applications, which are usually extremely cost-effective if any significant amount of grid infrastructure extensions are required (more than one quarter to one-half mile).
- **Standby Power** – DG may be used in the event of an outage to provide back-up to the electric grid, when designed to perform this function.

### 5.4.5 System-Based DG

Applications that affect the transmission and distribution system and the broader energy market include:

- **Managing T&D Constraints** – DG technologies are used to reduce load in specific locations of the utility transmission and distribution grid.
- **Improving T&D System Efficiency** – By increasing the number of DG generators connected to the grid, more customers can be served with the existing infrastructure. In addition, DG can be located closer to load pockets, reducing the need for unnecessary transmission and distribution infrastructure.
- **Targeted, Incremental Capacity Additions** – DG technologies provide the flexibility to add smaller, incremental additions to the grid system that better match the demand growth in a particular segment of the grid.
- **Market Improvement** – Increasing the number of power suppliers can decrease the potential for the type of market power exerted during 2000–2001 in California.

### 5.5 Distributed Generation Market Overview

In the past, the San Diego region has had success with DG technologies and was a leader in Qualifying Facility installations in the early 80s. The region is currently experiencing moderate-to-high market penetration of DG technologies due to high prices for electricity. For the last decade, industry experts have outlined the benefits of a transition from centralized power system, in which large power stations generate power that is delivered to customers via the transmission and distribution infrastructure, to a more distributed model, in which customer produce all or a portion of their power needs at their facility. This transition is tantamount to the transition of the computer industry from mainframe to personal desktop computers. A number of factors are driving this trend including energy security, increased energy prices, increased difficulty siting larger infrastructure and technological advances and improved efficiencies.

Since the September 11 terrorist attacks, there has been an increased emphasis on energy security. Large centralized power plants and supply lines can be vulnerable to attack and sabotage. Because of its decentralized nature, DG is less susceptible to disruption. In addition, increased energy prices during 2000–2001 led all customer classes to consider DG. Finally, technology is driving increased efficiencies. Traditionally, cost and electrical efficiencies were gained by the economies of scale of
large-scale base load power plants. Today, smaller systems, particularly those that capture and utilize waste heat, can achieve more than double the efficiency of larger power plants.

5.5.1 Inventory of DG in San Diego Region

The San Diego region currently has 527 DG sites for a total capacity of 372.3 MW of DG capacity. Table 5-5 indicates the total number of sites and capacity for the DG technologies in use. In subsequent tables, further detail is provided on each technology including the current level of market penetration, the potential for market expansion and a summary of how the technology should be viewed in the larger context of regional energy planning.

Table 5-5. DG Capacity in San Diego County (2002)

<table>
<thead>
<tr>
<th>Technology</th>
<th>Number of Systems</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP</td>
<td>50</td>
<td>327.2</td>
</tr>
<tr>
<td>Bio Gas</td>
<td>11</td>
<td>30.3</td>
</tr>
<tr>
<td>Hydro</td>
<td>6</td>
<td>6.7</td>
</tr>
<tr>
<td>Steam Turbine</td>
<td>2</td>
<td>6.6</td>
</tr>
<tr>
<td>PV</td>
<td>452</td>
<td>1.6</td>
</tr>
<tr>
<td>Wind</td>
<td>6</td>
<td>0.0085</td>
</tr>
<tr>
<td>Total</td>
<td>527</td>
<td>372.3</td>
</tr>
</tbody>
</table>

Source: SDG&E, EPA, and SDREO.

5.5.1.1 Combined Heat and Power Plants (CHP)

The average power plant loses more than two-thirds of the energy content of the input fuel in the form of heat. CHP systems capture and use that heat to generate both thermal and electrical energy. “CHP,” also called cogeneration, can significantly increase the efficiency of energy utilization, reduce emissions of criteria pollutants and CO₂, and lower operating costs for industrial, commercial and institutional users.¹⁶

San Diego County currently has 50 combined heat and power plants, representing about 327.2 MW of capacity. Table 5-6 lists the sites by technology type.

Table 5-6. CHP by Technology

<table>
<thead>
<tr>
<th>Technology</th>
<th>Number of Systems</th>
<th>Capacity (KW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reciprocating Engines</td>
<td>26</td>
<td>20,428</td>
</tr>
<tr>
<td>Microturbines</td>
<td>8</td>
<td>730</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>4</td>
<td>157,300</td>
</tr>
<tr>
<td>Gas Turbines</td>
<td>12</td>
<td>148,733</td>
</tr>
<tr>
<td>Total</td>
<td>50</td>
<td>327,191</td>
</tr>
</tbody>
</table>

Source: CEC

5.5.1.2 Potential for CHP

A total of 12,108 MW of remaining CHP potential was identified for California split fairly evenly between the industrial and commercial sectors,¹⁷ and represents approximately 726 MW for San Diego.

Table 5-7 provides an estimate of the remaining CHP potential in the commercial and industrial market. The table shows that smaller CHP systems of 1 MW and less represent the largest market in the future for the commercial market. Larger systems of one or more megawatts are in higher proportion for the industrial market.

Table 5-7. Estimated Remaining CHP Potential in the C&I Market, San Diego

<table>
<thead>
<tr>
<th>Size Category</th>
<th>Commercial</th>
<th></th>
<th>Industrial</th>
<th></th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sites</td>
<td>MW</td>
<td>Sites</td>
<td>MW</td>
<td>Sites</td>
</tr>
<tr>
<td>50–250 kW</td>
<td>1,414</td>
<td>126</td>
<td>n.a.</td>
<td>n.a.</td>
<td>1,414</td>
</tr>
<tr>
<td>250–1,000 kW</td>
<td>158</td>
<td>86</td>
<td>77</td>
<td>39</td>
<td>235</td>
</tr>
<tr>
<td>1–5 MW</td>
<td>32</td>
<td>60</td>
<td>35</td>
<td>71</td>
<td>67</td>
</tr>
<tr>
<td>5–20 MW</td>
<td>4</td>
<td>27</td>
<td>6</td>
<td>63</td>
<td>10</td>
</tr>
<tr>
<td>&gt;20 MW</td>
<td>1</td>
<td>37</td>
<td>3</td>
<td>217</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>1,609</td>
<td>336</td>
<td>121</td>
<td>390</td>
<td>1,730</td>
</tr>
</tbody>
</table>

Source: CEC

In the industrial sector, the applications are concentrated in the petroleum, food processing, pulp and paper, and wood processing industries. In the commercial sector, the applications are concentrated in data centers, telecommunications, high tech applications, pharmaceuticals, biotechnology, education, restaurants, lodging, and apartment buildings. For this reason, the absolute market potential for DG may be limited and potentially lower than SAIC’s estimates, noted SDG&E in its review of the draft REIS.

5.5.1.3 Summary: CHP

Combined heat and power applications, including microturbines, reciprocating engines, fuel cells and gas turbines will make up the highest capacity of any DG technology in the region.

5.5.2 Landfill Gas

The largest increase in renewable energy nationally is expected to come from biomass energy. Biomass energy sources are estimated to almost double from 36.6 to 65.7 BkWh by 2020 for the US. An estimated 16.4 billion kWh of electricity could be generated using renewable biomass fuels in California. A profile of selected landfill sites appears in Table 5-8.

Electricity generation from municipal solid waste and the use of landfill gas is expected to increase by 15.9 Billion kWh from 1999 to 2020. The national forecast estimates no new plants that burn solid waste would be added. However, plants that burn landfill gas capacity are projected to grow by 2.1 GW.

The San Diego region has 7 operational landfill gas generation plants. Table 5-8 outlines the primary characteristics of these power plants. Other digester gas generation exists at the Encina WWTP, Escondido Hale Ave., the Cardiff WWTP and an additional unit is currently planned for Oceanside.

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18 Estimates represent 6 percent of the total CA market potential in the Market Assessment of Combined Heat and Power in the State of California report.

### Table 5-8. Existing Landfill and Wastewater Gas-fired Generator

<table>
<thead>
<tr>
<th>Features</th>
<th>Miramar SLF Phase I</th>
<th>Miramar SLF Phase II</th>
<th>Jamacha LF</th>
<th>Pt. Loma wastewater Plant</th>
<th>San Marcos LF</th>
<th>South Chollas LF</th>
<th>Sycamore LF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated Methane Generation (mmscf/day)</td>
<td>6.12</td>
<td>6.12</td>
<td>0.26</td>
<td>NA</td>
<td>4.61</td>
<td>0.95</td>
<td>2.76</td>
</tr>
<tr>
<td>Current Landfill Gas Collected (mmscf/day)</td>
<td>6.5</td>
<td>N/A</td>
<td>N/A</td>
<td>NA</td>
<td>1</td>
<td>1.1</td>
<td>1</td>
</tr>
<tr>
<td>Generation System Type</td>
<td>Cogen</td>
<td>Recip</td>
<td>Gas Turbine</td>
<td>Cogen</td>
<td>Gas</td>
<td>Recip Engine</td>
<td>Recip Engine</td>
</tr>
<tr>
<td>Electricity Sold to (utility)</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
<td>SDG&amp;E</td>
</tr>
<tr>
<td>Current Capacity (MW)</td>
<td>6.4</td>
<td>3.8</td>
<td>0.28</td>
<td>4.57-5.77</td>
<td>1.3</td>
<td>N/A</td>
<td>1.4</td>
</tr>
<tr>
<td>Estimated Potential Capacity (MW)</td>
<td>19</td>
<td>19</td>
<td>N/A</td>
<td>8.0</td>
<td>14</td>
<td>3</td>
<td>9</td>
</tr>
</tbody>
</table>


Note: Estimated capacities may require significant expansions of existing facilities.

### 5.5.2.1 Potential for Landfill Gas

As noted above, two candidate sites were identified as providing a potential new source of landfill gas: Ramona at 0.07 mmscf/day and South Chollas (No. 2) at 0.95 mmscf/day. For these sites to be considered candidates, they must have at least 1 million tons of municipal solid waste (MSW) available for producing landfill gas.

The City of San Diego’s Point Loma Waste Water Treatment Plan currently has an additional 2.5 to 3.5 MW of digester gas-fueled generation of which 1.2 MW is now being developed utilizing a diesel as a dual fuel digester gas peaking facility. But additionally, the City of San Diego could possibly generate up to 4.6 MW today at Loma Linda landfill and another 1.3 MW at another facility. The City has not pursued these projects due to restrictions that do not allow customers to supply their own generation. For example, excess generation from the Pt. Loma Waste Water Treatment Plant could supply the City’s largest single load of nearly 8 MW, which is Pump Station #2, just a few short miles from the generation source. Instead, the City must sell excess power from generation sites at prices tied to lower avoided costs (approximately 2 to 3 cents per kWh), then purchase power from SDG&E at other sites at higher standard commercial rates (approximately 12 to 14 cents per kWh). This is a tremendous disincentive for the City to develop this beneficial renewable resource. The City has a goal of supplying up to 15 percent of its energy requirements from DG, including backup power protection for police, fire, and pool heating and hospital plant protection.

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20 Conversation with Tom Alspaugh, City of San Diego Metropolitan Wastewater Department, May 21, 2002.
5.5.2.2 Summary: Landfill

Landfill gas, comprising both landfill gas and solid waste separation and incineration, represents good potential options. State-of-the-art incineration systems are working in Europe as part of residential developments, generating heat and power. The City of San Diego has significant potential to produce landfill energy sources through landfill gas and incineration energy. Greater cooperation is encouraged between SDG&E and the City to create positive incentives to encourage the development of these resources for the good of the region. The City and the County are currently investigating measures to expand landfill possibilities. Current retail wheeling restrictions limit the possible expansion of landfill-gas fired power generation facilities. Serious consideration should be given to increasing the total share of energy from landfill sites, using various technologies. Landfill energy has the potential of providing up to 100 MW of local electric demand capability by 2030.

5.5.3 Hydro Power

While San Diego does not have sufficient indigenous water resources to produce significant hydro generation, limited hydro is available through applications in the water and wastewater public sectors. Currently the region has 8.32 MW of hydro-generated power plants.21 (See Table 5-9).

<table>
<thead>
<tr>
<th>Facility Name</th>
<th>Capacity (MW)</th>
<th>Date On Line</th>
<th>System Owner</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alvarado Hydro Facility</td>
<td>1.99</td>
<td>04/30/1985</td>
<td>San Diego County Water Authority</td>
</tr>
<tr>
<td>Badger Filtration</td>
<td>1.48</td>
<td>07/08/1987</td>
<td>San Diequito Water District</td>
</tr>
<tr>
<td>Bear Valley</td>
<td>1.60</td>
<td>03/15/1986</td>
<td>City of Escondido</td>
</tr>
<tr>
<td>Miramar Hydro Facility</td>
<td>0.80</td>
<td>04/15/1985</td>
<td>San Diego County Water Authority</td>
</tr>
<tr>
<td>Olivenhain Municipal Water District</td>
<td>0.45</td>
<td>09/30/1988</td>
<td>Olivenhain Municipal Water District</td>
</tr>
<tr>
<td>Point Loma</td>
<td>1.35</td>
<td>09/01/1984</td>
<td>City Of San Diego</td>
</tr>
<tr>
<td>Rincon Hydro</td>
<td>0.30</td>
<td>06/08/1983</td>
<td>City Of Escondido</td>
</tr>
<tr>
<td>San Francisco Peak Hydro</td>
<td>0.35</td>
<td>12/15/1985</td>
<td>City Of Oceanside</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>8.32</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: CEC Powerplant Database and SDG&E.

5.5.3.1 Hydro Potential

The County Water Authority is currently planning to build a 40 to 90 MW pumped storage facility at the Olivenhain/Lake Hodges site. If built, this facility would add to the current pumped-storage capacity of 3,630 MW at seven other plants throughout the State of California. While they are net consumers of energy, their output for meeting peak demand is very reliable. By pumping uphill during the night and producing electricity during the peak hours, these plants flatten the daily load curve; therefore, they serve to increase system-wide economy by using energy from baseload plants that are most efficient when run continuously and reducing the need for peaking plants during the day.

5.5.3.2 Summary: Hydro Power

Hydropower will likely remain a small percentage of total regional power supply. To increase power supply diversity and in-region generation, the region should continue to explore all cost-effective hydro opportunities.

5.5.4 Photovoltaics

There is significant growth of PV in San Diego County. Currently, there are 445 PV projects and 5 PV/Wind hybrid projects in San Diego County representing about 1.6 MW22 of power generation. Additionally, another 117 projects totaling 2.1 MW have completed interconnection agreements with

22 San Diego Gas and Electric Net Metered Spreadsheet provided by Bob Keithly.
SDG&E but have not been permitted. San Diego has among the best solar resources in the nation. According to the National Renewable Energy Laboratory, San Diego receives an average of 5.7 usable hours of peak sunshine per day, with a high of 6.5 hours in August and a low of 4.6 hours in December.\footnote{Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors, NREL. Golden, CO.}

Net metering, the ability to connect renewable power generating systems directly to the grid, and receive a retail credit for power produced and supplied to the grid, has dramatically increased the market for grid-connected photovoltaics. Generation companies are beginning to incorporate PV as part of larger generation projects to achieve mandated renewable portfolio standards. Sempra Energy Resources installed a 100-kW system at their new Eldorado combined-cycle power plant in Nevada.

Residential-scale applications, in particular, have experienced a dramatic increase in use over the past several years, increasing from 11 in 2000 (29 kW) to 270 in 2001 (836 kW). As of mid-May 2002, there are 119 projects representing 402 kW. At least four major residential builders offer solar as an option for new homes in San Diego.

As a result of AB 29X, the net metering limitation was increased from 10 kW to 1 MW in April 2001. This, combined with enhanced incentives, education and promotion through the DOE’s Million Solar Roofs\footnote{SDREO partnered with DOE in 1999 setting a goal of deploying 20,000 solar roofs by 2010.} and the CPUC San Diego Self-Generation Program\footnote{This program is administered by the SDREO in the San Diego region. See www.sdenergy.org/selfgen.}, more businesses are beginning to consider PV. Larger systems are now coming on-line in increasing numbers.\footnote{SDG&E notes that one large PV system is installed, one is in feasibility study, and no known projects planned as of 12/8/02. Projects not known at this time may not be installed in a year’s time.} One 137 kW system was installed in 2000 in Carlsbad, and several projects in the 750-kW to 1-MW range will be installed within a year’s timeframe.

### 5.5.4.1 Potential for Photovoltaics in the San Diego Region

Photovoltaics could play a significant role in regional energy planning. Potential market penetration depends largely on module prices, utility electricity prices and the existence of government incentives. Assuming all funds are allocated through the CPUC Self-Generation program administered by SDREO, the region will have deployed about 8 MW of solar by the end of 2004.

Among the most promising markets for photovoltaics include large commercial and industrial customers and new home construction. The C&I segment is attractive because multiple government incentives make systems cost-effective.

The new home construction market also can be cost-effective due to long-term mortgage financing, bulk purchases, standard installations and systems. The San Diego Association of Governments estimates that the San Diego region will add approximately 180,000 new single-family homes by 2010.\footnote{2000 Cities/County Forecast Table 2, Total Housing Units by Jurisdiction and Sphere of influence. San Diego Association of Governments, February 1999.} If 10 percent of projected new homes included a 2-kW photovoltaic system, 36 MW of renewable capacity would be added to the region. Installing photovoltaics in new home construction could help to meet the growing demand of the region. The city of San Diego noted that year around PV only provides above 20% of its rated capacity in San Diego.

While the new home construction market is very attractive, policies to mandate installation of photovoltaics and other solar equipment might be short sighted, however, policies to promote pre-wiring new homes may be appropriate.\footnote{Similar to existing codes that require pre-plumbing for solar water heating in the City of Carlsbad.}

Another promising market segment includes local governments and public agencies. There is strong political support to install photovoltaics on public agency facilities, including schools and government...
buildings. The inability to receive the tax benefits has been the most significant barrier to increased deployment in this sector.

Several innovative strategies could enable public agencies as well as commercial and residential customers to install photovoltaics. Large volume and aggregated purchases is one strategy to reduce prices. The Sacramento Municipal Utility District (SMUD) has successfully purchased large volumes of photovoltaic modules at relatively reduced prices. The California Conservation and Power Finance Authority (CPA) is also exploring the possibility of entering into large volume contracts with photovoltaic equipment suppliers and systems integrators. Partnering with the CPA on such a program presents opportunity for a regional organization that could aggregate such purchases.

Another strategy is to develop financing mechanisms for both public agencies and businesses. Currently, several companies are offering third-party financing arrangements for a non-profit business to purchase, install, maintain and own a photovoltaic system. The company then sells the solar-generated power to the “host” at a percent discount to below utility rates. This could enable public agencies to install photovoltaics on facilities with no up-front capital costs.

The CPA also is developing financing instruments that could allow public agencies and potentially businesses access to low interest rates.

In fall 2001, voters in the City of San Francisco approved a ballot measure enabling the City to issue revenue bonds for the purchase and installation of energy efficiency, wind and photovoltaics. The City will service the bond debt with the energy savings realized through the energy projects. This is another strategy to deploy large amounts of photovoltaics, which could reduce costs, which should be considered at a regional level.

A final consideration is that local county taxing authorities can as part of property tax collections consider billing customers for investments in photovoltaics and the revenue recovery can be treated as an amortized investment.

5.5.4.2 Summary: Photovoltaics

PV represents a strong opportunity for the San Diego region to establish some level of sustainable energy diversity. Substantial cost reductions are anticipated through increased module production and aggregated purchasing strategies. This study projects that PV could economically represents between 230 and 865 MW of capability over the next 30 years. The absence of government incentives could dramatically curtail market penetration of photovoltaics, however. Continued tax credits, incentives and developer support will be needed.

5.6 Fuel Cells

While SDG&E installed and operated a 250-kW prototype fuel cell in 1997, no stationary fuel cells are currently operational in the San Diego region. However, fuel cells hold long-term promise of generating electricity efficiently with minimal pollution. At over $5,500 per kilowatt (installed), fuel cells are still too expensive for the residential market and have been applied mostly in limited commercial and industrial applications. Some developers are hoping to reduce the high capital costs down to $1,500 per kilowatt by late-2005. That would cost an average homeowner about 10 cents per kilowatt-hour for the five-year life of the system.

The industry also has been struggling with resolving technology issues, most significantly, the longevity of the fuel, cell stack, which is an expensive component of the system.

Due to the uncertainty in the timing and the resolution of these issues, and the development of the market, it is not clear whether fuel cells will become a significant resource in the near-term. This study anticipates that remaining technological issues will be resolved in the near-term, and prices will be reduced to the extent that they become competitive in the medium-term (2010 to 2015).

30 Alten Energy and Solar Commercial Roofing are two companies offering third-party financing at discounts of 10 to 20 percent.
The U.S. Navy will host one-year field tests of up to nine 5-kW PlugPower fuel cells at Naval Base Coronado and Naval Base Point Loma. These demonstrations should provide valuable information on the performance and feasibility of fuel cells for the residential market.

5.6.1 Fuel Cell Potential
The future market penetration of fuel cells is difficult to determine. Future deployment of fuel cells will depend on technological advances and the cost of natural gas and electricity. While fuel cells hold great promise for a transition to a hydrogen economy, currently the potential for fuel cell deployment in the region is relatively low in the next 5 to 10 years.

5.6.2 Summary: Fuel Cells
This study projects that fuel cells could represent as much as 15 to 70 MW of service by 2030. This estimate is highly speculative due to the uncertainties about the technology and its cost. It is not anticipated that the cost of fuel cells will drop quickly and suddenly as some studies project. Fuel cell advancements will not start reaching technical and economic efficiency needed for higher market acceptance until around 2020 and beyond. Currently, fuel cells are the least attractive DG technology available from the standpoint of economics.

5.7 Renewable Energy Technologies
5.7.1 Wind
There are six grid-connected wind systems installed in San Diego County for a total capacity of 14.5 kW. The San Diego region has limited wind resources. Ocean breezes prevalent in the coastal range are not strong enough for consistent wind power production. However, some potential exists in the mountains of East County. Figure 5-5 shows a wind map for San Diego County. Wind energy resources are characterized by wind power density classes, ranging from Class 1 to Class 7 (low to high). Good wind resources—Class 3 and above—have an average annual wind speed of at least 13 miles per hour. The National Renewable Energy Lab has developed a wind resource map for Southern California, which indicates several East County regions with wind resources of Class 3 and above. On some occasions during Santa Ana conditions, east county winds can exceed 25 mph. Some of the ideal wind conditions, however, are located in national forests and the deployment of this resource may be limited.

Figure 5-5. Wind Speeds By Location in San Diego County

<table>
<thead>
<tr>
<th>Wind Power Class</th>
<th>Resource Potential</th>
<th>Wind Power Density at 50 m W/m²</th>
<th>Wind Speed at 50 m mph</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Excellent</td>
<td>500-600</td>
<td>16.8-17.9</td>
</tr>
<tr>
<td>6</td>
<td>Outstanding</td>
<td>600-800</td>
<td>17.9-19.7</td>
</tr>
</tbody>
</table>

*Wind Speeds are based on a Weibull k value of 2.0*

Large-scale wind power systems need a significant amount of unobstructed property area for the turbine towers and capture of wind. San Diego County has specific zoning regulations for wind turbines, which include setback requirements and tower height restrictions.

Currently, ideal San Diego region wind power locations are limited by availability of adequate electricity transmission capacity. With these inherent limitations, there are few viable large-scale applications for wind power in San Diego County. However, East County business and homeowners in Class 3 and above areas could benefit from small-scale wind power to offset part or all their energy needs through self-generation.

### 5.7.2 Potential for Wind

No wind farms are currently sited in San Diego County. There are significant wind resources (in excess of 500-MW potential)\(^3\) in eastern San Diego County in the vicinity of the Laguna and Jacumba Mountains, which have Class 6 and Class 5 winds, respectively. The major barrier to tapping this resource is the lack of adequate transmission infrastructure to transport the power to the grid.\(^3\) Even more wind resources are available in Northern Baja California. Estimates are well in excess of 500 MW. The closest wind farm development is north of San Diego County in the San Gorgonio Pass, west of Palm Springs, which totals 421.1 MW of wind capacity and generated 805 MWh in 1998.\(^3\)

The city of San Diego rightfully points out that there are local siting issues that exist. These include bird kills, noise, and aesthetics.

### 5.7.3 Summary: Wind

Contrary to general opinions, wind energy has the potential of being a significant resource meeting San Diego County’s energy requirements. Development of these resources could be made more attractive by leveraging green ticket markets that are sold to entities that need to achieve certain levels of renewable energy generation to meet renewable portfolio standards. Wind energy potential ranging from 8 MW to in excess of 500 MW is possible over the next 30 years (more if further development of available wind resources in Baja California and east and north of San Diego County are considered).

It should also be noted that wind energy capacity availability is highly variable and uncertain. The California ISO noted in its Summer 2002 report that Wind resources in the State of California vary from 100 to 1,200 MW during peak hours. The availability factor is assumed for resource planning purposes to be about 20 percent.

The development of wind resources has largely been supported by a 1.5 cent per kWh federal wind energy Production Tax Credit (PTC), which was first enacted in 1992.

### 5.8 Solar Water Heating

No summary data of total installed pool or DHW units exists for the region although through anecdotal evidence, historically, this has been the best market for renewables, in particular, for pools. In addition, increases in natural gas prices have significantly increased the deployment of pool and DHW solar systems in San Diego.

Solar water heating is typically not viewed as a distributed generation technology because it does not generate electricity. However, it can offset both electric and natural gas consumption and should be considered a valuable energy resource in the region. Based on data from the Solar Rating and

\(^3\) Confidential conversation with industry sources (potential developers).

\(^3\) Conversations with wind developers indicated that a study was recently done by SDG&E that indicated that a 28-mile line extension would be required to tie this wind resource into the local grid. The cost of this transmission line could exceed $20 million.

\(^3\) American Wind Energy Association. 2002
Certification Corporation, a typical solar water heating system generates the equivalent of 3,400 kWh annually.\textsuperscript{34}

More than one-half million solar hot water systems have been installed in the United States, mostly on single-family homes. The majority of these systems are used to heat swimming pools. Government incentives available from the mid-1970s to the mid-1980s led to a significant increase in the number of solar water heating systems installed. Since that time, overall installations have dwindled but there are significant increases among some applications.

In 2001, 33,000 new solar pool heating systems were installed in the United States in 2001.\textsuperscript{35} According to the Florida Solar Energy Center (FSEC), the energy output of this quantity of solar systems translates into an electrical generating facility of approximately 594 MW.\textsuperscript{36} Approximately 10,000 new systems were installed in California. More than 1,000 systems were installed in San Diego County during 2001.\textsuperscript{37}

Solar water heaters for domestic use comprise a smaller segment of the market. There are no data available on the current stock of installed systems in the San Diego region. A notable project in the region is the Shea Homes High Performance Home project located in Scripps Highland. Shea Homes is installing solar water heaters on 397 homes as part of an energy-efficiency project that includes both solar water heaters and photovoltaics.

### 5.8.1 Potential for Solar Water Heating

Tremendous potential exists in San Diego County to deploy solar water heating systems in many segments of the market. As mentioned above solar pool heaters are the most cost-effective and widely used application. Commercial and institutional swimming pools in the region are a natural market for solar pool heating systems. In addition, pools in schools, parks, hotels, and apartment complexes also represent significant market opportunity.

As is the case with photovoltaics, the new home construction market is a significant opportunity to deploy solar water heaters for domestic use. Additionally, programs tied to reroofing of existing homes should be considered. However, mandatory programs may not be the most productive method to increase deployment. Providing incentives could be a more effective way to motivate customers to consider solar water heaters.

In September 2000, Governor Davis signed Senate Bill 1345 that provides funding for solar water-heating systems as well as distributed generation systems. The California Energy Commission is administering the Solar and Distributed Generation Grant Program.\textsuperscript{38} The program provides $750 rebates for solar domestic water heaters and $250 for pool heaters. Since the program requires a building permit, many pool installations—which do not typically require a permit—have not used the $250 rebate because the time and cost for a permit is roughly equivalent to the rebate. Domestic solar water heating on the other hand has benefited from the program. The program is not currently funded for fiscal year 2003. The record budget deficit could make reauthorization of the program difficult.

\textsuperscript{35} The Solar Rating and Certification Corporation was established in 1980 to administer a certification, rating, and labeling program for solar collectors and a similar program for complete solar water and swimming pool heating systems.
\textsuperscript{36} Estimates bases on an average of 1,000 Btu per square foot per day and an average of 5 hours per day for 5 months per year.
\textsuperscript{37} Based on its relative size, SDG&E’s territory typically represents ~6 to 7 percent of statewide energy calculations. A 10-percent factor was used here to reflect a higher rate of pool heating systems in southern California.
\textsuperscript{38} See http://www.consumerenergycenter.org/solaranddg/index.html.
5.8.2 Summary: Solar Water Heating
Solar water heating represents a significant opportunity to diversify the regional energy power mix. Current incentives make this technology attractive. Paybacks are still somewhat longer than other conservation measures.

5.9 Geothermal
Even though geothermal is the largest source of renewable energy in California, there are no geothermal power generation plants in San Diego County. Much of the thermal energy in the region is located to the east and south of San Diego County.39

5.9.1 Potential for Geothermal
Imperial County has vast geothermal energy in deep thermal deposits located at Heber and East Mesa. One plant at Heber was developed by SDG&E in the 1980s. EIA energy resource maps indicate some projects of more than 1 MW on the California-Mexico border, however, none within San Diego County. One of the primary barriers to accessing these resources is the initial capital investment required to drill exploratory wells, which can cost between $1–2 million each. Better assessment and location of geothermal resources are the subject of research currently underway by the CEC and DOE.

5.9.2 Summary: Geothermal
Significant opportunities exist for developing geothermal resources in Imperial County and in Northern Baja. While these resources are not located in San Diego County, the potential exists for partnering with Imperial Irrigation District or CFE in Mexico to develop these resources to improve fuel diversity in the region. Geothermal is estimated to increase from 80 to 300 MW over the next 30 years (in Imperial County and Baja California).40

5.9.3 SDG&E and Renewable Interest Comments on Renewable Potential Estimates
SDG&E commented in its review of the final REIS draft that the CEC report, Renewable Energy Report (November 2001), that interest in renewable energy systems is quite low, primarily due to cost considerations. SAIC feels that the capital cost curve over the next 10 to 15 years will be the major factor affecting the use of distributed renewable systems. SAIC used detailed cost curves from its work with DOE/NREL and these were used as the basis of the penetration estimates. Codes and incentives will also be important. Other commenters felt that the SAIC estimates are too low.

5.10 Effective Market Potential of DG in the San Diego Region
DG can play an important role in energy planning in the San Diego region.

Potential exists for additional market penetration of DG technologies in the San Diego region. Table 5-10 presents an estimate of the market potential for distributed resources. The numbers shown are cumulative over time for low-, medium-, and high-growth scenarios. The estimates are based on national and state estimates and ratios, current penetration trends in San Diego County, and growth rates and maturity development rates of the technologies.

40 These resources are not really distributed generation resources, but still a significant form of renewable resource.
Table 5-10. Estimates of Effective Incremental Market Potential For DG (in MW)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>DG Technology</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>CHP/DG</td>
<td>250</td>
<td>360</td>
<td>800</td>
<td>1250</td>
</tr>
<tr>
<td></td>
<td>PV</td>
<td>6</td>
<td>12</td>
<td>40</td>
<td>175</td>
</tr>
<tr>
<td></td>
<td>Landfill</td>
<td>4</td>
<td>10</td>
<td>20</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>15</td>
<td>40</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td>Fuel Cells</td>
<td>2</td>
<td>5</td>
<td>8</td>
<td>15</td>
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<td></td>
<td>Wind</td>
<td>80</td>
<td>200</td>
<td>400</td>
<td>600</td>
</tr>
<tr>
<td>Medium</td>
<td>CHP/DG</td>
<td>360</td>
<td>650</td>
<td>1200</td>
<td>1600</td>
</tr>
<tr>
<td></td>
<td>PV</td>
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<td>225</td>
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<td></td>
<td>Landfill</td>
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<tr>
<td></td>
<td>Geothermal</td>
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<td>100</td>
<td>125</td>
<td>200</td>
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<tr>
<td></td>
<td>Fuel Cells</td>
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<td>20</td>
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<td>40</td>
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<td>100</td>
<td>300</td>
<td>500</td>
<td>700</td>
</tr>
<tr>
<td>High</td>
<td>CHP/DG</td>
<td>500</td>
<td>800</td>
<td>1400</td>
<td>1765</td>
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<tr>
<td></td>
<td>PV</td>
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<td>275</td>
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<td>8</td>
<td>15</td>
<td>50</td>
<td>75</td>
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<tr>
<td></td>
<td>Geothermal</td>
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<td>150</td>
<td>200</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td>Fuel Cells</td>
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<td>70</td>
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<td>Wind</td>
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<td>Total</td>
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<td>627</td>
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<td>2150</td>
</tr>
<tr>
<td></td>
<td>DG Non-Renewable</td>
<td>250</td>
<td>360</td>
<td>800</td>
<td>1250</td>
</tr>
<tr>
<td></td>
<td>DG - Renewable</td>
<td>107</td>
<td>267</td>
<td>528</td>
<td>900</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>516</td>
<td>1097</td>
<td>1970</td>
<td>2840</td>
</tr>
<tr>
<td></td>
<td>DG Non-Renewable</td>
<td>360</td>
<td>650</td>
<td>1200</td>
<td>1600</td>
</tr>
<tr>
<td></td>
<td>DG - Renewable</td>
<td>156</td>
<td>447</td>
<td>770</td>
<td>1240</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>838</td>
<td>1455</td>
<td>2420</td>
<td>3285</td>
</tr>
<tr>
<td></td>
<td>DG Non-Renewable</td>
<td>500</td>
<td>800</td>
<td>1400</td>
<td>1765</td>
</tr>
<tr>
<td></td>
<td>DG - Renewable</td>
<td>338</td>
<td>655</td>
<td>1020</td>
<td>1520</td>
</tr>
</tbody>
</table>

5.11 Potential Customer Benefits

- **Reliability** – Commercial and industrial customers are increasingly demanding reliable, high-quality power. Many industries require “nine nines” (99.9999999 percent) of reliability. This translates into less than 1 second of outages per year. DG can be a strategy to ensure power reliability. Customer acceptance of distributed resources in the future may be driven largely by concerns for reliability.

- **Peak Demand Reduction** – DG technologies can help reduce customer peak demand and consumption. Currently, a commercial customer on the AL-TOU tariff would pay a $0.12/kWh charge for peak consumption, a $10/kW peak demand charge and a $6/kW non-coincident demand charge for the highest demand registered at any time, which potentially could occur on peak. Innovative strategies of integrating DG technologies with demand reduction strategies and energy management systems can increase demand reductions.

- **Choice in the Absence of Direct Access** – CPUC Decision 02-04-052 approved April 2002, eliminated the option for electricity customers to purchase power from energy providers other than the local IOU (e.g., Green Mountain, Commonwealth Energy). DG provides

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42 Interim Decision Moving the Proceedings On Direct Access Cost Responsibility Surcharges From A.00-11-038 ET AL. TO R.02-01-011 or Subsequent Proceeding, CPUC, April 2002.
customers choice and control over their energy planning in the absence of alternative energy service providers.

- **Hedge Against Price Volatility** – DG can provide large load customers a hedge against future volatile prices and an option for local supply when market or service conditions warrant it.

### 5.12 Other Regional Benefits

- **Power Generation Diversity to Mitigate Market Risk** – If electric wholesale prices are more volatile and much higher than the cost of natural gas to produce the power, using DG plants to produce additional electricity for the market is a very attractive option. However, there is much uncertainty as to how many hours per year market conditions will exist.

- **Avoided Capacity Costs from Grid-based Power Supply Options** – Analysis of the WSCC and San Diego region found capacity values starting at the $100/kW-yr level in 2002 and in some cases approaching $150/kW-year in 2002 for the capacity constrained scenario. DG units from purely an economic perspective, not counting service reliability, become very attractive at costs of $75/kW-year and above. In addition, over the 30-year study period there will be occasions of intermittent price volatility due to the boom and bust cycles of power plant development and load constrained pockets. Future capacity values will rise more than $100/kW-yr (and this may happen as early as this summer for the next 2 years) and this suggests that all customers with sizeable process and large facility infrastructure load requirements consider DG as a hedge to higher future capacity prices and for additional reliability. The future will also involve more interruptible capacity and demand bid programs.

- **DG Impact on Air Quality** – By increasing the efficiency of energy use through renewable technologies and CHP applications, DG can significantly reduce emissions of criteria pollutants and greenhouse gases. In addition, siting large-scale centralized power plants could be difficult in the San Diego region due to limited emission credits.

- **Resource Efficiency** – While future central station plants will generate electricity more efficiently than the 30- to 35-percent average rate through the late 1990s, DG installations with proper thermal/electric balance have design efficiencies of 80 to 90 percent and will still result in significant overall energy savings. On-site use of DG also reduces transmission and distribution system line losses to zero from typical central unit line losses of 4 to 12 percent.

- **Energy System Security** – Decentralized DG is less susceptible to attacks and sabotage than centralized power plants. Damage to a centralized power plant could cause widespread disruptions.

- **Economic Development** – It has been reported that retaining a dollar in the local economy can have a multiplier effect that is as much as 8 times. Using locally supported DG initiatives, including leveraging the use of local DG resource firms can help create or maintain jobs, and economize energy prices which have a major burden on local businesses. Every effort should be made to use life cycle costing principals to screen and evaluate energy development options, including recognizing the advantages that some smaller scale energy technology may have more favorable impacts on the local economy than others.

- **Added Reserve Capacity** – DG can add to the state and regional need for additional reserve capacity. Adequate reserve capacities contribute to price stability by lowering reliance on last-minute spot market power purchases.

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43 Note: the State of California may be developing a policy to avoid such cycles by instituting capacity credits and using the California Power Authority and local utilities to generate more power on a cost basis. Also, the power industry and financial markets may be doing their own “self correcting.”


Many DG units can “back start.”

**Reduced Reliance on Imported Power** – Increasing energy supply by increasing DG capacity can ensure that sufficient regional generating capability exists in the region, thereby reducing reliance on imported power, which is now dependent on limited transmission entering the county. It is prudent to have a balance of grid and local capacity and electric energy capability. Local DG investments should be considered as insurance when larger regional power markets become volatile and capacity is in short supply and or cost avoidance and damage avoidance when power supply is interrupted.

### 5.13 Potential Utility Benefits

In the current restructured electric industry in California, distributed generation options can offer grid support to the distribution utility

- **Incremental System Capacity Additions** – The construction and permitting period for both centralized power plants and transmission and distribution upgrades is on the order of 3 to 7 years. Adding localized DG capacity in segments of the T&D system that are most constrained can be achieved more quickly and potentially is more cost effective.

- **Avoid or Defer Infrastructure Investments** – Adding DG in capacity constrained areas could defer and possibly obviate the long lead-time and expense of infrastructure expansions, particularly new transmission investments.\(^\text{46}\)

- **Lower T&D Losses** – DG technologies are located at or near the site of consumption and therefore do not incur line losses associated with long transmission lines and the distribution process.

- **Increased Gas Flows** – Increased DG deployment also could represent improved gas flow for gas utilities. Most DG technologies combust natural gas to create electricity.

- **Relieve Grid Capacity Strains** – DG is a viable mechanism to relieve capacity constrained segments of the utility transmission and distribution system.

### 5.14 Economic Development Impacts of Energy Efficiency and Distributed Generation

Energy fuels the growth of San Diego’s economy. The economy, in turn, directly employs thousands of workers and each year provides billions of dollars in economic activity and millions of dollars in taxes and other revenues to local government.\(^\text{47}\)

The availability of lower-cost energy will become increasingly important as long as the region has the goal of expanding its economic engine built on high technology, biotechnology, telecommunications and other economic sectors. These sectors are important to the region’s economic prosperity because they provide relatively high wages, and bring new dollars into the region’s economy through exports.

In evaluating the impacts of energy efficiency and DG investment decisions on the economy and economic development, several factors need to be considered, including:

- Total required investment in energy efficiency and DG
- The energy savings as a result of implementation of energy efficiency
- The retained energy dollars as a result of increased efficiency and customer-owned electricity generation in the region versus importing electricity

\(^{46}\) The creation of demand response and demand bid programs are designed to address both emergency and economic dispatch and use of onsite generation when market conditions need this capacity.

\(^{47}\) SDG&E rightfully pointed out that the REIS was not a transmission planning study and therefore these impacts are not proven.
The potential incremental increase in revenues for companies offering energy efficiency/DG services and improvement in jobs in the County

The potential multiplier effect from dollars that are retained in the County

The impact of high costs and future price uncertainty on economic growth

The opportunity of energy efficiency and clean generation technologies to fuel a new services cluster

As experienced over the past 2 years, high-energy prices can significantly dampen economic growth and consume limited disposable income. In 2000–2001, the region spent more than $6.4 billion on electricity and natural gas, roughly 3.4 percent of the region’s $95 billion Gross Regional Product (GRP). Of this amount, more than $3.8 billion left the region’s economy. During the same time period, despite reducing our consumption, the region spent nearly $155 million more on electricity and natural gas than it would have spent in 1999. The estimated increased costs of electricity and natural gas for the region from 2000 through 2006 is expected to exceed $7.7 billion.

In addition, the opportunities that can be presented by capitalizing on this market are equally impressive. From 2002 through 2030, it is estimated the region will spend approximately $166 billion on electricity and natural gas. As the region learned from the last 2 years, the risks of not controlling these costs are very high. By improving electricity end-use efficiency by only 1 percent per year, the region could save more than $1.3 billion through 2030 (cumulative). A slightly more aggressive efficiency target of improving our efficiency by 2 percent per year saves more than $2.7 billion. Eliminating growth in electricity end-use would save nearly $4.5 billion. This would be accomplished through a variety of measures and pricing methods.

5.15 Potential Investment Impacts of Energy Efficiency, Demand Response and Distributed Generation on the Local Economy

Table 5-11 shows estimates of the level of investment in energy efficiency/demand response and distributed generation through 2030, along with the estimated employment and gross wages to support these growing industry segments. The data in the table show a 5 to 1 investment return from energy efficiency and DG. For investing as much as $3.6 billion the community gets an economic benefit of $17.8 billion, under the medium scenario. Thousands of jobs would also be created in the community over the 30-year period.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Energy Efficiency Investment ($ Million)</th>
<th>Distributed Generation Investment ($ Million)</th>
<th>Total Investment ($ Million)</th>
<th>Total Economic Impact ($ Million)</th>
<th>Firms</th>
<th>Employment</th>
<th>Gross Wages ($1,000s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>$632</td>
<td>$2,060</td>
<td>$2,692</td>
<td>$13,460</td>
<td>60</td>
<td>2,500</td>
<td>$95,000</td>
</tr>
<tr>
<td>Medium</td>
<td>$664</td>
<td>$2,490</td>
<td>$3,154</td>
<td>$15,770</td>
<td>200</td>
<td>14,323</td>
<td>$931,000</td>
</tr>
<tr>
<td>High</td>
<td>$850</td>
<td>$2,700</td>
<td>$3,550</td>
<td>$17,750</td>
<td>300</td>
<td>17,176</td>
<td>$1,100,000</td>
</tr>
</tbody>
</table>

Assumes 59% of energy costs leave the economy, which is highly conservative. In some portions of the country, nearly 80 percent of energy expenditures leave the economy. (Source: Skip Laitner, The Hidden Link: Energy and Economic Development, Urban Consortium Energy Task Force.

Comparing actual expenditures to projected expenditures at historical prices inflated at historical rates.

Likely to be a conservative estimate based on historical growth rates versus the 2001 and 2002 depressed levels of electricity consumption.

Based on an estimate of 60 energy firms in 2002, averaging 42 employees per firm with average annual earnings of $38,000 per employee.

Assume an economic multiplier effect of 5 to 1.
An example of the impacts of energy efficiency can be drawn from a recent energy efficiency program. In 2000, SDREO began implementing a program that installed energy efficient “cool” roofs on buildings. SDREO estimates that it will install more than 25 million square-feet of energy efficient roofing by the end of 2002. Total program costs will be about $5 million; total investment of customers for the roofs (minus incentives) is approximately $37 million, with an incremental investment of approximately $1.8 million (the premium for installing an energy efficient roof). Over the 10-year life of the roof (which is conservative), the energy savings are in excess of 24 million kWh and costs savings are in excess of $7.5 million.

Considering one element of the distributed generation projections of this Study illustrates the potential impacts of a solid DG-based strategy. For PV, the most costly of the technologies considered, to achieve the medium case estimate of 250 MW by 2030, the region would need to experience a 17 percent average growth in deployment of PV per year. If this strategy is pursued, the cumulative electricity costs savings through 2030 are in excess of $1 billion. Additional benefits include jobs to support the manufacturing, assembly and maintenance of the systems. These jobs are relatively high paying, and could be grown within the region.

Two key questions are raised from the perspective of the region’s approach to electricity and natural gas supply choices and the overall economy:

1. How can energy programs be developed to reduce the drain of energy dollars from the region?
2. How can the region better position itself through actions to lower energy costs and improve energy self-sufficiency such that energy costs are not an economic disadvantage, but an economic advantage?

In 1992, the Sacramento Municipal Utility District (SMUD) implemented a program to obtain as much as 650 megawatts of equivalent power capacity by the year 2000. According to a recent report published by the California State University, the program had the following results and impacts:

1. $59 million spent locally on energy efficiency measures
2. Avoided spending $45 million to purchase power from other regions
3. Increased regional income by $124 million, achieving an economic multiplier of 2.11
4. Created about 880 direct-effect jobs
5. Added $22 million to the area's wage-earning households.

Additional long-term benefits accrued to the region through lowered overhead or operating costs for participants (resulting from the continued energy savings of energy efficiency improvements over the 10 to 20-year life of the efficiency measure) and, therefore, increased disposable income. These energy dollars are more likely to remain in the local economy, creating an economic multiplier.

5.16 Disadvantages of DG to the San Diego Region

While there are many advantages to deploying DG in the region, several disadvantages must be considered in determining its appropriate role. Disadvantages of DG include:

- **Dispatchability** – Many distributed generation technologies cannot easily dispatch power onto the grid when needed. This is particularly true for renewable technologies including photovoltaics and wind. The city of San Diego (MWWD) notes that it has a 1.2 MW digester gas peaking unit and other biogas fueled and geothermal systems that could be dispatched, if required.

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53 Not all of this roofing is located in San Diego County, but the program numbers will be used for this illustration.
54 Based on an average of $1.50 per square foot.
55 Based on an average of a 5-percent premium for energy efficient roofing materials.
- **Coordination of DG Units for Grid Planning** – Many smaller decentralized power generation facilities could be more difficult to manage. This would be particularly true if individual generators who could produce more energy than needed to power a specific site put excess power into the grid. Fewer, larger generators are easier to manage and plan than many, smaller ones.

- **Gas Infrastructure Affects** – Increased reliance on natural gas-fired DG technologies could require infrastructure upgrades. A major limiting factor in considering widespread market penetration of natural-gas-fired distributed generation systems is proximity to natural gas mains. Some larger DG systems require high-pressure gas service. Access to a high-pressure line or the installation of a localized device to increase gas pressure is required. However, this additional cost of a fuel gas compressor is significant and can easily make the option not cost effective. To add a high pressure gas line to serve an on-site turbine for a gas generator, the cost may be as much as another $50,000 to $100,000 depending on the size of the unit and distance and size of the line.

- **Potential Effects on the Transmission and Distribution System** – While no evidence exists to verify the concern that a dramatic increase in DG technologies could affect the T&D system, the potential need for small-scale upgrades should be considered.

- **Still Need Permitting and Emission Offsets for Larger Units** – DG units will still have to meet clean air and emission permitting requirements and possible offsets. MWWD noted that some biogas plants are very cost-effective when compared to retail rates, if cost-effective designs are used.

### 5.16.1 Economics

Historically DG technologies have higher capital cost than combined-cycle gas turbine systems and other base load power supply options. Increased electricity and natural gas prices combined with declining DG equipment costs are making these technologies competitive with utility power.

### 5.16.2 Price of Energy

The main factor in determining whether DG applications are cost effective for customers is the cost of utility power and natural gas, along with the value placed on reliability. While both electricity and natural gas prices reached historic highs in 2000–2001, they have settled down to rates that are 30 to 40 percent pre-energy crisis levels. At current energy prices, some DG applications are very cost-effective (e.g., CHP) while most are marginally cost effective (e.g., solar PV with full tax advantages).

Green pricing programs that take into account the value of externalities, such as the environment, help make renewable compete on a more level playing field with fossil-fueled power. According to the National Renewable Energy Laboratory (NREL), as of January 2002, a total of 650 MW of new renewable energy capacity has been installed as a result of utility and competitive green pricing programs, and another 440 MW is expected to be installed in 2002. Of this total, 93 percent is wind, 4 percent is biomass, 1.7 percent is small hydro, 0.7 percent is geothermal, 0.6 percent is solar and 0.2 percent is landfill gas.\(^{57}\) Green pricing programs have consumers pay a premium for purchasing green power, which can vary between 0.6 and 5.0 cents per kWh. Green power programs are currently offered in markets in 23 states. Public Service of Minnesota had such a program where 7 percent of its customers participate.

### 5.16.3 Regulatory Issues and Tariffs

The State of California is working toward a more coordinated energy efficiency, demand response and renewable energy strategy – even though there may be much uncertainty in direction on the market design for the State. Over the last several months there have been a number of significant developments occurring that will create significant opportunities for San Diego County in the future to

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realize its high potential for energy efficiency, demand response, renewables and DG. These events include the following:

- Recent CPUC approval of an OIR regarding the implementation of real time and dynamic pricing (See: [http://38.144.192.166/efficiency/2002-06-07_en_banc/2002-06-07_TRANSCRIPT.PDF](http://38.144.192.166/efficiency/2002-06-07_en_banc/2002-06-07_TRANSCRIPT.PDF))
- The proposed 2005 CEC building code may require the incorporation of photovoltaics and that all new buildings be wired for real time meters and demand response thermostats
- The CPUC must approve any tariffs to support real time pricing and demand response programs.
  - For 2001-2003 the CPUC energy efficiency and conservation programs will total $424 million and result in 452 MW peak savings
  - Programs cover retrofits and renovations
  - Lighting and appliances
  - New construction
  - Comprehensive group development programs for universities and housing complexes
  - HVAC technologies
  - A total of $102 million is reserved for local project funding
  - A variety of demand response programs are supported (Over 1,300 MW of curtailable load is available)
  - The CPUC also grants funds for customers producing electricity on-site for up to 1 MW without exporting for sales. This program also provides higher grants for renewable generation options.
- The California Power Authority has access to capital and loans to support the installation of demand responsive equipment and loans
  - $30 million of tax exempt bonds for the purchase and installation of energy efficient projects or renewable and clean energy resources
  - Tax exempt loans to state and local public agency buyers of DG and efficiency equipment and services—minimum size is $2 million
  - A DG public procurement program for public agencies
  - Third party financing for DG
  - A demand reserves partnership program
  - Financing of TOU meters and communications technology.

Other proposed new state programs for which bills passed the California legislature and are awaiting gubernatorial approval include:

- SB 1038 which requires a renewable energy efficiency development program for the state to be submitted to the legislature
- SB 1038 would provide substantial new funds for the development of new renewable projects in California by amending the renewable resource trust fund
- AB 57 would require Procurement Plan be developed to achieve a 20% renewable portfolio and grow at a rate of 1% a year—provided sufficient funds are available. A risk management policy and program is also required to avoid price shocks.
5.16.4 Inability to Wheel Power Offsite

Currently customers cannot easily transfer power generated at a site with limited loads to another site with high loads. For example, the City of San Diego Environmental Services Department has conducted several feasibility studies to install up to 1 MW of photovoltaics at the closed Miramar Landfill. Under the current regulatory framework, the City could not transfer or exchange the excess power generated at the Miramar Landfill to its other facilities, which draw power from the local utility grid.

5.16.5 Interconnection

Rule 21, a standard interconnection agreement among the state’s IOUs, facilitates the interconnection process for DG technologies, and several other interconnection-related barriers still exist.

One may review the handbook on Rule 21 interconnection issues by visiting SDG&E’s web page to understand the complexity of interconnection.

5.16.6 Net Metering

AB 1890 provided for net metering, which allows customers to connect a renewable energy generating system directly to the utility distribution and transmission grid and to receive retail credit for excess generation. This law enabled the grid-connected photovoltaics market in California and greatly improved the economics of renewable technologies.

Incorporated into the California Public Utilities Code as Section 2827, the original law allowed net metering for photovoltaic or wind systems up to 10 kW. This limited net metering to the residential and small commercial customers. In addition, the law stipulated that total net metered systems could not be more than 0.1 percent of peak demand of the local investor-owned utility. In San Diego this translated to a cap of approximately 3.8 MW of photovoltaics and wind.

In Spring 2001, Governor Davis signed into law AB 29X, which amended section 2827 of the California Public Utility Code to increase the system size limit to 1 MW, eliminate the 0.1 percent peak demand cap and exempted net metered customers from standby charges. These amendments will sunset on December 31, 2002.

The changes included in AB 29X were viewed as positive development for the deployment of renewable energy technologies, particularly photovoltaics. Reinstating both the 10-kW system size limit and the 0.1 percent peak demand cap on net metered systems could significantly reduce market penetration of photovoltaics in the San Diego region. This is especially true since the region currently has 1.6 MW of photovoltaics in operation as of May 2002 and an additional 2 MW were in development. At the current rate of deployment, photovoltaic installations in the San Diego region likely will reach the 4-MW mark in the next 1 to 2 years.

Additionally, if the provisions of AB 29X sunset at the end of 2002, customers that install photovoltaics will be required to pay standby charges. This could make many projects uneconomical.

5.16.7 Tariffs

- Schedule A-V1 was closed effective 10/01/02. It was replaced by AL-TOU-CP. Terms and conditions of AL-TOU-CP are slightly different than AV-1.

5.16.8 Departing Load Fee

The CPUC is conducting a proceeding to consider establishing an exit fee for customers who either participates in direct access contracts or who generate a portion of their power onsite with distributed generation technology.

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58 See http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.
Departing load fees are being considered mainly because the CA Department of Water and Resources (DWR) has purchased long-term power contracts and many experts believe that the burden for servicing the associated debt should be borne by all ratepayers. Customers who purchase power from a source other than DWR or generate a portion of their own power would pay no or a smaller portion of the debt, while those still purchasing their power from their local utility would shoulder a proportionally larger burden.

Many DG technologies are marginally cost-effective and departing load fees could significantly inhibit further market penetration.

### 5.16.9 Permitting

Two important areas of permitting exist for energy efficiency and DG—air emissions and local area permits for building and construction. What follows is a review of these permitting issues and requirements. The agencies potentially involved in DG siting approvals are the following:

- **Air District: Air quality permitting** — Primary area is the control of air pollution to protect public health. May have CEQA responsibility as lead agency or responsible agency. Compliance with federal and state Clean Air Act requirements jurisdiction defined by county limit or a group of counties comprising an air district.

- **Local planning department: Environmental assessment** — Primary areas are land use and zoning issues. May have CEQA responsibility as lead or responsible agency. Project impacts evaluated for conformance and environmental impacts. Noise impacts evaluated by this agency. Jurisdiction defined by city or county limit.

- **Building department: Building permit approvals** — Approvals issued for projects in conformance with building code requirements. Also ensures project design is consistent with industrial and worker safety. Jurisdiction typically defined by city or county limit.

- **Fire department: Fire protection and safety** — Approvals issued for projects in conformance with fire code requirements. May also be organization responsible for portions of environmental health-related requirements. Jurisdiction typically defined by city or county limit.

- **Environmental health: Public health and safety** — Approvals issued for projects in conformance with federal and state hazardous materials and waste management requirements. May also have responsibilities associated with fire and building code issues.

- **Jurisdiction defined by city or county limit: Water and wastewater district; public works** — Water supply and discharge. Approvals issued for allowable discharge to sewer system; evaluates waste streams that may enter various bodies of water (e.g., lakes, streams, bays, estuaries, coastal waters, etc.). Ensures compliance with storm water requirements. Project conformance with federal Clean Water Act and local water and wastewater quality requirements.

The potential obstacles for DG permitting remain the same obstacles as identified by the Energy Commission in its evaluation of the CEQA review, building permit and air permit streamlining process. Specifically, there is not uniformity and/or consistency among the different approval agencies within the same categorical areas. Delays in permitting are not necessarily driven by the unique nature of DG. Sempra Connections, the Sempra Energy subsidiary that works with customers to build onsite DG systems, reports that while a local permit for a microturbine may take 30 days, but permitting a small building enclosure may take up to 90 days or more. APCD tries to process permits within 90 days even though they have 180 days.

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59 See Administrative Law Judge’s Ruling Clarifying Scope and Adjusting Hearing Schedule Relating to Departing Load Customer Issues, issued April 5, 2002 in A.00-11-038 et al.
5.17 Air Permits

For regional Air Quality Managers, reducing emissions from electric generation is a key element in effort to achieve/maintain standards. The current focus by APCD is to require Best Available Retrofit Control Technology for upgrades of existing plants and installation of Best Available Control Technology (BACT) for new plants/facilities. BACT forecasted to reduce NOx from existing plants by 70 to 90 percent. Power plant emissions account for less than 1 percent of statewide total of reactive organic gasses (ROG), carbon monoxide, and particulate matter under ten microns (PM 10); less than 3 percent of oxides of nitrogen (NOx), and less than 5 percent of sulfur (SOx).

A recent report on DG potential in California stated the following regarding emissions and air quality:

- Economic potential for utility-owned peaking DG is substantial as they can provide peaking capacity at lower overall cost than traditional central generation.
- Base load DG does not currently compete economically with the wholesale market except for Combined Heat and Power (CHP).
- DG systems that capture heat can significantly improve the economics of DG projects; Report estimates that up to 15 percent of utility new load forecast could use CHP.
- According to San Diego APCD, unless DG projects zero or near-zero emission technologies, emission rates (pounds/mwh) are usually higher than new, large central power plants. Also, their emissions are nearer to ground level, which may result in greater impacts on ambient air quality conditions.
- DG has in many instances emission features that are much improved over the average electric generation technology in the market. When compared with the newest and most advanced generating plants, however, DG emission characteristics do not appear to be as attractive. MWWD reports that renewable DG and CHP with high efficiencies should compete favorably with combined cycle plants using a boiler to produce hot water, or using a flair from landfill gas.

The goal of environmental control agencies and the state of California is to ensure that DG emissions become comparable to the per kWh emissions levels of new central plants on an emissions per kWh basis by 2007.

A recent study performed by the Center for Clean Air Policy shows that on-site generation displaces a mix of other generators depending on the location and operating characteristics of the DG project. Because DG displaces a mix of new and existing generators with higher average emissions, the environmental outcome for DG is always positive.

The analysis described above shows that gas-based DG would actually be beneficial to air quality in most applications and locations. Based on this assessment, it is inappropriate to attempt to hold conventional DG technologies to the standard of well-controlled gas combined cycle projects. The primary result of such an approach will be that DG projects that could reduce emissions will be prevented from being installed and the environment will suffer. In light of these results, a better regulatory approach must be developed which is protective of the environment through the encouragement of beneficial DG technologies.

5.18 Local Building Permits

An important permitting hurdle exists for new DG projects at the local level. The primary local permit processes are conducted by multiple agencies, e.g., city and county governments, air districts. Obtaining approvals from various entities can be time-consuming and costly, as well as confusing to

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61 “Clean Power, Clean Air and Brownfield Redevelopment”, Catherine Morris, Center for Clean Air Policy.
project developers who are not well versed in the local government requirements and procedures and to agency personnel who are not knowledgeable regarding DG technologies. Consequently, the deployment of DG may be hindered because of the involved and costly permit processes. In order to overcome these obstacles, the permit process must be understood, and opportunities to reduce confusion and costs should be developed.

The levels of government involvement and review and approval obstacles were presented in the California Energy Commission December 2000 report, “Distributed Generation: CEQA Review and Permit Streamlining” (P700-00-019). The three permit processes identified by the Energy Commission included land-use approvals, building permits and air permits with particular emphasis on the requirements for approval and permits, as well as opportunities identified to streamline the California Environmental Quality Act (CEQA) review and permitting processes.

As a result of this effort, the Energy Commission Staff provided local governments with training, technical assistance, and guidance on the amended CEQA guidelines.

This approach enables the Energy Commission to maintain its neutrality regarding the acceptability of individual DG projects, while still facilitating DG project deployment.

The number of approvals locally will vary depending on project characteristics such as the size and complexity, geographic location, the extent of other infrastructure modifications (e.g., gas pipeline, distribution system, sewer connections), and potential environmental impacts of construction and operations.

The primary approvals that DG sources must obtain consist of the following:

- Local jurisdiction pre-construction and construction approvals
- Planning department land use and environmental assessment/review
- Building department review and approval of project design and engineering
- Air district approval for construction

Local distribution utility approval:

- Interconnection study
- Natural gas pipeline connection/supply

Local jurisdiction post-construction and operation approvals:

- Planning department and building department confirmation and inspection of installed DG source
- Air district confirmation that DG emissions meet emissions requirements

5.19 Role of Local Governments in Deploying DG

Public agencies at all levels play an important role in promoting DG technologies. Federal and state agencies are critical stakeholders in the DG deployment, however the below focuses on the role of local governments in deploying DG technologies.

5.20 Streamline Permitting for DG

The role of local governments is also critical to the future of distributed generation in California. Permitting of DG is most likely to be performed by local governments. As such, local governments will need access to information that will assist them in making these permitting decisions. Some local governments conduct DG-specific economic development activities. For example, several California jurisdictions—including San Carlos, San Diego, Long Beach, San Francisco, Santa Monica, Santa
5.21 Identify and Address Barriers

Local governments can review their permitting and siting procedures to identify potential barriers to DG installations. Local governments in cooperation with the SDREO can develop model policies in area concerning DG technologies.

5.22 DG Demonstration

Local government facilities offer ideal settings for demonstrating DG technology, because public institutions can tolerate longer payback periods than private businesses and their demonstration sites are visible to local residents and businesses. A number of California cities and counties are now installing DG projects, with assistance from the Local Government Commission and the Energy Commission.

5.23 Revenue Bonds to Procure DG

Local governments have bonding authority that can be used to finance energy projects including energy efficiency and distributed generation in public building. Voters in the City of San Francisco in November 2001 approved a $100-million revenue bond to conduct energy efficiency upgrades and install photovoltaic and wind power generation equipment. The energy savings from the financed projects will fund the bond payments unlike general obligation bonds, which are typically paid for through tax revenues.

5.24 CA Power Authority

Local governments in the region could access tools and programs currently in development by the California Power and Conservation Financing Authority (CPA). The CPA plans to assemble master contracts for DG technologies including fuel cells and photovoltaics. Local governments could use these contracts to procure DG technologies and services much like they currently can participate in state purchases of other equipment such as vehicles. Also, the CPA is developing several financing programs that could facilitate the purchase of DG technologies. For example, the CPA recently made available $30 million of tax exempt Industrial Development Bonds to provide below-market rate loans to manufacturing companies producing or choosing to install clean energy solutions in California.

5.25 Recommended Actions for Promoting Energy Efficiency, Demand Response, and Expanding DG/Renewables

5.25.1 Energy Efficiency and Demand Response

- All residential and small business customers should be on time-of-use meters and tariffs, and customers of 200 kW and higher should be encouraged to be on real-time pricing tariffs once the CPUC has agreed how to value wholesale electricity by time which is essential for RTP to work.
- A strong regional policy supporting aggressive conservation and demand management should be encouraged in the County.
- Improved coordination and collaboration is needed between SDREO and other energy service providers, including SDG&E

62 Distributed Generation Strategic Plan (Draft), publication # 700-02-002D, May 2002. CEC.
64 See http://www.capowerauthority.ca.gov/
The region should consider condition-of-sale regulations to upgrade existing buildings to meet minimum efficiency levels.

Local stakeholders should be better organized to influence regulatory bodies (e.g., CPUC, CPA, CEC) on allocation and spending of region’s public benefit funds.

A demand-side strategies task force should be formed to enhance coordination of programs, gaining cohesive regional positions on key issues, and to enhance access to critical data to evaluate cost-effectiveness of options. Sub-committees should address specific areas of distributed generation, demand response and energy efficiency.

The region should closely monitor and track the results of resource development and load management initiatives, seek to achieve continuous improvement in these programs and report the results to the public.

Create a market based demand response capacity program

Tax incentives and other economic incentives should be used to lure energy efficiency and distributed resource firms into the region.

Intensity of support for interruptible capacity programs should vary in intensity depending on market conditions.

Encourage the CEC and CPUC to continue to support cost-effective energy efficiency through existing public-good funding.

Consider using more peak/off-peak sensitive rate designs, with large delta’s.

5.25.2 DG/Renewables

The region should consider committing to achieving 30 percent of available demand requirements through DR resources by 2030.

There is a need to streamline permitting for DG applications in the county.

If the region creates a joint action agency, serious consideration should be given to the support of a joint development of renewable energy projects in and outside the region for energy used in the region.

An organized regional corporate pledge and commitment program should be developed to support strong commitment to regional DR and green energy development.

SDREO should develop a help desk and clearinghouse to help investors in renewable and clean energy technologies. A more active DG coalition should be formed to address the exit fee issue.

A renewable energy economic development program should occur whereby producers and suppliers of clean energy are encouraged to locate in the county.

SDREO should develop a renewable resource index and tracking system.

Developmental support for renewable resources in Northern Baja California and Tijuana areas should considered. A joint plan should be developed to achieve a renewable goal for the entire bi-national metropolitan area.

Take advantage of the CPA desire to add more reserve capacity in California—potentially new sources of capital may be available.

Create economic development zones that offer advanced power services;

Form a San Diego DG Working Group comprised of industry experts, local governments and utility representatives.

Explore opportunities to aggregate DG equipment purchases.
- Use local government organizations to demonstrate renewable technologies and encourage other businesses to do the same.
- Encourage the CEC and CPUC to continue to support cost-effective distributed generation and renewables through existing public-good funding.
- Have renewable and CHP included as part of the PUC’s new project design incentives programs.
6 Options and Scenario Analysis

6.1 Summary Findings of the Analysis

The San Diego region faces a highly uncertain energy future. There is uncertainty regarding the demand forecast, generation supply, fuel prices for generation, and the level of energy efficiency and DG-renewables that will help avoid supply/demand imbalances.

With the current economic conditions in the energy market, it is not certain when and if new generation will be built. The region also would be severely impacted if one of the two major transmission lines serving the county were not able to import power.

The implications are that a balanced portfolio of generation, transmission and energy efficiency-demand reduction and DG-renewables are needed to help limit these risks.

The balanced portfolio would be achieved by:

- Ensuring that new generating plants are built when needed
- Extending the life of marginal generation units that are planned to be terminated in the next few years if no new generation is built
- Considering expanding new transmission capability to the extent required to achieve a balanced portfolio
- Aggressively pursuing energy efficiency, DG and renewables.

The scenario analysis shows that with a strong commitment to energy efficiency and DG-renewables, the region can avoid building from one to two new generating plants over the 2002–2030 planning period. It is estimated that from two to three generation plants of 500 MW will be needed during this period, assuming other resources are also provided. Some of this new capacity can be offset with repowering of existing generating units.

A key outcome of the region’s energy strategy should be to seek secure supply, develop flexible options and achieve price stability.

The most critical time period that needs to be managed is the next 5 years—between 2002 and 2006. The region needs to carefully monitor the supply/demand balance during this period and ensure that needed generation and other resources occur as planned.

Specific recommendations by time period are the following:

6.1.1 Short Term (2002–2006)

1. The region may be facing significant retirements of older economically less attractive generating plants such as Cabrillo Units 1–3. There will be a net capacity reduction in the County if no new generating units are built or are repowered. These units could be either extended or repowered to help contribute to the new generation supply that is needed during this period.¹

¹ SDG&E points out that South Bay and Cabrillo Units are must run and cannot be shut down without replacements.
2. It is not clear that any of the identified generating projects will be built during this period although one to two new generating plants are needed between now and 2010. The region needs to address this issue and take action to insure that adequate new generating supply is available.

3. There is a shortage of transmission capacity serving San Diego County. This affects the County's ability to import contracted power supply and affects regional reliability.

4. The County is now served by two major power plants for South Bay and Cabrillo, which are older units and will be retired by 2009. Some Cabrillo units will continue to operate beyond this period. As new generation or transmission is added to the resource base, the competitiveness of these units will come into question. However, these units are valuable candidates for life extension and a valuable backup for reliability support.

5. Significant investments in energy efficiency and DG-renewables could help alleviate a near term tight supply/demand balance. This should be a priority.

6. The region is currently relying on the market to fulfill its generating needs, yet this market has little cash flow and liquidity at the moment and no new significant plants in the County are being built.

7. The region is not an attractive location for new plant development. The region needs to balance its need for new generation in the County with that of having a link to substantial new generation that will be built in neighboring areas including Arizona and North Baja. Currently there are transmission limitations to these markets.

8. A region-wide dynamic load flow and optimization study is needed of County transmission and distribution (T&D) in order to identify areas of improvement in capacity and reliability. T&D planning should be conducted in a more integrated manner before significant new resource investment occurs.

9. Under a lower growth scenario, a combination of new in-County generation additions, power imports and energy efficiency and DG-renewables, the County can avoid significant imbalances in the next 5 years.

6.1.2 Medium Term (2006–2010)

1. The region will need from one-to-two new base load plants (or an existing unit repowered or replaced) of 500 MWs each during this period, depending on what resource development occurs in the 2002–2006 time period. If new transmission is built by 2006 there should be no need for additional transmission until the post 2015–2020 period, except for transmission linking San Diego County to North Baja.

2. If demand growth is higher than expected, and if fewer power plants and less transmission capacity are developed than needed, significant imbalances could occur. On the other hand, if the plants are built and the levels of energy efficiency and DG-renewables occur as expected, the region should meet its load obligations.

3. A new transmission line to the North would help the region improve reliability and price stability for power, and create a market for capacity that is developed in the County. This would also limit potential stranded cost for capacity in the County. In addition, the region would have access to power from the North and East, with added transmission interconnection to Arizona from Orange County.

4. By this period Cabrillo Units 1–4 and potentially South Bay will have been retired. However, if no new generation or transmission is developed, the operation of these units may have to be extended as a stop-gap measure to assure adequate coverage of load and to meet minimum reliability requirements.
5. An outage of either the largest unit or a major transmission supply line could create significant supply shortages and be very costly to the region.

6.1.3 Long Term (2010 and Beyond)

1. A substantial amount of new generation will be built in Arizona and North Baja by this time, providing less expensive sources of power. The region should monitor this situation and see how economical this power supply is—provided the necessary transmission access exists.

2. Significant new generating capacity will be needed in the post 2020 time period. It is expected that new power plant projects will be considered and developed, or that additional import capability will exist.

3. Additional transmission to the North and East will be needed to take advantage of the generation that is being developed in these adjacent regions. Also, if natural gas prices are high due to the higher demand for gas from new power plants, Arizona represents a possible hedge against higher prices with the possibility of additional coal plants being built.

4. The state and region should be experiencing a significant amount of DG and renewable penetration during this period.

5. There is the chance that significant new interstate transmission access will occur linking Southern California to the Eastern part of the United States. As natural gas prices increase, and as the cost of new coal plants is reduced, more coal plants will be developed in the post 2020 period and could be a source of lower cost and stable electricity.

6.2 Background

This section presents the results of the scenario analysis and implications for alternative energy supply and demand conditions. In addition, key assumptions for alternative wholesale electric supply price conditions are also presented. Implications from alternative energy efficiency, DG and renewable supply levels and the potential implications of forced outages or import supply interruptions are also presented. The capacity supply impacts of additional transmission are also investigated. This analysis does not include a cost and reliability assessment of transmission options, although the value of transmission was evaluated in terms of contributing to the region’s peak load requirements.

A forward electric wholesale price analysis was completed by analyzing generation expansion in the WECC during the period 2002–2030, using New Energy’s MarketPower. This latter analysis takes into account different assumptions on gas prices, assumed plants that will be built in the WECC, transmission constraints that are likely to exist in the region, and the premium price for power plants built in the state and region. A higher discount rate was assumed for power plants being built in California due to the high political and market risks that exist for new plant development.

6.3 The Scenarios

A scenario approach was used to evaluate each electric supply and demand situation for the 2002–2030 period. Figure 6-1 illustrates the scenarios and inputs used in evaluating resource options. Appendix D presents data on the planned generation plants in operation during this period and the peak demand forecast.

The supply and demand growth scenarios were used to describe possible alternative future energy resource conditions, recognizing a broad portfolio of supply and demand conditions.
options. These are described below. In addition, the possible conditions that would affect generation expansion in San Diego County and the WECC were modeled using the MarketPower Model. This led to a series of forward prices that define the avoided energy and capacity prices to screen demand side program options. Consistent with the growth scenarios, estimates of demand side and DG-Renewable resource options were evaluated using the avoided costs. This is presented in Chapter 5 and the estimates appear in the scenarios below. This chapter focuses on the supply/demand growth scenarios and the forward demand and energy price estimates.

The key assumptions for the energy supply and demand growth scenarios are presented in Table 6-1. Key features of the scenarios are the following:

- **Scenario 1 – The Low Growth and Optimistic Scenario**: The expected optimistic development of in-County generation and a low deployment of energy efficiency, on-site distributed generation (DG) and renewable resources are assumed. Because of low load growth and relatively stable prices, there is a minimum level of demand management and DG-renewables developed.

- **Scenario 2 – The Base Case/Medium Demand Growth and Optimistic Supply Scenario**: Expected power plant development occurs as planned from earlier announced projects even though many of these projects are indefinitely on hold. A moderate deployment of energy efficiency, demand reduction, DG and renewable resources occurs. There is also investment in advanced meters and institution of pricing initiatives. Added incentives for distributed generation and local generation investments occur because locational marginal pricing (LMP) is applied in Southern California. The effects of new transmission on capacity supply are also investigated. The impact of a forced outage on the largest generating unit and transmission supply artery is also evaluated.

- **Scenario 3 – High Demand Growth and Worst Case Development Scenario**: Aggressive deployment of on-site distributed generation and renewable resources. This scenario represents an aggressive effort to balance network capacity, generation supply and demand options. This scenario also incorporates the SDG&E 1-in-10 year planning condition.

Assumptions for the Base Case Medium Demand Growth scenario include the following:

- SONGS receives a license extension in the late 2002–2010 time period and continues operation through 2030.
- The Cabrillo power plant is repowered or replaced after 2010.
- The Otay Mesa plant is built and made operational by December 31, 2004. (Note: this is not a certainty).
- The South Bay goes off line by the end of 2010.
- Cabrillo Unit 1 is retired in 2004, Unit 2 in 2006 and Unit 3 in 2008 due to an assumption that steam units are retired after 50 years of operation.
- There are 213 MWs of gas turbines (GTs).
- Qualified Facilities or “QFs” are 175 MWs of generating capacity.
- Peaker additions provide 213 MWs of generation.
- Two additional power plants with a nominal output of 500 MWs are built between 2010 and 2020. This could be any one of a number of projects currently being considered (e.g., Sempra Palomar in Escondido, ENPEX or some other unit).
- The state of California implements a policy of achieving a 15-percent reserve margin over the CA-ISO peak and each regional ISO utility is responsible for achieving their proportion of this peak.
The state of California and the region lag slightly behind in meeting the required renewable energy portfolio standard imposed by AB 57 that has a goal of ensuring that at least an additional 1 percent per year of the electricity sold by the electrical corporation is generated from renewable energy resources.

Defined proportions of energy efficiency and DG-renewables are achieved based on the COMPASS analysis presented in Chapter 5 and estimates that appear in Table 5-10.

### Table 6-1. Description of Demand and Supply Scenarios

<table>
<thead>
<tr>
<th>Key Drivers/Attributes</th>
<th>Low Demand Growth and Optimistic Supply</th>
<th>Base Case: Medium Demand Growth and Optimistic</th>
<th>High Demand Growth and Worse Case Supply</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Peak Load Growth Rate</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>1.2%</td>
<td>1.4%</td>
<td>1.6%</td>
</tr>
<tr>
<td>Electric*</td>
<td>1.8%</td>
<td>2.0%</td>
<td>2.5%</td>
</tr>
<tr>
<td><strong>Energy Growth Rate</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>1.0%</td>
<td>1.2%</td>
<td>1.4%</td>
</tr>
<tr>
<td>Electric</td>
<td>2.0%</td>
<td>2.3%</td>
<td>2.5%</td>
</tr>
<tr>
<td><strong>Metering Situation</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200 kW and above have interval metering/real-time pricing not used until 2005</td>
<td>200 kW and above have time-of-use meters and limited demand response programs</td>
<td>200 kW and above have interval meters In addition, 75% of customers less than 200 kW have time-of-use meter</td>
<td></td>
</tr>
<tr>
<td><strong>Transmission Pricing</strong></td>
<td>No LMP pricing</td>
<td>LMP pricing</td>
<td>LMP pricing</td>
</tr>
<tr>
<td><strong>Wholesale Power Prices</strong></td>
<td>Low/stable prices</td>
<td>Medium/Mod. Volatile</td>
<td>Highly Volatile</td>
</tr>
<tr>
<td><strong>California Energy Market Situation</strong></td>
<td>No choice for next 3 years</td>
<td>Limited choice 4–5 years</td>
<td>Competitive market post 5 years</td>
</tr>
<tr>
<td><strong>Generation Supply</strong></td>
<td>Optimistic supply. Identified projects are built as scheduled. Includes Otay Mesa by 2004, Cabrillo units start retiring, and South Bay is replaced.</td>
<td>Optimistic supply. Identified projects are built as scheduled. Includes Otay Mesa by 2004, Cabrillo units start retiring, and South Bay is replaced. Simultaneous import capability increases to 3200 MW.</td>
<td>Pessimistic supply or worse case supply. No new generation is developed over the 30-year period. No new transmission except small upgrades and additions. Simultaneous import capability stays at 2500 MW.</td>
</tr>
<tr>
<td><strong>Transmission Constraints</strong></td>
<td>No Rainbow Valley</td>
<td>Rainbow Valley or alternative is built by 2009 Capacity Reservation Market in place</td>
<td>Rainbow Valley or alternative is built in 2010 Capacity Reservation Market in place</td>
</tr>
<tr>
<td><strong>Energy Efficiency/ Demand Response</strong></td>
<td>Lower investment level and impacts</td>
<td>Moderate investment level and impacts</td>
<td>High investment level and impacts</td>
</tr>
<tr>
<td><strong>Distributed Resources/ Renewables</strong></td>
<td>Low priority, little support</td>
<td>Medium priority, moderate support</td>
<td>High priority, high contribution</td>
</tr>
</tbody>
</table>

Appendix D presents the list of assumed generation plant availability for the 2002–2030 study period. Defined proportions of energy efficiency, DG, load management and renewables are presented based on meeting certain cost effectiveness criteria. A range of low, medium and high cost-effective measures is included. In addition, to the base case or medium scenario, two demand growth sensitivity analyses were completed.
6.4 The Resource Balance: Supply and Demand Balance with Energy Efficiency and DG-Renewable Resource Options

Table 6-2 presents a summary of the supply/demand growth scenario using SAIC’s base forecast for the low, medium and high demand growth scenarios. The low and medium scenarios are based on SAIC’s application of the 50-50 SDG&E and CEC forecasted growth rates from 2002–2010. Then SAIC extrapolated the growth rates to 2030. The high growth rate is driven by the SDG&E 1-in-10 forecast growth rate that appeared in the Valley Rainbow filing of July 2002. The “SD Peak and Reserves” includes a 15-percent reserve margin that the state is working to achieve. The forecast peak demand includes losses and it is also applied to a small part of Orange County—this load can vary as much as 4 to 6 percent in any 1 year. This load was included after discussions with SDG&E, because much of the generation expansion and import decisions are based on a system wide planning requirement.

For the low and medium growth scenarios, the optimistic generation supply assumptions were used. The generation and import data consist of in-basin generation that includes existing steam units, namely Cabrillo Units 1 to 5 and South Bay Units 1 to 4. Except for Cabrillo Units 4 and 5, the remaining Cabrillo units are expected to be terminated by 2007, because they will have been in operation for 50 years and are relatively less efficient in terms of heat rates. South Bay is expected to be retired around 2006–7 and replaced by 2009. A replacement to South Bay is assumed as part of new generation additions in the County. GTs are assumed to total 213 MW for the planning period. QFs and Cogeneration that SDG&E recognizes is estimated to be 175 MW. Peakers are estimated to be 336 MW. The estimates of in-County generation appear in Appendix D. These units were reviewed and corroborated with SDG&E. The new generation was announced before the current down-turn in the power development business that has been occurring over the past 18 months.

The imports component or the generation and import values shown in Table 6-2, assume the Valley Rainbow T&D project is completed which increases the simultaneous import capability to 3,200 MW, and provides by 2006 for an additional 720 MW of export capability that does not currently exist. However, there is uncertainty on whether or not this line will be built. The analysis shows no deficits over the planning period. This is because a relatively lower growth rate is assumed (1.8 and 2.0% versus the 1-in-10 growth rate of more than 2.5%). In addition, new generating units are assumed as well as a large contribution from energy efficiency and DG-renewable.

The estimated demand growth rates for the low and the medium demand growth scenario are a bit lower than the SDG&E 1-in-10 growth rate. In sensitivity analysis SAIC uses the SDG&E 1-in-10 growth rate used for the Valley Rainbow filing by SDG&E and reserves of 15 percent were added. The sensitivity analysis shows that the region either has sufficient supply to meet near term peak load requirements or it will face a deficit as early as the 2004–2006 time period—if no new resources are built. The new resources could include such possibilities as Otay Mesa, repowering existing facilities, new transmission or if the estimated level of DSM and renewables is realized. If this does not occur, then the region could face some imbalance and higher prices.

The high growth and pessimistic supply scenario assumes no new generation is added nor any new transmission capability—leaving the region to a simultaneous import level of 2,500 MW. This scenario shows near term imbalances, which increase, to large levels in the final 10-year decade of the planning study.

Table 6-3 shows a summary of the supply/demand balance under each of the scenarios assuming a worse case supply, energy efficiency and DG-renewable supply condition. The low and medium growth rates are based on 1.8- and 2.0-percent growth. The higher growth rate is based on a 2.5-percent growth rate—which parallels the SDG&E 1-in-10 growth rate. These scenarios also assume a worse case supply situation with no new supply from generation or other transmission. The scenarios show shortages or imbalances occurring very early—as early as 2006, and possibly as early as 2004.
### Table 6-2. Supply/Demand Balance Assuming Optimistic Energy Efficiency and DG-Renewables, 2006-2030 (MW)

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Low Demand</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5429</td>
<td>6489</td>
<td>7757</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>5171</td>
<td>5562</td>
<td>5562</td>
<td>5562</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>467</td>
<td>860</td>
<td>1742</td>
<td>2741</td>
</tr>
<tr>
<td>Net</td>
<td>601</td>
<td>993</td>
<td>815</td>
<td>546</td>
</tr>
<tr>
<td><strong>Medium Demand</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5429</td>
<td>6618</td>
<td>8067</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>5860</td>
<td>5562</td>
<td>5562</td>
<td>5562</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>661</td>
<td>1387</td>
<td>2523</td>
<td>3651</td>
</tr>
<tr>
<td>Net</td>
<td>1484</td>
<td>1520</td>
<td>1467</td>
<td>1146</td>
</tr>
<tr>
<td><strong>High Demand</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5932</td>
<td>7593</td>
<td>9720</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>5171</td>
<td>5562</td>
<td>5562</td>
<td>5562</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>1032</td>
<td>1823</td>
<td>3165</td>
<td>4396</td>
</tr>
<tr>
<td>Net</td>
<td>1166</td>
<td>1453</td>
<td>1134</td>
<td>238</td>
</tr>
</tbody>
</table>

* Adjustments mean reduced peak demand from energy efficiency, demand reduction programs, DG-renewables.

### Table 6-3. Supply/Demand Balance Assuming Worse Case Supply, Energy Efficiency, and DG-Renewables, 2006-2030 (MW)

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Low</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5429</td>
<td>6489</td>
<td>7757</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>3961</td>
<td>3889</td>
<td>3889</td>
<td>3889</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>233</td>
<td>430</td>
<td>870</td>
<td>1370</td>
</tr>
<tr>
<td>Net</td>
<td>-843</td>
<td>-1110</td>
<td>-1730</td>
<td>-2498</td>
</tr>
<tr>
<td><strong>Medium</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5429</td>
<td>6618</td>
<td>8067</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>3961</td>
<td>3852</td>
<td>3852</td>
<td>3852</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>336</td>
<td>684</td>
<td>1263</td>
<td>1825</td>
</tr>
<tr>
<td>Net</td>
<td>-740</td>
<td>-893</td>
<td>-1503</td>
<td>-2390</td>
</tr>
<tr>
<td><strong>High</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD Peak + Reserves</td>
<td>5037</td>
<td>5932</td>
<td>7593</td>
<td>9720</td>
</tr>
<tr>
<td>Generation +Imports</td>
<td>4859</td>
<td>4650</td>
<td>3852</td>
<td>3852</td>
</tr>
<tr>
<td>Adjustments*</td>
<td>516</td>
<td>912</td>
<td>1573</td>
<td>2199</td>
</tr>
<tr>
<td>Net</td>
<td>129</td>
<td>-1168</td>
<td>-2168</td>
<td>-3669</td>
</tr>
</tbody>
</table>

* Adjustments mean reduced peak demand from energy efficiency, demand reduction programs, DG-renewables.
The result of the scenario analysis shows that the region:

- Needs to be more proactive in securing future supply capacity—whether from generation or transmission
- The region needs to carefully monitor the retirements of existing plants and the scheduling of more efficient replacement plants in the region
- The region has import obligations that exceed import capability which means that some of these imports that are take or pay obligations will not be able to reach the local market
- Unplanned outages of SONGS or SWPL which are the two main paths of electric imports into the County could create severe shortages unless additional in basin supply or new transmission is added
- SDG&E is correct in its Valley Rainbow filing that it is difficult to plan on any new generation being built in San Diego County under the current conditions of the electric supply industry and the fact that San Diego is not the most attractive location to site and build new power plants. For this reason, the region needs to be much more proactive in securing new generation and carefully managing the interplay of new generation development, older generation retirements, the siting and need for new transmission and defining the role for energy efficiency, demand reduction, and DG-renewable programs.
- Energy efficiency, demand reduction and DG-renewables should be aggressively pursued because they are good insurance to manage the risks of higher than expected demand growth and excessive dependency on natural gas fired generation or imports. Programs that lower coincident peak demand should be a priority.

Table 6-4 presents a more detailed presentation of the Base Case/Medium scenario. A key finding from the evaluation of this scenario is that it provides a flexible resource base where a number of variable outcomes can occur that leave sufficient reserves to meet demand. The following observations can be made:

- If all resources occur as expected, including two new base load plants and a possible repowering project, no new generation would be needed over the balance of the planning period.
- If one major project does not occur—whether it is one base load plant or if the Valley Rainbow project does not occur, there would still be sufficient net reserves available to positively balance supply and demand. However, reliability could still be jeopardized.
- The region could withstand a shortfall of energy efficiency and DG-renewables if only one half of the resources were provided—there would still be sufficient reserves.
- These findings already include an assumed 15 percent surplus investment in generating capability to stabilize prices and provide for minimum levels of reliability.
- However, when a major outage occurs from the loss of the largest generation unit in the region or when a forecast variance of 10 percent occurs reserves drop to approximately 700 MW over the critical 2006–2010 time period.
### Table 6-4. Base Case Moderate Demand Growth and Optimistic Supply, 2002-2030 (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast (Note 1)</td>
<td>3741</td>
<td>4380</td>
<td>4721</td>
<td>5755</td>
<td>7015</td>
</tr>
<tr>
<td>15% reserves (Note 2)</td>
<td>561</td>
<td>657</td>
<td>708</td>
<td>863</td>
<td>1052</td>
</tr>
<tr>
<td>Total SD County Capacity Requirements</td>
<td>4302</td>
<td>5037</td>
<td>5429</td>
<td>6618</td>
<td>8067</td>
</tr>
<tr>
<td><strong>In-County Generation (Existing)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conventional Steam Power Plants (Note 3)</td>
<td>1635</td>
<td>1426</td>
<td>628</td>
<td>628</td>
<td>628</td>
</tr>
<tr>
<td>GT Total</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
</tr>
<tr>
<td>QF/Cogen</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
</tr>
<tr>
<td>Peakers</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>2359</td>
<td>2150</td>
<td>1352</td>
<td>1352</td>
<td>1352</td>
</tr>
<tr>
<td><strong>In-County Generation (New)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Otay Mesa</td>
<td>510</td>
<td>510</td>
<td>510</td>
<td>510</td>
<td>510</td>
</tr>
<tr>
<td>South Bay 2 or Repowering of SB 1 Plant</td>
<td></td>
<td>500</td>
<td>500</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>New Peakers</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>New Unknown (Repower or New Plants)</td>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>0</td>
<td>510</td>
<td>1010</td>
<td>1010</td>
<td>1010</td>
</tr>
<tr>
<td><strong>Total In-County Generation</strong></td>
<td>2359</td>
<td>2660</td>
<td>2362</td>
<td>2362</td>
<td>2362</td>
</tr>
<tr>
<td><strong>In-County Generation Percent</strong></td>
<td>55%</td>
<td>53%</td>
<td>44%</td>
<td>36%</td>
<td>29%</td>
</tr>
<tr>
<td><strong>Surplus/Deficit Before Transmission</strong></td>
<td>-1943</td>
<td>-2377</td>
<td>-3067</td>
<td>-4256</td>
<td>-5705</td>
</tr>
<tr>
<td><strong>Import Capability (Note 4)</strong></td>
<td>2500</td>
<td>3200</td>
<td>3200</td>
<td>3200</td>
<td>3200</td>
</tr>
<tr>
<td><strong>Net Balance/Imbalance (Note 5)</strong></td>
<td>557</td>
<td>823</td>
<td>133</td>
<td>-1056</td>
<td>-2505</td>
</tr>
<tr>
<td><strong>Alternatives</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Reduction (Note 6)</td>
<td>40</td>
<td>145</td>
<td>290</td>
<td>553</td>
<td>811</td>
</tr>
<tr>
<td>DG- Non-Renewable (Note 7)</td>
<td>150</td>
<td>360</td>
<td>650</td>
<td>1200</td>
<td>1600</td>
</tr>
<tr>
<td>DG- Renewable/ San Diego County (Note 7)</td>
<td>25.1</td>
<td>156</td>
<td>447</td>
<td>770</td>
<td>1240</td>
</tr>
<tr>
<td><strong>Total Adjustments</strong></td>
<td>215</td>
<td>661</td>
<td>1387</td>
<td>2523</td>
<td>3651</td>
</tr>
<tr>
<td><strong>Net Surplus/Deficit (Note 8)</strong></td>
<td>772</td>
<td>1484</td>
<td>1520</td>
<td>1467</td>
<td>1146</td>
</tr>
<tr>
<td>Encina Unit 5 Outage (-329 MW)</td>
<td>443</td>
<td>1155</td>
<td>1191</td>
<td>1138</td>
<td>817</td>
</tr>
<tr>
<td>Forecast Variance of 10%</td>
<td>69</td>
<td>717</td>
<td>719</td>
<td>562</td>
<td>115</td>
</tr>
</tbody>
</table>

Note 1: Annual peak load requirement including transmission losses. Excludes impacts of incremental DSM programs.

Note 2. Assumes realization of desired 15% reserve margin for price stability and reliability.

Note 3: Existing steam generating plants and units in operation as shown in Table D-2 in Appendix D.

Note 4: Simultaneous import capability is the maximum amount of power that can be imported at the same time. This may vary form actual transmission capacity due to export and other load balancing requirements.

Note 5: Net imbalance is the net surplus or deficit of resources to meet peak load and reserves before demand response programs and DG being considered.

Note 6. Impacts of demand response, DG and renewables based on the COMPASS analyses

Note 7: Estimated DG resource impacts from Table 5-10.

Note 8. Net surplus or deficit in known capacity for the stated time period.

Table 6-5 shows a more severe supply situation. This scenario is a "worst case" situation that includes the following:

- No Otay Mesa, and no repowering of South Bay and no new units such as Palomar are built.
- Cabrillo Units 1, 2, and 3, are retired.
- South Bay 1 is retired by 2009.
- Only about one-half of the potential demand reduction and DG-renewables is produced.
Table 6-5. High Demand Growth and Worse Case Supply Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast (Note 1)</td>
<td>3741</td>
<td>4380</td>
<td>5158</td>
<td>6603</td>
<td>8452</td>
</tr>
<tr>
<td>15% reserves (Note 2)</td>
<td>561</td>
<td>657</td>
<td>774</td>
<td>990</td>
<td>1268</td>
</tr>
<tr>
<td>Total SD County Capacity Requirements</td>
<td>4302</td>
<td>5037</td>
<td>5932</td>
<td>7593</td>
<td>9720</td>
</tr>
<tr>
<td>In-County Generation (Existing)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conventional Steam Power Plants (Note 3)</td>
<td>1635</td>
<td>1426</td>
<td>628</td>
<td>628</td>
<td>628</td>
</tr>
<tr>
<td>GT Total</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
</tr>
<tr>
<td>QF/Cogen</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
</tr>
<tr>
<td>Peakers</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
</tr>
<tr>
<td>Subtotal</td>
<td>2359</td>
<td>2150</td>
<td>1352</td>
<td>1352</td>
<td>1352</td>
</tr>
<tr>
<td>In-County Generation (New)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Otay Mesa</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Repowering South Bay Power Plant</td>
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<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>New Peakers</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>New Unknown (Repower or New Plants)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Subtotal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total In-County Generation</td>
<td>2359</td>
<td>2150</td>
<td>1352</td>
<td>1352</td>
<td>1352</td>
</tr>
<tr>
<td>In-County Generation Percent</td>
<td>55%</td>
<td>43%</td>
<td>23%</td>
<td>18%</td>
<td>14%</td>
</tr>
<tr>
<td>Surplus/Deficit Before Transmission</td>
<td>-1943</td>
<td>-2887</td>
<td>-4580</td>
<td>-6241</td>
<td>-8368</td>
</tr>
<tr>
<td>Import Capability (Note 4)</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
</tr>
<tr>
<td>Net Balance/Imbalance (Note 5)</td>
<td>557</td>
<td>-387</td>
<td>-2080</td>
<td>-3741</td>
<td>-5868</td>
</tr>
<tr>
<td>Alternatives</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Reduction (Note 6)</td>
<td>40</td>
<td>97</td>
<td>184</td>
<td>373</td>
<td>556</td>
</tr>
<tr>
<td>DG- Non-Renewable (Note 7)</td>
<td>75</td>
<td>250</td>
<td>400</td>
<td>700</td>
<td>883</td>
</tr>
<tr>
<td>DG Renewables (Note 7)</td>
<td>25.1</td>
<td>169</td>
<td>328</td>
<td>500</td>
<td>760</td>
</tr>
<tr>
<td>Total Adjustments</td>
<td>140</td>
<td>516</td>
<td>912</td>
<td>1573</td>
<td>2199</td>
</tr>
<tr>
<td>Net Surplus/Deficit (Note 8)</td>
<td>697</td>
<td>129</td>
<td>-1168</td>
<td>-2168</td>
<td>-3669</td>
</tr>
<tr>
<td>Encina Unit 1 Outage (-329 MW)</td>
<td>368</td>
<td>-200</td>
<td>-1497</td>
<td>-2497</td>
<td>-3998</td>
</tr>
<tr>
<td>Ten Percent Peak Load Variance</td>
<td>-6</td>
<td>-638</td>
<td>-2013</td>
<td>-3158</td>
<td>-4843</td>
</tr>
</tbody>
</table>

Note 1: Annual peak load requirement including transmission losses. Excludes impacts of incremental DSM programs.
Note 2: Assumes realization of desired 15% reserve margin for price stability and reliability.
Note 3: Existing steam generating plants and units in operation as shown in Table D-2 in Appendix D.
Note 4: Simultaneous import capability is the maximum amount of power that can be imported at the same time. This may vary from actual transmission capacity due to export and other load balancing requirements.
Note 5: Net imbalance is the net surplus or deficit of resources to meet peak load and reserves before demand response programs and DG being considered.
Note 6: Impacts of demand response, DG and renewables based on the COMPASS analyses.
Note 7: Estimated DG resource impacts from Table 5-10.
Note 8: Net surplus or deficit in known capacity for the stated time period.

This analysis shows that the region swings from a strong surplus in the Medium Case/Optimistic Supply analysis (Table 6-4) to a short-term and ongoing deficit that is extreme in later years. This condition is not practical and likely to occur—although the risks of such a situation should be known. It is expected that new generation will be built. Current import capability of 2,500 MW is assumed with no new transmission being added to the region. If for some unanticipated reason the entire transmission corridor through SONGS is interrupted, as actually occurred in February of this year, the import capability serving San Diego County would be reduced to approximately 1,200 MW. This would
create a severe supply situation in the County if it occurred during a period of high demand. Adding a major new transmission path such as Valley Rainbow could provide an additional 700 MW of import capability in the near term, which would be very valuable in such a dire situation. Furthermore, there is only 720 MW of export capability from San Diego County northward to the rest of the state. With additional transmission capacity and two-way flow capability like Valley Rainbow or other transmission capacity, this could significantly increase the export capacity and create greater incentives for new generation developers to locate in the County. This would also help stabilize in-basin capacity values and help avoid the higher cost of LMP pricing.

The region is also faced with a very unique situation. The region has a regional power supply commitment that exceeds the simultaneous import capability. Current import requirements are:

<table>
<thead>
<tr>
<th>Description</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchased power (take or pay) CDWR contracts</td>
<td>2,100</td>
</tr>
<tr>
<td>Self serve or direct access imports</td>
<td>600</td>
</tr>
<tr>
<td>SONGS imports</td>
<td>430</td>
</tr>
<tr>
<td><strong>Total Required Import Capability</strong></td>
<td><strong>3,130</strong></td>
</tr>
<tr>
<td><strong>Maximum Import Capability Today</strong></td>
<td><strong>2,500</strong></td>
</tr>
<tr>
<td><strong>Deficit</strong></td>
<td><strong>(630 MW)</strong></td>
</tr>
</tbody>
</table>

The imports of SONGS and direct access customers take precedence over CDWR contracts. This means that the region is paying for CDWR power that it cannot import and use. In addition, the cost that the region pays for the CDWR power is assessed to SDG&E and the region on an annualized basis. The region will not know what the fixed and variable cost allocations are until an order is issued by the commission regarding the allocated costs.

A final sensitivity analysis was completed for the high-growth, 1-in-10 planning conditions: the expected generation units were added; Valley Rainbow or other transmission is built (see Table 6-6); and, the expected energy efficiency and DG-renewables occur. The results are a positive net balance except for a small deficit in 2030. If an unscheduled outage occurs, the net surplus is impacted, which underscores the value of a diverse portfolio.

### 6.4.1 Caveats

There are a number of caveats that should be considered when reviewing the scenarios. They include the following:

1. This analysis does not model reliability issues for the transmission network and hence trade-offs of plant or transmission line development or location is not modeled or evaluated. This type of analysis is being completed as part of the Valley Rainbow proceeding.

2. Capacity values of the DG and renewables may be inflated because they do not take into account availability at peak. Sensitivity analyses were used to test the potential impacts of lower capacity availability.

3. Peak load requirements could be 10 to 12 percent higher (which one of the sensitivity analyses addresses) to accommodate abnormal summer peak weather and a higher than anticipated economic recovery. This is why the 15-percent reserve margins are planned for as shown in the table.

4. The load forecasts can vary significantly from one reporting period to another. This is why low-, medium-, and high demand growth forecasts were used.

5. The current mix of resources, including in-basin generation supply, demand-side options and transmission imports (at least in the aggregate) will vary in proportion as the market evolves and future investments must be taken into account.

6. A drop in new generation occurs in the 2020–2030 period because no new generation units have been proposed for that period. It is likely that new generation units will be proposed in the 2015–2020 time period as reserves start to decline.
### Table 6-6. High Demand Growth and Optimistic Supply, 2002-2030 (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast (Note 1)</td>
<td>3741</td>
<td>4673</td>
<td>5158</td>
<td>6603</td>
<td>8452</td>
</tr>
<tr>
<td>15% reserves (Note 2)</td>
<td>561</td>
<td>701</td>
<td>774</td>
<td>990</td>
<td>1268</td>
</tr>
<tr>
<td>Total SD County Capacity Requirements</td>
<td>4302</td>
<td>5374</td>
<td>5932</td>
<td>7593</td>
<td>9720</td>
</tr>
</tbody>
</table>

#### In-County Generation (Existing)

<table>
<thead>
<tr>
<th>Category</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Steam Power Plants (Note 3)</td>
<td>1635</td>
<td>1426</td>
<td>628</td>
<td>628</td>
<td>628</td>
</tr>
<tr>
<td>GT Total</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
<td>213</td>
</tr>
<tr>
<td>QF/Cogen</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
<td>175</td>
</tr>
<tr>
<td>Peakers</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
<td>336</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>2359</td>
<td>2150</td>
<td>1352</td>
<td>1352</td>
<td>1352</td>
</tr>
</tbody>
</table>

#### In-County Generation (New)

<table>
<thead>
<tr>
<th>Category</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Otay Mesa</td>
<td>0</td>
<td>510</td>
<td>510</td>
<td>510</td>
<td>510</td>
</tr>
<tr>
<td>Repowering South Bay Power Plant</td>
<td>0</td>
<td>0</td>
<td>500</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>New Peakers</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>New Unknown (Repower or New Plants)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>0</td>
<td>510</td>
<td>1010</td>
<td>1510</td>
<td>1510</td>
</tr>
<tr>
<td><strong>Total In-County Generation</strong></td>
<td>2359</td>
<td>2660</td>
<td>2362</td>
<td>2862</td>
<td>2862</td>
</tr>
</tbody>
</table>

#### In-County Generation Percent

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>55%</td>
<td>49%</td>
<td>40%</td>
<td>38%</td>
<td>29%</td>
</tr>
</tbody>
</table>

#### Surplus/Deficit Before Transmission

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surplus/Deficit</td>
<td>-1943</td>
<td>-2714</td>
<td>-3570</td>
<td>-4731</td>
<td>-6858</td>
</tr>
</tbody>
</table>

#### Import Capability (Note 4)

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Import Capability</td>
<td>2500</td>
<td>3200</td>
<td>3200</td>
<td>3200</td>
<td>3200</td>
</tr>
</tbody>
</table>

#### Net Balance/Imbalance (Note 5)

<table>
<thead>
<tr>
<th>Year</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Balance/Imbalance</td>
<td>557</td>
<td>486</td>
<td>-370</td>
<td>-1531</td>
<td>-3658</td>
</tr>
</tbody>
</table>

#### Alternatives

<table>
<thead>
<tr>
<th>Category</th>
<th>2002</th>
<th>2006</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Reduction (Note 6)</td>
<td>40</td>
<td>145</td>
<td>290</td>
<td>553</td>
<td>811</td>
</tr>
<tr>
<td>DG- Non-Renewable (Note 7)</td>
<td>150</td>
<td>360</td>
<td>650</td>
<td>1200</td>
<td>1600</td>
</tr>
<tr>
<td>DG Renewable (Note 7)</td>
<td>25.1</td>
<td>156</td>
<td>447</td>
<td>770</td>
<td>1240</td>
</tr>
<tr>
<td>Total Adjustments</td>
<td>215</td>
<td>661</td>
<td>1387</td>
<td>2523</td>
<td>3651</td>
</tr>
<tr>
<td><strong>Net Surplus/Deficit (Note 8)</strong></td>
<td>772</td>
<td>1147</td>
<td>1017</td>
<td>992</td>
<td>-7</td>
</tr>
<tr>
<td>Encina Unit 1 Outage (-329 MW)</td>
<td>443</td>
<td>818</td>
<td>688</td>
<td>663</td>
<td>-336</td>
</tr>
<tr>
<td>Ten Percent Variance in Forecast</td>
<td>69</td>
<td>351</td>
<td>173</td>
<td>2</td>
<td>-1181</td>
</tr>
</tbody>
</table>

### 6.5 Wholesale Electric Price Forecast

#### 6.5.1 Methodology and General Assumptions

Forward prices were used to determine the capacity and energy values in the market over a 30-year period. The prices were estimated using New Energy’s “Market Power” model. The model analyzed the need for and dispatch of plants for the entire WECC. A competitive market model was assumed for wholesale electric prices. The WECC market was modeled, because it drives the marginal cost for the last unit of power purchased. The marginal costs are influenced by the types of plants dispatched, fuel costs, capital costs, heat rates, financial risks, transmission constraints and other factors. The marginal costs are also used to evaluate the benefits of energy efficient, demand reduction and renewable technology measures.

California Department of Water and Resources (CDWR) contracts\(^2\) are not viewed as reflecting true marginal cost—even though they are expected to have an influence on retail prices through 2010. CDWR contracts are not market based— as evidenced by the state renegotiating the contracts. The result for evaluating energy efficiency and demand response programs from a retail customer’s perspective may underestimate the near term benefits to customers. However, these benefits are inflated due to the peculiar situation that exists when state representatives entered into contracts

\(^2\) DWR continues to renegotiate these contracts. http://www.dwr.water.ca.gov/
during a very unique condition in the market. In effect, a more conservative analysis was applied in this assessment.

This report presents a forecast of wholesale electric forward prices for San Diego County and adjacent areas. The approach for preparing the forecast was to simulate the behavior of the market through the use of a general equilibrium model. General equilibrium models produce projections of energy prices through the dispatch of specific generating units or groups of generating units while producing an optimized plan through time.

6.5.2 Long Run Marginal Cost (LRMC) of Electric Generating Capacity

The LRMC of generating capacity was determined based upon the lowest-cost capacity resource that may be utilized in a given year additional capacity is required. In general, this approach closely resembles the “Peaker Method” used in past Integrated Resource Planning (IRP)\(^3\) studies.

The approach SAIC used to evaluate each region in the WECC (1) Was additional capacity required in that year; (2) If so, what is the lowest cost resource to serve that load. In the long run this resource was typically a simple-cycle combustion turbine. The cost of this generation alternative was determined as the capital recovery and fixed O&M costs associated with this equipment’s operation. However, if existing mothballed generation were available at a lower cost that equipment would be evaluated as the marginal unit.

An additional note is required for the generic simple-cycle combustion turbine used for San Diego County. In general, a 300-MW simple-cycle combustion turbine based upon GE 7F equipment was used. These units are large and capture all economies of scale available for this technology. However, San Diego County is disadvantaged in that the number of suitable sites for generating units is limited. Therefore, an assumption was made that smaller simple-cycle combustion turbine would be installed and larger sites would be reserved for combined-cycle combustion turbines. The cost parameters for a smaller unit based upon GE LM6000 technology was used. These units would allow for the installation of units on sites of approximately 50 MW.

The marginal cost of energy was based upon the dispatch of the most expensive unit in the region or the costs of imports from other regions. These costs would include: (1) The cost of fuel; (2) Emissions allowances; and (3) Non-fuel O&M costs such as water, water treatment chemicals and incremental maintenance costs.

The following general assumptions were employed in this analysis:

1. The projections were in nominal (2002) dollars.

2. SAIC assumed that a competitive wholesale electric market would develop in the California and the WECC. This is comparable to California Energy Commission (CEC) modeling assumptions.

Inflation forecasts used were adopted from the CEC. This report provided inflation estimates in nominal dollars until 2012. For periods after 2012 estimates for the last year were interpolated to the end of the study period.

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\(^3\) Integrated resource planning was in vogue in the 1980’s and 1990’s as a method of trading off supply and demand resources based on the last increment of capacity and energy needed to meet load requirements. The last increment of resource was viewed as the marginal cost upon which all demand resources were evaluated. As the electric industry moved from a cost based to a market based industry, interest and relevance of IRP started to wane.
6.5.3 Other Assumptions

6.5.3.1 Market Areas
SAIC performed this analysis for the primary market areas of The Western Electricity Coordinating Council (WECC) (formerly the WSCC).\(^4\) A map of the WECC can be found in Figure 6-2. The California/Southern Nevada/Baja, California was further differentiated to isolate San Diego County, Southern California and Baja California.

6.5.3.2 Existing Generation Stock
All plants in North Baja California and the WECC including priority plants where the ground was either broken or significant permits have been obtained (e.g., Otay Mesa Power Plant) were included in the analysis. Sensitivity analyses based on different gas supply prices (recognizing their higher prices in California) and transmission access with and without Valley Rainbow were added as options in the analysis. The Market Power model took these factors into account when scheduling and dispatching the plants, depending on the scenario.

The total current generation in the WECC is 164,000 MW. The Market Power model contains a database of all electric generating units in the various reliability councils. The source of this information is Resources Data International (RDI).

These databases contain the following information for each unit:

1. Technology
2. In-service date
3. Maximum capacity
4. Heat rate
5. De-ration factors (i.e., the performance erosion of a plant under different atmospheric and meteorological conditions)
6. Fuel type
7. Forced-outage rate
8. Scheduled outage requirements.

6.5.3.3 Fuel Prices
The primary fuel prices that establish the marginal cost (dispatch price) are natural gas, residual fuel oil and coal. Nuclear fuel and distillate oil are also used in the region but rarely, if ever, establish dispatch prices. Furthermore, hydroelectric units are also sub-marginal. Fuel prices were established as follows:

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\(^4\) The Western Electricity Coordinating Council (WECC) was created on April 18, 2002 by merger of WSCC, the Western Regional Transmission Association (WRTA), and the Southwest Regional Transmission Association (SWRTA). Source: http://www.wecc.biz/wscc_rta_merger.html
- **Natural Gas** – Natural gas prices at Henry Hub\(^5\) were adopted from the CEC. Table 6-7 details these values.

- **Residual Oil** – Residual oil forecasts produced by RDI were used in this analysis. Plants in Southern California were limited to a maximum residual oil burn of 2 percent per year.

- **Nuclear Fuel** – Nuclear fuel will increase at the weighted average of all other inflation costs of the economy.

- **Coal** – Coal price forecasts were supplied by RDI. Existing major coal units were generally forecasted on a station basis for larger units. Smaller and generic units were forecasted based upon regional coal price estimates.

| Table 6-7. Natural Gas Prices Delivered to Electric Generating Units ($/MCF) |
|--------------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| SoCal Gas/ San Diego     | 2.94     | 3.00     | 3.06     | 3.16     | 3.25     | 3.33     | 3.41     | 3.48     | 3.56     |


These projections are produced from a general equilibrium model of the western United States. An alternative gas price forecast was prepared based upon projections from the U.S. DOE-EIA. These prices were derived from projections in the Annual Energy Outlook (AEO 2002), which is the EIA’s annual energy forecast based on a general equilibrium model of North America. The CEC natural gas price projections provided pricing points for all regions modeled in the WECC. The EIA forecast used basis differentials constructed from Gas Daily pricing points. All natural gas price forecasts conformed to the CEC inflation forecast.

6.5.3.4 Load Growth

Load growth projections for non-California entities were taken from Form 714 filings made with the Federal Energy regulatory Commission (FERC). These filings were California load forecasts, with the exception of San Diego Gas & Electric, and were taken from the CEC 2002–2012 Electricity Report. The specific details of the SDG&E forecast are discussed in the Electricity Forecast section.

6.5.3.5 New Generation

New generation was introduced in this analysis in two ways: 1) Specifically identified units and 2) priority generating units introduced by the model in the creation of the expansion plan. For the first 3 years we know what plants will be built. In future years, we know some units will be built and the model solves this assuming the lowest available cost technology to meet the load requirements for the forecast period. Often this is a combined cycle gas unit.

Figure 6-3 presents the estimated level of new generation that is anticipated in the WECC as of December 2001. Since then a substantial number of plants—approximately 50 percent have been indefinitely delayed or cancelled due to the financial market being concerned about capital and liquidity of developers.

The number of new megawatts of generating units was specifically identified was performed through extracts from the RDI NewGen database. After these reviews were performed, the projects deemed not likely to occur based on discussions with industry experts and specific developers were omitted.

Table 6-8 specifies the heat rates for combined-cycle and simple-cycle combustion turbines. The heat rate of the prototype technologies decreased over time in order to account for changes in technology.

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\(^5\) This is a natural gas trading and supply hub located on the Gulf Coast.
Table 6-8. Projected Full Load Heat Rates by Technology Projected to Be Achieved in the Period 2002–2030 (Btu/kWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>Simple-Cycle Combustion Turbine</th>
<th>Combined-Cycle Combustion Turbine</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002–2008</td>
<td>10,487</td>
<td>6,566</td>
</tr>
<tr>
<td>2009–2013</td>
<td>10,427</td>
<td>6,435</td>
</tr>
<tr>
<td>2014–2018</td>
<td>10,070</td>
<td>6,306</td>
</tr>
<tr>
<td>2019–2030</td>
<td>9,871</td>
<td>6,180</td>
</tr>
</tbody>
</table>

Source: Ram MaDulgula of Sargent and Lundy. Theoretical minimums in heat rates for prototype generation units.

Prototype technologies for California and non-California applications had different installed costs and emissions outputs. The installed cost for California units is provided in Table 6-9.

Table 6-9. Installed Cost of Various Generation Technologies – 2002 Dollars per Kilowatt

<table>
<thead>
<tr>
<th>Technology</th>
<th>California Application</th>
<th>Non-California Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple-Cycle Combustion Turbine</td>
<td>$550</td>
<td>$385</td>
</tr>
<tr>
<td>Combined-Cycle Combustion Turbine</td>
<td>$850</td>
<td>$650</td>
</tr>
<tr>
<td>Coal-fired Steam Plant</td>
<td>Not Applicable</td>
<td>$1600</td>
</tr>
</tbody>
</table>

Source: Ralph Zarumba prior work at Sargent and Lundy.

The installed cost reflects the overall higher costs associated with siting a unit in California, attaining stricter NOx emission standards and property costs. Coal-fired steam units were assumed to only be feasible in non-environmentally sensitive regions and thus excluded California.

All prototype generation was assumed to require a 14.5-percent IRR for the base case. This is about what is required to obtain a normal return levelized with investment bonds with a 50-50 cap structure. An alternative high cost of capital case was also run. In this scenario generating units constructed in California were assumed to require an IRR of 16.5 percent. The 2-percent premium for California plants is due to increased regulatory and financial risk.
6.5.3.6 Unit Retirements

Unit retirements for steam units were assumed to occur when a unit reaches 50 years of age. Simple cycle combustion turbines were assumed to have an economic life of 35 years. For the nuclear plants in the region, SAIC assumed these units would receive 20-year life extensions after the initial 40-year license expired. Hydroelectric units were assumed to not retire.

6.5.3.7 Emissions Allowances

California has very serious problems with the creation of ozone by NOx, and therefore is currently implementing every feasible control measure to reduce NOx emissions. Consequently, it is difficult to create voluntary surplus conditions of NOx emissions for use as offsets, because of stringent state and federal emission control requirements. For this reason, allowances in California are significantly more expensive than in the majority of the non-attainment regions of the United States. Also, ozone allowances in California are significantly more expensive than in the majority of the non-attainment regions in the United States. NOx allowances for California were priced at the equivalent of $10,740 per ton-year in 2002. After that time period it is assumed the price increased with inflation.

The balance of the WECC priced NOx allowances at $1,600 per ton. SOx allowances were priced at $303 per ton escalating at inflation.

6.5.3.8 Forced Outage Rates

Forced outage rates were adopted based upon NERC GADS data. Forced outage rates were assigned based upon generating unit category.

6.5.3.9 Scheduled Outage Hours

Scheduled outage hours for each generating unit category used NERC GADS data.

6.5.3.10 Transmission Interconnections

Transmission interconnections were modeled using a transportation methodology, i.e., the capacity of transmission interconnections between regions was assumed not to vary within a given period. The transmission capabilities for the majority of the WECC were adopted from various WECC publications where non-simultaneous transmission was published. Detailed information about the SDG&E area was received from the Company and various CPUC filings.

6.5.3.11 Assumptions About Unspecified Generation Units

The Market Power model creates an optimal generation expansion plan based on the assumptions and parameters that were entered into the model. SAIC identified the following technologies as potential new generation additions in our analysis: A simple-cycle combustion turbine and combined cycle combustion turbine, which could be constructed in all areas except California. Simple- and combined-cycle combustion turbines, which could be constructed in California, are more expensive to build and operate because of higher construction costs and more stringent emissions standards.

6.5.3.12 Assumptions About Peak Demand

SDG&E’s peak demand and energy usage forecast was adopted until 2006. After that time period from 2007–2020, the CEC forecast was used. After that time period, the growth rates were extrapolated. For the other California utilities, the CEC forecast was adopted. For non-California entities the Form 714 forecasts filed with the FERC were used.

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6 Source: http://www.nerc.com/~gads/
6.5.3.13 Forward Price Analysis

Forward price assumptions and analyses were estimated for four different cases representing different generation planning and expansion assumptions:

- **Base Case Analysis:** CEC gas price projections and standard assumptions for new generation and prototype new generation. This is the definitive forecast in California, with details specific to the west coast including delivered gas prices from San Juan Basin and local distribution fees.

- **EIA Gas Forecast:** SAIC used EIA projections of natural gas prices, and a lower forecast in generation based on a general equilibrium model for North America.

- **Higher Capital Cost and IRR Analysis:** Because a significant amount of new California generation is based upon political uncertainty. A higher IRR was used to capture fact that there may be of more risk in building plants in California. This is due to eminent domain, need to renegotiate contracts; delays in permit applications, etc.

- **Pessimistic, Low Construction:** Based upon a reduced level of construction in the 2002–2005 time period, the planned projects were cut 50 percent in the short-term and reduced projects in longer term by 75 percent in the WECC.

6.6 Results

6.6.1 Capacity Price Forecasts

Figure 6-4 presents a graph of the capacity prices that the Market Power model produced. Table 6-10 presents forward energy capacity values from 2002–2030.

**Figure 6-4. Capacity Prices, 2002–2030**

Note: Capacity prices are volatile in the post-2025 period due to some delay in plants being built and not all generating plants being identified in the later years to meet load growth. The forward prices in the later years are likely to be lowered due to new projects being identified in the late 2015–2020 and beyond time period.
Table 6-10. Forward Capacity Values ($/kW-yr)

<table>
<thead>
<tr>
<th>Area</th>
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<tr>
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<tr>
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</tr>
<tr>
<td>EIA Gas Forecast</td>
<td>$99.14</td>
</tr>
</tbody>
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| Key Assumptions       | 2010  | 2011  | 2012  | 2013  | 2014  | 2015  | 2016  | 2017  |
| Base                  | $112.37 | $115.79 | $119.53 | $123.39 | $127.19 | $131.16 | $135.48 | $140.13 |
| High Capital Costs    | $124.33 | $128.12 | $132.27 | $132.45 | $140.60 | $145.13 | $149.80 | $154.66 |
| Pessimistic Capacity  | $112.35 | $108.11 | $100.75 | $101.03 | $107.42 | $130.72 | $135.55 | $139.95 |
| EIA Gas Forecast      | $112.37 | $115.79 | $119.53 | $123.39 | $127.20 | $131.21 | $135.45 | $139.83 |

| Key Assumptions       | 2018  | 2019  | 2020  | 2021  | 2022  | 2023  | 2024  | 2025  |
| Base                  | $144.62 | $149.18 | $154.03 | $159.04 | $164.24 | $169.91 | $175.10 | $180.77 |
| High Capital Costs    | $159.73 | $164.53 | $170.32 | $175.89 | $181.90 | $182.12 | $182.35 | $182.35 |
| Pessimistic Capacity  | $144.56 | $149.03 | $153.79 | $159.02 | $164.07 | $169.24 | $180.76 | $180.76 |
| EIA Gas Forecast      | $144.33 | $149.05 | $154.14 | $159.15 | $164.30 | $169.62 | $180.78 | $180.78 |

| Key Assumptions       | 2026  | 2027  | 2028  | 2029  | 2030  |
| Base                  | $180.98 | $180.87 | $256.53 | $263.86 | $253.10 |
| High Capital Costs    | $240.48 | $192.59 | $319.34 | $227.05 | $234.88 |
| Pessimistic Capacity  | $180.95 | $180.91 | $259.41 | $267.59 | $212.02 |
| EIA Gas Forecast      | $186.63 | $192.68 | $198.92 | $205.36 | $233.53 |

<table>
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<tr>
<th>NPV@15 Percent</th>
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<th>Pessimistic</th>
<th>EIA Gas Forecast</th>
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<td>$326.36</td>
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<td>$666.16</td>
<td>$819.90</td>
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6.6.2 Energy Price Forecasts

Figure 6-5 presents a forecast of the energy prices for 2002–2030. Table 6-11 presents energy forward price projections from 2002–2030.

![Forward Energy Prices ($/MWh)](image)

**Figure 6-5. Forward Energy Prices ($/MWh)**

<table>
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<th>Scenario</th>
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<tr>
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<tr>
<td></td>
<td>35</td>
</tr>
<tr>
<td>High Capital Costs Weekday</td>
<td>36</td>
</tr>
<tr>
<td></td>
<td>35</td>
</tr>
<tr>
<td>Pessimistic Capacity Additions Weekday</td>
<td>37</td>
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<tr>
<td></td>
<td>36</td>
</tr>
<tr>
<td>EIA Gas Forecast Weekday</td>
<td>29</td>
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<td></td>
<td>29</td>
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</table>

*These prices are critical for valuing existing and new generation and also for developing avoided costs for screening demand-side programs. These prices were also used to screen and evaluate demand-side options in the project as well.*
6.6.3 California Department of Water Resources (CDWR) Long-Term Power Contracts

The modeling completed for the WECC forward prices is based on the economic dispatch of combined cycle gas turbines and approximates the marginal cost of power in the WECC. The CDWR contracts are not expected to be the marginal resource at any time in the future. The CDWR is an active player in the wholesale market either purchasing or selling power. The CDWR contracts represent a limited proportion of the total power supply and the contract’s time of termination varies. The CDWR contracts do not create the market price over a 30-year period under investigation in this study. The marginal costs as driven by the forward prices were used to estimate the avoided costs for DSM and DG programs. Most analyses indicate that the CDWR contracts are above market cost. The premium of the contract prices over the market price should be treated as a stranded cost similar to the high-embedded costs of nuclear units in the 1980s.

The methodology employed to produce the wholesale price estimates used the most current assumptions available at the time the analysis was conducted. The objective was to produce estimates of the Long Run Marginal Cost (LRMC) for capacity and energy for the 30-year period of the analysis. The methodology used to produce these estimates is discussed below.

While forward prices presented in this report are somewhat lower than current DWR contracts, the result will be a slight underestimation of the economic attractiveness of DSM and renewables. However, in the post-2010 period, when DG and renewable resources are expected to gain significant ground, our prices are a realistic representation of the long run market value (LRMV).

6.6.4 California Financial Investment Climate and Cost of Building Plants in San Diego County

A major issue that will affect the cost and investment level of new power projects in San Diego and California is the current financial investment climate nationally and in particular, California, for power plant development. Enron’s recent filing for bankruptcy and other energy marketer equity declines resulted in a 10-percent reduction in market capitalization (worth more than $4.2 billion) of the top 10 companies with exposure to Enron. Five major companies have publicly announced capital budget cuts of more than $6 billion. Because of this and other factors, California is facing great risk from current and proposed power development project delays and cancellations in the state. Unfortunately, the recent contract renegotiation with Calpine does not require that Otay Mesa plant be built (although it is strongly encouraged) by the end of 2004. Continued press reports on the state’s energy problems plus the perceived regulatory climate in the state creates an image to the investment community that California is a high-risk environment for new power plants. For this reason, a higher rate-of-return was assumed in the SAIC Analysis. Generating plants built in Mexico and other areas of the WECC are less costly. These areas are likely to be considered first by developers before many newer plants will be built in the region.

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7 According to SDG&E the CDWR contracts represent about 47% of the power for the region for at least the next 5 years. The CDWR contracts were not used as a basis of the analysis because they do not set wholesale power prices in the Western Power region—on the margin. The analysis used in this study assumed market-driven wholesale prices.


7 Recommendations

7.1 Background

This section presents recommendations developed through the scenario-based findings presented in Chapter 6 of this report. The region’s energy odyssey is just beginning in terms of dealing with market dynamics, uncertainty, volatile energy prices, evolving energy policy, and the evaluation of energy infrastructure investment options. While the region has gone through substantial energy pricing stresses over the past 2 years, there are significant risks that remain. Many of the region’s energy problems are unsolved, and there is a need to identify options to create a more secure energy future rather than one that resembles the reactive past. The San Diego region has an opportunity to manage this condition in the future. The fundamental criteria for addressing the region’s energy future includes the following:

- **Diversification of energy supply.** The region needs to be proactive in diversifying electricity, natural gas and other energy resources serving the region.
  - Develop a portfolio of resource options that help protect the region from supply disruptions and price volatility. The region should select an energy resource portfolio consisting of targeted proportions of energy supply options based on cost and reliability factors.
  - A preference toward lower cost, clean energy options should be pursued.
  - The region should recognize that additional transmission assets are valuable and necessary to promote increased reliability, price stability and access to potentially less expensive electricity supply from the south and east.
  - The region needs to develop an improved bi-national coordination and collaboration program for broad regional energy infrastructure development and consider the deployment of clean and renewable energy resources.
  - It is important to recognize that not all “demand-side” and renewable resources have equivalent capacity values based on availability when needed. Nevertheless, these options are important hedges to market price volatility, in addition to other financial instruments that exist.
  - Options and hedges will be needed to limit the impacts of continued natural gas price volatility. While combined cycle gas turbines built inside the region offer the best opportunities for more efficient combustion and emissions reduction over base units, there is the risk of price volatility from over-reliance on natural gas.

- **The continued threat of market power is a risk for the region.** The region needs to guard against the threat of market power for both electricity and natural gas supply. There is growing evidence of these abuses in both energy markets. Natural gas supply and price will drive much of the energy economy in San Diego County and the Western states over the next 10 to 15 years. A constant vigilance on comparing California border prices to other regional city gate prices is needed, and a close monitoring of intrastate natural gas transmission costs is also needed.

- **The continued negative impacts of the evolving market.** The region needs to protect itself against additional experiments in market design. In spite of how hard California worked to “get it right” by developing a working market design, the outcome of California’s effort is now painfully evident. In particular, San Diego County experienced the first significant pain of this experiment and is experiencing continued economic stress. The high cost of energy that the region is facing will have a critical impact on future job creation and the quality of life in the county. Now the condition is even worse because no real permanent solution has yet been identified. The region needs to develop its own regional energy strategy and coordinate the development of future resources that help support future economic expansion in the region and not retard growth.
There will likely be significant political maneuverings among the California agencies, the Western states and the federal government—notably the Federal Energy Regulatory Commission (FERC)—on market design. The region needs to be active in shaping this discussion and outcome on market design. The region should also leverage the use of regional core competencies and capabilities in shaping its own regional energy supply capability as embodied by the City and County of San Diego, the Port of San Diego, the San Diego County Water Authority, the San Diego Association of Governments and its Regional Energy Office. SDG&E as the local distribution company also has an important role to play as does Sempra, CFE and merchant developers.

- **Creation of a more formal regional approach to energy planning, decision-making, and resource allocation.** The region should seriously consider the creation of an energy development authority to diversify ownership and moderate the market dynamics of energy assets serving San Diego County. This Authority could support the use of public capital for electric and natural gas supply projects and invest in large-scale energy efficiency, distributed generation and clean energy resources. In addition, new merchant generation and transmission projects will be identified in states outside California, which have the potential to serve the San Diego market. Every possible attempt should be made to consider entering into supply agreements or joint ventures with these projects if found to be cost effective, and contribute to market competition to stabilize or lower energy prices. This energy development authority should also cooperate with the Port of San Diego, the San Diego Water Authority and other agencies in considering current and potentially new asset development opportunities in the county to meet future supply requirements. The region needs to seriously consider the use of these public assets as a hedge against excessive reliance on merchant development and market-based development initiatives. This is especially critical considering that the California power contracts as recently renegotiated still remain above market prices and current rates in San Diego County are among the highest in the nation.

- **A more comprehensive and coordinated approach to the evaluation of new energy assets.** This includes completing a comprehensive load flow evaluation regarding the location of new power plants and transmission lines. No new significant energy infrastructure projects should be developed until such an evaluation is completed. Trade-offs between new transmission and new generation plant investments in either North or South county locations should be evaluated.

- **Closer monitoring of regulatory proceedings, in particular, increased integration of SDG&E and SoCal gas planning, resource supply, and regional transmission pricing.** Greater monitoring of legislation and regulatory initiatives needs to be completed by the region and formal testimony and interaction in such proceedings is needed. This active engagement will be critical if the region embarks on its own energy supply and demand management strategy.

- **Explore strategies to reduce natural gas transportation prices from the California border to San Diego.** Regulatory decisions over the next 2 years can have a major impact on the delivered price of natural gas to the region. The region should also seek ways to obtain gas supplies from lower cost natural gas production regions.

- **Significant cost-effective distributed generation and renewable supplies exist and should be maximized, along with energy efficiency and demand response programs up to the avoided costs of the CDWR contracts.** These resources are good insurance against market perturbations and dysfunctions and protect against political risk and infrastructure failure.
7.2 Considerations for Key Infrastructure Development

7.2.1 Short Term (2002–2006)

Organizational Planning and Coordination

1. **Create a joint energy development authority.** This organization can solidify community support and garner sorely needed financial resources for new energy infrastructure projects. Organizations may include: the cities within San Diego County, the County of San Diego, the San Diego County Water Authority, the Port of San Diego, and the San Diego Regional Energy Office. Close coordination with SDG&E, Sempra Energy and other merchant developers will be required.

2. **Strengthen the existing** regional energy policy planning council. The current Regional Energy Policy Advisory Council (REPAC) has some of the attributes necessary, but more formal rules and provisions on policy review and affirmation are needed to build regional consensus.

3. **Increase participation in appropriate state and federal regulatory and legislative proceedings and forums.** The regional has the ability to influence these proceedings and to inform and gain support for its regional energy strategy. In particular, FERC is likely to have a greater impact on Western regional electric and natural gas supply economics and markets in the future.

Electric Infrastructure

1. **Expedite the repowering or replacement of the Cabrillo and South Bay plants and ensure that the Otay Mesa plant is built.** This could provide a good share of the locally needed capacity over the next 10 to 20 years and will increase regional gas efficiency. Also, some of the consolidation and financial plights of local generators may be an opportunity for the region to acquire assets that may provide a hedge to mitigate some market risk.

2. **Monitor and evaluate potential merchant transmission development consortia as they become known.** Some new developments are underway that may provide access to lower cost electricity.

3. **Complete a region-wide generation and transmission optimization transmission study within 1 year.**

Natural Gas Infrastructure

1. **Investigate ways to reduce natural gas transmission costs for deliveries from the California border.** More access to natural gas supply and pipeline capacity should be investigated.

2. **Closely monitor and evaluate the planning and cost allocation of the SoCalGas costs of service that serve SDG&E.**

3. **Encourage the interconnection of the region’s supply to Baja Norte pipeline and potential expansion of this pipeline in order to increase supply options.**

Energy Efficiency, Demand Reduction Programs, Distributed Resources and Renewables

1. **Aggressively promote energy efficiency, distributed resources and renewables as a “supply” resource.** The region needs to achieve consensus on what the most attractive targets are considering other resource and market dynamics. The investment level of these resources needs to be offset with avoided supply costs.

   - A regional conservation and distributed generation investment market should be created whereby investments into energy efficiency can result in an entitlement for offsetting possible natural gas or emissions curtailments. A conservation and emissions bid market should be considered, as market conditions warrant.
- Aggressively pursue renewable resource opportunities in San Diego County. Significant resources of wind exist in the County. Photovoltaics due to estimated cost reduction over the next 15 years and technology/manufacturing improvements can provide a substantial amount of renewable energy in the region.

2. Local ordinances, rules and tax/bond funds should be considered to help reach the conservation and renewable targets that have been defined. Public financing could be acquired through state and local bonds and revenues recovered through energy savings.

3. Maximize the efficiency of existing public benefit funds and seek additional funds. The region contributes over $65 million per year to fund public interest programs. The region should ensure these funds are being spent and allocated to the best interest of the public. If necessary, additional funds should be made available if it is shown that the public investment is cost-effective and warranted to support the region’s strategy. Close monitoring of the spending of these public resources is necessary with the results reported to the public on a regular basis. Periodic market research should be completed to evaluate the state of market conditions and the need for additional program improvements, resource reallocation or additions.

4. The region should strongly support the development of appropriate time-of-use pricing for electricity. There are a few tariffs and programs that take advantage of the time-of-use pricing, however, more aggressive state policy is necessary to maximize this valuable approach.

5. The highest priority should be placed on maximizing the efficiency of existing, particularly older buildings. Homes and buildings built today are much more efficient than those built 20 to 30 years ago. The greatest opportunity exists to maximize efficiency of facilities while upgrades and revitalization are occurring.

6. Economic tax credits to promote smart energy decisions. The region should consider an added economic development tax credit for projects that incorporate a certain level of enhanced efficiency and for businesses that promote and support sustainable energy practices.

7.2.2 Mid Term (2006–2010)

Organizational Planning and Coordination

1. Coordinate city and county zoning and land use planning with needed energy infrastructure development in San Diego County. This can be accomplished through the current plans to incorporate the Regional Energy Strategy into the Regional Comprehensive Plan. Regional plans should include pre-purchased and set aside energy transportation corridors that are related and set aside based on energy, wildlife and best use land use principles.

2. Link regional energy resource development initiatives to addressing global warming issues. Major cities in the United States are developing their own greenhouse gas initiatives.

Electric Infrastructure

1. Develop an appropriate level of transmission to out-of-region supply. Additional transmission lines needed in order of importance include: 1. transmission lines to the south; 2. a line to the north (2004–2010 time period), and to the east in the post-2010 time period.

2. Develop more electric transmission system interconnections with renewable energy development sites in Eastern San Diego County and the North County. Special attention is also needed for new transmission lines to new renewable and DG sites in Imperial Valley and the California-Mexico border areas.

3. Coordinate with Baja California to promote the development of local renewable resources. A significant amount of renewable resources exist particularly, wind and
geothermal. The primary barrier to accessing these resources is the lack of transmission interconnects to the grid.

**Natural Gas Infrastructure**

1. **Position the region to be better insulated from the risks posed by the declining availability of natural gas.** There is a possibility that domestic natural gas production will decline in the United States during this period. The implications of this situation on the availability, price and spark spread of natural gas to electric prices could be significant. The volatility of gas and electric prices may also be significant. The value of potentially relying on LNG and building access to new gas markets could also potentially set a high marginal cost of gas.
   - Additional interstate supply and delivery of natural gas into the region needs to be considered. The potential for Rocky Mountain Gas and natural gas from other supply basins should be considered.
   - The region should support additional interstate natural gas supply directly into the region to control intrastate natural gas transportation prices.

**Energy Efficiency, Distributed Resources and Renewables**

1. **Position the region** to take advantage of a maturing wind and photovoltaic markets. As demand continues to increase for renewable resources throughout the world and the United States, economic opportunities to support these industries will grow. The region should position itself as the “Silicon Valley” of advanced energy technology development firms. A strong economic development program that recruits a cadre of clean energy manufacturers, developers and service companies should be created. The region should also leverage the growing number of local energy service and automation companies that exist in the area.

2. **Continue to maximize the benefit of resources that reduce the peak demand.** A significant amount of dispatchable peak load from demand reduction efforts should be available that can assist in meeting reliability and economic dispatch requirements of the region.

**7.2.3 Long Term (Post 2010)**

**Organizational Planning and Coordination**

1. **The possibility exists to create an integrated North American energy power market that includes WECC, Canadian and Mexican power.** A fully integrated grid with regional controls could be created, which would help stabilize western regional power prices, plus provide access to less expensive power sources.
   - FERC should work closely with the Government of Mexico to address a coordinated approach to energy markets and infrastructure projects in the region. A bi-national energy infrastructure commission should be created with the governments of Canada and Mexico.
   - This may create an opportunity for the San Diego region to diversify its fuel supply for generation. It may also create some risks if local plants cost too much to produce power which would stimulate the need for greater access to the Palo Verde region power.

2. **Bi-national regional commitments and adherence to common environmental policy should be encouraged.**

**Electric Infrastructure**

1. **If not well managed, in-basin generating assets may run below 35% and reserves will continue below what is needed to moderate price volatility.** This is especially a risk in the post-2020 time period. Depending on committed transmission development projects, a third 500-MW plant may be needed. The potential exists to expand existing facilities, such as a possible second plant at the Otay Mesa site.
2. **Additional transmission may be needed** to increase reliability, increase the simultaneous import levels and provide additional capacity, which will start declining unless new generating projects are identified.

3. **Emerging technologies will present options for more efficient management of resources.** For example, a potential direct-current (DC) transmission or other type of transmission line currently under development may also be available for better, more efficient delivery of less volatile priced power. The need for this capacity will be based on other project developments, including both demand-side and development of DG activity in the region.

**Natural Gas Infrastructure**

1. **The region should position itself to take advantage of the one or two LNG facilities that may be operational by this time.** Additional production and supply diversity for natural gas may be needed. Great concern exists to not only meet natural gas demand but to also diversify supply sources and avoid market power threats.

**Energy Efficiency, Distributed Resources, and Renewables**

1. **Position the region to benefit from new and emerging technologies that will provide greater flexibility, options and efficiency.** By this time all conventional and low- and moderate-cost DSM should be implemented. Potential future breakthrough DSM projects may include the use of microchips for control, nano-technology for high-efficiency lighting and low energy displays, fuel cells and advanced solar systems. There may also be a resurgence of landfill and bio-solid use in selected locations. DG/DR systems could also be available for smaller customer uses, including some smaller residential applications.

2. **Position the region to benefit from new and emerging technologies that will provide greater use of renewables.** A significant amount of renewable energy production may also occur during this period.
Appendix A: Contributors, Authors, and Acknowledgements

A.1 Contributors/REIS Study Project Team

The San Diego Regional Energy Infrastructure Study (REIS) is the result of a nine-month effort involving the funding, cooperation and effort of many individuals and organizations. The Study was made possible by financial support of the City of San Diego (City), the County of San Diego (County), the San Diego County Water Authority (CWA), the San Diego Association of Governments (SANDAG), the Utility Consumers Action Network (UCAN), the San Diego Regional Energy Office (SDREO), and the Port of San Diego (Port). The following individuals representing the Project Team contributed a great deal of time and effort in seeing the project through to completion:

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County of San Diego
Joe Minner, Patricia Zeitounian

Port of San Diego
Bill Hays, David Merk, Dan Wilkens

San Diego Association of Governments (SANDAG)
Steve Sachs, Mike McLaughlin

San Diego County Water Authority (SDCWA)
Scott Willett, Chris Guild

San Diego Regional Energy Office (SDREO)
David Rohy, Kurt Kammerer, Scott Anders, Alan Sweedler, Michael Magee, John Moot, Ashley Watkins

Utility Consumers Action Network (UCAN)
Michael Shames, Jodi Beebe

A.2 Principal Authors

Mr. Todd Davis from Science Applications International (SAIC) led the SAIC Team and was the principal investigator. Other team members consisted of Tom Londos, John Westerman, William King and Robert Lorand of SAIC. Ralph Zarumba, a private consultant, led the power system modeling and forward pricing analysis. John Burkholder of Beta Consulting, led the natural gas system analysis.
A.3 Other Project Contributors (Interviews and Input)

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City of El Cajon
Councilmember Dick Ramos

Enpex Corporation
Dick Hertzberg

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Sempra Energy
Mike Schmidt

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Peter Tereschuck

Economic Development Corporation
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NRG
Steve Hoffman
### Appendix B: List of Acronyms Used in This Study

<table>
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<tr>
<th>Acronym</th>
<th>Definition</th>
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<tr>
<td>AEO</td>
<td>Annual Energy Outlook</td>
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<tr>
<td>AGC</td>
<td>Automatic generation control</td>
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<td>APCD</td>
<td>Air Pollution Control District</td>
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<td>BACT</td>
<td>Best available control technology</td>
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<td>Biennial Cost Allocation Procedure</td>
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<tr>
<td>ESCO</td>
<td>Energy service company</td>
</tr>
<tr>
<td>ESP</td>
<td>Electric service provider</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>FSEC</td>
<td>Florida Solar Energy Center</td>
</tr>
<tr>
<td>GIR</td>
<td>Gas Industry Restructuring</td>
</tr>
<tr>
<td>GRP</td>
<td>Gross regional product</td>
</tr>
<tr>
<td>HRSG</td>
<td>Heat Recovery Steam Generator</td>
</tr>
<tr>
<td>HVAC</td>
<td>Heating ventilation and air conditioning</td>
</tr>
<tr>
<td>ICIP</td>
<td>Incremental Cost Incentive Pricing</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor owned utility</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent power producer</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Planning</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent systems operator</td>
</tr>
<tr>
<td>JPA</td>
<td>Joint Power Authority</td>
</tr>
<tr>
<td>kV</td>
<td>Kilovolt</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt Hour</td>
</tr>
<tr>
<td>LADWP</td>
<td>Los Angeles Department of Water and Power</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>LRMC</td>
<td>Long-run market costs</td>
</tr>
<tr>
<td>LRMV</td>
<td>Long run market value</td>
</tr>
<tr>
<td>LSE</td>
<td>Load Supplying Entities</td>
</tr>
<tr>
<td>MCF</td>
<td>One thousand cubic feet of natural gas</td>
</tr>
<tr>
<td>MD02</td>
<td>CAISO’s Market Design 2002</td>
</tr>
<tr>
<td>NERC</td>
<td>National Energy Reliability Council</td>
</tr>
<tr>
<td>NOx</td>
<td>Oxides of Nitrogen</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
</tr>
<tr>
<td>MMBtu</td>
<td>One million Btu</td>
</tr>
<tr>
<td>MSEC</td>
<td>Mobile source emission credits</td>
</tr>
<tr>
<td>MSW</td>
<td>Municipal Solid Waste</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt Hour</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>------------------------------------------------</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operation and maintenance</td>
</tr>
<tr>
<td>PBR</td>
<td>Performance based ratemaking</td>
</tr>
<tr>
<td>PM</td>
<td>Particulate matter</td>
</tr>
<tr>
<td>PM-10</td>
<td>Particulate matter under ten microns</td>
</tr>
<tr>
<td>Port</td>
<td>Port of San Diego</td>
</tr>
<tr>
<td>PPM</td>
<td>Parts per million</td>
</tr>
<tr>
<td>PURPA</td>
<td>The Public Utility Regulatory Policy Act of 1978</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic(s)</td>
</tr>
<tr>
<td>QF</td>
<td>Qualifying facility</td>
</tr>
<tr>
<td>RDA</td>
<td>Resources Data International</td>
</tr>
<tr>
<td>REPAC</td>
<td>Regional Energy Policy Advisory Council</td>
</tr>
<tr>
<td>RES</td>
<td>Regional Energy Strategy</td>
</tr>
<tr>
<td>RMR</td>
<td>Reliability must-run</td>
</tr>
<tr>
<td>ROG</td>
<td>Reactive Organic Gasses</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization</td>
</tr>
<tr>
<td>RTP</td>
<td>Real-time Pricing</td>
</tr>
<tr>
<td>SAIC</td>
<td>Science Application International Corporation</td>
</tr>
<tr>
<td>SANDAG</td>
<td>San Diego Association of Governments</td>
</tr>
<tr>
<td>SDREO</td>
<td>San Diego Regional Energy Office</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>San Diego Gas and Electric</td>
</tr>
<tr>
<td>SEER</td>
<td>Seasonal energy efficiency ratio</td>
</tr>
<tr>
<td>SMUD</td>
<td>Sacramento Municipal Utility District</td>
</tr>
<tr>
<td>SO_x</td>
<td>Oxides of sulfur</td>
</tr>
<tr>
<td>SWRTA</td>
<td>Southwest Regional Transmission Association</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>Transmission and Distribution</td>
</tr>
<tr>
<td>TOU</td>
<td>Time-of-use</td>
</tr>
<tr>
<td>UCAN</td>
<td>Utility Consumers Action Network</td>
</tr>
<tr>
<td>UDC</td>
<td>Utility distribution company</td>
</tr>
<tr>
<td>VAV System</td>
<td>Variable air volume system</td>
</tr>
<tr>
<td>VOC</td>
<td>Volatile Organic Compounds</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
<tr>
<td>WRTA</td>
<td>Western Regional Transmission Association</td>
</tr>
<tr>
<td>WSCC</td>
<td>Western System Coordinating Council</td>
</tr>
</tbody>
</table>
Appendix C: Glossary of Terms Used in This Study

AGGREGATOR – An entity responsible for planning, scheduling, accounting, billing, and settlement for energy deliveries from the aggregator’s portfolio of sellers and/or buyers. Aggregators seek to bring together customers or generators so they can buy or sell power in bulk, making a profit on the transaction.

AIR POLLUTION – Unwanted particles, mist or gases put into the atmosphere as a result of motor vehicle exhaust, the operation of industrial facilities or other human activity.

ANCILLARY SERVICES – The services other than scheduled energy that is required to maintain system reliability and meet WSCC/NERC operating criteria. Such services include spinning, non-spinning, and replacement reserves, voltage control, and black start capability. Services that the Independent System Operator may develop, in cooperation with market participants, to ensure reliability and to support the transmission of energy from generation sites to customer loads. Such services may include: regulation, spinning reserve, non-spinning reserve, replacement reserve, voltage support, and black start.

APPLIANCE EFFICIENCY STANDARDS – California Code of Regulations, Title 20, Chapter 2, Subchapter 4: Energy Conservation, Article 4: Appliance Efficiency Standards. Appliance Efficiency Standards regulate the minimum performance requirements for appliances sold in California and apply to refrigerators, freezers, room air conditioners, central air conditioners, gas space heaters, water heaters, plumbing fittings, fluorescent lamp ballasts and luminaries, and ignition devices for gas cooking appliances and gas pool heaters. New National Appliance Standards are in place for some of these appliances and will become effective for others at a future date.

AVOIED COST – The cost the utility would incur but for the existence of an independent generator or other energy service option. Avoided cost rates have been used as the power purchase price utilities offer independent suppliers.

BALLAST – A device that provides starting voltage and limits the current during normal operation in electrical discharge lamps (such as fluorescent lamps).

BASE LOAD – The lowest level of power production needs during a season or year.

BASE LOAD UNIT – A power generating facility that is intended to run constantly at near capacity levels, as much of the time as possible.

BASELINE FORECAST – A prediction of future energy needs which does not take into account the likely effects of new conservation programs that have not yet been started.

B/C– Benefit-cost ratio/Cost effectiveness – measured in terms of:

- Participant Test – NPV bill savings divided by the NPV cost to participate in DSM
- Utility Test – NPV of fuel and capacity savings to the utility divided by dollars invested in DSM including equipment and program
- Societal Test – Total Energy and Capacity savings divided by program costs.

BIOMASS – Energy resources derived from organic matter. These include wood, agricultural waste, land-fill gas, digester gas and other living-cell material that can be burned to produce heat energy.

BRITISH THERMAL UNITS — Measure of energy.

BROKER — an entity arranging the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold (Public Resources Code section 331(b)).
BUILDING ENERGY EFFICIENCY STANDARDS – California Code of Regulations (California Code of Regulations), Title 24, Part 2, Chapter 2-53; regulating the energy efficiency of buildings constructed in California.

BUILDING ENVELOPE – The assembly of exterior partitions of a building, which enclose conditioned spaces, through which thermal energy may be transferred to or from the exterior, unconditioned spaces, or the ground. [See California Code of Regulations, Title 24, Section 2-5302]

CALIFORNIA ENERGY COMMISSION – The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000 et seq.) responsible for energy policy. The Energy Commission’s five major areas of responsibilities are:

- Forecasting future statewide energy needs
- Licensing power plants sufficient to meet those needs
- Promoting energy conservation and efficiency measures
- Developing renewable and alternative energy resources, including providing assistance to develop clean transportation fuels
- Planning for and directing state response to energy emergencies
- Funding for the Commission's activities comes from the Energy Resources Program Account, Federal Petroleum Violation Escrow Account and other sources.

CAPACITY – The maximum load a generating unit, generating station, or other electrical apparatus is rated to carry by the user or the manufacturer or can actually carry under existing service conditions.

CAPACITY CHARGES – Usually expressed as $1 kw-year. A kw-year is the value of electric capacity for a period of one year. These values change over time vs. a $1 kw value which is an average or more stable use of the term.

CAPACITY RELEASE/MARKET – A secondary market for capacity that is contracted by a customer, which is not using all of its capacity.

CALIFORNIA DEPARTMENT OF WATER RESOURCES – (CDWR) Primary responsibility is water resource development and management. Also buys electricity for investor-owned utilities in wholesale market and resells power to investor owned utilities in form of long term contracts. These contracts have recently been renegotiated by CDWR. This is viewed as a temporary solution.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) – Scheduler, balancing and settlement of wholesale power transaction for California utilities making wholesale power transactions

CALIFORNIA POWER AUTHORITY – Focus is on developing peak reserve margin and in developing renewable energy and conservation projects. Success depends on ability to issue bonds and have them purchased.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) – A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately owned utilities and 20,000 transportation companies. The major duties of the CPUC are to regulate privately owned utilities, securing adequate service to the public at rates that are just and reasonable both to customers and shareholders of the utilities; including rates, electricity transmission lines and natural gas pipelines. The CPUC also provides electricity and natural gas forecasting, and analysis and planning of energy supply and resources. Its main headquarters are in San Francisco.

CARBON DIOXIDE – A colorless, odorless, non-poisonous gas that is a normal part of the air. Carbon dioxide, also called CO2, is exhaled by humans and animals and is absorbed by green growing things and by the sea.
CHILLER – A device that cools water, usually to between 40 and 50 degrees Fahrenheit for eventual use in cooling air.

CHP – Combined Heat and Power, also known as cogeneration.

CIRCUIT – One complete run of a set of electric conductors from a power source to various electrical devices (appliances, lights, etc.) and back to the same power source.

CLIMATE ZONE – A geographical area is the state that has particular weather patterns. These zones are used to determine the type of building standards that are required by law.

COGENERATOR – Co generators use the waste heat created by one process, for example during manufacturing, to produce steam, which is used, in turn, to spin a turbine and generate electricity. Co generators may also be QFs.

COGENERATION – Cogeneration means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards:

- At least 5 percent of the cogeneration project’s total annual energy output shall be in the form of useful thermal energy.
- Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

COMBINED CYCLE PLANT – An electric generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

CONSERVATION – Steps taken to cause less energy to be used than would otherwise be the case. These steps may involve improved efficiency, avoidance of waste, reduced consumption, etc. They may involve installing equipment (such as a computer to ensure efficient energy use), modifying equipment (such as making a boiler more efficient), adding insulation, changing behavior patterns, etc.

CONTROL AREA – An electric power system, or a combination of electric power systems, to which a common automatic generation control (AGC) is applied to match the power output of generating units within the area to demand. The control area of the ISO is the state of California.

COOLING DEGREE DAY – A unit of measure that indicates how heavy the air-conditioning needs are under certain weather conditions.

COOLING LOAD – The rate at which heat must be extracted from a space in order to maintain the desired temperature within the space.

CUBIC FOOT – The most common unit of measurement of natural gas volume. It equals the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor. One cubic foot of natural gas has an energy content of approximately 1,000 Btus. One hundred (100) cubic feet equals one therm (100 ft$^3 = 1$ therm).

DAY-AHEAD MARKET – The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading day that is conducted by the ISO, the PX, and other Scheduling Coordinators. This market closes with the ISO’s acceptance of the final day-ahead schedule.

DAYLIGHTING – The use of sunlight to supplement or replace electric lighting.

DAYLIGHTING CONTROL – A control system that varies the light output of an electric lighting system in response to variations in available daylight.

DEGREE DAY – A unit, based upon temperature difference and time, used in estimating fuel consumption and specifying nominal annual heating load of a building. When the mean temperature is
less than 65 degrees Fahrenheit the heating degree-days are equal to the total number of hours that temperature is less than 65 degrees Fahrenheit for an entire year.

DEMAND RESPONSE PROGRAM – A demand reduction program where for economic or low reserve reasons a customer reduces their peak load for incentive compensation which may be either on an intermittent day head basis or for a longer term.

DEMAND SIDE MANAGEMENT (DSM) – Planning, implementation, and evaluation of utility-sponsored programs to influence the amount or timing of customers’ energy use.

DEMAND (Utility) the level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts.

DEMAND BILLING – The electric capacity requirement for which a large user pays. It may be based on the customer's peak demand during the contract year, on a previous maximum or on an agreed minimum. Measured in kilowatts.

DEMAND CHARGES – The sum to be paid by a large electricity consumer for its peak usage level.

DEPARTMENT OF ENERGY (DOE) – The federal department established by the Department of Energy Organization Act to consolidate the major federal energy functions into one cabinet-level department that would formulate a comprehensive, balanced national energy policy. DOE's main headquarters are in Washington, D.C.

DERIVATIVES – A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

DIRECT CURRENT (DC) – Electricity that flows continuously in the same direction.

DISTRIBUTION – The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

DISTRIBUTED GENERATION – A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

DISTRIBUTION SYSTEM (Electric utility) – The substations, transformers and lines that convey electricity from high-power transmission lines to ultimate consumers.

DISTRIBUTION UTILITY – The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The Disco can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.

Distributed Resources (DR) – Includes energy efficiency, load management, renewables and distributed generation.

ECONOMIC EFFICIENCY – A term that refers to the optimal production and consumption of goods and services. This generally occurs when prices of products and services reflect their marginal costs. Economic efficiency gains can be achieved through cost reduction, but it is better to think of the concept as actions that promote an increase in overall net value (which includes, but is not limited to, cost reductions).

ECONOMIZER AIR – A ducting arrangement and automatic control system that allows a heating, ventilation and air conditioning (HVAC) system to supply up to 100-percent outside air to satisfy cooling demands, even if additional mechanical cooling is required.
ENERGY EFFICIENCY – Using less energy/electricity to perform the same function. Programs designed to use electricity more efficiently – doing the same with less. For the purpose of this paper, energy efficiency is distinguished from DSM programs in that the latter are utility-sponsored and financed, while the former is a broader term not limited to any particular sponsor or funding source. “Energy conservation” is a term which has also been used but it has the connotation of doing without in order to save energy rather than using less energy to do the same thing and so is not used as much today. Many people use these terms interchangeably.

ENVIRONMENTAL PROTECTION AGENCY – A federal agency charged with protecting the environment.

EPA Act – The Energy Policy Act of 1992 addresses a wide variety of energy issues. The legislation creates a new class of power generators, exempt wholesale generators (EWGs), that are exempt from the provisions of the Public Utilities Holding Company Act of 1935 and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid.

ENERGY SERVICES COMPANIES (ESCOs) – ESCOs would be created in a deregulated, openly competitive electric marketplace. The Energy Services industry would be made up of power aggregators, power marketers and brokers, whose job is to match buyers and sellers, tailor both physical and financial instruments to suit the needs of particular customers, and to allow even the smallest residential customers to form buying groups or cooperatives that will give them the same bargaining power as large industrial customers.

ENERGY EFFICIENCY RATIO (EER) – the ratio of cooling capacity of an air conditioning unit in Btus per hour to the total electrical input in watts under specified test conditions. California Code of Regulations, Section 1602(c)(6).

EFFICIENCY – The ratio of the useful energy delivered by a dynamic system (such as a machine, engine, or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

ELECTRIC GENERATOR – A device that converts a heat, chemical or mechanical energy into electricity.

ELECTRICITY – A property of the basic particles of matter. A form of energy having magnetic, radiant and chemical effects. Electric current is created by a flow of charged particles (electrons).

EMISSION STANDARD – The maximum amount of a pollutant legally permitted to be discharged from a single source.

ENERGY – The capacity for doing work. Forms of energy include: thermal, mechanical, electrical and chemical. Energy may be transformed from one form into another.

EER (Energy Efficiency Ratio) – The ratio of cooling capacity of an air conditioning unit in Btus per hour to the total electrical input in watts under specified test conditions. [See California Code of Regulations, Title 20, Section 1602(c)(6)]

ENERGY INTENSITY – The ratio of Gross Regional Product to energy consumed. A measure of economic energy efficiency.

ENERGY MANAGEMENT SYSTEM – A control system (often computerized) designed to regulate the energy consumption of a building by controlling the operation of energy consuming systems, such as the heating, ventilation and air conditioning (HVAC), lighting and water heating systems.

ENERGY CHARGE – The amount of money owed by an electric customer for kilowatt-hours consumed.

ENERGY CONSUMPTION – The amount of energy consumed in the form in which it is acquired by the user. The term excludes electrical generation and distribution losses.
ESCO – Efficiency Service Company. A company that offers to reduce a client’s electricity consumption with the cost savings being split with the client.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) – regulates interstate sales and transportation of electric and natural gas.

FLUORESCENT LAMP – A tubular electric lamp that is coated on its inner surface with a phosphor and that contains mercury vapor whose bombardment by electrons from the cathode provides ultraviolet light which causes the phosphor to emit visible light either of a selected color or closely approximating daylight.

FORCED OUTAGE RATE – the percentage of time a plant is out of operation. This is the single most important determinant of local reliability of power. The higher the outage rate the lower the reliance on a unit when needed.

FORWARD ELECTRIC PRICES – Projected wholesale prices for energy and capacity based on natural gas prices, plant heat rates, transmission access, market demand, and plant dispatch.

FUEL CELL – A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

FUEL DIVERSITY – A utility or power supplier that has power stations using several different types of fuel. Avoiding over-reliance on one fuel helps avoid the risk of supply interruption and price spikes.

GENERATING STATION – A power plant and ancillary equipment including fuel storage.

GEOTHERMAL ELEMENT – an element of a county general plan consisting of a statement of geothermal development policies, including a diagram or diagrams and text setting forth objectives, principles, standards, and plan proposals, including a discussion of environmental damages and identification of sensitive environmental areas, including unique wildlife habitat, scenic, residential, and recreational areas, adopted pursuant to Section 65303 of the Government Code.

GEOTHERMAL ENERGY – Natural heat from within the earth, captured for production of electric power, space heating or industrial steam.

GIGAWATT (GW) – One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

GIGAWATT-HOUR (GWH) – One million kilowatt-hours of electric power. California's electric utilities generated a total of about 270,000 gigawatt-hours in 1988.

GREENHOUSE EFFECT – The presence of trace atmospheric gases make the earth warmer than would direct sunlight alone. These gases (carbon dioxide [CO2], methane [CH4], nitrous oxide [N2O], tropospheric ozone [O3], and water vapor [H2O]) allow visible light and ultraviolet light (shortwave radiation) to pass through the atmosphere and heat the earth's surface. This heat is re-radiated from the earth in form of infrared energy (longwave radiation). The greenhouse gases absorb part of that energy before it escapes into space. This process of trapping the long wave radiation is known as the greenhouse effect. Scientists estimate that without the greenhouse effect, the earth's surface would be roughly 54 degrees Fahrenheit colder than it is today – too cold to support life, as we know it.

GREENHOUSE EFFECT (relating to buildings) – The characteristic tendency of some transparent materials (such as glass) to transmit radiation with relatively short wavelengths (such as sunlight) and block radiation of longer wavelengths (such as heat). This tendency leads to a heat build-up within the space enclosed by such a material.
GRID – A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

HEAT RATE – A number that tells how efficient a fuel-burning power plant is. The heat rate equals the Btu content of the fuel input divided by the kilowatt-hours of power output.

HEATING DEGREE DAY – A unit that measures the space heating needs during a given period of time.

HEATING LOAD – The rate at which heat must be added to a space in order to maintain the desired temperature within the space.

HEATING SEASONAL PERFORMANCE FACTOR – A representation of the total heating output of a central air-conditioning heat pump in BTUs during its normal usage period for heating, divided by the total electrical energy input in watt-hours during the same period, as determined using the test procedure specified in the California Code of Regulations, Title 20, Section 1603(c).

HVAC (Heating Ventilation and Air Conditioning) – A system that provides heating, ventilation and/or cooling within or associated with a building.

HYDROELECTRIC POWER – Electricity produced by falling water that turns a turbine generator. Also referred to as HYDRO.

INCAPESCENT LAMP – An electric lamp in which a filament is heated by an electric current until it emits visible light.

INDEPENDENT POWER PRODUCER – An Independent Power Producer (IPP) generates power that is purchased by an electric utility at wholesale prices. The utility then resells this power to end-use customers. Although IPPs generate power, they are not franchised utilities; government agencies or QFs. IPPs usually do not own transmission lines to transmit the power that they generate.

INDEPENDENT SYSTEM OPERATOR (ISO) – An ISO is the entity charged with reliable operation of the grid and provision of open transmission access to all market participants on a non-discriminatory basis. The California ISO is located at Folsom, California.

INTERCHANGE (Electric utility) – The agreement among interconnected utilities under which they buy, sell and exchange power among themselves. This can, for example, provide for economy energy and emergency power supplies.

INTERCONNECTION (Electric utility) – The linkage of transmission lines between two utilities, enabling power to be moved in either direction. Interconnections allow the utilities to help contain costs while enhancing system reliability.

INTEGRATED RESOURCE PLANNING (IRP) – A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act amendments of 1992.

INTERMITTENT SERVICE (Electric utility) – Electricity supplied under agreements that allow the supplier to curtail or stop service at times.

INTERVAL METERING – The process by which power consumption is measured at regular intervals in order that specific load usage for a set period of time can be determined.

INVESTOR OWNED UTILITY – A company, owned by stockholders for profit, that provides utility services. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives.
INDEPENDENT SYSTEM OPERATOR (ISO) – A neutral operator responsible for maintaining instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

KILOVOLT (kv) – One-thousand volts (1,000). Distribution lines in residential areas usually are 12 kv (12,000 volts).

KILOWATT (kW) – One thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home, with central air conditioning and other equipment in use, might have a demand of four kW each hour.

KILOWATT-HOUR (kWh) – The most commonly-used unit of measure telling the amount of electricity consumed over time. It represents one kilowatt of electricity supplied for one hour. A typical San Diego home consumes about 500 kilowatt-hours per month.

LANDFILL GAS – Gas generated by the natural degrading and decomposition of municipal solid waste by anaerobic microorganisms in sanitary landfills. The gases produced, carbon dioxide and methane, can be collected by a series of low-level pressure wells and can be processed into a medium Btu gas that can be burned to generate steam or electricity.

LOAD CENTERS – A geographical area where large amounts of power are drawn by end-users.

LIFE-CYCLE COST – Amount of money necessary to own, operate and maintain a building over its useful life.

LIFE EXTENSION – A term used to describe capital expenses, which reduce operating and maintenance costs associated with continued operation of electric utility boilers. Such boilers usually have a 40-year operating life under normal circumstances.

LIQUEFIED NATURAL GAS (LNG) – Natural gas that has been condensed to a liquid, typically by cryogenically cooling the gas to minus 327.2 degrees Fahrenheit (below zero).

LOAD (1) – The amount of electric power supplied to meet one or more end user's needs.

LOAD (2) – An end-use device or an end-use customer that consumes power. Load should not be confused with demand, which is the measure of power that a load receives or requires.

LOAD DIVERSITY – The condition that exists when the peak demands of a variety of electric customers occur at different times. This is the objective of "load molding" strategies, ultimately curbing the total capacity requirements of a utility.

LOAD FACTOR – A percent telling the difference between the amount of electricity a consumer used during a given time span and the amount that would have been used if the usage had stayed at the consumer's highest demand level during the whole time. The term also is used to mean the percentage of capacity of an energy facility—such as power plant or gas pipeline—that is utilized in a given period of time.

LOAD MANAGEMENT – Steps taken to reduce power demand at peak load times or to shift some of it to off-peak times. This may be with reference to peak hours, peak days or peak seasons. The main thing affecting electric peaks is air-conditioning usage, which is therefore a prime target for load management efforts. Load management may be pursued by persuading consumers to modify behavior or by using equipment that regulates some electric consumption.

LOAD SHIFTING – A load shape objective that involves moving loads from peak periods to off-peak periods. If a utility does not expect to meet its demand during peak periods but has excess capacity in the off-peak periods, this strategy might be considered.

LUMEN – A measure of the amount of light available from a light source equivalent to the light emitted by one candle.
LUMENS/WATT – A measure of the efficacy of a light fixture; the number of lumens output per watt of power consumed.

LUMINAIRE – A complete lighting unit consisting of a lamp or lamps together with the parts designed to distribute the light, to position and protect the lamps and to connect the lamps to the power supply. California Code of Regulations, Section 2-1602(h)].

MARGINAL COST – The sum that has to be paid the next increment of product of service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity.

MARKET – An agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, the difference is that a marketer represents the generator while a broker acts as a middleman.

MARGINAL COST – In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

MARKET CLEARING PRICE – The price at which supply equals demand in the Day Ahead and Hour Ahead Markets.

MARKET PENETRATION – The incidence of adoption of a new technology or practice as a percent of the total eligible market size.

MARKET POWER – The ability of one or more suppliers and traders to manipulate or game the market to serve their own benefit.

MAXIMUM DEMAND – Highest demand of the load within a specified period of time.

MCF – One thousand cubic feet of natural gas, having an energy value of one million Btu. A typical home might use six MCF in a month.

MEGAWATT (MW) – One thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough energy to power 1,000 average California homes.

MEGAWATT HOUR (MWH) – One thousand kilowatt-hours, or an amount of electricity that would supply the monthly power needs of a typical home having an electric hot water system.

METER – A device for measuring levels and volumes of a customer’s gas and electricity use.

MICROTURBINES – A small turbine engine used to produce power at a customer facility.

REAL TIME METER – A meter that can measure instantaneous loads at certain intervals.

METHANE (CH4) – the simplest of hydrocarbons and the principal constituent of natural gas. Pure methane has a heating value of 1,1012 Btu per standard cubic foot.

MUNICIPAL ELECTRIC UTILITY – A power utility system owned and operated by a local jurisdiction.

MUNICIPAL SOLID WASTE – Locally collected garbage, which can be processed and burned to produce energy.

MUNICIPALIZATION – The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.

MUNICIPAL UTILITY – A provider of utility services owned and operated by a municipal government.

NATURAL GAS – Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.
NATURAL MONOPOLY – A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries, which exhibit decreasing average long-run costs due to size (economies of scale). According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

NET CAPABILITY – Maximum load carrying ability of the equipment, excluding station use.

NET GENERATION – Gross generation minus the energy consumed at the generating station for its use.

NONRESIDENTIAL BUILDING – any building which is heated or cooled in its interior, and is of an occupancy type other than Type H, I, or J, as defined in the Uniform Building Code, 1973 edition, as adopted by the International Conference of Building Officials.

NON-FIRM ENERGY – Electricity that is not required to be delivered or to be taken under the terms of an electric purchase contract.

NORTH BAJA PIPELINE PROJECT – A major pipeline from Arizona to North Baja California that runs parallel to the US/Mexican border – but is located in Mexico.

NOx – Oxides of nitrogen that are a chief component of air pollution that can be produced by the burning of fossil fuels. Also called nitrogen oxides. NOx is a precursor to Ozone – a public health threat.

OCCUPANCY SENSOR – A control device that senses the presence of a person in a given space, commonly used to control lighting systems in buildings.

OFF-PEAK – Periods of relatively low system demands.

ON-PEAK ENERGY – Energy supplied during periods of relatively high system demand as specified by the supplier.

OPTIONS – An option is a contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period of time. May either be standardized, exchange-traded, and government regulated, or over-the-counter customized and non-regulated.

OTAY MESA PLANT – A 510 MW power plant slated for on line operation by December 31, 2004. The developer and owner is Calpine. The plant will be located in Chula Vista, in South San Diego County.

OUTAGE (Electric utility) – An interruption of electric service that is temporary (minutes or hours) and affects a relatively small area (buildings or city blocks).

OZONE – A kind of oxygen that has three atoms per molecule instead of the usual two. Ozone is a poisonous gas, but the ozone layer in the upper atmosphere shields life on earth from deadly ultraviolet radiation from space. The molecule contains three oxygen atoms (O3).

PARALLEL PATH FLOW – As defined by NERC, this refers to the flow of electric power on an electric system’s transmission facilities resulting from scheduled electric power transfers between two other electric systems. (Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path’s resistance.)

PARTIAL LOAD – An electrical demand that uses only part of the electrical power available. [See California Code of Regulations, Title 24, Section 2-5342(e) 2]

PARTICULATE MATTER (PM) – Unburned fuel particles that form smoke or soot and stick to lung tissue when inhaled. A chief component of exhaust emissions from heavy-duty diesel engines.
PASSIVE SOLAR ENERGY – Use of the sun to help meet a building’s energy needs by means of architectural design (such as arrangement of windows) and materials (such as floors that store heat, or other thermal mass).

PASSIVE SOLAR SYSTEM – A solar heating or cooling system that uses no external mechanical power to move the collected solar heat.

PERFORMANCE-BASED REGULATION (PBR) – Any rate-setting mechanism that attempts to link rewards (generally profits) to desired results or targets. PBR sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost-of-service. Other definitions include light-handed regulation that is less costly and less subject to debate and litigation. A form of rate regulation which provides utilities with better incentives to reduce their costs than does cost-of-service regulation.

PEAK DEMAND – See PEAK LOAD.

PEAK LOAD – The highest electrical demand within a particular period of time. Daily electric peaks on weekdays occur in late afternoon and early evening. Annual peaks occur on hot summer days.

“PEAKER” – A power generating station that is normally used to produce extra electricity during peak load times.

PEAKING CAPACITY – Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads; this equipment is usually designed to meet the portion of load that is above base load.

PEAKING UNIT – A power generator used by a utility to produce extra electricity during peak load times.

PHOTOVOLTAIC CELL – A semiconductor that converts light directly into electricity.

PIPELINE – A line of pipe with pumping machinery and apparatus (including valves, compressor units, metering stations, regulator stations, etc.) for conveying a liquid or gas.

POWER – Electricity for use as energy.

POWER GRID – A network of power lines and associated equipment used to transmit and distribute electricity over a geographic area.

POWER PLANT (Note: Two separate words, not one word.) – A central station generating facility that produces energy.

POWER POOL – An interstate or regional power exchange where wholesale power is bought and sold. Scheduling and settlement and regional transmission coordination also occurs. The pool may own, manage and/or operate the transmission lines ("wires") or be an independent entity that manages the transactions between entities. Often, the power pool is not meant to provide transmission access and pricing, or settlement mechanisms if differences between contracted volumes among buyers and sellers exist.

POWER PURCHASE AGREEMENT – This refers to a contract entered into by an independent power producer and an electric utility for buying and selling power.

PPM (PARTS PER MILLION) – The unit commonly used to represent the degree of pollutant concentration where the concentrations are small.

PREFERRED DAY-AHEAD SCHEDULE – A Scheduling Coordinator's preferred schedule for the ISO day-ahead scheduling process.

PRICE CAP – Situation where a price has been determined and fixed.
PROGRAMMABLE CONTROLLER – A device that controls the operation of electrical equipment (such as air conditioning units and lights) according to a preset time schedule.

PROVIDER OF LAST RESORT – A legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

PUMPED HYDROELECTRIC STORAGE – Commercial method used for large-scale storage of power. During off-peak times, excess power is used to pump water to a reservoir. During peak times, the reservoir releases water to operate hydroelectric generators.

PURPA (The Public Utility Regulatory Policy Act of 1978) – Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity.

QUALIFYING FACILITY – QFs are non-utility power producers that often generate electricity using renewable and alternative resources, such as hydro, wind, solar, geothermal, or biomass (solid waste). QFs must meet certain operating, efficiency, and fuel-use standards set forth by the Federal Energy Regulatory Commission (FERC). If they meet these FERC standards, utilities must buy power from them. QFs usually have long-term contracts with utilities for the purchase of this power, which is among the utility's highest-priced resources.

R-VALUE – A unit of thermal resistance used for comparing insulating values of different material. It is basically a measure of the effectiveness of insulation in stopping heat flow. The higher the R-value number, a material, the greater its insulating properties and the slower the heat flow through it. The specific value needed to insulate a home depends on climate, type of heating system and other factors.

RADIANT ENERGY – Energy transferred by the exchange of electromagnetic waves from a hot or warm object to one that is cold or cooler. Direct contact with the object is not necessary for the heat transfer to occur.

RADIATION – The flow of energy across open space via electromagnetic waves such as light. Passage of heat from one object to another without warming the air space in between.

RATE BASE – Value of property upon which a utility is permitted to earn a specific rate of return.

RATE CLASS – A group of customers identified as a class and subject to a rate different from the rates of other groups.

RATE STRUCTURE – The design and organization of billing charges by customer class to distribute the revenue requirement among customer classes and rating period.

RATEPAYER – This is a retail consumer of the electricity distributed by an electric utility. This includes residential, commercial and industrial users of electricity.

REAL-TIME MARKET – The competitive generation market controlled and coordinated by the ISO for arranging real-time imbalance energy.

REAL-TIME PRICING – The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

REFRIGERANT – A fluid such as freon that is used in cooling devices to absorb heat from surrounding air or liquids as it evaporates.

RELIABILITY MUST-RUN GENERATION – Utilities will be allowed to generate electricity when hydro resources are spilled for fish releases, irrigation, and agricultural purposes, and to generate power that is required by federal or state laws, regulations, or jurisdictional authorities. Such requirements include
hydrological flow requirements, irrigation and water supply, solid-waste generation, or other generation contracts in effect on December 20, 1995.

RELIABILITY – Electric system reliability has two components – adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

RELIABILITY MUST-RUN GENERATION/Unit (RMR) – Generating units that the owner must have available to run when called upon by the ISO to meet reserve and reliability requirements.

RENEWABLE ENERGY – Resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro and wood. Although particular geothermal formations can be depleted, the natural heat in the earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents and ocean thermal gradients.

RENEWABLE RESOURCES – Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

REPOWERING – Either refurbishing or replacement of generating equipment, controls, water intakes and cooling system to improve efficiency and lower emissions. Repowering can result in a 30% efficiency or heat rate improvement.

RESERVE – The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its users' needs.

RESERVE MARGIN – The differences between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

RESTRUCTURING – The reconfiguration of the vertically-integrated electric utility. Restructuring usually refers to separation of the various utility functions into individually operated and -owned entities.

RETAIL COMPETITION – A system under which more than one electric provider can sell to retail customers, and retail customers are allowed to buy from more than one provider. (See also direct access)

RETAIL MARKET – A market in which electricity and other energy services are sold directly to the end-use customer.

Seasonal Energy Efficiency Ratio (SEER) – The total cooling output of a central air conditioning unit in BTUs during its normal usage period for cooling divided by the total electrical energy input in watt-hours during the same period, as determined using specified federal test procedures. [See California Code of Regulations, Title 20, Section 1602(c)(11)]

SETTLEMENT – The process of financial settlement for products and services purchased and sold. Each settlement involves a price and quantity. Both the ISO and PX may perform settlement functions.

SET POINT – Scheduled operating level for each generating unit or other resource scheduled to run in the Hour-ahead Schedule.
SLACK CAPACITY – The amount of pipeline capacity in excess of demand that is needed to generate the benefits of competition. There is no slack capacity when all existing available capacity is used to meet demand. When there is no slack capacity consumers lose the benefits of competition and gas prices will dramatically increase. Need sufficient reserves for a competitive market to function.

SOLAR COLLECTOR – A component of an active or passive solar system that absorbs solar radiation to heat a transfer medium which, in turn, supplies heat energy to the space or water heating system.

SOLAR CELL – A photovoltaic cell that can convert light directly into electricity. A typical solar cell uses semiconductors made from silicon.

SOLAR COLLECTOR – A surface or device that absorbs solar heat and transfers it to a fluid. The heated fluid is then used to move the heat energy to where it will be useful, such as in water or space heating equipment.

SOLAR ENERGY – Heat and light radiated from the sun.

SOLAR HEAT GAIN – Heat added to a space due to transmitted and absorbed solar energy.

SOLAR HEATING AND HOT WATER SYSTEMS – Solar heating or hot water systems provide two basic functions: (a) capturing the sun’s radiant energy, converting it into heat energy, and storing this heat in insulated storage tank(s); and (b) delivering the stored energy as needed to either the domestic hot water or heating system. These components are called the collection and delivery subsystems.

SOLAR IRRADIATION – The amount of radiation, both direct and diffuse, that can be received at any given location.

SOLAR POWER – Electricity generated from solar radiation.

SOLAR RADIATION – Electromagnetic radiation emitted by the sun.

SOLAR THERMAL POWER PLANT – means a thermal power plant in which 75 percent or more of the total energy output is from solar energy and the use of backup fuels, such as oil, natural gas, and coal, does not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

SOLAR THERMAL – The process of concentrating sunlight on a relatively small area to create the high temperatures needed to vaporize water or other fluids to drive a turbine for generation of electric power.

SOx – Oxides of sulfur that are component of air pollution that can be produced by the burning of fossil fuels. Also called sulfur dioxide. SOx is known to cause smog and acid rain and is more predominant in burning of fuels in vehicles and power plants that burn coal and oil.

STEAM ELECTRIC PLANT – A power station in which steam is used to turn the turbines that generate electricity. The heat used to make the steam may come from burning fossil fuel, using a controlled nuclear reaction, concentrating the sun’s energy, tapping the earth’s natural heat or capturing industrial waste heat.

STORAGE TYPE WATER HEATER – A water heater that heats and stores water at a thermostatically controlled temperature for delivery on demand. [See California Code of Regulations, Title 20, Section 1602(f)(6)]

STRANDED COSTS/STRANDED ASSETS – See embedded Costs Exceeding Market Prices.

SUBSTATION – A facility that steps up or steps down the voltage in utility power lines. Voltage is stepped up where power is sent through long-distance transmission lines. It is stepped down where the power is to enter local distribution lines.
SYSTEM – A combination of equipment and/or controls, accessories, interconnecting means and terminal elements by which energy is transformed to perform a specific function, such as climate control, service water heating, or lighting. [See California Code of Regulations, Title 24, Section 2-5302]

TAKE AWAY CAPACITY – Ability of California natural gas transmission companies to take gas supply form the California border and distribute it to local distribution utilities. The state generally needs to work on improving its intrastate take away capacity.

TARIFF – A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

THERM – One hundred thousand (100,000) British thermal units (1 therm = 100,000 Btu).

THERMAL POWER PLANT – any stationary or floating electrical generating facility using any source of thermal energy, with a generating capacity of 50 megawatts or more, and any facilities appurtenant thereto. Exploratory, development, and production wells, resource transmission lines, and other related facilities used in connection with a geothermal exploratory project or a geothermal field development project is not appurtenant facilities for the purposes of this division. Thermal power plant does not include any wind, hydroelectric, or solar photovoltaic electrical generating facility.

TON OF COOLING – A useful cooling affect equal to 12,000 Btu hours.

TIME-OF-USE METER – A measuring device that records the times during which a customer uses various amounts of electricity. This type of meter is used for customers who pay time-of-use rates.

TIME-OF-USE RATES – Electricity prices that vary depending on the time periods in which the energy is consumed. In a time-of-use rate structure, higher prices are charged during utility peak-load times. Such rates can provide an incentive for consumers to curb power use during peak times.

TITLE 24 – The State of California’s Building Code that ensures compliance with energy standards, developed and administered by the California Energy Commission.

TRANSMISSION – Transporting bulk power over long distances.

TRANSMISSION CONSTRAINT – Transmission line capacity limitations that prevent power from being delivered to markets where needed. Usually results in curtailments and higher prices.

TURBINE GENERATOR – A device that uses steam, heated gases, water flow or wind to cause spinning motion that activates electromagnetic forces and generates electricity.

UDC (Utility distribution company) – An entity that owns a distribution system for the delivery of energy to and from the ISO-controlled grid, and that provides regulated, retail service to eligible end-use customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

UTILITY – A regulated entity, which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, “utility” refers to the regulated, vertically integrated electric company. “Transmission utility” refers to the regulated owner/operator of the transmission system only. “Distribution utility” refers to the regulated owner/operator of the distribution system, which serves retail customers.

VAV System (Variable Air Volume System) – A mechanical HVAC system capable of serving multiple zones which controls the temperature maintained in a zone by controlling the amount of heated or cooled air supplied to the zone.

VENTILATION – The process of supplying or removing air by natural or mechanical means to or from any space. Such air may or may not have been conditioned or treated.

VOLT – A unit of electromotive force. It is the amount of force required to drive a steady current of one ampere through a resistance of one ohm. Electrical systems of most homes and office have 120 volts.
VOLTAGE OF A CIRCUIT (Electric utility) – The electric pressure of a circuit, measured in volts. Volts are analogous to water pressure or flow rate.

WATT – A unit of measure of electric power at a point in time, as capacity or demand.

WATT-HOUR – One watt of power expended for one hour.

WEATHERSTRIPPING – Specially designed strips, seals and gaskets installed around doors and windows to limit air leakage.

WHEELING – The transmission of electricity owned by a third party to another buyer.

WHOLESALE POWER MARKET – The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services.

WIRES CHARGE – A broad term, which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

WESTERN SYSTEM COORDINATING COUNCIL (WSCC) – A voluntary industry association created to enhance reliability among western utilities.
Appendix D: Demand and Generation Scenarios and Forward Prices

D.1 Background
This section presents the demand forecast methodology that was used for estimating the electric demand in each of three scenarios. The demand forecast, as noted earlier, consisted of using the SDG&E 50-50 forecast up until 2006 and then using the CEC forecast for years beyond. To complete a sensitivity 1.8 percent for the low forecast, 2.0 percent for the medium forecast and 2.5 percent for the high demand forecast.

D.2 Electric and Demand Scenario Forecasts
D.2.1 Electric Forecast

Figure D-1 presents the electric load forecast. Data for this forecast, except the adjustments for the sensitivity analyses came from SDG&E and the CEC. This forecast includes losses and excludes the 15% reserves.

Figure D-2 presents the estimated projection for electric consumption. The total GWh of electric sales range from 32,000 GWh to 42,000 GWh in 2030. These sales projections are comparable to the CEC sales forecasts. While the CEC assumed an average growth rate of 2.3 percent, SAIC used 2.0, 2.3, and 2.5, percent as the basis of its low, medium, and high projections, respectively.
D.2.2 Natural Gas Forecast

Table D-1 presents the natural gas forecast by scenario. The low scenario uses a 1.0-percent growth rate. The medium scenario uses a 1.2-percent growth rate and the high scenario uses a 1.5-percent growth rate. The use of gas for power plants may also serve to increase gas load. On the margin, the growth of new power plants in the region that use natural gas could be the largest single growth area. Another potentially important driver for growth is the use of natural gas for cogeneration. This compares to about 40 percent of today’s load, according to SDG&E.

Table D-1. Total Historical and Projected Retail Sales Estimate (MMTherms)

<table>
<thead>
<tr>
<th>Year</th>
<th>Natural Gas Retail Sales Scenarios</th>
<th>Maximum Daily Sendout</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low Case 1.00%</td>
<td>Medium Case 1.20%</td>
</tr>
<tr>
<td>1995</td>
<td>703</td>
<td>703</td>
</tr>
<tr>
<td>1996</td>
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<td>944</td>
</tr>
<tr>
<td>2030</td>
<td>999</td>
<td>1003</td>
</tr>
</tbody>
</table>

The growth rates for maximum winter peak day sendout are estimated to be 1.2, 1.4, and 1.6 percent, for the low, medium, and high scenarios.

Residential use of natural gas may grow at a rate of about 0.5 percent and commercial uses are projected to grow at a rate of 2.0 to 5.0 percent per year.¹

¹ The 5% growth rate is provided by SDG&E.
D.3 Electric Capacity and Energy Forward Prices

This section presents a short description of the following:

- Electric forward pricing methodology employed
- Areas modeled
- Key Assumptions
- Results.

D.3.1 Methodology Employed

SAIC used the Market Power dispatch model, which was developed by New Energy Associates of Atlanta, Georgia. This model simulates electric energy and capacity prices using a dispatch algorithm. The specific algorithm employed uses a linear programming technique. A typical weekday and weekend day is modeled for every month of every year. Hourly periods were specified for 2-hour periods (e.g., Hours 1–2, 3–4, etc.). These periods were then combined for specific analyses. The period 2002 through 2030 was modeled.

D.3.2 Areas Modeled

In order to capture the behavior of the area electricity market, SAIC modeled the entire WSCC, including British Columbia, Alberta, and Baja California. The total generation in this region totaled 164,000 MW in 2000.

D.3.3 Assumptions

The base case natural gas price forecast was adopted from the CEC projections. These projections are produced from a general equilibrium model of the western United States. An alternative gas price forecast scenario was also prepared and used based upon projections from the U.S. DOE-EIA. These projections are based upon a general equilibrium model of North America.

The CEC natural gas price projections (Figure D-3) provided pricing points for all regions modeled in the WSCC. The EIA forecast used basis differentials constructed from Gas Daily pricing points. All natural gas price forecasts conformed to the CEC inflation forecast.

Figure D-3. Natural Gas Price Forecast

Natural Gas Prices for Electric Generation in San Diego County

[Graph showing natural gas prices from 2002 to 2012, with pricing points for CEC and EIA forecasts.]
Other fuel forecasts were adopted from sources such as RDI or the EIA. In general, these other fuels (residual oil, distillate oil, coal, and uranium) are not establishing the market price in this region.

SAIC adopted the CEC inflation forecast (Figure D-4). This forecast averaged increases of 2.4 percent per year for the period 2001 through 2012. SAIC extrapolated additional growth rates from 2013–2030.

Figure D-4. Inflation Forecast Used

New generating units identified in the State of California were based upon a developer consensus estimate. This estimate was made based upon communications with marketers about specific projections (both their own and competitors), which would be completed. Projects outside of California were identified through various databases and other public information sources. The plants that were included in the analysis were:

- 20,952 MW of planned generation was identified to come online
- After January 2002 in the WSCC, 7,112 MW of that capacity is located in California.

Market Power creates an optimal generation expansion plan based upon the assumptions and parameters entered into the model. SAIC identified the following technologies as potential new generation additions in our analysis.

- A simple-cycle combustion turbine and combined cycle combustion turbine, which could be constructed in all areas except California.
- Simple- and combined-cycle combustion turbines, which could be constructed in California. These units are more expensive due to higher construction costs and more stringent emissions standards.
- A coal plant, which could be constructed in the Rockies and Montana/Wyoming.

SDG&E’s peak demand and energy forecast was adopted until 2006. After that time period the CEC forecast was used. For the other California utilities the CEC forecast was adopted.

For non-California entities the Form 714 forecasts filed with the FERC were used.

Transmission interconnection capacities for the WSCC were adopted from various sources. San Diego County specific-transfer capabilities were confirmed by discussions with SDG&E personnel, including proposed projects such as Rainbow Valley. A transmission tariff of $3/MWh between regions was adopted. Transfers within regions were assumed to have a marginal price of zero.
D.3.4 Results

The following forward price analysis was produced in this study:

- A base case using CEC gas price projections and standard assumptions regarding identified new generation and prototype new generation. The CEC forecast and GADS data standard forced outage rates were used. This is the definitive forecast in California, with details specific to the west coast, including delivered gas prices from San Juan basin and local distribution fees.

- An alternative gas price scenario using EIA projections of natural gas prices. A lower forecast for generation is based on a general equilibrium model for North America.

- An alternative scenario assuming a higher IRR for California generation based upon political uncertainty. This scenario captures facts that there may be more risk in building plants in California than other Western states due to public comments about eminent domain, power contract negotiations, etc.

- An alternative scenario based upon a reduced level of construction in the 2002–2005 time period. In this scenario the number of planned projects was cut by 50 percent over the short term and this increased to a 75-percent reduction level for the WSCC. This scenario shows what would happen if marketers were to take action to avoid boom or bust cycles, by holding back on new plant development.

D.4 Generating Plants in San Diego County (2002–2030)

Table D-2 presents a current database on the current and proposed retirements of generating plants in San Diego County.
<table>
<thead>
<tr>
<th>Planned Generating Unit Capacity and Retirement Schedule for San Diego County, 2002–2030 (MW)</th>
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<table>
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<tr>
<th>Assumption: Steam units retired at 50 years – triggers retirements of Cabrillo 1-2-3</th>
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<tr>
<td><strong>Existing Steam Units</strong></td>
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<td>Cabrillo 5</td>
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</tr>
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<td>South Bay 2</td>
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<td>South Bay 3</td>
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<td>South Bay 4</td>
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<td><strong>Total Steam Units</strong></td>
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<table>
<thead>
<tr>
<th>Assumption: GTs/Jets are replaced as retired</th>
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<tr>
<td>Coronado – North Island 2</td>
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<tr>
<td>Division GT</td>
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<tr>
<td>Cabrillo GT 1</td>
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<tr>
<td>Cabrillo GT 2</td>
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<tr>
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<td><strong>Total GTs and Jets</strong></td>
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<td>Misc Customer Owned Capacity</td>
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<td><strong>Total QF / Cogen</strong></td>
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<th><strong>Peak Additions</strong></th>
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<td>El Cajon / CalPeak</td>
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<td>Ramco Escondido</td>
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<td>Ramco Chula Vista</td>
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<td><strong>Total PJual Additions</strong></td>
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<th><strong>Grand Total</strong></th>
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D-6
## Appendix E: Natural Gas System Data

### Table E-1. Historical and Forecast Natural Gas Consumption (therms) (Actuals through 2001 shown in bold)

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<thead>
<tr>
<th>Year</th>
<th>Historical and Base Case (Medium Growth)</th>
<th>Low Forecast</th>
<th>High Forecast</th>
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Table E-2. Historical and Forecast Natural Gas Demand (actuals through 2001 shown in bold)

<table>
<thead>
<tr>
<th>Year</th>
<th>Low Case</th>
<th>Medium Case</th>
<th>High Case</th>
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Figure E-1. System Map for SDG&E with Major Pipeline Interconnections
### Table E-3. SDG&E Firm Service Day (FSD) Demand

#### 1 in 10 year Recurrence Interval

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<th>Year</th>
<th>Core (MMcfd)</th>
<th>Firm Noncore C&amp;I (MMcfd)</th>
<th>Firm EG (MMcfd)</th>
<th>Total (MMcfd)</th>
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Description of SDG&E Potential Gas Infrastructure Projects

Rainbow to Escondido 30-inch pipeline
This pipeline would extend 23 miles from the Rainbow station and would tie in with the existing 16-inch line further south. The lead-time for this pipeline is 2 to 3 years, of course depending on various factors. The majority of this pipeline would be planned for installation in franchise rights of way (roadways). The cost of this project is estimated at $38 million, with only nominal operating and maintenance (O&M) costs. It would add about 45 MMcfd to the system capacity. It could also be extended further south and would be considered the first phase of the Rainbow to Santee line.

Rainbow to Fallbrook 30-inch pipeline
This pipeline would extend 15 miles from the Rainbow station to the Fallbrook area, and would tie into the existing 30-inch line at Fallbrook. The route would follow the existing 30-inch pipeline route, which does not follow franchise positions. Therefore it would require acquisition of right-of-way and environmental permitting, which will influence the 3- to 4-year lead-time estimate. Cost is approximately $29 million, and would add about 50 MMcfd to system capacity.

Rainbow to Santee 30-inch pipeline
Project #1 described above is the northern 23 miles of this project. The total length of this pipeline would be 49 miles, extended all the way to the existing 36-inch Pipeline 2000 in Santee. Essentially, this pipeline would complete a loop between the Rainbow Compressor station and the southern extreme of the SDG&E service territory. The project was discussed at length with SDG&E personnel and they confirmed this project as being the ideal project to significantly improve system reliability, especially in time of emergencies or when other transmission lines are in need of maintenance. The lead-time for this project is estimated at 3 to 4 years, with the southern portion being the most problematic since it goes through federal government property and various sensitive environmental zones. The cost of this entire project would be about $90 million and would add 150 to 170 MMcfd to system capacity. Similar to Line 6900, this line could be built in phases, or increments, as demand increases over time.

Rainbow to Main Line Valve #7 30-inch and Miramar to Santee 30-inch pipeline
The 30-inch Rainbow to Main Line Valve #7 begins at Rainbow and extends 25 miles south to the existing 30-inch line in the vicinity of the City of Carlsbad. Project # 2 described above is the northern15 miles of this project. This pipeline would require significant environmental permitting and rights of way acquisition, causing lead times to run 3 to 4 years. Cost would be approximately $47 million, with only nominal O&M charges.

The 30-inch Miramar to Santee pipeline would be about 7.5 miles from the Miramar Marine Corps Air Station to the City of Santee. This pipeline would tie into the 30-inch transmission line at Miramar and the 36-inch line in Santee. Lead time estimated at 3 to 4 years. Cost of this project is about $15–20 million.

Both of these projects would add about 100–120 MMcfd capacity to the SDG&E system. Although this pipeline resembles a third transmission line into the SDG&E service territory like the Rainbow to Santee line, it does not go to the southern extreme end of the system. Therefore, it would not provide the same level of reliability of that line.

Carlsbad Compressor Station and Miramar to Santee 30-inch
This potential project would install a new 17,000 bhp station in the City of Carlsbad located south of Main Line Valve #7. The lead-time for this project is 3 to 4 years, but since this area is highly developed locating a compressor station there would be difficult. The initial capital expense is estimate at $34 million, however this facility would also incur about $4 million a year in annual operating expenses for labor, fuel, O&M, and emission compliance costs. The 30-inch diameter pipeline is the same as described in project 4 above. Combined with the compressor station, these two projects would add about 90 to 100 MMcfd of capacity to the system for a total cost of about $50 million.
Gas Regulatory Proceeding Summaries


This decision is a fundamental structural change in the gas industry, especially in Southern California. First, firm receipt point capacity will be auctioned off by SoCalGas. SDG&E customers will have the opportunity to bid for this capacity directly. Second, SDG&E customers can contract directly for storage on SoCalGas' system. Other existing noncore gas supply options will be eliminated such as noncore gas sales, and core subscription option. The GIR also represents a return to embedded cost ratemaking, at least for the SoCalGas system, albeit on the backbone transmission and storage systems only. The SDG&E fixed costs will remain as they are today on a LRMC ratemaking basis. Essentially non-core customers in San Diego County are losing direct utility service options.

2. SDG&E Gas System Investigation (I. 00-11-002)

This proceeding was prompted by the gas curtailments that occurred on the SDG&E system during the winter of 2000/2001. At the time of this report, a proposed decision had been released by the ALJ in the proceeding. No final CPUC decision has been issued. Many important issues to San Diego gas consumers will result from this proceeding, such as: reliability standards, curtailment rules, interruptible/firm service rates, firm capacity reservations/open seasons, expansion policies, and other issues. The ALJ proposed decision also orders SDG&E to file a written report every six months on its capacity planning, demand forecast, and the status of its expansion projects. No other utility in the state is required to do this, however this potential new CPUC directive may eventually apply to the other gas utilities in the state. Only the San Diego APCD and the two major power plants in San Diego were active in this proceeding, and their participation was mainly focused on gas curtailment priorities and issues related to electric generation.


Biennial Cost Allocation Proceedings, or BCAPs, are critical to all gas customers in California. Although both SDG&E and SoCalGas filed their 2002 BCAP applications in late 2001, they were essentially made moot by the GIR decision in December. For that reason, both Sempra utilities completely re-filed their applications in March 2002. Upon a request by the CPUC staff organization ORA, a 1-year delay was requested—and granted by the CPUC, thus making these revised filing moot as well. Utility proposals in these 2002 BCAP applications were never entered into evidence, sponsored by witnesses, or had any discovery conducted on them, therefore we have to be careful in talking about them. BCAPs set the gas cost allocation for all ratepayers, including SDG&E as a wholesale customer of SoCalGas. Fundamentally it is a “zero sum game”, meaning that once the total revenue requirement of the utility has been set, the cost allocation methodology recovers those costs from all customers, with one customer class paying more if another pays less. Therein lies much of the controversy between customer classes in a BCAP proceeding. BCAPs are the single most important proceeding for all gas consumers, including electric generators. This is the proceeding where the SEMPRa wide EG rate was established, resulting in a huge windfall for EGs on the SDG&E system, to the consternation of Los Angeles based EG customers. Proposals surfacing in the 2002 SDG&E BCAP included the proposed “peaking rate,” potential transition to embedded cost ratemaking from current LRMC ratemaking, 15-year commitments by EG customers, and many more. Whether these issues are revisited in the 2003 BCAP remains to be seen.

4. SoCalGas/SDG&E Portfolio Consolidation Proceeding (A. 01-01-021)

Proposed in early 2001, this concept met little resistance by any party in hearings held mid-2001. The proceeding is essentially over, with the ALJ issuing a proposed decision approving the application. However, an alternate decision has also been issued which denies the application. After comments, this will be followed by the final CPUC decision. In a combined portfolio with SoCalGas, San Diego’s gas consumers will comprise less than 10 percent of the total portfolio, which will mean the priority will be with SoCalGas customers. Historically, SDG&E has been more economical in buying natural gas than SoCalGas, except for Winter 2000 and 2001. However, SoCalGas’ access to firm interstate capacity shielded its customers from the extreme run-up in gas commodity costs last winter. SDG&E will also no longer be providing any commodity sales to its noncore customers, which is a reduction of service options for them.
## Appendix F: Power System Data

### Table F-1. Power Plants Located in San Diego County

<table>
<thead>
<tr>
<th>--NAME--</th>
<th>--KV--</th>
<th>-P MAX-</th>
<th>Owner</th>
<th>RMR</th>
<th>CDWR</th>
<th>ISO Peaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>GTS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CORONADO (North Island 1)</td>
<td>12.5</td>
<td>18.0</td>
<td>Cabrillo II</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
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<tr>
<td>CORONADO (North Island 2)</td>
<td>12.5</td>
<td>18.0</td>
<td>Cabrillo II</td>
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<td>No</td>
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<tr>
<td>DIVISNGT</td>
<td>12.5</td>
<td>14.0</td>
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<td>No</td>
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<tr>
<td>ENCINAGT</td>
<td>12.5</td>
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<td>Cabrillo II</td>
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<td>No</td>
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<tr>
<td>KEARN2AB (Kearney GT2)</td>
<td>12.5</td>
<td>15.0</td>
<td>Cabrillo II</td>
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<td>NAVSTGT (Naval station 1)</td>
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<td>OLDTWNGT Naval Training Center</td>
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<td>15.0</td>
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<td>SOUTHBGT</td>
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<td>Duke</td>
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**GT Total** 304.0 MW

<table>
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<th>Steam Units</th>
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<th>RMR</th>
<th>CDWR</th>
<th>ISO Peaker</th>
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<tr>
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<td>No</td>
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<td>No</td>
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<td>Cabrillo 1</td>
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<td>No</td>
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<td>ENCINA 5</td>
<td>24</td>
<td>329.0</td>
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<td>No</td>
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<td>No</td>
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<td>Duke</td>
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**Steam Total** 1628.0 MW

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<th>QF/CoGen</th>
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<th>CDWR</th>
<th>ISO Peaker</th>
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<tr>
<td>DIVISION</td>
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<td>47.0</td>
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<td>GOALLINE</td>
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<td>50.0</td>
<td>PurEnergy</td>
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<td>No</td>
<td>No</td>
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<td>NOISLMTR (North Island)</td>
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<td>33.0</td>
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<td>No</td>
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<td>22.0</td>
<td>AEI</td>
<td>Yes</td>
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<td>No</td>
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<td>Misc Customer Owned Capacity(4)</td>
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<td>Misc</td>
<td>No</td>
<td>No</td>
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**QF Total** 175.0 MW

<table>
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<th>Peakers For 2001</th>
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<th>Owner</th>
<th>RMR</th>
<th>CDWR</th>
<th>ISO Peaker</th>
</tr>
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<tr>
<td>BORDER/Larkspur</td>
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<td>49.0</td>
<td>Coral</td>
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<td>Yes(1)</td>
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<tr>
<td>BORDER/Larkspur</td>
<td>69</td>
<td>49.0</td>
<td>Coral</td>
<td>No</td>
<td>Yes(1)</td>
<td>No</td>
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<tr>
<td>BORDER/CalPeak(3)</td>
<td>69</td>
<td>49.0</td>
<td>CalPeak</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
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<tr>
<td>ESCNIDO/CalPeak(3)</td>
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<td>49.0</td>
<td>CalPeak</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Ramco Escondido</td>
<td>69</td>
<td>49.0</td>
<td>Ramco</td>
<td>No</td>
<td>No</td>
<td>Yes(2)</td>
</tr>
<tr>
<td>Ramco Chula Vista</td>
<td>13.8</td>
<td>42.0</td>
<td>Ramco</td>
<td>No</td>
<td>No</td>
<td>Yes(2)</td>
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</table>

**Peaker Total** 287.0 MW

**Grand Total** 2394.0
Details of the Proposed Otay Mesa Power Plant.

The plant will require a 0.1-mile connection to San Diego Gas & Electric's (SDG&E) existing 230-kV Miguel–Tijuana transmission line that passes near the eastern boundary of the Otay Mesa site. The project will use dry-cooling technology, which is discussed later in this chapter. The process water for steam generation and potable water for domestic needs will be supplied by reclaimed water from the Otay Water District via a 0.2-mile pipeline connection. Wastewater from the plant will be transported to San Diego County's sewer system from the plant, via a new 2-mile pipeline that will connect to an existing line in Johnson Canyon.

Otay Mesa will use dry cooling. Some of the main features of dry cooling are:

- It reduces water consumption by 95 percent
- Smokestacks have no plumes
- Reduced permitting process
- The key disadvantages of dry cooling is the systems are the noise, large land requirements and cost, which can be as much as 15-percent higher, noted an article in the San Diego Union-Tribune.

Figure F-1. Map
Proposed Sempra Energy Palomar Energy Project (Source: CEC)

On November 28, 2001, Palomar Energy LLC (Palomar) filed an Application for Certification (AFC), for its proposed Palomar Energy Project (PEP) with the California Energy Commission seeking approval to construct and operate a 500-megawatt (MW) natural gas-fired, combined-cycle electric generating facility. The plant will be owned and operated by Palomar, a wholly owned subsidiary of Sempra Energy Resources. The proposed project would be located on a vacant 20-acre site within a proposed 186-acre industrial park in the City of Escondido, California. The industrial park project is known as the Escondido Research and Technology Center (ERTC). The ERTC project and a draft Specific Plan for the industrial park project area are currently undergoing a California Environmental Quality Act (CEQA) review, with the City of Escondido as Lead Agency. Schedule. The project is proposed to be operational in the summer of 2004. Facility Operation. The proposed power plant will consist of two General Electric 7FA natural-gas fired combustion turbine-generators (CTGs) equipped with dry low nitrogen oxide (NOx) combustors and evaporative inlet air coolers, as well as two heat recovery steam generators (HRSG), a steam turbine generator and associated auxiliary systems and equipment. In addition to the dry low NOx combustors, the power plant will also be equipped with selective catalytic reduction (SCR) systems for NOx control and oxidation catalyst systems for carbon monoxide (CO) and volatile organic compounds (VOCs) control. NOx emissions will be controlled to 2.0 parts-per-million volume dry basis (ppmvvd) at 15-percent oxygen by the SCR systems. CO emissions will be controlled to 4.0 ppmvd at 15-percent oxygen using an oxidation catalyst system. The project’s electric generation will be connected to a new 230-kV switchyard adjacent to the facility. From the switchyard, generated power will be transmitted to an existing San Diego Gas & Electric (SDG&E) 230-kV transmission line located adjacent to the project site. Electricity Market. Electricity generated from this facility may be sold to the California Department of Water Resources (DWR) under an existing contract with Sempra Energy Resources. The City of Escondido has also expressed interest in purchasing electricity from the project. The applicant has indicated that all electricity sales will be in accordance with the appropriate market rules.

Fuel. Natural gas will be the only fuel utilized by the two new CTGs. Natural gas will be supplied to the CTGs via an existing SDG&E natural gas pipeline located immediately adjacent to the project site.

Water. The Palomar Energy Project will utilize approximately 3.6 million gallons per day of reclaimed water provided by the City of Escondido’s Hale Avenue Resource Recovery Facility (HARRF). Reclaimed water will be conveyed to the site by a new 1.1-mile, 16-inch, pipeline connecting to an existing City of Escondido reclaimed water main on Harmony Grove Road. The project’s cooling tower will evaporate nearly 75 percent of the reclaimed water.

Assumptions for the Wholesale Electric Price Forecast

SAIC prepared a forecast of wholesale electric prices for San Diego County and adjacent areas. Our approach in preparing this forecast was to simulate the behavior of this market through the use of a general equilibrium model. General equilibrium models produce projections of energy prices through the dispatch of specific generating units or groups of generating units while producing an optimized expansion plan through time. The model SAIC choose to perform this analysis was the Market Power model distributed by New Energy Associates of Atlanta, Georgia.

General Assumptions

The following general assumptions were employed in this analysis:

- SAIC prepared these projections in nominal (current year) dollars;
- The area modeled in these simulations was the WSCC;
- SAIC assumed that a competitive wholesale electric market would develop in the California and the WSCC.
Inflation
Inflation forecasts used in this forecast were adopted from the California Energy Commission (CEC) Electricity Outlook Report. This report provided inflation estimates until 2012. For periods after 2012 estimates for the last year were extrapolated until the end of the study period.

Market Areas
SAIC performed this analysis based upon market areas. The primary market areas in the WSCC are as follows:

- The Rocky Mountain region;
- The Pacific Northwest;
- Arizona-New Mexico;
- California / Southern Nevada / Baja California.

The California/ Southern Nevada / Baja California was further differentiated to isolate San Diego County, Southern California and Baja California.

Existing Generation Stock
The Market Power model contains a database of all electric generating units in the various reliability councils. New Energy receives this data from RDI. These databases contain the following information for each unit:

1. Technology
2. In-service date
3. Maximum capacity
4. Heat rate
5. De-ration factors
6. Fuel type
7. Forced outage rate
8. Scheduled outage requirements

Fuel Prices
The primary fuel prices that establish the marginal cost (dispatch price) are natural gas, residual fuel oil and coal. Nuclear fuel and distillate oil are also used in the region but rarely if ever establish dispatch prices. Furthermore, hydroelectric units are also sub-marginal. Fuel prices were established as follows:

Natural Gas
Natural gas prices at Henry Hub were adopted from the CEC. Table F-1 details these values.

| Table F-2. Natural Gas Prices Delivered to Electric Generating Units ($/MCF) |
|---------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| SoCal Gas/ San Diego      | 2.94 | 3.00 | 3.06 | 3.16 | 3.25 | 3.33 | 3.41 | 3.48 | 3.56 | 3.63 | 3.70 |


An alternative natural gas price scenario was based upon projections of natural gas prices produced by the US DOE-EIA. These prices were derived from projections in AEO 2002, the EIA’s annual energy forecast.
Residual Oil

Residual oil forecasts produced by Resource Data International were used in this analysis. Plants in Southern California were limited to a maximum residual oil burn of 2 percent per year.

Nuclear Fuel

Nuclear fuel was escalated at the rate of inflation.

Coal

Coal price forecasts were supplied by Resource Data International. Existing major coal units were generally forecasted on a station basis for larger units. Smaller and generic units were forecasted based upon regional coal price estimates.

Load Growth

Load growth projections for non-California entities were taken from Form 714 filing made with the Federal Energy Regulatory Commission (FERC). These filings were:

California load forecasts, with the exception of San Diego Gas and Electric, were taken from the CEC 2002–2012 Electricity Report. The specific details of the SDG&E forecast is discussed elsewhere in this report.

New Generation

New generation was introduced in two manners in this analysis: (1) Specifically identified units and prototype generating units introduced by the model in the creation of the expansion plan.

Specifically identified projects and prototype projects introduced by the model. Provided below in Figure F-2 is a chart summarizing the number of megawatts of new projects that were specifically identified and included in our modeling.

Figure F-2. New Projects in the WSCC

The number of new megawatts of generating units specifically identified was performed through extracts from the RDI NewGen database. After these extracts were performed project personnel then analyzed results to exclude projects that we felt were unlikely to occur.

The Market Power model creates this expansion plan by choosing from the fleet of potential new units that may be constructed during a specific period (prototype technologies) and determine which technologies need to be added in order to create the most economic expansion plan. Therefore, after specifically identified units are added to the generation mix an algorithm in the model as additional...
units until such time as an economic expansion plant has been achieved. The characteristics of the prototype technologies are discussed below.

The prototype technologies periodically decreased the specified heat rate in order to account for changes in technology. Table F-3 specifies these heat rates for combined-cycle and simple-cycle combustion turbines:

Table F-3. Projected Full Load Heat Rates (Btu/kWh) by Technology Projected to Be Achieved in the Period 2002–2030

<table>
<thead>
<tr>
<th>Years</th>
<th>Simple-Cycle Combustion Turbine</th>
<th>Combined-Cycle Combustion Turbine</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002–2008</td>
<td>10,487</td>
<td>6,566</td>
</tr>
<tr>
<td>2009–2013</td>
<td>10,427</td>
<td>6,435</td>
</tr>
<tr>
<td>2014–2018</td>
<td>10,070</td>
<td>6,306</td>
</tr>
<tr>
<td>2019–2030</td>
<td>9,871</td>
<td>6,180</td>
</tr>
</tbody>
</table>

Prototype technologies for California and non-California applications had different installed costs and emissions outputs. The installed cost for California units are provided in Table F-4.

Table F-4. Installed Cost of Various Generation Technologies – 2002 Dollars per Kilowatt

<table>
<thead>
<tr>
<th>Technology</th>
<th>California Application</th>
<th>Non-California Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple-Cycle Combustion Turbine</td>
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<td>$385</td>
</tr>
<tr>
<td>Combined-Cycle Combustion Turbine</td>
<td>$850</td>
<td>$650</td>
</tr>
<tr>
<td>Coal-fired Steam Plant</td>
<td>Not Applicable</td>
<td>$1,600</td>
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</table>

The installed cost reflects the overall higher costs associated with siting a unit in California, attaining stricter NOX emission standards and property costs. Coal-fired steam units were assumed to only be feasible in non-environmentally sensitive regions and thus excluded California.

All prototype generation was assumed to require a 14.5 percent IRR for the base case. An alternative high cost of capital case was run. In this scenario generating units constructed in California were assumed to require an IRR of 16.5 percent due to regulatory risk.

Unit Retirements

Unit retirements for steam units were assumed to occur when a unit reaches 50 years of age. Simple cycle combustion turbines were assumed to have an economic life of 35 years. For the nuclear plants in the region SAIC assumed these units would receive 20-year life extensions after the initial license life of 40 years expired. Hydroelectric units were assumed to not retire.

Emissions Allowances

California has very serious problems with the creation of ozone. For this reason ozone allowances in California are significantly more expensive than in the other major of the non-attainment regions in the United States. SAIC assumed that NOx allowances for California were priced at the equivalent of $10,740 per ton-year in 2002. After that time period we assumed they increased with inflation.

The balance of the WSCC priced NOX allowances at $1,600 per ton. SOX allowances were priced at $303 per ton escalating at inflation.

Forced Outage Rates

Forced outage rates were adopted based upon NERC GADS data. Forced outage rates were assigned based upon generating unit category.
Scheduled Outage Hours

Scheduled outage hours for each generating unit category used NERC GADS data.

Transmission Interconnections

Transmission interconnections were modeled using a transportation methodology, i.e., the capacity of transmission interconnections between regions was assumed not to vary within a given period. The transmission capabilities for the majority of the WSCC were adopted from various WSCC publications where non-simultaneous transmission were published. Detailed information about the SDG&E area was received from the Company and various CPUC filings.
SAIC’s approach to screening, designing and evaluating demand side programs including energy efficiency and demand response was the following:

- Reviewed sector sales and selected loads
- Identified applicable programs
- Gathered data on technology impacts, market size, saturation of efficiency measures, energy and demand savings, implementation costs
- Designed programs
- Entered data into the COMPASS\(^2\) model
- Analyzed programs using COMPASS
- Summarized results.

The screening model used is Silicon Energy’s COMPASS model. SAIC licensed the model for use in this project.

Key features of the model are the following:

- COMPASS is designed for demand side market planning
- Information is organized in relational databases
- Detailed information stored in specific databases
- Markets and growth, technology characteristics, rates and other key data for the 30-year period
- Output allows evaluation of demand-side management programs from different perspectives
- Based on California Standard Practice Tests

Other Compass features:

- All data and analysis in a single software package
- Integrates complex multi-factor analysis procedures
- Relational database manages all relevant data
- Full feature rate model
- Explicit modeling of market penetration and diffusion
- Market adoption calculated with and without program (accounts for free-riders)
- Benefit/cost methodology consistent with standard practice methodology
- Scenario analysis capability

See Figure G-1 regarding the general structure of the model.

\(^2\) Stands for the “Comprehensive Market Planning and Analysis System.”
Figure G-1. Overview of COMPASS

The following market data by segment was used in the analysis of DSM potential (Table G-1).

<table>
<thead>
<tr>
<th>Sector</th>
<th>RESID</th>
<th>RESID</th>
<th>COMM</th>
<th>COMM</th>
<th>COMM</th>
<th>INDUS</th>
<th>INDUS</th>
<th>INDUS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment</td>
<td>Single Family</td>
<td>Multi Family</td>
<td>Comm Buildings</td>
<td>Comm MWH Sales</td>
<td>Comm Flr Space</td>
<td>Indust Lighting</td>
<td>Indust Motors</td>
<td>Ind MWH Sales</td>
</tr>
<tr>
<td>Description</td>
<td>Number of Homes</td>
<td>Number of Homes</td>
<td>Total Number of Commercial Buildings</td>
<td>Total MWH Sales to Commercial Buildings</td>
<td>Total SF of Commercial Buildings</td>
<td>MWH Sales For All Industrial Lighting Programs</td>
<td>MWH Sales For All Industrial Motors Programs</td>
<td>MWH Sales For All Sales Based Industrial Programs</td>
</tr>
<tr>
<td>Units</td>
<td>HOMES</td>
<td>HOMES</td>
<td>Buildings</td>
<td>MWH Sales</td>
<td>1000 sf</td>
<td>MWH Sales</td>
<td>MWH Sales</td>
<td>MWH Sales</td>
</tr>
<tr>
<td>Year 2002 Estimate</td>
<td>641.11</td>
<td>408.07</td>
<td>86.93</td>
<td>661.10</td>
<td>503.47</td>
<td>249.66</td>
<td>691.86</td>
<td>1979.00</td>
</tr>
<tr>
<td>Growth Rate, %/year</td>
<td>1.3</td>
<td>1.8</td>
<td>2.30</td>
<td>2.30</td>
<td>2.30</td>
<td>3.30</td>
<td>3.30</td>
<td>3.30</td>
</tr>
<tr>
<td>Demolition Rate, %/year</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Discount Rate, %</td>
<td>15.00</td>
<td>15.00</td>
<td>12.50</td>
<td>12.50</td>
<td>12.50</td>
<td>12.50</td>
<td>12.50</td>
<td>12.50</td>
</tr>
</tbody>
</table>

In applying the model the following assumptions were used:

- SDG&E Rates were used as inputs in the COMPASS Rates Database
  - Residential
    - Domestic Rate Schedule DR
    - Natural Gas Rate GR
  - Commercial
    - General Service Time Metered, Schedule AL-TOU
    - Commodity Rate EECC (DWR Decision)
    - Gas for Core Commercial Customers Rate GN-3
    - Escalation Rate: 2.09% per year
    - COMPASS uses marginal rate (tail block) to compute bills and savings
COMPASS technology data file consists of:

- Technology characteristics feature in COMPASS was used to input energy consumption:
  - For Base and Associated DSM Technology
  - For New and Existing Vintage

- Data entered included:
  - Technology cost and change in cost over time
  - Current market share of the base/DSM technology
  - Average customer energy/demand by season and time period
  - Coincidence factor to determine impact during system peak
  - Diversity factor to estimate impact on customer bill

- The COMPASS mass-market acceptance file consists of:
  - COMPASS uses market acceptance scenarios to estimate penetration of the DSM technology
  - Market acceptance files have different inputs for Program and No-Program case
  - To estimate technical potential, market potential for program case is set to 100% and for no-program case is set to 0% (i.e. program is credited with 100% of the savings)
  - Market acceptance scenarios in SDREO analysis included Payback Acceptance Curves or Direct Entry based on the technology.
  - COMPASS default payback acceptance curves were used
  - Payback acceptance curves were different for Residential, Commercial, and Industrial sectors

**Figure G-2. Calculating Market Size in COMPASS**

<table>
<thead>
<tr>
<th>A. Total Market Size</th>
<th>B. Market Size with Base Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depends on new or existing, retrofit or replacement</td>
<td>[ A \times \text{Current Share of Base Technology} ]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>C. Eligible Market [B* Eligible Fraction]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portion of Market this is eligible based on program criteria</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>D. Willing Market [C* (1-Unwilling Fraction)]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portion of Market that would be willing to accept the measure if it were given away at no cost to the participant</td>
</tr>
</tbody>
</table>

- Willing Market is a small fraction of the total market
- Final Adoption can be much smaller than willing market

**Compass Utility Characteristics File**

Key assumptions used were:

- Loss Factors (10% in Summer, 9% in Winter)
- Discount Rates for Utility (12%), TRC (12%), Societal (9.5%)
- Inflation Rate (2.09%)
- Electric Avoided Capacity and Energy Costs by season and period (see next page)
- Electric Avoided T&D Costs ($10/kW-year with 3% esc)
- Gas Avoided Costs
- Sales, # of customers, Revenue Requirements

**Table G-2. Electric: Avoided Costs for Energy and Capacity (Base Case)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Capacity, $/kW/year</th>
<th>Energy, $/MWH</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Summer</td>
<td>Winter</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2002</td>
<td>99.14</td>
<td>-</td>
</tr>
<tr>
<td>2003</td>
<td>99.28</td>
<td>-</td>
</tr>
<tr>
<td>2004</td>
<td>96.98</td>
<td>-</td>
</tr>
<tr>
<td>2005</td>
<td>90.43</td>
<td>-</td>
</tr>
<tr>
<td>2006</td>
<td>99.77</td>
<td>-</td>
</tr>
<tr>
<td>2007</td>
<td>99.94</td>
<td>-</td>
</tr>
<tr>
<td>2008</td>
<td>100.11</td>
<td>-</td>
</tr>
<tr>
<td>2009</td>
<td>100.29</td>
<td>-</td>
</tr>
<tr>
<td>2010</td>
<td>112.37</td>
<td>-</td>
</tr>
<tr>
<td>2011</td>
<td>115.79</td>
<td>-</td>
</tr>
<tr>
<td>2012</td>
<td>119.53</td>
<td>-</td>
</tr>
<tr>
<td>2013</td>
<td>123.39</td>
<td>-</td>
</tr>
<tr>
<td>2014</td>
<td>127.19</td>
<td>-</td>
</tr>
<tr>
<td>2015</td>
<td>131.16</td>
<td>-</td>
</tr>
<tr>
<td>2016</td>
<td>135.48</td>
<td>-</td>
</tr>
<tr>
<td>2017</td>
<td>140.13</td>
<td>-</td>
</tr>
<tr>
<td>2018</td>
<td>144.62</td>
<td>-</td>
</tr>
<tr>
<td>2019</td>
<td>149.18</td>
<td>-</td>
</tr>
<tr>
<td>2020</td>
<td>154.03</td>
<td>-</td>
</tr>
<tr>
<td>2021</td>
<td>159.04</td>
<td>-</td>
</tr>
<tr>
<td>2022</td>
<td>164.24</td>
<td>-</td>
</tr>
<tr>
<td>2023</td>
<td>169.61</td>
<td>-</td>
</tr>
<tr>
<td>2024</td>
<td>175.10</td>
<td>-</td>
</tr>
<tr>
<td>2025</td>
<td>180.77</td>
<td>-</td>
</tr>
<tr>
<td>2026</td>
<td>180.98</td>
<td>-</td>
</tr>
<tr>
<td>2027</td>
<td>180.87</td>
<td>-</td>
</tr>
<tr>
<td>2028</td>
<td>256.53</td>
<td>-</td>
</tr>
<tr>
<td>2029</td>
<td>263.86</td>
<td>-</td>
</tr>
<tr>
<td>2030</td>
<td>253.10</td>
<td>-</td>
</tr>
</tbody>
</table>
Table G-3. Utility Revenue Requirements

<table>
<thead>
<tr>
<th></th>
<th>Revenue, $ (1)</th>
<th>MWH Sold Year 2000 (1)</th>
<th>MWH Sold Year 2001</th>
<th>MWH Sold Year 2002</th>
<th>$/MWH (computed)</th>
<th>Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>729,798,797</td>
<td>6,304,063</td>
<td>6,392,320</td>
<td>6,481,812</td>
<td>115.77</td>
<td>1.40%</td>
</tr>
<tr>
<td>Small C/I</td>
<td>746,793,366</td>
<td>6,125,149</td>
<td>6,266,027</td>
<td>6,410,146</td>
<td>121.92</td>
<td>2.30%</td>
</tr>
<tr>
<td>Large C/I</td>
<td>309,731,267</td>
<td>2,614,082</td>
<td>2,700,347</td>
<td>2,789,458</td>
<td>118.49</td>
<td>3.30%</td>
</tr>
<tr>
<td>Other</td>
<td>7,544,357</td>
<td>74,264</td>
<td>75,749</td>
<td>77,264</td>
<td>101.59</td>
<td>2.00%</td>
</tr>
</tbody>
</table>

(1) Source: FERC Form 1, Year 2000, Page 300-301

The Programs

- Residential
  - Advanced metering and control
  - Photovoltaics
  - Retrofit program
  - Condition of Sale
  - Title 24 Plus

- Commercial/Industrial
  - Demand flexibility
  - High efficiency motors
  - High efficiency lighting
  - Photovoltaics
  - Retrofit program
  - E2Pro: Energy and Environment Program

Program Design in Compass

- Program design in COMPASS combines data from all databases with program design elements to estimate program participation and effectiveness

- Program description data includes:
  - New or existing customer
  - Utility characteristics data
  - Retrofit or replacement program
  - Existing facility or new facility
  - Persistence, start, years program in effect and duration
  - Assignment of customer rates, technology options, and market acceptance ramp up rate and technology diffusion
  - Eligible customer percent, unwilling percent and no program cases
  - Incentive type and amount
  - Program costs – one time fixed, annual fixed, annual variable
  - Repurchase rate
  - Drop out rate.
Table G-4. Program Costs

<table>
<thead>
<tr>
<th>Program File</th>
<th>Program Name</th>
<th>Market Acceptance</th>
<th>Program Type</th>
<th>Eligible Percent</th>
<th>Percent - Program</th>
<th>Percent - No Program</th>
</tr>
</thead>
<tbody>
<tr>
<td>R-AM</td>
<td>Advanced Metering, Pricing and Control</td>
<td>Direct Entry</td>
<td>Replacement</td>
<td>100%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>R-RE-PV</td>
<td>Photovoltaics</td>
<td>Direct Entry</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-XX</td>
<td>Residential Retrofit</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-LC</td>
<td>Lighting – CFL</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-CF</td>
<td>Space Conditioning – Wholehouse Fans</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-CT</td>
<td>Space Conditioning – Programmable Tstat</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-AI</td>
<td>Envelope – Attic Insulation</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-WP</td>
<td>Envelope – Window Pane Glazing</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-WG</td>
<td>Water Heating Efficiency Gas</td>
<td>Res PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-WE</td>
<td>Water Heating Efficiency Electric</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-IG</td>
<td>Wtr Htr Insulation and Flow Control - Gas</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-IE</td>
<td>Wtr Htr Insulation and Flow Control - Elec</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>R-RT-PP</td>
<td>Pool Pumps</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RS</td>
<td>Condition of Sale HERS Rating</td>
<td>Direct Entry</td>
<td>Replacement</td>
<td>100%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>R-24</td>
<td>Title 24 Plus House</td>
<td>Res PB Accept</td>
<td>Retrofit</td>
<td>50%</td>
<td>20%</td>
<td>80%</td>
</tr>
<tr>
<td>C-DR</td>
<td>Flexible, Market Driven Demand Response</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>20%</td>
<td>20%</td>
<td>100%</td>
</tr>
<tr>
<td>C-RE-PV</td>
<td>Photovoltaics</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>10%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-XX</td>
<td>Commercial Retrofit</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LC</td>
<td>Lighting – CFL</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LB</td>
<td>Lighting – T8</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LS</td>
<td>Lighting – T5</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LT</td>
<td>Lighting – Control Timer</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-CH</td>
<td>Space Conditioning – High Efficiency</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-CS</td>
<td>Cool Storage</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-RC</td>
<td>Envelope – Cool Roofs</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-DG</td>
<td>Distributed Generation Promotion</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-E2</td>
<td>E2 – Clean Energy and Environment Program</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-DR</td>
<td>Flexible, Market Driven Demand Response</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-MO-EE</td>
<td>High Efficiency Motor and Drive New &amp;</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-LI-HE</td>
<td>High Efficiency Lighting</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-E2</td>
<td>E2 – Clean Energy and Environment Program</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
</tbody>
</table>

Table G-5. Program Eligibility and Penetration

<table>
<thead>
<tr>
<th>Program File</th>
<th>Program Name</th>
<th>Market Acceptance</th>
<th>Program Type</th>
<th>Eligible Percent</th>
<th>Percent - Program</th>
<th>Percent - No Program</th>
</tr>
</thead>
<tbody>
<tr>
<td>R-AM</td>
<td>Advanced Metering, Pricing and Control</td>
<td>Direct Entry</td>
<td>Replacement</td>
<td>100%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>C-DR</td>
<td>Flexible, Market Driven Demand Response</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>20%</td>
<td>20%</td>
<td>100%</td>
</tr>
<tr>
<td>C-RE-PV</td>
<td>Photovoltaics</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>10%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-XX</td>
<td>Commercial Retrofit</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LC</td>
<td>Lighting – CFL</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LB</td>
<td>Lighting – T8</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LS</td>
<td>Lighting – T5</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-LT</td>
<td>Lighting – Control Timer</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-CH</td>
<td>Space Conditioning – High Efficiency</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-CS</td>
<td>Cool Storage</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-RT-RC</td>
<td>Envelope – Cool Roofs</td>
<td>Com PB Accept</td>
<td>Replacement</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-DG</td>
<td>Distributed Generation Promotion</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>C-E2</td>
<td>E2 – Clean Energy and Environment Program</td>
<td>Com PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-DR</td>
<td>Flexible, Market Driven Demand Response</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-MO-EE</td>
<td>High Efficiency Motor and Drive New &amp;</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-LI-HE</td>
<td>High Efficiency Lighting</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>I-E2</td>
<td>E2 – Clean Energy and Environment Program</td>
<td>Ind PB Accept</td>
<td>Retrofit</td>
<td>85%</td>
<td>20%</td>
<td>20%</td>
</tr>
</tbody>
</table>
Scenarios – Low, Medium, and High Cases

- Low, medium, and high DSM impact scenarios were developed
- Differences in scenarios are shown
- Use different marginal costs for each scenario
- Program incentives, costs and penetration rates varied.

Table G-6. Low, Medium, and High Case Scenarios

<table>
<thead>
<tr>
<th></th>
<th>LOW</th>
<th>MEDIUM</th>
<th>HIGH</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Marginal Electric Costs</strong></td>
<td>EIA Gas Price Scenario</td>
<td>Base Case Scenario</td>
<td>High Capacity Costs Scenario</td>
</tr>
<tr>
<td><strong>Marginal Gas Costs</strong></td>
<td>CEC Gas Price Forecast</td>
<td>CEC Gas Price Forecast</td>
<td>CEC Gas Price Forecast</td>
</tr>
<tr>
<td><strong>Program Design</strong></td>
<td>Duration, years – 30 years</td>
<td>30 years</td>
<td>30 years</td>
</tr>
<tr>
<td><strong>Incentives</strong></td>
<td>50% of High Case</td>
<td>75% of High Case</td>
<td>100% of High Case</td>
</tr>
<tr>
<td><strong>Direct Entry Market Acceptance</strong></td>
<td>50% of High Case</td>
<td>75% of High Case</td>
<td>100% of High Case</td>
</tr>
<tr>
<td><strong>Program Costs</strong></td>
<td>50% of High Case</td>
<td>75% of High Case</td>
<td>100% of High Case</td>
</tr>
</tbody>
</table>

Table G-7. Comparison of CHP Technologies

<table>
<thead>
<tr>
<th>Factors</th>
<th>Diesel Engine</th>
<th>NG Engine</th>
<th>Steam Turbine</th>
<th>Gas Turbine</th>
<th>Micro-Turbine</th>
<th>Fuel Cells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Efficiency (LHV)</td>
<td>30–50%</td>
<td>24–45%</td>
<td>30–42%</td>
<td>25–40%</td>
<td>20–30%</td>
<td>40–70%</td>
</tr>
<tr>
<td>Footprint (Sq ft/kW)</td>
<td>0.22</td>
<td>0.22–0.31</td>
<td>&lt;0.1</td>
<td>0.02–0.61</td>
<td>0.15–1.5</td>
<td>0.6–4</td>
</tr>
<tr>
<td>Installed Cost ($/kW)</td>
<td>$800–1,500</td>
<td>$800–1,500</td>
<td>$800–1,000</td>
<td>$700–900</td>
<td>$500–1,300</td>
<td>&gt;$3,000</td>
</tr>
<tr>
<td>O&amp;M Cost ($/kWh)</td>
<td>0.005–0.008</td>
<td>0.007–0.015</td>
<td>0.004</td>
<td>0.002–0.008</td>
<td>0.002–0.01</td>
<td>0.003–0.015</td>
</tr>
<tr>
<td>Fuels</td>
<td>Diesel and Residual</td>
<td>NG, Biogas, Propane</td>
<td>All</td>
<td>NG, Biogas, Propane, Distillate</td>
<td>NG, Biogas, Propane, Distillate</td>
<td>Hydrogen, NG, and Propane</td>
</tr>
<tr>
<td>NOx Emissions (lb/MWh)</td>
<td>3–33</td>
<td>2.2–28</td>
<td>1.8</td>
<td>0.3–4</td>
<td>0.4–2.2</td>
<td>&lt;0.02</td>
</tr>
<tr>
<td>CHP Output (BTU/kWh)</td>
<td>3,400</td>
<td>1,000–5,000</td>
<td>n/a</td>
<td>3,400–12,000</td>
<td>4,000–15,000</td>
<td>500–3,700</td>
</tr>
<tr>
<td>Usable Temperature For CHP (F)</td>
<td>180–900</td>
<td>300–500</td>
<td>n/a</td>
<td>500–1,100</td>
<td>400–650</td>
<td>140–700</td>
</tr>
</tbody>
</table>
Appendix H

Addendum To Draft Report

This section reviews the comments that were submitted after the 45-day comment period, which closed on November 30, 2002. The following organizations submitted comments:

1. Air Pollution Control District
2. BIOCOM/San Diego
3. Border Power Plant Working Group
4. City of Chula Vista
5. City of San Diego MWWD
6. Coronado Chamber of Commerce
7. East County Economic Development Council
8. EnergySC.Net
9. Environmental Health Coalition
10. Greenpeace
11. National City Chamber of Commerce
12. Pacifica Companies (Two separate comments)
13. Powers Engineering
14. Qualcomm
15. Richard Heath and Associates
16. SANDAG
17. San Diego Air Pollution Control Board
18. San Diego Gas and Electric
19. Sierra Club, San Diego Chapter
20. South County Economic Development Council
21. Southwest Center for Environmental Research and Policy (SCERP)
22. Technical Training Associates
23. The League of Women Voters of San Diego

Comments ranged from short one page general comments of support to lengthy and more extensive comments covering six or more pages. By far, the most extensive comments were received from Greenpeace, the Border Power Plant Working Group, Air Pollution Control District of the County of San Diego, the City of Chula Vista, the Environmental Health Coalition, Sierra Club of San Diego and San Diego Gas and Electric Company.

What follows is a review of the comments submitted, followed by the report Author’s response to the comments, based on consultation and review of the comments with subcontractors.
A vast majority of commenters felt that the REIS was a very good and positive first step toward identifying the sources and uses of energy and a preliminary definition of the possible strategy options over the future. SDG&E also expressed this view. However, a number of organizations felt that the REIS could be improved. What follows below is a review of these comments and the response of the Author to the comments:

1. Provide more documentation on the energy efficiency and renewable analysis (SANDAG, for example). Greenpeace concluded its review of the report by saying that it: “agrees with many of the conclusions for the REIS and appreciates the work that has gone into the study.”

Response: Extensive documentation manuals and model inputs and outputs from the Compass analysis, which was used to evaluate DSM options, are available at SDREO. This information documents program design, program costs, market penetration rates, avoided energy and capacity costs, and cost effectiveness using the California Standard Practice. To keep the report from being too lengthy it was decided to keep detailed program documentation in separate volumes. Anyone interested may consult these documents at SDREO’s office.

2. More attention is needed on the environmental impacts of the REIS. The Southwest Center for Environmental Research and Policy suggested that the environmental concerns have not been appropriately addressed. “The report does not do enough to present a comprehensive review of the environmental issues related to energy.” The Center recommends that REPAC address an environmental agenda that parallels the energy agenda that is being discussed for the county. More attention is needed on the environmental problems created by energy generation in the county to solve specific environmental emission problems. The Border Power Plant Working Group suggested that the approval process for new plants requiring an air quality permit was over exaggerated, and that model approval processes exist (i.e., as was experienced with Otay Mesa). They went on to recommend that a model environmental performance capability of new power plants be defined and followed. If new plants meet this model approval process, then the approval process is timely, reasonable and appropriate.

Response: The environmental impacts from the COMPASS analysis was completed and reported. The main focus of the project was infrastructure. Environmental implications of new power plants and repowering were assumed to be addressed in the separate permitting processes, which have to meet state and regional standards of emission levels. The general emission performance levels of different types of plants were reported. It was also assumed that new plants replacing old plants would save substantial amounts of primary energy and emissions. Since the actual scheduling of these new projects is uncertain, and the general belief that there would be improved environmental impacts, no additional analysis was completed – other than for the DSM component.

3. Some commenters felt that the REIS was too conservative in its conservation and renewable assessment (Sierra Club and Greenpeace), and others felt that the potential was too exaggerated (SDG&E). The Border Power Plant Working Group felt that more detailed treatment is needed of the geothermal potential in the Salton Sea area – where Cal Energy estimates that there may be as much as 2,000 MW of untapped geothermal potential in the immediate area. The Border Power Plant
Working Group suggested that a more detailed discussion of how SDG&E will meet its 20 percent renewable portfolio obligations passed under SB 1078 and the SDG&E renewables plan should be included as an Appendix in the REIS document. The Sierra Club felt that Sections 5.5 to 5.15 were deficient regarding the options to implement renewable energy technologies for the San Diego region. They recommend that an action plan should be approved for the region to penetrate the market with attractive economical and clean energy technology. The Sierra Club also felt that fuel cells were not given as much consideration as what they feel is warranted.

Response: The Authors feel that the report found the mid point of potential opportunity for implementing low, medium and higher levels of DSM, renewables and DG. Tactical plans and resource economics will likely dictate how much potential is actually realized. The recent allocation of CDWR contracts and their cost and purchase provisions, will also have a strong influence on how much of the resources are supplied and consumed. The State’s renewable portfolio standard will also have an impact on this. The market potential estimates only focused on regional (i.e., San Diego county, California-Mexico Border, Imperial Valley and Orange County) opportunities. Also, much analysis and consideration of fuel cells occurred, and while a break through may be possible, the authors, recognizing a long history of optimism regarding the maturity and growth of fuel cells which has not been realized, decided to take a conservative view of fuel cell potential. Also, the capital cost reduction of fuel cells is not viewed as significantly declining until the post 2015 period. In addition, The City of San Diego MWWD rightfully points out the high capital costs and limited market response to solar PV, and that there are some barriers to wide spread adoption to renewables in San Diego County. A lot of future deployment of renewable will depend on capital cost reduction, government incentives and the tactical plan that is developed.

4. A few commenters felt that the report underestimated the amount of energy efficiency renewable potential in San Diego County. (Greenpeace, Sierra Club) Reference was given to the vast geothermal resources in Imperial County and in North Baja. A substantial amount of wind energy potential was also said to exist in the California/Mexico border area.

Response: See previous answer.

5. Some commenters expressed reservations and had questions about the details of the pros and cons in creating a joint power authority before any decision was made about whether or not this would be a good solution to the region’s energy problems (City of Chula Vista, and SANDAG)

Response: Clearly more San Diego stakeholder investigation of this issue is needed, especially in light of the newly allocated CDWR power contracts and purchase provisions. Also, separate CPUC investigation into customer exit fees also need to be considered. There are pros and cons of joint action. Both successes and failures have been recorded with public control over utilities. There have been very good successes from BPA, LADWP, TVA, MLGW, JEA and others. Also, there have been some problems such as the Washington Public Power Supply System, and Philadelphia Gas Works – the largest municipally-
owned gas system in the US. Although there are data furnished by the American Public Power Association (APPA) that shows municipally-owned systems do have cost advantages—about 10% lower prices than investor-owned power, it appears that there are situational factors that contribute to success and failure. Also, it appears that some California municipals did not experience the super heated regional wholesale prices and market manipulations caused by some marketers in 2001. If anything, this speaks to the need for generation hedges to avoid similar market price volatility in the future. A major consideration now is what are the implications of the CDWR contracts, including their cost, terms and portfolio share represented for SDG&E. Also, the expiration schedule of the contracts is also an important question. When, as SDG&E reports, it has enough supply resources to meet area electric needs for up to ten years as they commented in their review of the Draft REIS, they should document this and the community should be engaged in evaluating the reasonableness of the contract provisions.

6. Some organizations felt that the treatment given to the Bi-national energy strategy was too limited and even somewhat ignored this important area. In particular, the pollution impacts of cross border power plant development is a key concern. In addition, a new EPA cross border air quality initiative was not emphasized which could help address cross border energy development solutions.

Response: The Authors agree that more attention is needed on the bi-national issues and opportunities. The emphasis on bi-national affairs was treated and addressed in a separate study by one of the project sponsors and only some of the findings were referenced. In the development of the upcoming energy strategy more emphasis should be placed on bi-national perspectives, resources and market opportunities. The possibility of joint project development and investment should be explored and deliberated, considering the renewable energy resource and central generation plant opportunities in North Baja.

7. A few commenters expressed a concern about the lack of recognition of the 1160 MW that is available in Mexicali that have some constraints in getting the power to San Diego. These plants in Mexicali should have been discussed more.

Response: It is correct that limited attention was devoted to the 1160 MW plants in Mexicali. The simultaneous import capability into San Diego County from these and other plants including imports from SONGS and the new CDWR contracts plus green energy power are all issues that need to be further investigated in the strategy for San Diego County. The REIS found that currently a maximum 2500 MW of power can be simultaneously imported from these plants and other resources outside of San Diego County. This constraint was imposed in the study. Clearly there are more power resources outside the county that can be imported (given other demand requirements) that may not be imported under current constraints. This is why we feel that a regional transmission study is needed that looks at the best way to optimize both local power plant development and transmission reinforcement. SDG&E says it already does this to some degree. But we feel that a grander, more comprehensive and integrated investigation is needed and that a broader range of criteria should be considered.


8. A comment was mentioned that the study should recommend “required close coordination of activities between energy and the non-energy related regional planning issues, such as water resources, waste management, water treatment plants, and other social needs for the region.” (Energy SC)

Response: The Authors believe that the report makes a strong recommendation for more comprehensive regional energy planning involving a wide range of stakeholders. This includes water, waste water, solid waste/bio gas, and other possible infrastructure providers. We agree with the League of Women Voters that consumer group representation should be included in developing the energy strategy and programs. All key planning assumptions, price forecasts, contracts, cost allocations and growth forecasts should be explored publicly and reviewed locally before decisions are made by remote regulatory bodies. Similarly recently submitted SDG&E green energy purchase portfolio provisions and the work papers on capacity allocations from CDWR should be identified and discussed in the community and a regional position should be presented on these matters well before decisions are made. Otherwise, a default and potentially suboptimal regional energy development path will occur with greater risks. The region has serious constraints to growth that need to be addressed.

9. Only a few comments were expressed about the study’s treatment of LNG. One commenter said that as gas prices increase over $3.60/MMBTU, renewables become more competitive. Another commenter expressed reservations about using more LNG to supply the region pointing out that the supply of gas will come from areas that have much political instability. The use of more LNG was viewed as not learning from our past in terms of being dependent on OPEC.

Response: LNG infrastructure projects are highly speculative at the moment. At least one LNG plant could be built in the next ten years. Potential risks from LNG or even other internationally imported energy sources need to be considered in light of the overall portfolio and the ability of the infrastructure to meet projected demand. The report sites some risk in basing a substantial amount of new power generation on natural gas as the primary fuel. The fact that LNG is being considered as a backup, should indicate the potential tightness of gas supply over the next ten years. After earlier drafts of this report have been completed, more reports and evidence were reported about potential natural gas constraints and price impacts. This should be a potential warning to the region to find options in its resource portfolio for meeting electric demand. Also, weather events and international crises could also increase gas prices in the short-term markets, which are used to balance supply and demand.

10. One comment pertained to the fact that the REIS report authors may not appreciate and know about the “incredible potential for power plant construction just south of our border.” (Greenpeace)

Response: The Authors are indeed aware of this potential. In fact, San Diego is located near a substantial amount of electric generation plant development – Palo Verde, North Baja, Pacific Northwest and Four Corners creates access to potentially huge power supply opportunities. But the transmission capacity has to be available – especially if the market and the state of California are not attractive markets at the present time to build new capacity. However, a careful
look at the CDWR contracts is needed to evaluate how much supply and at what cost these resources are available.

11. One commenter felt that the study failed to review the water desalination issue and the synergies with central power plants (EnergySC).

Response: It is recognized that the project did not devote much attention to the San Diego water desalination possibility. This study did not look at specific power development or transmission projects, which have to be evaluated at both regional and local levels. Instead, this project evaluated the mix of technologies based on their general characteristics, cost and performance. Desalination is growing in interest, such as a major project sponsored by the City of Tampa, Florida. The value of desalination projects are very site specific. We feel that water desalination project feasibility and economic attractiveness is best evaluated as part of a specific project feasibility study. The team also recognizes that water supply and imports into California is a great issue in the west and one that California needs to address – such as greater regional coordination issues on California use of Colorado River water supply. Water resource issues and cost of supply are a limit to growth that must be dealt with. Also, climate trends and implications on water supply need to be further investigated – especially for future power plants in the west. Serious drought conditions in the WSCC region occurred existed this past year in the very same areas where current and project major new power plant development has and is expected to occur.

12. Many comments pertained to the treatment given to DG. A reviewer wanted more coverage on micro grids (Energy SC), the possibility of wheeling power using the SDG&E system (EnergySC).

Response: A strong DG technology project team was assigned and used on this project. A substantial number of DG projects have been completed by this team in other forums. Near term DG opportunities are dependent on state incentives, interconnection and exit fees and other factors. Natural gas prices also need to be considered. DG can be very attractive for facilities with both thermal and electric loads – and even more attractive if a premium is placed on reliability. However, the cost implications of the CDWR contracts and price escalation issues need to be explored before one decides it is economic to rely heavily on DG.

13. A couple commenters wanted the study to investigate electric municipalization (Energy SC and the City of Chula Vista).

Response: Electric municipalization was not an objective of the project sponsors for the REIS.

14. Two commenters suggested that the energy development impacts on low-income groups and that there is a need for additional funding for energy efficiency pogroms targeted toward low-income groups is needed (RHA and Environmental Health Coalition). RHA suggested the need for an assessment of the impacts and needs of low-income groups in San Diego County.

Response: We agree with these comments in terms of considering energy development impacts on prices and on the communities where certain lower
income and ethnic groups reside are important issues. Since this project did not focus in detail on any one-development project, these issues were not investigated – although the team recognizes that there is a tendency to locate energy development facilities near lower income and ethnic concentrated communities. The Authors are also very concerned about the equity issues of energy development projects and the rate impacts of demand side programs including conservation and load management given the proportion of firm contract deliveries that are embodied in the CDWR contracts. As the regional energy strategy is developed, close attention to lower income community impacts of energy development projects and the rate impact of energy efficiency and renewable programs need to be considered.

15. One organization criticized the report as being too focused on electricity and natural gas. More attention should have been devoted to the overarching need to reduce energy cost and pollution (Technical Training Associates)

Response: The project sponsors clearly wanted the study to focus on electric and natural gas infrastructure, as well as on energy efficiency, DG and renewables. No other energy resources were included, except renewables.

16. One commenter suggested that the South Bay Power plant be torn down and that power lines along the east side of South Bay should be moved underground (Pacifica Companies)

Response: South Bay is scheduled to be removed in the latter part of this decade. Existing transmission asset conversions on specific sites was not a focus of the study.

17. A number of commenters offered specific policies, strategies and tactical programs to pursue.

Response: These types of recommendations are best left up to the sponsors and community as they move forward to developing the REIS strategy.

18. A couple of comments were made on the finding in the study that San Diego needs to develop at least two power plants over the next 8 years. Some challenged this finding saying that conservation, DG, renewables could avoid this. Greenpeace compared the REIS with the CPUC review of Valley Rainbow and its own conclusions – recognizing that the REIS findings included DG, Renewables and energy efficiency, which the CPUC review did not.

Response: The region could potentially get by without one or two new power plants if all the expected energy efficiency, DG and renewables were to occur in the medium or low growth scenario. However, reliability and market price issues for power could also be a concern. The goal of the regional energy strategy should be devoted to more than one objective – this includes reliability, economy of power prices, price stability, air quality and local self-determination as possible objectives. Given this, a diverse portfolio of energy resources should be considered. This is why two power plants over the next ten years were suggested. This does not seem to be an unreasonable assumption in a scenario.
approach. This provides the region options in case something happens with higher load growth or other resources do not get realized as expected.

19. A considerable number of comments were expressed about Valley Rainbow. Many commenters were supporters of the project (BIOCOM, local chambers of commerce, to name a few). A fewer number of respondents were against the project (Pacifica). Pacifica actually reviewed recent CPUC actions about the controversy surrounding the line and some inconsistency in CPUC decisions on the line. Pacifica felt that the REIS actually relied too heavily on SDG&E’s position justifying support for the line. SDG&E felt that the report gives contradictory or inconsistent support for the project, and that the Author’s of the project should take a stronger stand. In the review of the REIS energy balance tables and the CPUC regional forecast shown on page 50 of the proposed decision by ALJ Cooke, show that the region can actually get by without the project if more energy efficiency, renewables and DG were to occur.

Response: The main body of the report and executive summary are clear about the need for more transmission. It is valuable and needed. However, the report in general refrained from endorsing specific projects other than Otay Mesa, and possible repowering opportunities. Also, the report felt that there was time to make a final decision on new transmission and that a rush to judgment was not needed in the short term. The study is clear about the need for more transmission to the south, then north and then east. The region needs to improve the process of evaluating infrastructure right of way in advance of project requirements and the selection of land for infrastructure development.

Comments By Organizations and Treatment of Comments

1. Air Pollution Control District – we agree with all the major suggested areas of correction and the final REIS incorporated those changes.

2. Chambers of Commerce and Economic Development Authorities (i.e., National City Chamber of Commerce, San Diego’s Voice for Bi-National Business, East County EDC, Coronado Chamber of Commerce) -- all expressed strong support for Valley Rainbow. Comments were made by the chambers that the REIS and regional energy strategy needs to strongly support Valley Rainbow. The position of the REIS team on Valley Rainbow has been articulated above.

3. City of Chula Vista – did not agree with the recommendations on the construction of additional transmission lines, and the study's recommendations on additional power plants to be developed in the region. They believe that the study has not proven that future electric and natural gas requirements could not be met by efficiency and DG. Many questions were raised about the creation of a joint power authority. The Authors agree that more local investigation is needed on JPA’s and the community comfort and support or non-support on this issue. First, there is a need to evaluate the implications of the CDWR contracts. The Author also believes that the energy resource balance tables that appear in Chapter 6 present scenarios that show the implications and reserves, given the portfolio of resources that are assumed to exist.

4. The League of Women Voters – the future REIS draft should include a discussion on how future power prices will be set because it is not clear that future plants would lower prices. The LOWV believe that a discussion on how prices could be reduced and demand reduced would be valued. The SAIC
authors believe that this should be a major focus of the Energy Strategy team. The DSM assessment was based on avoiding more expensive costs and limiting rate impacts. The Authors also believe that the ten year impacts of CDWR contracts and other SDG&E resource supply decisions need to be evaluated at least every two years in a formal process, which can be considered in regulatory decisions in a routine and timely fashion. The CDWR contract rate impacts on the community also needs to be explored -- above what is reported in CPUC documents. The Authors also believe SDG&E does do regional energy development plans such as in the area of transmission planning, but much of this planning still appears to be somewhat narrowly focused and fragmented on a particular functional issue. Under the current regulatory makeup in the state, Integrated Resource Planning appears to be more relevant now than over the past 2-3 years. The CPUC should require this type of planning on a San Diego-wide basis taking into account the CDWR contracts. Local input on the resource portfolio and cost impacts should also be explored.

5. Environmental Health Coalition – Stated that all energy decisions must include an evaluation of the environmental justice impacts. REPAC should initiate a series of workshops in conjunction with community grass roots and assistance organizations. New energy development projects that impact local communities should not be developed where the energy is shipped elsewhere. There is a need to insure that the energy produced stays within the region. The region should refuse power that is produced from facilities that do not meet federal environmental laws. The San Diego region should fully fund and expand weatherization energy efficiency programs. A “just transmission” program for workers employed in the energy sector should be available that provides training programs for renewable energy jobs. The region should position itself as the “silicon valley” of advanced clean energy technology development firms. The aggressive promotion of renewables and energy efficiency should be pursued. The study should more clearly outline its assumptions used for estimating energy efficiency potential. There is a need for more public involvement and recommendations for a regional energy strategy. The Authors believe that these comments should be addressed in the strategy development and tactical planning phase.

6. San Diego Gas and Electric Company – extensive comments were received ranging from the comment that the “draft study remains a valuable addition to the on-going discussion of how to meet the region’s growing energy needs, in part because it reaffirms the assessment of most energy industry participants that more energy infrastructure is needed.” A major comment made by SDG&E is that the study is out of date because the draft study was written before the state made its final determination of the amount of power allocated to SDG&E from California’s long-term CDWR contracts. SDG&E goes on to say that “with that allocation complete, the San Diego region now has virtually no need for additional power for years to come, a situation that will require significant revisions to the current study…. The intent of the study was well meaning – to explore San Diego energy infrastructure needs, was well meaning. However, events have preempted many of the Draft Study’s conclusions and recommendations.” (Emphasis added). SDG&E went on to mention that the conclusions that the study should have reached are the following:

a. The region has sufficient energy available for years to come, as a result of the state’s recent allocation of power
b. Valley Rainbow should have been supported more strongly and clearly and developers of local energy infrastructure need support

c. Prudent planning requires a broad and balanced portfolio of new supply and infrastructure based on realistic assessments – the study is over optimistic on predictions about the amount of long term efficiency, DG and demand management

d. Infrastructure planners were excluded from most of the study’s development

e. Planning and support for energy efficiency is already occurring. Additional comments were made about making technical corrections to the report

It should be pointed out that during and throughout the project, SDG&E management and planning staff were consulted in the project. Very good and timely support in the form of responses to data requests and meetings to review report findings occurred as part of the review opportunities given to the project sponsors. In fact, there were at least four meetings with SDG&E, and three formal reviews of earlier project documents. After careful consideration, a number of modifications to the document were made in terms of factual statements. Also, it should be clear that the opinions and conclusions expressed in the REIS are those of the Authors and not necessarily those of any one stakeholder. Each review led to the Author and subcontractors to revise the reports based on factual suggestions. Additional factual comments were submitted in this fourth round and serious consideration was given to all comments. Moreover, a large proportion of the factual suggestions was incorporated from all the comments submitted, including SDG&E.

The Author’s response to some of SDG&E’s comments is the following:

1. Local energy planners and SDG&E should work more closely together with the public in developing the regional energy strategy in order to insure that recent developments in CDWR power plant allocations, cost allocations are understood. Right now recent decisions, additional cost allocation decisions are still being negotiated. Proposed orders on the cost allocations have been issued. However, there is still much misconception about what these recent decisions entail. The implications of these decisions need to discussed vis a vis the level and amount of DSM, renewables and DG that can be cost effectively invested in. There are low income and customer equity issues, price impact issues, local resource planning issues, and reliability issues that need to be explored. We feel that SDG&E and the community should jointly investigate these issues in an open process. Remote regulatory decisions do not necessarily bring about the public scrutiny that is required on such critical economic development and reliability issues.

2. SDG&E needs to address the possible inconsistency that there is enough electric capacity and supply for the region in light of the capacity allocations when it is not clear how much of the capacity and resulting energy will be able to be imported into the county. There are still simultaneous import restrictions of 2500 MW and later 3200 MW, plus power obligations from SONGS, SWPL and imports from Mexico. Simply
saying that there is 2900 MW in their comments on the REIS, and adding that this is enough capacity to meet ten years of future electric needs must be documented. This is a regulatory decision that bounds SDG&E and its rate payers for many years to come. The impacts of this decision should be discussed between SDG&E and those developing the future energy strategy for the San Diego region.

3. We agree with SDG&E that they and other energy developers should be much more actively involved in future deliberations. Senior executives of SDG&E should also participate in this process in the future. It should also be pointed out that SDG&E was heavily consulted and had tremendous opportunity to participate and engage project personnel during the project. The CAISO and CPA were contacted many times about the infrastructure issues. The Port of San Diego, CWA, and other plant operators and developers were also consulted.

4. SDG&E feels that the Authors were too liberal in their estimate of DSM, renewables, and DG and other commenters felt that the study estimates were too low. What is more important is that over time with periodic revisions, these estimates should be routinely revised in future study revisions. The action plan will be the real telling sign of what resources actually get delivered and become the bedrock of the portfolio. The Authors stand behind the estimates, and recognize that some of the resource potential is a stretch. This is why scenarios where developed and sensitivity analyses were completed.

5. The Author also feels that the overall process of screening, evaluating, and gaining consensus of local regional energy projects has to be improved.

The Author and subcontractors want to thank San DAG, SDREO, and the project sponsors for their guidance and support. We also wish to thank SDG&E for its furnishing of timely data and to discuss with the Authors key infrastructure issues. We also thank all the organizations and individuals commenting on the draft REIS. We found a rich set of perspectives, insights and some very good recommendations – many of which the Author agrees with. Also, we did give careful consideration to all the comments submitted.

To Summarize:

The Authors feel that the major issues facing the region are:

1. Careful review and evaluation of the electric supply portfolio, costs, risks and implications for portfolio development
2. An evaluation of how the CDWR contracts affect new project development like Otay Mesa, and other resource options
3. A comprehensive regional transmission optimization study is needed that considers a wide range of resources and costs
4. An integrated resource plan and strategy should be considered
5. New transmission appears to be needed in the future. The major uncertainty is when and what the local price and market impacts are to the region. A lot of
assumptions went into the results of the Valley Rainbow analysis and the real economic value depends on certain key assumptions occurring. Some of the results of Valley Rainbow analyses contract other regional ISO analyses on zonal or locational marginal pricing. These anomalies need to be explored.

6. A community-wide energy planning process is needed and the CPUC should encourage this in local regions as part of rate cases and future cost allocations.

7. A stronger cross border energy and environmental development process is needed.

8. Energy efficiency, renewables and DG do provide significant resource potential for the region. The amount of resource potential should be based on the avoided costs and rate impacts, given the newly allocated CDWR contracts and the proportion of the total SDG&E electric portfolio that its represents.