TECHNICAL
REPORT

Natural Gas and Israel's Energy Future

A Strategic Analysis Under Conditions of Deep Uncertainty

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Preface

This report assesses the opportunities and risks that the government of Israel faces in shifting to an energy mix that is increasingly dominated by domestic and imported natural gas. The goal of the analysis is to explore elements of robust strategies for exploiting the use of natural gas to minimize potential consequences from such risks. This report applies newly developed methods for strategic planning and decisionmaking under deep uncertainty for these assessments. The analysis also considers broader issues related to energy in Israel.

The funding to support this study was generously provided by the Y&S Nazarian Family Foundation in the interest of contributing to the further development of Israeli society. The intent is to do so by making objective analyses available to Israel's officials and to the Israeli public so as to support public-policy decisionmaking and to enhance the level of public discussion on such national issues.

This report will be of interest to decisionmakers and the staff of several offices of the government of Israel as well as its lawmakers. It will also be of interest to those wishing to understand how it may be possible for planners and decisionmakers to determine strategies and courses of action when all of the relevant information is not only unknown but, to a certain degree, unknowable. Finally, those both inside and outside Israel who have an interest in that country's energy, economic, and environmental future will find this report to be of value.

The RAND Environment, Energy, and Economic Development Program

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Summary

Israel has experienced considerable growth in the past two decades. Ensuring a sufficient supply of energy, particularly electricity, to meet the ever-greater demands of a booming economy is a national concern. Israel began to introduce natural gas into its energy mix only in 2004. This report is an examination of strategic alternatives available to Israel to make greater use of domestic and imported sources of natural gas in the future. We explore both natural-gas utilization and supply-infrastructure strategies in an environment characterized by extreme uncertainty and potentially large consequences.

The project was funded by the Y&S Nazarian Family Foundation and benefited from guidance by an informal government steering committee chaired by the director general of the Ministry of National Infrastructures (MNI), the relevant ministry for energy policy in Israel. This steering committee also included representatives from the following government offices and companies:

- the Prime Minister's Office
- Ministry of Finance
- Ministry of the Interior
- Ministry of Environmental Protection
- National Security Council
- Ministry of Foreign Affairs
- Electricity Authority
- Natural Gas Authority
- Israel Electric Corporation (IEC)
- Israel Natural Gas Lines Corporation (INGL).

Although the government of Israel was not formally the client for this work nor was RAND under contract to that government, the steering committee permitted a close association between the project and the senior government decisionmakers.

The benefits we worked to derive from this project included the following:

- applications of new, computer-based methodologies to provide an analysis of how different natural-gas strategies, policies, and infrastructures might enhance the robustness[1] of Israel's energy posture despite the prevailing uncertainties

[1] We use the word *robustness* in this instance to reflect the likelihood of any particular course of action to yield outcomes that are deemed to be satisfactory according to whatever criteria are selected for assessment across a wide range of possible

- an expandable modeling and analytical framework for energy analysis that may be further developed by RAND or others within Israel
- an examination of which factors among the many unknowns could have the greatest effect and therefore the largest influence over policy choices
- a guide for how whatever strategy may ultimately be chosen by Israel's planners may be modified in light of updated information and new circumstances
- a detailed external perspective based on objective analysis of Israel's choices that also draws from the international experience with natural gas
- a presentation of findings that are also intended to enhance the level of public discussion of issues relating to energy in Israel and with respect to natural gas in particular
- an example of a method for long-term policy analysis that may be applied in the same format to other issues of this character that Israel faces.

We conducted the analysis in two steps. In the first, we used computer modeling to search across thousands of scenarios to discover and improve strategies for the utilization of natural gas in Israel. We sought those strategies that, to the year 2030, would be low in total cost, in total emissions of greenhouse gases (GHGs), and in land-use requirements. We sought strategies that were robust enough to achieve set threshold values for these criteria across 1,265 alternative plausible future states of the world. We then applied the same process to the discovery of robust supply-infrastructure strategies for natural gas. In this instance, we searched for those strategies that would achieve low cost, avoid excessive depletion of domestic natural-gas reserves, and have low susceptibility to unmet demand in case of unintended supply cutoffs. We tested these strategies for their ability to achieve similar threshold values across a set of 5,000 different plausible futures. From this analysis, we were able to draw inferences about policy choices that would tend to enhance the robustness of natural-gas utilization and supply-infrastructure strategies.

Natural Gas In Israel

The discoveries in 1999 at the Noa and Mari-B exploratory concessions held by Delek Group consortia meant that, for the first time, Israel had discovered a significant domestic fossil-fuel supply. The government-owned INGL was established to build high-pressure gas pipelines. These first conducted natural gas to the power plants of IEC in 2004. Also, natural-gas pipeline shipments from Egypt to Israel began flowing in May 2008. Other potential sources of natural gas for Israel consist of new deepwater offshore discoveries, such as the Tamar find in January 2009 and Dalit shortly thereafter, possible further new shallow-water finds similar to Yam Tethys, importation in the form of liquefied natural gas (LNG), and possible new pipelines from other foreign sources.[2]

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future states of the world. This is in contrast to an optimal course of action that may achieve the best results among all possible plans but does so only under a narrowly defined set of circumstances.

2 LNG is often confused with natural-gas liquid (NGL), compressed natural gas (CNG), liquefied petroleum gas (LPG), and gas to liquid (GTL). The composition of LNG is distinct from these other natural-gas varieties. LNG is about 95 percent methane and 5 percent other gases. NGL is mostly composed of hydrocarbon gases heavier than methane, such as ethane, propane, and butane. LPG is 95 percent propane and butane. The composition of CNG is the same as pipeline-quality natural gas. Unlike pipeline natural gas, though, CNG is pressurized up to 3,600 pounds per square inch gauge

Natural gas is difficult to transport. Unlike petroleum and its derivatives, natural gas requires a large initial investment in infrastructure to carry it from its point of extraction to its point of use. The difficulty of transporting gas has a large role in its development and use in Israel. Natural gas is purchased by individual major Israeli customers in the power and manufacturing sectors contracting directly with the supplier. This contrasts with what has been the historical practice in most other countries, in which—at least in the early days of natural-gas use—there is one government or regulated private-sector purchase that then distributes gas to potential domestic users.

The biggest use for natural gas in Israel now and in the prospective future is in the electricity-generation system. In 2007, 69.6 percent of Israel's electricity was produced by coal, 3.2 percent by fuel oil (also referred to as *heavy oil* and known as *mazout* in Hebrew), 19.8 percent by natural gas, and 7.4 percent by diesel oil (that is, medium distillates, also referred to as *gas oil*, or *soler* in Hebrew). Plans by the government call for 40 percent of Israel's electricity to be produced eventually by natural gas.

A Framework for Weighing Alternatives Against Uncertainty

We created an analytical framework to inform many decisions that will need to be made to the year 2030, a period long enough that at least two generations of Israelis will be affected. This period is also long enough that the problem of how to deal with the myriad alternative paths the future may take is a serious concern. Therefore, our intent was to discover which strategies for natural-gas use in Israel appear most robust to uncertainties and surprises.

The logic of the analysis we present in this report is that it is not sufficient to optimize strategy for one assumed set of conditions in the presence of the deep uncertainty that surrounds long-term planning and analysis. Rather, the goal should be to seek those strategies that might not be optimal in any given future but are likely to prove robust. That is, they will achieve certain minimal criteria set by planners and the larger society across a wide range of plausible future states of the world. In this case, what we need from a model is not a prediction. As we systematically vary assumptions about factors whose future values are presently unknowable, we generate an ensemble of alternative futures purposefully constructed so as to act as a test bed for helping select among policy alternatives. In effect, we are now asking which uncertainties would affect our decisions today and how specific values of these presently uncertain factors might affect our choice among actions.

In this study, RAND researchers applied an innovative, quantitative robust decision method approach, *robust decisionmaking* (RDM), to long-term policy analysis.[3] Using the robustness criterion allows policymakers to understand more clearly the nature of their problem and the behaviors of its possible solutions. The goal is not to mechanize policy decisionmaking; it is to enhance our powers of observation and ability to draw insightful inferences.

(psig) and stored in welding bottle–like tanks. GTL is the process of converting natural gas to such products as methanol, dimethyl ether (DME), and other chemicals (Foss, 2007).

[3] More information on robust decision methods may be found, at increasingly technical levels of discussion, in Popper et al. (2005), Lempert et al. (2003), and Lempert et al. (2006). Another robust decision method is the Robust Adaptive Planning™ (RAP™) method developed by Evolving Logic.

It is convenient to categorize the components of an RDM analysis into four general classes. The first class represents the external uncertainties—the X factors outside the control of the planner or decisionmaker. The second group contains those factors that are under control by different government bodies and other actors in Israel—levers, or L factors. The third is the class of different measures (M factors) used to determine how closely the outcomes produced by candidate strategies under particular assumptions about future conditions come to meeting policy goals and criteria for goodness. The final set is the relationships (R factors) that tie the first three together. These represent either formal or informal models of cause and effect that determine how different actions taken in varying circumstances will lead to the outcomes they do.

Table S.1 might be viewed as a capsule summary of our report. It lists the factors that are specifically explored in the analysis to follow.

Predictions are not our end goal in an arena in which reliable prediction is not credible. Realizing that we cannot be sufficiently predictive, we seek some means to understand how we can choose today's actions most wisely in light of our long-term objectives. In this case, what we need from a model is not a prediction. We use a model to encapsulate our understanding of how the world works and to vary systematically the assumptions about factors whose future values are presently unknowable. This generates a large set of alternative futures purposefully constructed so as to act as a test bed for helping select among policy alternatives.

To implement this mode of analysis and apply it to Israel's choices about natural-gas use, this project built an entirely new analytical environment. We did so by using and integrating three different simulation models to analyze Israel's energy system. We then placed them within a software environment designed to support and automate the large numbers of simulations required. Figure S.1 provides a conceptual overview of the relationships between these models.

The three simulation models are the Model for Analysis of Energy Demand (MAED), the Long-Range Energy Alternatives Planning (LEAP) system for which we built a detailed model of Israel's energy economy, and the Wien Automatic System Planning (WASP) package. CARs™ is a computer program that automates operation of the simulation models and facilitates large numbers of simulations.[4]

Finding Robust Strategies for Natural Gas

We formed candidate strategies to be evaluated by considering the outcomes they produce when applied to each future state of the world in our test set. This produced a set of detailed scenarios. When we compare such results from all strategies, we may then draw conclusions about the relative strengths and weaknesses of each compared to the alternative strategies.

Each candidate strategy we used for evaluation of alternatives was framed in the form of a set of rules. In circumstances in which change is required but insufficient information exists to make modifications based on concrete analysis (as is most often the case in the real world), rules of thumb play a large role. Therefore, we constructed our strategies around such rules. Our approach was to craft an initial set of rather simple, rule-based strategies; simulate the scenario outcomes of these strategies; and then use these results to modify the strategies by adding

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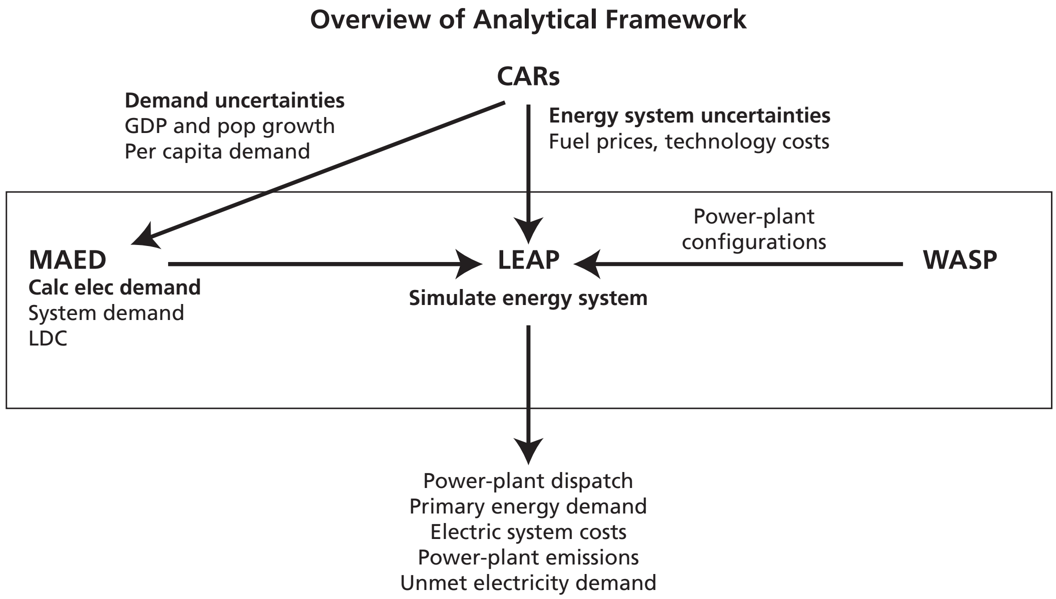
[4] The CARs software was developed by Evolving Logic, which provided access to it for this study.

Table S.1
Uncertain and Variable Factors Explored in This Analysis, Arranged by Factor Type

Factor Type	Description	Factors
X	Exogenous (outside of decisionmakers' control)	Price path for coal Price path for natural gas Cost of carbon dioxide (CO_2) emissions Cost of fossil-fuel technology Cost of non–fossil fuel technology Availability of non–fossil fuel technology Demand for electricity Cost of efficiency improvements Administrative limits on GHG emissions Cost of capital Supply from foreign pipelines Discovery of new domestic reserves Fixed cost of LNG installation Variable cost of LNG supply Fixed cost of new domestic natural gas Variable cost of new domestic natural gas Cost of storage capacity Cost of capital
L	Levers (within decisionmakers' control)	New plant type and primary fuel National infrastructure construction Level of reserve generation capacity (policy) Share of generation capacity from coal and nonfossil fuel (policy) Dispatch order of electricity generation Administrative control of GHG emission levels Administrative control of land use Imposition of price on carbon emissions Adoption of non–fossil fuel technology and capacity Energy-efficiency enhancement Target level of reserve capacity Rate of domestic reserve depletion Level and timing of LNG capacity Fuel storage types Fuel storage levels
R	Relationships among factors	WASP package MAED LEAP system RAND natural-gas supply model
M	Measures used to gauge success	Total system costs Total fuel costs Balance of cost-sharing over generations Annual natural-gas supply requirement GHG emissions Land-use requirements Level of reserve generation capacity (actual) Share of generation capacity from coal and nonfossil fuel (actual) Depletion of domestic reserves (actual) Cost of providing a given level of supply insurance Cost of implementing supply insurance Potential unmet demand for electricity

NOTE: Each list of factors is divided into two sections. The first section of each list corresponds to the first of our two main research questions: What is a robust strategy for the utilization of natural gas in Israel through the year 2030? These pertain to the discussion presented in Chapters Five and Six of this report. The second section of each list is factors that are key to finding answers to the second question: What is a robust strategy for ensuring the supply of natural gas at the levels required to support the chosen utilization strategy? This question is treated in a separate analysis of natural-gas supply security that is presented in Chapter Seven.

Figure S.1
Conceptual Diagram of Main Model Modules Operating Within the Computer Assisted Reasoning System Environment



NOTE: GDP = gross domestic product. CARs = Computer Assisted Reasoning® system. LDC = load-duration curve.
RAND *TR747-S.1*

more sophistication and introducing new strategy types. Those strategies whose results were completely dominated by the results of others were dropped from the set.

We went through several generations of strategies following these basic forms:

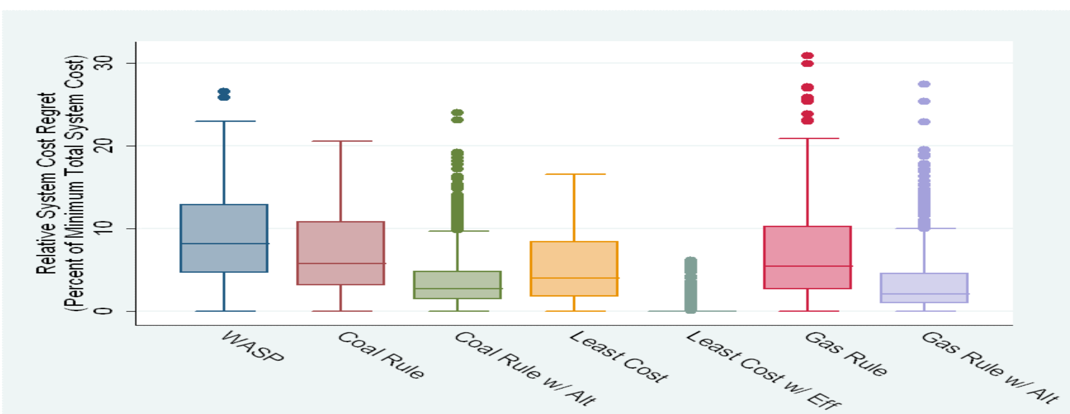
- *WASP Strategy.* This strategy serves as our reference strategy. It is an energy plan that emerges from the WASP optimization-model program when it is given a set of assumptions on demand and costs that correspond to the planning assumptions used by the MNI. As such, it alone among the candidate robust strategies is not rule based and was never modified.
- *Coal Rule Strategy.* The essence of this strategy is to carry forward a program that will add new coal-fired generating plants to provide the electricity base load for reasons of cost, the relative certainty of primary-fuel supply, and the need to ensure that the integrity of the national grid is maintained. Natural gas–fueled facilities are also added and assumed to be used during those times and conditions when it is economically efficient to utilize natural gas.
- *Least Cost Strategy.* When observation of reserve margins and peak power percentages triggers a new plant building decision, the strategy's algorithm will observe the relative cost of the available generating technologies—coal, natural gas, and solar thermal (as well as pumped storage)—and choose the one that produces electricity at the least cost.
- *Gas Rule Strategy.* Like the Coal Rule strategy, Gas Rule uses the reserve margin and fraction of peak power capacity as triggers to add new capacity. It does so by adding natural gas–fueled combined cycle (CC) plants (NGCC plants) and combustion turbines (CTs) but includes an option to build one new coal plant if the cost of building and operating a coal plant is less than that for an NGCC plant.

These basic-form strategies were varied by setting triggers (e.g., caps on GHG emissions, desired share of generation coming from coal) using different sensitivities to components of costs; varying the level of costs that triggered shifts between generation technologies; employing alternative, nonfossil fuels; determining whether policies to enhance efficiency were employed to reduce demand; and so forth.

The main test suite of alternative strategies included the WASP reference strategy and two detailed forms of each of the three other types. Each of these seven strategies was applied to 1,400 alternative specifications of future conditions (e.g., natural-gas prices, electricity-demand growth, cost of alternative non–fossil fuel technologies) This yielded a set of 9,800 detailed scenarios tracing development of Israel's electricity-generating sector through the year 2030. We examined the results from several perspectives. Figure S.2 shows the distribution for each of the strategies of the 1,400 results in terms of present value (PV) of total system costs in the period 2021–2030, when there is a good deal of variation in the energy infrastructure that will have resulted from applying the strategy. The midpoint of each box is at the median value among the full 1,400 for that strategy. The vertical axis shows the regret for following the particular strategy under the individual scenario conditions. This is the difference between the actual outcome (in this case, the net PV of total costs for the last decade in the analysis period) and the least-cost outcome (that is, the result we would have achieved if we had complete foreknowledge of future conditions and had therefore applied the optimal strategy for those conditions).

Except for several outlier scenarios, the WASP strategy has the highest mean relative system-cost regret, followed by the regret plot resulting for the Gas Rule strategy. Those scenarios that would favor the former would be unfavorable to the latter and vice versa. Those strategies

Figure S.2
Relative System-Cost Regret (PV) of Candidate Strategies, 2021–2030



NOTE: Coal Rule_Alt = Coal Rule strategy with alternatives. Least Cost_Eff = Least Cost strategy with efficiency. Gas Rule_Alt = Gas Rule strategy with alternatives. A box-plot chart is read by viewing the horizontal rule within each box as marking where the median value (50th percentile) in the distribution falls. The upper border of the box is set at the value that corresponds to the 75th percentile, while the lower border of the box is set at the 25th percentile. The whiskers extending above and below the box (if any) incorporate the points of the distribution that are furthest from the median value that fall outside the interquartile range described by the bounds of the box. This line is extended up to 1.5 times the length of the interquartile range from the closest box border. Any points of the distribution that lie beyond this whisker extension would be plotted individually as outliers.

RAND *TR747-S.2*

that include possibilities for demand-efficiency enhancements and the use of alternative generation technologies have the lowest regret, both relative and absolute, in general.

Figure S.3 shows natural-gas demand in the year 2030 in billion cubic meters (BCM) of natural gas per year. The current domestic supply source will become depleted in the early part of the next decade. The median value for all of the strategies is well above the 7-BCM capacity of Israel's current sole foreign-source pipeline, so, in the majority of scenarios, Israel would need to develop additional supply from newly discovered domestic sources, a new international pipeline for supply from some other country, or LNG facilities to make up the balance.

The simulations track pollutants emitted during the course of a year from each generation plant. Figure S.4 shows, in aggregate, the scenario outcomes for emission of GHGs. The range of outcomes is wide indeed. In some scenarios, in which there is no price attached to CO_2 emissions, increases approach 250 percent greater than the 2005 emissions in futures, in which coal is quite inexpensive. A broad finding from this result, particularly when compared to the cost-regret outcomes, is that it is not possible to look at any single metric to evaluate the relative performance of alternative candidate strategies. Each has positive behavior according to some measures while registering more-disappointing performance in others. This having been said, those strategies incorporating efficiency-enhancement measures and the possibility for use of non–fossil fuel technologies generally show less problematic outcomes across the various performance measures than do the others. This is despite being vulnerable to the additional uncertainty of the (possibly high) cost for achieving these efficiencies and employing the alternative fuel technologies.

Seeking a Robust Course for Israel

The analysis showed that strategies vary in vulnerability to certain conditions and that they have different relative strengths with respect to performance criteria of importance to Israel.

Figure S.3
Annual Natural-Gas Demand in 2030

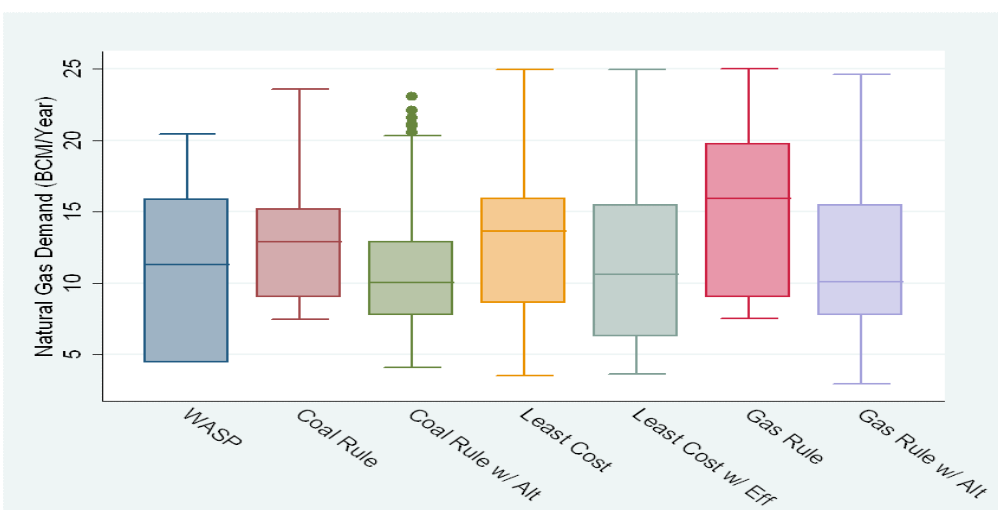


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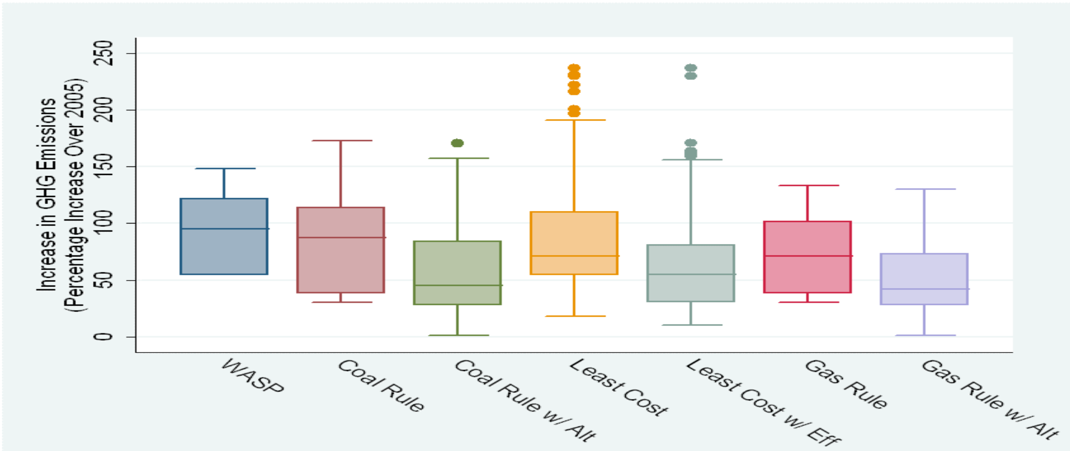
Figure S.4
Increase in Greenhouse-Gas Emissions in the Year 2030 over 2005 Levels



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No one strategy unambiguously dominates the others. We therefore identified threshold values of what would be acceptable with respect to three important measures:

- *System Costs.* If the regret of a scenario outcome with respect to PV system costs in the last ten years of the study period (2021–2030) is within 5 percent of the costs for the zero-regret strategy or strategies, then this is considered an acceptable outcome.
- *GHG Emissions.* Our analysis shows that it would be difficult and would require extraordinary circumstances for Israel to cease the increase of its GHG emissions over the term of this study. If a scenario yields an outcome of GHG emissions by 2030 no more than 25 percent greater than the emissions recorded in 2005, the last year for which we had complete information, it is deemed successful.
- *Land Use.* The land-use metric contains two criteria. The first is whether the average land use required for comparable output of electricity by the installed capacity called for in a scenario is greater in 2030 than that currently found in Israel. If so, then the scenario fails. In addition to the intensity criterion, the second criterion relates to the total size of the area actually required to support the electricity-generating infrastructure. The threshold level will be to have an infrastructure footprint no than more than 50 percent greater than the smallest footprint achieved by any strategy under the same conditions.

Figure S.5 summarizes the behavior of each strategy with respect to the criterion thresholds across the full set of test scenarios.[5] As may be readily seen, across all strategies, it is the emission criterion that leads to the greatest share of unsuccessful scenario outcomes. For the cost-threshold criterion, while the Least Cost_Eff strategy meets this criterion measure in nearly 100 percent of the scenarios, the same strategy without the demand-management component (Least Cost) does so far less frequently, in only 59 percent of the scenarios. Note

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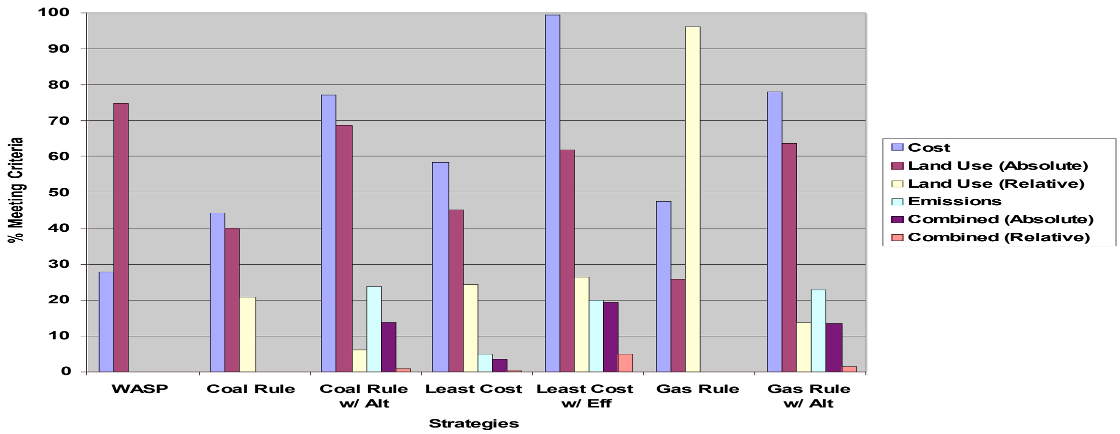
[5] We report two forms of the combined land-use criteria. In the first instance, Land Use (Relative) (and therefore Combined [Relative]) uses the relative measure of land-use footprint we have described. We also analyzed a second form that sets an absolute cap of 8,100 MW (megawatts) of new installed capacity in the form of main natural-gas power-generating plants, Land Use (CC) (and therefore the Combined [CC] result).

Figure S.5
Percentage of Scenarios in Which Each Strategy Meets Metric Criteria



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that, under the most restrictive form that combines the results for all three criteria (Combined [Relative]), in the best instance, only one strategy meets all three objectives in even 5 percent of scenarios.

Three strategies—Coal Rule_Alt, Least Cost_Eff, and Gas Rule_Alt—consistently dominate the other four strategies with respect to each of the three criteria. Interestingly, the addition of the efficiency and alternative-energy component to each of these former strategies allows them to display a higher share of success scenarios than the Least Cost strategy under the cost criterion.

There is an important point to bear in mind before drawing conclusions from these findings. These views show only an aggregate view of strategic performance by use of scenario outcomes. It would be an error, however, to look only at raw percentages as shown in Figures S.2–S.4 and draw final conclusions about robustness. To be sure, this level of analysis does provide some valuable insight into strengths and weaknesses. But the implicit assumption behind statistics such as these is that all possible future sets of conditions are of equal interest and importance. We need to move in a direction that will allow us to better understand precisely which conditions and which scenarios lead to the principal failure modes for each candidate strategy, the better to judge which strategy might best serve stakeholder interests.

We use data-mining techniques to conduct an analysis of failure conditions for each strategy. Using the results, we take the three best-performing strategies from the original set and modify them so as to perform better under conditions that would otherwise have proven challenging for the strategy in its unmodified form.

- *Least Cost_Eff (Modified).* This strategy continues to follow the Least Cost rules and employs efficiency-enhancing measures as well. However, if conditions warrant, it may choose to retire one or two coal-fired generating plants.
- *Gas Rule_Alt (Modified).* As with the Least Cost_Eff (Modified) strategy, there is now the option of retiring one or two coal-fired plants. In addition, this strategy now pays more attention to the costs of introducing alternative-fuel electricity sources before doing so.

Finally, in the year 2021, if conditions for natural gas prove too costly, the strategy ceases to employ the Gas Rule approach and instead employs the Least Cost strategy rules.

- *Coal Rule_Alt (Modified).* The strategies of the Coal Rule family by design already have a certain level of safety-valve mechanisms encoded in their operational algorithms. The only modification we have introduced is to make the decision about investing in alternative-fuel capacity cost sensitive.

Table S.2 shows the combined results of testing the three new modified strategies, as well as their corresponding unmodified forms, in each of the 5,000 test futures and applying the same thresholds we used previously.

The effect of introducing relatively simple modifications to the base strategies to permit more-adaptive behavior appears to be large. Whereas previously the base form of Coal Rule_Alt was successful in only about 2 percent of the cases with respect to all three metrics, the success rate has been enhanced sixfold after introducing the modification. The change is even more dramatic in the case of the Gas Rule–form strategy. The performance increases from about 2 percent success across all the scenarios to 36 percent. The change for the Least Cost_Eff (Modified) strategic form is less dramatic than this but still nearly a sixfold increase in success. The modified form of the Gas Rule we have tested in this analysis emerges as the most interesting candidate to form the basis of a robust approach to framing Israel's natural-gas utilization strategy.

The point is not that Israel should adopt our test Gas Rule plan as its approach to national planning for the use of natural gas. Rather, it is to demonstrate that this rather simple-minded approach within the parameters of the model we developed can meet the objective criteria set for it in nearly 40 percent of the deliberately widely ranging scenarios we have simulated. It does so with only the most limited of foresight capability and only rudimentary rules for plan switching. This suggests that a more detailed adaptive approach, adding such elements as prospective land-use planning for energy on a national level, cost tracking focusing on key elements of cost, and emission monitoring and enforcement, could be the means for constructing implementation-ready, adaptive energy solutions that would guide the utilization of natural gas and meet at least three of the four criteria we have utilized to characterize scenario outcomes.

Table S.2
Percentage of Scenarios in Which Each Modified-Form Strategy and the Wien Automatic System Planning Strategy Meet the Metric Criterion Thresholds

Strategy	Cost	Land Use (Relative)	Emissions	Combined
Coal Rule_Alt	77	7	24	2
Coal Rule_Alt (Modified)	67	21	18	12
Least Cost_Eff	99	26	20	5
Least Cost_Eff (Modified)	99	54	39	27
Gas Rule_Alt	78	14	23	2
Gas Rule_Alt (Modified)	94	96	39	36

NOTE: Red indicates that the strategy meets that criterion threshold in fewer than 10 percent of the scenarios. Orange indicates that the strategy meets that criterion threshold in 10–30 percent of the scenarios. Yellow indicates that the strategy meets that criterion threshold in 31–75 percent of the scenarios. Green indicates that the strategy meets that criterion threshold in more than 75 percent of the scenarios.

Robust Supply-Infrastructure Strategies

What level of natural-gas supply may be planned without compromising the desire to also minimize exposure to risk in the supply of this fuel? We examine what would be required to meet demand under the most natural gas–intensive strategy, Gas Rule_Alt (Modified).

We constructed a further model based on our previous analyses of Israel's future natural-gas use, the behavior and requirements of the strategies for meeting demand, and now adding the possibility of sudden shortfalls in supply. The purpose is to explore answers to three main questions:

- What infrastructure is needed to meet Israel's long-term natural-gas demand and at what cost?
- How rapid would depletion of natural gas from new domestic reserves need to be?
- How robust can Israel be to changes in future deliveries of natural gas through foreign import pipelines?

We assessed four different strategies for natural-gas infrastructure development that assume that new gas supplies could come from new domestic deepwater (DDW) sources and from an LNG terminal. The model we used is designed to be expanded to consider other sources. The DDW Only strategy tries to supply all future gas demand from such reserves. The two versions of the Joint DDW/LNG strategies simultaneously build supply capacity from the DDW reserves and construct an LNG terminal but differ in how they operate. In the Joint DDW/LNG (LNG Priority) strategy, natural gas is supplied first from the LNG terminal up to its capacity, and then any residual demand is supplied from DDW sources. In the Joint DDW/LNG (DDW Priority) strategy, the converse is true. Finally, the DDW Then LNG strategy builds capacity at the DDW reserve first up to a limit and then builds an LNG terminal when needed.

The model was evaluated for six different levels of demand over the period to 2030 by selecting specific scenarios from the test set utilized in performing the prior analyses. In each of these scenarios, the Gas Rule_Alt (Modified) natural-gas use strategy was run against a set of conditions selected to elucidate the types of infrastructure configurations needed to satisfy different levels of demand. These demand paths varied from requiring less than 7 to more than 25 BCM per year by 2030.

If the issue were only security of supply, it would not be so challenging. Costs of natural-gas supply and insurance of that supply also come into play. We again scanned across many scenarios to better understand the balance of cost and benefit. Using the RAND natural-gas supply model developed for Israel, we drew a sample set of 5,000 alternative possible future sets of conditions by varying assumptions about demand for natural gas, the fixed and variable costs peculiarly associated with fuel coming from DDW or LNG sources, the discount rate, and the amount of natural gas supplied from foreign-source pipelines. We also varied policies setting an explicit level of desired reserve capacity through different combinations of LNG and DDW investment, storage of natural gas in reservoirs, and storage of diesel as a switch fuel. We then examined the outcomes for each of the four supply strategies against each of the 5,000 alternative sets of future conditions. In doing so, we explicitly added costs of insurance to the cost of supply of natural gas.

We evaluated the outcomes with regard to several criteria and again established minimally acceptable thresholds for each:

- *Supply-System Costs.* Strategies that achieve these minimal thresholds across many alternative future states of the world and across several measurement criteria are termed as being more robust than those that fail to do so. Specifically, we set the cost threshold as being within 5 percent of the result shown by that strategy among the four that generates the lowest supply-system costs for that set of conditions.
- *Depletion of Domestic Reserves.* The threshold for DDW depletion we set at a total of 105 BCM through the year 2030.
- *Potential Unmet Demand.* For the criterion of being able to meet demand for natural gas, if the policy-specific target level for being able to replace a share of foreign supply has not been met and electricity generated from natural gas cannot be supplied at the target level, the outcome is considered a failure.

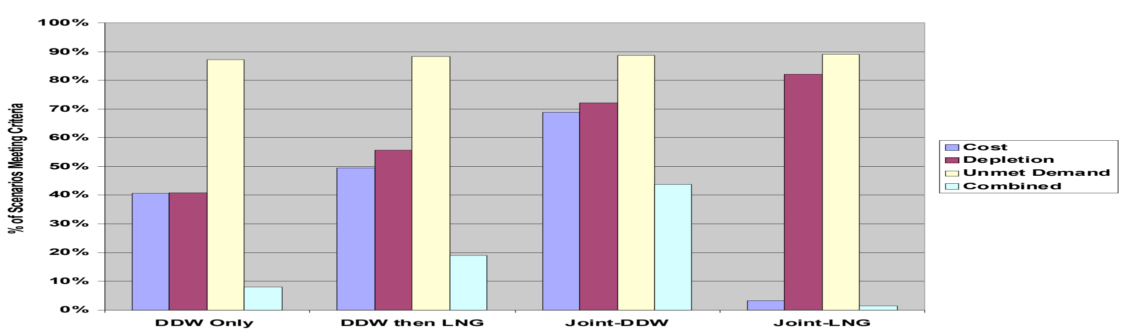
The results are shown in Figure S.6. For each of the four approaches, we calculate the share of scenario outcomes that meet the individual criterion threshold as well as the share of scenarios in which the strategy meets all three thresholds. As before, we note that this analysis treats all scenarios as being equally probable. It also does not weight the relative importance of the three criteria for assessing successful outcomes.

But, a further question yet remains. We have discussed only the costs of normal supply and for obtaining a certain level of insurance. But, if there is a need to actually make use of the supply-security assurance measures, how do the strategies compare? That is, what if Israel needed not only to pay the cost of an insurance policy but the deductible associated with each strategy as well?

To generate results, we imposed a one-year shutoff of all supplies through foreign pipeline sources in 2025. This was also the year in which several coal-fired power plants were retired under several of the demand scenarios we used for this analysis and the test bed of supply scenarios uses the Gas Rule_Alt (Modified) natural-gas utilization strategy. Therefore, the shock to supply comes at a particularly stressful time.

Further analysis makes clear that what drives both basic supply-insurance and emergency-supply costs is the ratio of costs uniquely associated with the LNG supply chain when com-

Figure S.6
Percentage of Scenario Outcomes Meeting Relative-Cost, Domestic Natural-Gas Depletion, and Supply-Reliability Criteria



RAND *TR747-S.6*

pared to those for DDW-derived natural gas. Therefore, the core issue becomes less one of how well each strategy will perform under varying assumptions about the probability of a year-long supply disruption than about how well they will perform under varying assumptions about the relative average supply costs.

This point is demonstrated in Figure S.7. It shows an expected relative regret in total cost for each strategy when faced by conditions represented by different price ratios. The choice among different supply strategies depends crucially on assumptions about the ratio between the unique costs associated with the alternative natural-gas supply sources. If cost were to be the only consideration, then choosing the Joint DDW/LNG (LNG Priority) strategy would imply a belief that the LNG/DDW cost ratio will be at the extreme low end on average. On the other hand, opting for the DDW Only approach would require holding the belief (and placing the bet) that this ratio will instead trend toward the high end of the range. Note that, if one had certain knowledge about what the price ratio would turn out to be, there is almost no level at which DDW Then LNG would be the optimal (minimum expected regret) strategy. On the other hand, if we truly did not have strong confidence in being able to predict this average ratio and instead viewed the likelihood of each value level as being uniform, it is precisely DDW Then LNG that suggests itself as a candidate robust strategy. Although it is rarely if ever the strategy that provides minimum cost under the prescribed conditions, it almost always runs second best throughout the range, and its failure tends to be more graceful in terms of cost than the other candidates.

This does not necessarily lead to an endorsement of the DDW Then LNG supply approach for Israel. There is also the question of what is passed on to future generations beyond the year 2030, the potential value of the security that comes from possessing a domestic natural-gas reserve, and the still-unresolved question of whether Israel truly would be able to draw on reserves as large as those required under some scenarios.

Figure S.8 encapsulates scenario outcomes for demand in a manner similar to that for expected relative regret with respect to cost. This time, the question is the level by which any DDW or other additional reservoirs must be depleted by 2030 if a given strategic course is followed. Whereas, in the discussion of cost differentials, it was price ratios that proved the key drivers, in this instance, it is the level of demand. We see a clear ranking of alternatives with

Figure S.7
Expected Total-Cost Relative Regret of Four Natural-Gas Supply Strategies: Liquefied Natural Gas/ Domestic Deepwater Premium Cost Ratio

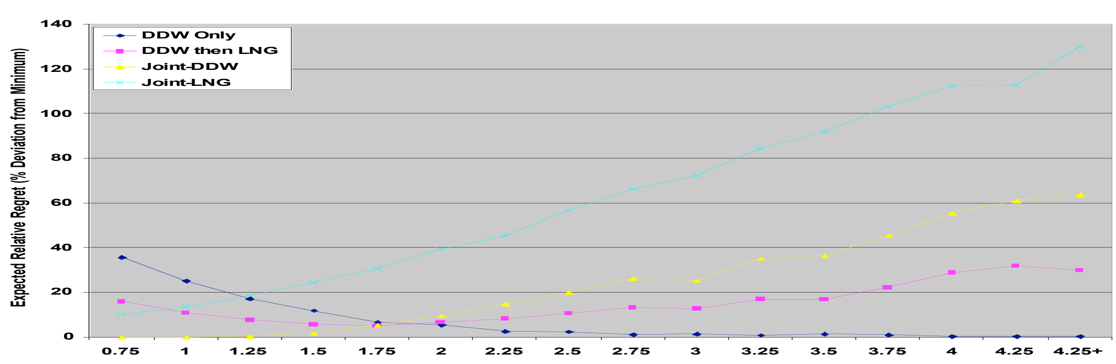


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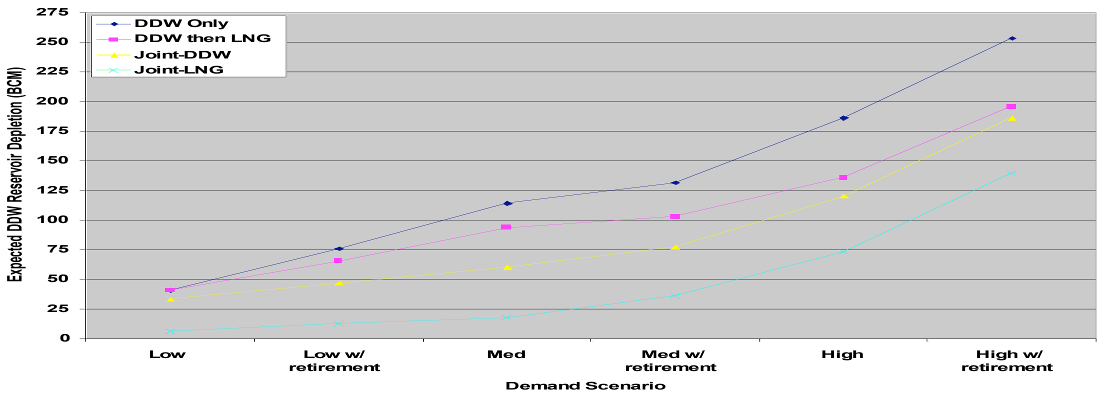
Figure S.8
Expected Domestic Deepwater Reservoir Depletion of Four Natural-Gas Supply Strategies: Level of Natural-Gas Demand



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no switches of the type we observe with respect to cost. The cost-versus-depletion trade-off is made clear when this ranking is compared with the cost trajectories shown in Figure S.7. The DDW Then LNG strategy is by no means the most favorable when measured in this dimension. Bear in mind, however, that these results are for demand scenarios evolving from the most natural gas–intensive use strategy. If we were to allow the possibility of other natural-gas utilization strategies than the one we have fixed by selecting the six demand scenarios, in the highest-demand region of this figure, the depletion would likely be tempered by the building of a second LNG installation or the construction of a coal-fired plant, depending on other circumstances.

These views provide decisionmakers with a concrete description of what the trade-offs are and what drives the differences between approaches. A political decision could be made about priorities among different objectives because, in the final analysis, the actual policy will result from political processes, political discourse, and political trade-offs. This is as it should be. What is valuable about views such as those shown in Figures S.7 and S.8 is that they provide a framework for establishing what ought to be the appropriate political trade space within which these discussions should occur.

Conclusions

As an independent research effort, we sought to develop an analytical framework that is extensible and that could be easily amplified by further input from those formally charged with the task of planning and developing Israel's energy future. Our emphasis was on tool building. In exercising these tools, we have explored what measures would be to Israel's greatest advantage in achieving a future profile for natural-gas use that reduces its people's exposure to vulnerabilities and risks. The following suggestions emerge from our analysis. These findings should not be viewed as conclusive but rather as indicative of areas for Israel's planners to explore in greater detail in exercising these tools:

- Demand management is Israel's first line of energy security.

- Israel should use current planning techniques to make decisions on capacity additions through 2015. For the period beyond 2015, a new major assessment of future demand and needs should be initiated using adaptive planning methods. Steps should be taken now to put that planning process in place.
- Israel may primarily invest in NGCC power plants, provided that sufficient supply may be ensured to fuel these plants.
- Israel should take delivery of contracted volumes of gas through its foreign supply pipeline and consider new contracts up to the pipeline's physical maximum, if this natural gas is competitively priced.
- Israel should prepare implementation (e.g., planning, regulations, design, contract formats) for an LNG terminal but could delay construction and first exploit newly discovered domestic sources.
- Israel needs to maintain a diversified mix of fuels for generating electric power. Israel should also invest in solar-thermal electric power plants or use solar thermal to preheat steam for fossil fuel–fired power plants.
- Israel's guidelines on the minimum threshold for electricity generated by coal should be reviewed to consider including other indigenously available, relatively secure means of generation, such as solar. The threshold levels should be evaluated from a total system perspective, including a more detailed study of the possibilities of load shedding at high levels of natural-gas use.
- The Israeli government should regulate the wholesale and retail prices of domestically produced natural gas on the basis of the cost of imported gas and to ensure an attractive rate of return for domestic producers.
- Israel should guard against disruptions in natural-gas supplies by storing sufficient quantities of diesel to smooth possible future supply disruptions.
- Israel should complete construction of the inland natural-gas supply pipeline, parallel to the existing offshore coastal pipeline.

The principal value this report presents is a detailed understanding of what are favorable future environments for Israel and, perhaps more importantly, what factors would lead to futures that are undesirable in light of Israel's goals and interests. We have demonstrated what actions and means would be to Israel's greatest advantage in achieving an energy future that reduces its people's exposure to vulnerabilities and risks. The following suggestions for the nation's planning process emerge from our analysis:

- Planning based on observation, well-defined priorities, and goals and that is advanced by means of rules designed to implement preapproved, flexible responses to updates in the available information can enhance robustness.
- We have quantified the dynamics of various trade-offs that planners face and provided an indication of where well-hedged positions among the various goals may be found.
- Three types of information may be developed from our findings and subsequent, more-detailed RDM analyses. These are *signposts* (indicators that may be monitored for early indications of conditions that may prove either favorable or unfavorable), *hedging* actions that provide some level of insurance against unfavorable consequences, and *shaping* actions (active measures taken to enhance the likelihood that conditions will remain or will become conducive to the plan).

Demand Management Is Israel's First Line of Energy Security

The most effective shaping action Israel could undertake is to institute policies that will enhance the efficiency of Israel's energy use. We found that almost all of the failure scenarios occurred when growth in demand was high. Even with important new discoveries of domestic natural gas offshore, the amount of this fuel required to meet demand in these energy-hungry futures raises serious questions about where the necessary fuel will come from. In addition, the relatively modest criterion for achieving success in controlling emissions of GHGs is very difficult to achieve even for natural gas–intensive strategies under high demand-growth conditions.

Data from our simulations suggest that a reduction in electricity demand that results in 1 percent less electricity consumption in 2030 will cause a 0.57 to 0.58 percent decrease in the PV of system cost between 2008 and 2030. Similarly, based on the mean estimates for the Least Cost strategy, a 1-percent reduction in 2030 electricity demand will cause CO_2 emissions to be 0.79 percent lower in 2030. Enhancing efficiency would have a large effect even on the narrower question of the level of natural-gas use for which to plan. *Steps taken to affect this factor of demand are among the highest-payoff actions that the government of Israel could take in the realm of energy policy.*

A Diversified Fuel Mix Enhances the Robustness of Strategies

The Gas Rule_Alt (Modified) strategy would potentially require the greatest supply of natural gas. But it also appears as the candidate most likely to possess the quality of robustness we had been seeking to discover. The fundamental thrust of the Gas Rule strategies is that natural gas be made the cornerstone fuel for generating electricity in Israel over the next two decades. The emphasis on natural gas in the highlighted strategy should not be understood in isolation from the rest of Israel's electricity generation and energy system. Only the heavily modified form of the strategy achieves an appropriate level of apparent robustness. This strategy presumes that Israel will adopt policies to enhance the efficiency of electricity consumption. It also presumes Israel will build the maximum level of alternative (nonfossil) fuel plants consistent with both availability and the underlying economics of doing so.

Simply to add natural-gas facilities without other measures could easily be cause for future regret. The final form of the Gas Rule that we examined implies that *Israel should seek a diverse set of primary-fuel types*. Natural gas is present in successful scenarios, but so is coal, diesel for backup and peak generation, and, importantly, as much non–fossil fuel technology as the system can take on given the realities of cost and availability. This is a point we would like to emphasize: *Implementing policies that maximize both efficiency improvements and utilization of non–fossil fuel alternatives makes as great a difference to final outcomes as any choice of base fuel.*

Accelerating the Use of Non–Fossil Fuel Alternatives Is Especially Critical for Israel

In contrast to the shaping strategy of increasing energy efficiency, diversification of fuels provides a hedge against potential risk. Our analysis shows that an indifference to costs when investing in nonfossil energy sources may lead to serious failures. But this is largely an artifact of the deliberately simplistic approach displayed in the earlier forms of our rule-based strategies. The planners for Israel are more than capable of detecting the signs that the technology and economics in the market for alternative energy are not fulfilling their hoped-for promise. We find the dangers of failing to exploit the potential of this avenue greater than the likely costs of doing so.

Natural gas will be a good fuel for Israel in meeting its needs for the immediate and longer-term future. Our analysis repeatedly shows, however, that overreliance leads to vulnerabilities in several dimensions. Israel should continue to accelerate its exploration of non–fossil fuel alternatives to provide a robust foundation to its renovated energy infrastructure.

Israel Should Plan for an Adaptive Course

It is the inherently flexible and adaptive character of the Gas Rule_Alt (Modified) strategy, more than any single element, that allows it to be successful across a wide range of future conditions. This suggests a useful approach to planning the construction of Israel's future energy infrastructure. We recommend that Israel take an approach that lays out goals and guidelines, criteria for success as well as rules for the road as short-term decisions need to be taken. Most important would be to set guidelines for the indicators that are to be monitored and the basic courses of action that will be taken depending on the values these indicators may take. Previously drafted adaptive changes may be introduced into actual energy-infrastructure build plans when conditions warrant.

As a practical matter, Israel might do well to consider a two-step approach to its planning for energy. The first step would be to plan for the period to 2015 in a traditional fashion. At the same time, a set of signposts, flexible responses, and archetypal plans would be prepared within a comprehensive planning framework. Then as 2015 (or a similar target date) draws close, these materials may be used to fashion the more-adaptive plans, policies, and procedures for the following period. This incremental approach can be further divided into smaller time periods as appropriate and comfortable within the planning institutions.

Regulatory Issues Affect Natural-Gas Planning and Are Affected by Analytical Outcomes

Our analysis focused on aggregate outcomes on a year-by-year basis. Deriving more-definitive implications for regulatory issues would require more-detailed analysis and modeling. We offer the following notes as a guide to what implications our analysis may have for discussions about natural-gas regulation.

It is clear that, in order to encourage the level of capital investments necessary to achieve the level of natural-gas use promised by recent domestic discoveries, transparent licensing and permitting regulations should be developed for exploration and production activities and building pipelines and natural gas–powered generation plants. Perhaps the most important stance by those charged with the crucial function of land-use planning in Israel is to recognize beforehand the contingent nature of much of the planning that needs to go forward from this point. In order to be in a position not only to react to previously identified signpost conditions but to exploit the opportunities they will present, it would be advisable to have in readiness the means to elaborate on basic preplans and quickly flesh them out in light of the contingencies of the future. This is not the most comfortable of positions in which a planner can find him- or herself, but being in a position to implement once the relevant signposts indicate the direction of needed response appears to be an important capability for Israel to nurture and enhance.

Israel Should Guarantee Sufficient Storage to Smooth Future Supply Disruptions in the Short Term

We have concluded that Israel can ensure that its supply of natural gas will be reasonably secure even as it becomes a major component of the nation's fuel mix. The risk stemming from fixed sources of supply of natural gas can be reduced by prudent planning. *Israel must have provision for storing standby supplies of switch fuels, primarily diesel.*

There is a case to be made for deferring construction of an Israeli LNG terminal until more is learned about other sources of supply and the scale of domestic need. A decision to immediately exploit domestic reserves and then add LNG when and if it appears there will be a future need can lead to satisfactory outcomes with respect to cost, depletion, and security of supply under many plausible sets of future conditions. Preparations for the LNG terminal may be made and approved in advance, permitting more-rapid implementation if signposts indicate that it would be expedient to do so.

Israel needs reasonable levels of standby reserve capacity at power plants and for the major levels of central storage to smooth possible jolts to the supply system. Also, *the planned inland high-pressure natural-gas pipeline should be built* to transport the volume of natural gas likely to be required, to provide some degree of redundancy in means for supply, and to provide more capacity for in-line storage.

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Our greatest thanks go to the Y&S Nazarian Family Foundation, whose generous support made this project possible. The foundation recognized that many of the issues that modern Israel faces would benefit from objective, fact-based policy research and analysis. It was the foundation's vision to supply an example of what leverage such inputs may provide to the solution of many of the state's fundamental domestic concerns. Our interactions with Sharon Baradaran, the foundation's president, during the course of our work have been both valuable and a source of considerable support.

Although this project was not formally performed on behalf of the State of Israel, the project team received welcome acceptance by the MNI, the Prime Minister's Office, the Ministry of Finance, and the other agencies and bodies that also provided representatives to the project's informal government steering committee. We wish to offer personal thanks to Hezi Kugler, director general of the MNI, and Gavriel Golan, adviser to the prime minister for planning and development, for their assistance in helping this project go forward. The project benefited considerably from the professional expertise and shrewd policy insights of Yinon Zribi, then senior professional adviser to the director general of the MNI. Our technical knowledge of natural-gas infrastructure and utilization in Israel was considerably enhanced by discussions with Jay Epstein, commercial director of INGL. We also extend thanks to the members of the informal government steering committee, who met several times during different stages of preparing this work to provide advice and a policy audience for initial findings. The many other experts in government, business, and the academic sector who were generous with their time and knowledge during our work are too numerous to name here. They know who they are, and we are grateful for their help and friendship; we could not have reached this point without their assistance.

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Abbreviations

AEO	Annual Energy Outlook
ANG	adsorbed natural gas
Bcf	billion cubic feet
BCM	billion cubic meters
BTU	British thermal unit
CARs™	Computer Assisted Reasoning® system
CC	combined cycle
CH_4	methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
Coal Rule_Alt	Coal Rule strategy with alternative fuels
CT	combustion turbine
DDW	domestic deepwater
DME	dimethyl ether
DOT	U.S. Department of Transportation
EIA	Energy Information Administration
EIT	economy in transition
EMG	Eastern Mediterranean Gas and Oil
EU	European Union
FERC	Federal Energy Regulatory Commission
Gas Rule_Alt	Gas Rule strategy with alternative fuels
GDP	gross domestic product

GHG	greenhouse gas
GTL	gas to liquid
GWh	gigawatt-hour
IAEA	International Atomic Energy Agency
IEC	Israel Electric Corporation
IGCC	integrated gasification combined cycle
INGL	Israel Natural Gas Lines Corporation
IOU	investor-owned utility
IPP	independent power provider
ISO	International Organization for Standardization
kcal	kilocalorie
kg	kilogram
KOGAS	Korea Gas Corporation
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
LDC	load-duration curve
LEAP	Long-Range Energy Alternatives Planning
Least Cost_Eff	Least Cost strategy with efficiency
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAED	Model for Analysis of Energy Demand
MAED_D	Model for Analysis of Energy Demand, all demand aggregated
MAED_EL	Model for Analysis of Energy Demand, electricity demand only
MIT	Massachusetts Institute of Technology
MMBTU	million British thermal units
MMcf	million cubic feet
MNI	Ministry of National Infrastructures
MW	megawatt
MWh	megawatt-hour

NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NGL	natural-gas liquid
NOP	national outline plan
NO_X	nitrogen oxide
O&M	operation and maintenance
OECD	Organisation for Economic Co-Operation and Development
PCC	pulverized-coal combustion
PM_{10}	particulate matter with particles no larger than 10 micrometers
ppt	parts per thousand
PRIM	patient rule induction method
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PV	present value
RAP™	Robust Adaptive Planning™
RDM	robust decisionmaking
SO_2	sulfur dioxide
SO_X	sulfur oxide
UNFCCC	United Nations Framework Convention on Climate Change
WASP	Wien Automatic System Planning

CHAPTER ONE

Introduction

Background

The Middle East is home to some of the most-significant energy-exporting nations of the world. It is also the location of Israel, a state that still does not enjoy formal recognition or diplomatic relations with the majority of its neighbors.[1] This means that Israel has always needed to look to domestic means or imports from outside the region for satisfying its energy demands. It does not exist in a regional electricity grid as do countries in other parts of the globe, so, though a small country, it must ensure self-sufficiency even in the face of disruptions.[2] Until recently, it has had few sources of domestic energy supply on which to draw. This makes it something of an energy island, not unlike South Korea or Japan, albeit on a considerably smaller scale.

Israel's situation of energy dependence is exacerbated by the formal state of war that many of the region's other governments maintain toward Israel. This means not only no trade with the region even under normal circumstances but also that the government of Israel must always consider the possibility of being made subject to active policies of energy-supply denial under circumstances in which the de jure state of war might encourage exporters to assume a more actively belligerent posture.

Formal responsibility for matters relating to energy and the nation's energy production and distribution systems are within the portfolio of the Ministry of National Infrastructures (MNI). However, Israel's general position in its region, and the asymmetric roles played by Israel and its potential antagonists in the global energy economy, place issues relating to energy demand and supply prominently in the list of national concerns.

These concerns stem not only from geopolitical considerations. Israel has experienced considerable economic and population growth in the past two decades, despite war and intifada. The ability of the energy-supply system, particularly with respect to electricity, to meet the ever-greater demands of a booming economy is a pressing matter irrespective of states of war and peace. As we discuss later, the narrow margin between demand and supply that presently exists and looms even larger in the near future is, in part, a result of inaction that itself stems from a lack of certainty about how best to meet those needs while also meeting other national goals that may be affected by decisions regarding the state's energy infrastructure.

1 Israel signed its peace treaties with Egypt in 1979 (Government of Israel and Government of the Arab Republic of Egypt, 1979) and with Jordan in 1994 (State of Israel and Hashemite Kingdom of Jordan, 1994).

2 Israel Electric Corporation (IEC) derives justifiable pride from the continuity of its service. While this might be taken for granted by the public it serves, doing so entails considerable cost, effort, and care. The need to avoid electricity shortages is an important criterion for determining how and by what means electricity is to be supplied.

Beyond national security, these would include concerns about health, the environment, the economy, land use, and the physical safety of the population.

Recent energy developments in Israel stand apart from this general pattern. Since 2004, natural gas has entered the primary-energy fuel stream and is expected to play an increasing role. This fuel departs from past experience in two ways. Natural gas is supplied from relatively recently discovered domestic reserves, available for the first time in volumes that are significant, and through a pipeline supplied by reserves located in Egypt, a nation that was a principal antagonist during the first half of Israel's existence. These new developments require an assessment of several questions:

- How far can and should Israel go in utilizing this new energy-fuel source?
- From what sources and in what amounts should it plan on being supplied with natural gas?
- In what manner should natural gas be developed to enhance its benefits while reducing exposure to several types of risk?
- What should be the future role of more-traditional fuels (oil, petroleum distillates, and coal) and renewable energy sources?
- What infrastructure (pipelines, liquefied natural gas [LNG] terminals, power-generation facilities) needs to be built and when?[3]

This report assesses the strategic alternatives available to Israel to ensure its energy supply in the present and in the course of the next two decades. In particular, we address the question of how and in what manner Israel may make use of domestic and imported sources of natural gas to address or alleviate various categories of risk associated with energy and fuel supply. This report explores risk-management strategies but in an environment characterized by extreme uncertainty and potentially large consequences. As such, it also addresses more-general issues of how it may be possible for planners and decisionmakers to determine strategies and courses of action when all of the relevant information is not only unknown but, to a certain degree, unknowable. The problem of natural-gas utilization and even energy policy writ large is not the only question of this type confronting policymakers in Israel and elsewhere.

The work carried out under this project was funded as a private initiative by the Y&S Nazarian Family Foundation. The foundation's intent was to provide a benefit to Israel by engaging the research and analytical capabilities of the RAND Corporation in a major project on an important topic on behalf of Israel's government and people. In discussions with government officials, business leaders, and academics in Israel, it was determined that, in the general field of energy, a close examination of alternative strategies for natural gas in Israel would be of benefit. Such an analysis would provide an external supplement to planning efforts already under way within the government of Israel. It would provide additional insights into international experience with natural gas, a fuel with which, until recently, Israel had relatively little

[3] LNG is often confused with natural-gas liquid (NGL), compressed natural gas (CNG), liquefied petroleum gas (LPG), and gas to liquid (GTL). The composition of LNG is distinct from these other natural-gas varieties. LNG is about 95 percent methane and 5 percent other gases. NGL is mostly composed of hydrocarbon gases heavier than methane, such as ethane, propane, and butane. LPG is 95 percent propane and butane. The composition of CNG is the same as pipeline-quality natural gas. Unlike pipeline natural gas, though, CNG is pressurized up to 3,600 pounds per square inch gauge (psig) and stored in welding bottle–like tanks. GTL is the process of converting natural gas to such products as methanol, dimethyl ether (DME), and other chemicals (Foss, 2007).

previous experience. It would also permit constructing an analytical framework that would not only illuminate and touch on many of the complex issues bound up in Israel's energy situation but also provide a basis for broadening to a fuller examination of other fuel paths.

The project benefited from guidance by an informal government steering committee chaired by the director general of the MNI, the relevant ministry for energy policy in Israel. This steering committee was also composed of representatives from the following government offices and companies:

- the Prime Minister's Office
- Ministry of Finance
- Ministry of the Interior
- Ministry of Environmental Protection
- National Security Council
- Ministry of Foreign Affairs
- Electricity Authority
- Natural Gas Authority
- IEC
- Israel Natural Gas Lines Corporation (INGL).

Although the government of Israel was not formally the client for this work nor was RAND under contract to that government, the steering committee permitted a close association between the project and the senior government decisionmakers whose offices wrestle with the issues related to natural-gas supply and utilization. In this way, the steering committee provided a useful source of insight, information, and criticism as the work proceeded. During the course of the project, the project team continued to meet with the steering committee as a whole as well as in sessions with individual members and their organizations.

Through the mechanism of the steering committee, the project team sought to conduct an analysis that would be of greatest use to decisionmakers inside Israel. Nevertheless, the study itself as well as its conclusions and findings must be viewed solely as representing the results of an independent RAND research effort. It does not necessarily reflect the views of the government of the State of Israel or of any of its constituent departments and agencies. Neither does it necessarily represent the views of those members of such departments and agencies whom the project team interviewed and consulted during the course of study.

When RAND began this study, it was well aware that the government of Israel would be concurrently making decisions and further developing its plans for exploitation of the natural-gas resource. Because the RAND effort was not privy to these deliberations, this raised the question of what would be the direct value to Israel of this independent effort. In conducting this study, we have attempted to provide several outputs that would be of value in themselves and contribute toward the decisionmaking and implementation of natural-gas development in Israel. These include the following:

- a detailed, objective analysis from an external perspective that would also draw on the international experience with natural gas
- use of new, computer-based methodologies to provide an analysis of what properties of alternative natural-gas strategies, policies, and infrastructures will enhance the robustness of Israel's energy posture

- in the context of the analysis, an examination of which factors among the many unknowns that Israel faces would have the greatest effect and, therefore, the largest influence over policy choices
- a guide for how whatever strategy is ultimately selected may be modified in light of updated information and new circumstances
- a presentation of materials in such a way that will enhance the level of public discussion of issues relating to energy in Israel and with respect to natural gas in particular by providing the background and context necessary for informed assessment
- an expandable modeling and analytical framework for energy analysis that may be further developed by RAND or others within Israel to conduct similar analysis across all fuel paths
- an example of a method for long-term policy analysis that may be applied in the same format to other issues of this character that Israel faces.

The remaining sections of this introduction lay out the detailed objectives of the analysis, the approach to treatment of decisionmaking and strategy under deep uncertainty, and the nature of the analysis that was pursued.

Energy, Competing Needs, and Risk in Israel

The problem facing Israel, as for any national government, is one of managing benefits and risks across multiple dimensions. There are a variety of strategies that a state may employ to ensure that its economy is limited in its exposure to risk arising from energy supply and consumption. Even in the United States, where state intervention is usually desired to be the minimum necessary to ensure the common good, policy exists at various levels of government on energy generation, distribution, transportation, regulation, and taxation. The United States also, for example, maintains a national strategic oil reserve as a deliberate matter of federal government policy to minimize the risk to the nation's economy and ability to conduct military and naval operations.

Israel, too, seeks to meet several needs while facing various categories of risk in the realm of energy that must be weighed and addressed. Given the central role of government decisionmaking in the Israeli system, this means that government must actively manage energy-related policies to manage the associated risks.

The term *energy security* is often used but rarely defined, at least in popular use.[4] In this analysis, we connect the concept of security to that of risk management: If one can reduce exposure to various types of risk affected by energy balances, either by limiting the situations in which deleterious outcomes might occur or by taking measures to ameliorate the effects of such outcomes should they arise, then security is enhanced. If not, then one may be said to be in a less energy-secure position. We further disaggregate the concept into risks affecting different aspects of a nation's collective interest. With respect to Israel, we attempted to focus on supply security as an aspect of national security, physical security, effects on markets and the economy, health and environment, and regulation and land use.

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4 One attempt to define the economic dimensions of energy security may be found in Toman (1993).

National Security

Israel's history makes national security the foremost concern of both government and the population at large. With respect to energy, the risks fall into two broad categories. The first is homeland defense. The nation's energy infrastructure may reasonably be expected to be a prime target for the enemy in time of war. It may be targeted either to create interruptions to the supply of energy to the military or to inflict costs on the civilian economy, thus creating pressure for the termination of hostilities. Different components of energy infrastructure have different vulnerabilities. Further, while some targets may be expected to occasion little collateral damage if struck (e.g., a coal-fired power plant), others could conceivably cause considerable further casualties in the case of a successful strike (e.g., an onshore LNG-receiving facility). This becomes a matter for active consideration when planning the energy infrastructure of a state that possesses both a living memory of being attacked and little strategic depth.

A second concern from the national-security perspective is the susceptibility to strategic denial. In this case, the concern is less with the result from direct hostility that targets infrastructure and more with the possibility of supply disruptions through other means. The tempo of modern warfare places great demands on energy availability. To point to an obvious example, the fuel requirement of the Israel Air Force is two orders of magnitude greater when engaged in active operations than during normal times. Further, there is a possibility that energy denial, if carried out effectively against an energy economy with inelastic fuel requirements that have been fixed by technology, supply source, and infrastructure decisions, could place Israel in a position of having fewer options and on worse terms than might otherwise be the case. In both senses of the concept, national security becomes an important consideration for energy infrastructure and supply planning in Israel.

Currently, the electricity sector in Israel is dominated by infrastructure that uses coal for fuel. Coal can be readily obtained from many sources, making it difficult to embargo. It is easy to transport and store. Natural gas has the opposite characteristics. Because it is relatively hard to transport, an expensive infrastructure is required to do so. The cost of this investment means that suppliers require long-term commitments that limit potential sources, making it relatively easy to embargo—albeit at a political and economic cost.

Physical Security

The preceding discussion about national security considers the possibility of collateral damage from facilities that were struck by enemy attacks. There is a similar general concern with the physical safety of the population in the case of catastrophic failure due to operational losses other than those inflicted by belligerents. As is the case with many of the risks that may be enumerated explicitly, the issue of physical security cuts across other explicit categories of risk, such as health and land use.

Under ambient conditions, natural gas is more volatile than other fuel types. This suggests the need for more-resilient and hardened systems in the case of natural-gas use when compared to other primary fuels to achieve a similar level of assurance about the risks of physical injury either to other systems or to individuals and neighborhoods.

Market and Economy

This category of risk also combines two potential aspects. Changes in the external energy market may also affect the energy market in Israel, principally in the form of rapid price changes. Thus, the first, narrower risk concept is focused solely on the balance of energy supply and demand. The second concept, economic risk (or more properly, risk to the economy) concerns the more-general effects that developments in the energy market may bring to the national economy.

Clearly, if the principal source of potential shock is price spikes, such as the one the world experienced in the oil market in 2008, there is considerable linkage with other energy prices. Nevertheless, while all prices may be expected to move in the same direction, the amplitude of change need not necessarily be of the same magnitude. For example, different fuel types have different capacities and costs for long-term storage. This results in differences in the ability to pace purchase decisions in such a way as to minimize price shocks.

Israel also faces another potential source of risk to its economy from the energy sector. The major physical capital investments in energy tend to be fairly *lumpy*. That is, for technical and economic reasons, there are minimal efficient scales for building power plants. This scale may vary by fuel type and technology (the minimal effective scale for a supercritical coal-fired electricity-generating plant differs from that for a combined cycle [CC] natural gas–fired [NGCC] plant, which, in turn, is different from that for a variety of renewable-energy alternatives). Nevertheless, the addition of new capital tends to be discrete and hefty versus continuous and incremental. On the other hand, Israel is a relatively small country and energy market. The size of an economically efficient plant dictated by technology will necessarily represent a large proportion of the total infrastructure for supplying energy to the country. The unexpected loss of even one such plant due to supply disruption, equipment malfunction, or other operational dysfunction could hold potentially large consequences for the nation's economy.

Health and Environment

One of the principal arguments in favor of natural gas in an economy like Israel's is to reduce the potential for damage either to the health of the population or to the environment of the country that might be attributable to the coal, fuel oil, and petroleum distillates on which Israel has relied previously. Clearly, the two are closely connected, though not necessarily one and the same.

Natural gas in its pure form is methane (CH_4), a gas at ambient temperatures, composed solely of carbon and hydrogen atoms. Its principal contaminant is water. When it burns, it produces carbon dioxide (CO_2), a greenhouse gas (GHG) implicated in global climate change, and water, but little else of harm to humans or to nature.

Coal also generates CO_2 and in greater amounts for the equivalent heat output than does natural gas. In addition, coal must be cleaned prior to or after burning (or both) to reduce the effusion of sulfur oxides (which combine with atmospheric water to produce sulfuric and sulfonic acids); various compounds of nitrogen and oxygen (collectively referred to as nitrogen oxides, or NO_X, that are injurious both to health and to the environment); heavy metals, such as mercury; and tiny particles of ash that may collect in the alveoli of the human lung.[5] It is both theoretically and practically possible to clean coal or the effluent from coal combustion to a very high standard. This entails a trade-off between costs and benefits. It is relatively easy and not too expensive to reduce, to a limited extent, the undesirable matter from smokestacks. However, if the concentration of pollutants in smokestack exhaust is desired to be cleaned to more-exacting standards, the costs rise asymptotically. And, as the result of research on the

5 In actual practice, the combustion of natural gas will also produce some amount of NO_X.

health and environmental effects of emissions resulting from combustion of coal, regulatory bodies have been regularly tightening standards, often as the result of pressure brought by citizens exposed to these emissions.

Regulation and Land Use

The period since the domestic economic crises of the 1980s has seen a steady progression of regulatory changes in Israel. Many have affected the energy sector. Overall, the thrust of policy has been to dismantle existing monopolies or to ensure that no new monopolies are formed, particularly in the realm of energy.[6] The Bazan oil refinery, in which the government had a large stake, was both privatized and split into two separate companies based respectively on the plants present at the previous monopoly's two major sites at Ashdod and Haifa. The INGL pipeline operator is a government-owned company that was specifically limited solely to the transport of natural gas through high-pressure pipelines. Transport through low-pressure pipelines and distribution to customers other than gas-fired power plants and major industrial users is envisioned to be carried out by smaller, regionally based, independent companies (yet to be formed at the time of this writing). And most significantly, IEC, a government-owned corporation whose beginnings antedated that of the state by a quarter of a century, is now also a target for privatization and breaking up into separate companies for generation, transmission, and distribution.

Many parts of the energy economy and each individual fuel stream are subject to regulation. The framing of those regulations will affect the growth and role in the nation's energy balance played by any such part. It will also affect the influence that such a sector will have on the other goals, interests, and risk elements affecting the nation. For this reason, there is an important regulatory component to the list of policy risks that needs to be made explicit.

In the case of Israel, there is a further aspect of government choice and, hence, risk. Israel is home to a population of a little more than 7 million residing on a land area of about 22,000 square kilometers. The area where the bulk of the population resides—and, hence, the energy demand is greatest—is less than half that total area. This means that land-use planning is of critical importance in Israel. Siting decisions will have large implications for the impact of the energy infrastructure on the lives of inhabitants. There will be many necessary trade-offs. Placing energy infrastructure at some distance from population centers (if possible) will entail fuel-transport costs and transmission losses. Some fuels, such as coal, have dramatically increased transport costs when located inland. Yet, Israel has only 200 kilometers of sea coast, which is also the locus for the bulk of the population. Any construction of large-scale projects, such as those typically required for energy and power generation, is problematic and faces many regulatory, political, and economic impediments. Also, depending on scale, fuel type, and technology choice, that energy infrastructure will have different footprints as a result of the choices that planners make. Therefore, this is a category of risk that has large and potentially varied implications for Israel.

[6] Many of the monopolies that have been affected by more-recent government policies were themselves the creation of earlier government policy models.

Decisionmaking Under Deep Uncertainty

In this report, we take on the problem of how to think about a strategy for the use of natural gas in Israel to the year 2030. That is, we seek to create an analytical framework that can inform the many decisions that will need to be made across a period long enough that at least two generations of Israelis will be affected. It is also long enough that the problem of how to deal with the myriad alternative paths the future may take is a serious enough concern that not to confront this uncertainty would be to neglect the heart of the planners' problem. Therefore, we need not only to address the question of how natural gas and the manner of its use may decrease or increase various types of risk. We must also ask, in view of both Israel's risk-reduction goals and the objective uncertainties that exist, which strategies for natural-gas use in Israel appear most robust to uncertainty and surprise.

For centuries, people have used many methods to grapple with the uncertainty shrouding the long-term future, each with its own particular strengths. Literary narratives, generally created by one or a few individuals, have an unparalleled ability to capture people's imagination. More recently, group processes, such as Delphi, have helped large groups of experts combine their expertise into narratives of the future. Statistical and computer-simulation modeling helps capture quantitative information about the extrapolation of current trends and the implications of new driving forces. Formal decision analysis helps to systematically assess the consequences of such information. Scenario-based planning helps individuals and groups accept the fundamental uncertainty surrounding the long-term future and consider a range of potential paths, including those that may be inconvenient or disturbing for organizational, ideological, or political reasons.

Despite this rich legacy, these traditional methods all founder on the same shoals: an inability to grapple with the long term's multiplicity of plausible futures. Any single guess about the future will likely prove wrong. Policies optimized to address well-understood risks may fail in the face of surprise. Even a well-crafted handful of scenarios will miss most of the future's richness and provides no systematic means to examine their implications.

This is particularly true for methods based on detailed models. Such models that look sufficiently far into the future should raise troubling questions in the minds of both the model builders and the consumers of model output. Yet, the root of the problem lies not in the models themselves but in the way in which models are used. Too often, we ask what will happen, thus trapping us into a losing game of prediction, instead of the question we really would like to have answered: Given that we cannot predict, which actions available today are likely to serve us best in the future?

The subtle shift in focus from model forecasts to our true interest—informing decisions—resolves many of the conundrums. Instead of determining the best model and solving for the strategy that is optimal (but fragilely dependent on assumptions), we should instead seek among our choices those actions that are most robust—those that achieve a given level of goodness across the myriad models and assumptions consistent with known facts. We use the word *robustness* in this instance to reflect the likelihood of any particular course of action to yield outcomes that are deemed to be satisfactory according to whatever criteria are selected for assessment across a wide range of future possible states of the world. This is in contrast to an optimal course of action, which may achieve the best results among all possible plans but does so only under a narrowly defined set of circumstances. An analytical strategy based on the concept of robustness also brings us closer to the actual policy reasoning process employed by senior planners and executive decisionmakers.

The approach we use is one that has been applied to a growing list of policy challenges that similarly require developing courses of action when many profound uncertainties remain.[7] The essence is to reverse the usual approach to uncertainty. Rather than seek to characterize uncertainties in terms of probabilities, a difficult task rendered nearly impossible precisely when we cannot know many of the relevant facts, we instead explore how different assumptions about the future values of these uncertain variables would affect the decisions we actually face: What would we need to believe was true in order to discard one possible strategy in favor of another?

This analytical method requires using the computer to support an iterative process in which humans propose candidate strategies, or sets of coordinated actions, as being potentially robust across a wide range of futures. We do so by observing the outcomes from these strategies in the many plausible future states of the world that are consistent with the data we have available today. These outcomes are assessed against a series of metrics for those variables about which we care most (in this case, fixed and variable costs, emissions, land use, security of supply, and the like), and the results may be compared to thresholds that have been previously set for each metric to define what outcomes are acceptable. (Some examples for the year 2030 might be that CO_2 emissions must be below a certain level; total costs may be within 5 percent of the strategy that would produce the lowest cost under the particular set of future conditions being examined, and so forth.)

Once we have identified the elements of a robust strategy, we use the computer to challenge these strategies in what amounts to stress tests by using a combination of computer-simulation models and extrapolations from data to discover futures in which these strategies may perform poorly. The alternative strategies may then be assessed, revised, and perhaps hybridized to hedge against these stressing futures, and the process is then repeated for the new strategies. Rather than first predicting the future in order to act on it, decisionmakers may now gain a systematic understanding of their best near-term options for shaping a long-term future while fully considering not all, but at least a vast number of, plausible futures.

In this study, we constructed models that provide a sufficient compilation of the facts we know about Israel's economy, energy balance, and energy infrastructure while providing means to alter those variables—future demand growth, future energy prices, future technology changes—about which we presently have little information. These latter suggest many alternative specifications of future conditions. We construct different types of strategies and see how each affects measures that are of interest to Israel across a test bed of widely diverging possible futures. The information on outcomes from the resulting scenarios will be used to examine what characteristics of each strategy makes them stronger or weaker and what conditions cause them to operate as they were intended—or fail. We then select those strategies that seem to yield acceptable outcomes across a wide range of futures and modify them to enhance their ability to perform under future sets of conditions that caused them stress. From this, we derive insights for planning Israel's natural-gas strategy to the year 2030.

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[7] See, for example, Popper, Lempert, and Bankes (2005); Lempert, Popper, and Bankes (2003); and Lempert, Groves, et al. (2006).

Report Outline

The analysis on which we report was carried forth in two stages. First, we examine the question of what level and type of natural-gas utilization, along with other energy resources, will best satisfy the criteria of acceptability in three areas of fundamental importance to Israel through the year 2030: energy cost, land-use requirements, and emissions. We then address the question of what supply and infrastructure strategy would provide robust support for the chosen natural-gas utilization strategy. In this case, the supply strategy would also be tested, this time against criteria of cost, natural-gas depletion rates, and reliability (that is, avoidance of unmet demand), again through the year 2030.

Chapter Two provides more-detailed background to aspects of the energy economy of Israel as they have bearing on the choice of strategy for natural-gas utilization.

Chapter Three describes in detail the methodology, databases, and modeling framework utilized in this analysis. In particular, it illuminates the problem of decisionmaking and plan development under conditions of *deep uncertainty*, when many important factors are presently unknowable and when probabilities are so difficult to specify that any expectation result derived from their use would have little credible basis for belief. We discuss in detail what uncertain factors are to be explored. These include not only uncertainties about factors outside the planners' control in Israel but also uncertainty about the effects that different policy levers within the government's control would have if they are employed under varying circumstances, as well as an exploration of the appropriate metrics to be used in determining the acceptability of outcomes. Chapter Four provides detail on the models that we utilized in conducting our study.

Chapter Five begins to lay out the results from performing the analysis. This chapter applies the elements discussed in the preceding two chapters to assess candidate robust strategies for natural-gas utilization in Israel. Chapter Six carries this forward by measuring strategies against the criteria for successful outcomes to determine how such strategies may be modified to enhance their robustness to future events. These insights yield conclusions that might be applied to policy choice and strategy development in Israel to provide a more robust character to the nation's planning of natural-gas use. This completes our examination of natural-gas utilization strategies in the context of Israel's energy needs.

Chapter Seven discusses how the supply of natural gas sufficient to support a robust utilization strategy may itself be made robust. It looks at policy levers, such as foreign pipeline supply, exploitation of domestic resources, LNG supply, pipeline infrastructure, and storage to determine which mixes and sequences will best provide a robust supply of natural gas to support the integration of this fuel into Israel's energy balance.

Chapter Eight provides our concluding findings and recommendations.

CHAPTER TWO

Natural Gas and Energy in Israel

History and Development of Natural Gas in Israel

Even before the founding of the state in 1948, and with renewed urgency after Israel came into being, there has been exploration to determine whether the land lying within the boundaries of Israel also shares in the Middle East's bounty of fossil-fuel resources. By and large, the answer has been no. Exploration for both petroleum and natural gas turned up only small deposits of both over the first half-century of the country's existence. To the extent that Israel has used fossil fuels other than natural gas during the 20th century (coal, oil, petroleum distillates [e.g., gasoline, diesel fuel, kerosene]), they have overwhelmingly been imported from abroad.

Before 1973, most fossil-fuel use, for both transportation and electricity generation, was accounted for by petroleum and petroleum products. The oil embargo that followed in the wake of the war fought between Israel and the combined forces of Egypt, Syria, and their allies in October 1973 caused concern to Israeli planners. The embargo exposed them to the real possibility that the state could be threatened by denying it access to vital energy resources—the *oil weapon*, as it was called at the time. As a result, Israeli government planners began to explore the use of coal as an energy resource that would be more difficult to embargo owing to both diversity and magnitude of supply. Thus, it was only in the early 1980s that Israel began to materialize plans for building large-scale coal-fired power plants. The technology of the day could not solve dependence on liquid fuels for transportation and other such uses, but it could relieve the anxiety over supplying electricity base load. By the year 2000, coal-fired plants produced more than 70 percent of Israel's electricity, with most of the balance accounted for by the use of diesel and heavy fuel oil.[1]

The peace treaty with Egypt in 1979 (Government of Israel and Government of the Arab Republic of Egypt, 1979) and the exploration and development of that country's natural-gas reserves raised a new possibility. The World Bank was interested in seeing these energy reserves developed in Egypt as a way of improving and diversifying the country's economy. However, in the early 1980s, the only practicable way to export natural gas was through pipelines. The technologies of compression and liquefaction were only largely prospective and did not therefore present themselves as solutions to the transportation problem. The best solution, rather, would be to find near neighbors that could take Egyptian natural gas via pipeline. On this basis, Israel, Egypt, and the World Bank agreed to a study on how best to develop a natural-gas market in Israel that would also facilitate the supply of natural gas from Egypt.

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[1] Heavy fuel oil is also known as *heavy oil* or *resid*. It is the fraction that remains after refining the high (gasoline) and middle (diesel) distillates from petroleum.

The World Bank study caused officials in Israel to consider what infrastructure would be needed to take fullest advantage of the prospect of receiving natural-gas deliveries directly from Egypt through a pipeline. No domestic natural-gas pipeline existed in Israel. The most extensive pipeline project in the country was the oil pipeline extending from Eilat on the Red Sea to the port of Ashkelon on the Mediterranean. This was constructed originally as an Israeli-Iranian joint venture both to take supplies of oil from Iran and to provide means for transshipping oil cargoes to Europe without the need to traverse the Suez Canal.[2] Planners began to assess how best to utilize natural gas, a fuel with which Israel heretofore had had little or no experience, that might originate in Egypt.

It was while this planning was under way that discoveries were made of commercial quantities of natural gas in the near offshore of Israel's coast. The discoveries in 1999 at the Noa and Mari-B exploratory concessions held by subsidiaries of the Delek Group in partnership with Noble Energy meant that, for the first time, Israel had discovered a significant domestic fossil-fuel supply. This naturally accelerated the planning for natural gas and heightened the interest. Total proven reserves from both fields were 32 billion cubic meters (BCM). The Natural Gas Sector Law passed the Knesset in 2002, and the Natural Gas Authority was created within the MNI. INGL, a government-owned company, was established to build the high-pressure gas pipelines that initially would service major users, such as electric-power stations and large industrial customers, but would then also feed into any future lower-pressure pipeline grid built by gas companies to distribute to smaller-demand natural-gas customers.[3] INGL began taking shipments of natural gas from the Delek concession fields—known as the Yam Tethys project—at its delivery point in the port of Ashdod in 2004 and delivered it to customers, initially power plants operated by IEC, another government company and the sole supplier of electricity to the Israeli grid.[4] The first deliveries were to the former heavy fuel oil–fired Eshkol electric power plant in Ashdod (retrofitted in 2003 for natural gas), soon followed by deliveries to the retrofitted former oil-fired Reading plant in Tel Aviv.

At the same time, natural gas was also discovered in fields that lay off both the southern Israeli coast and that of Gaza. The Gaza Marine field, with estimated reserves of about 35 BCM, was set aside by the government of then Prime Minister Ehud Barak to be a resource at the disposal of the Palestinian Authority and any political entity that would succeed it. This action was taken before the failure to reach agreement on completion of the Oslo peace process at the Camp David and Taba conferences of 2000 and before the inception of the second intifada in that year. Currently, this field is to be developed under a concession granted to BG Group. No development work has been undertaken to date, partly because of the political turmoil in which subsequent events have placed the Gaza region. There remains a resulting uncertainty about where the natural gas from Gaza Marine would be delivered.

The original idea of receiving natural-gas shipments from Egypt to Israel through a pipeline was not waylaid by the more-recent domestic finds offshore. On the contrary, the latter

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2 The Islamic Republic of Iran, the successor to the government of Shah Mohammad Reza Pahlavi, retains a 50-percent share in the venture. The pipeline is still used for oil transshipment, but the government of Iran is no longer actively engaged in the venture.

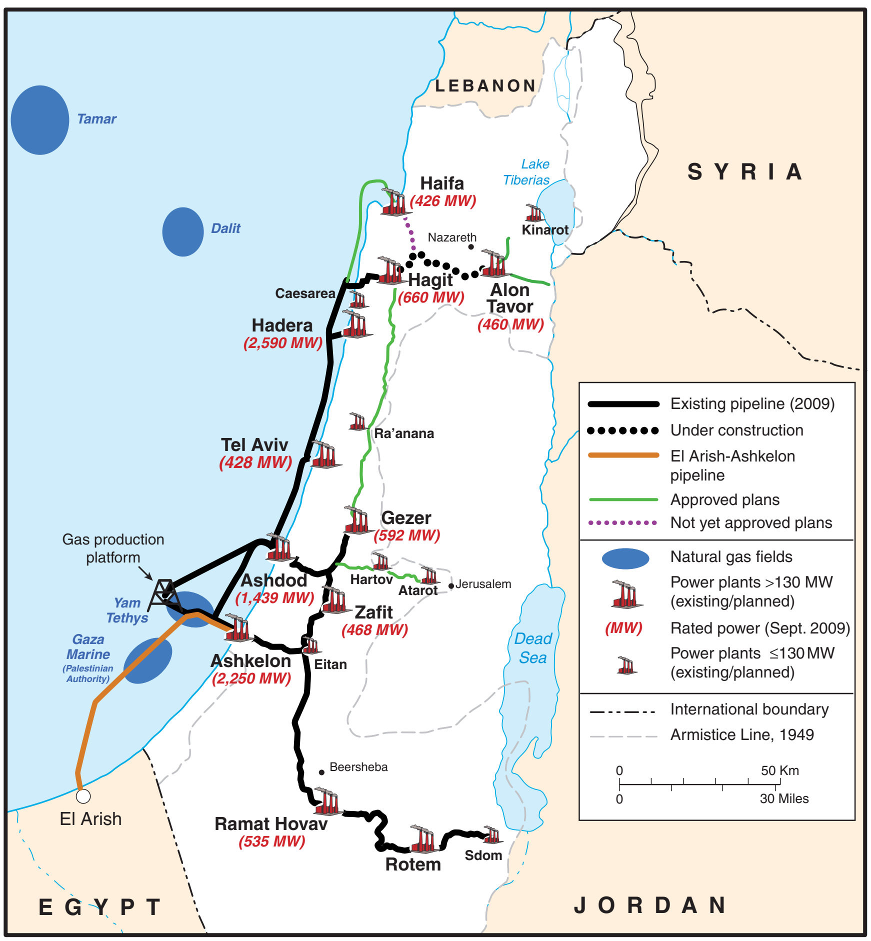
3 According to its government charter, INGL may only provide transportation services through its high-pressure pipelines. It may not purchase gas for resale, store it, nor establish low-pressure pipelines for wider distribution.

4 IEC is currently scheduled to be privatized, broken up into smaller components, or both. At the time this project was conducted, the ultimate form that IEC would take was yet to be determined.

served to enhance the interest in shifting away from other fossil fuels to natural gas as a primary fuel. In 2000, Eastern Mediterranean Gas and Oil (EMG) was formed as an Egyptian company with Israeli participation.[5] EMG purchases natural gas from the operators of the Egyptian fields. EMG undertook construction of an undersea pipeline from El Arish in Sinai to the Israeli port of Ashkelon (see Figure 2.1). The design capacity of this pipeline is for 7.0 BCM per year, the maximum that EMG (and, presumably, Egypt) has so far indicated that it will agree to supply to Israel. The first gas began flowing to Israel in the first half of 2008, albeit with periodic supply disruptions at the upstream end.

Both the natural gas produced from Yam Tethys and that transported from Egypt is purchased by individual Israeli customers of natural gas contracting directly with the supplier—either Delek, in the case of the domestic supply, or EMG, in the case of the natural gas from Egypt. This stands in contrast with what has been the historical practice in most other countries when natural gas is introduced as a fuel and certainly in the case of countries the size of

Figure 2.1
Natural-Gas Exploration Fields Off the Shore of Israel



RAND *TR747-2.1*

[5] The Israeli Group Merhav began with a 25-percent stake. Ownership of EMG has changed over the years, but Merhav, jointly with subsidiaries, still retains 25-percent voting rights ("Merhav Group of Companies," undated).

Israel. In most of these cases, either governments or government-chartered or -regulated companies have been the primary purchasers of natural gas from suppliers that then distribute the gas either directly to major customers or through distribution companies to all natural-gas consumers.

Purchase and market-organization arrangements of this type are a consequence of the difficulties in handling and transporting natural gas.[6] Unlike petroleum and its derivatives, which are liquids at normal temperatures and therefore relatively simple to transport, distribute, and store, the challenges posed by natural-gas use require a large initial investment in infrastructure to carry the gas from its point of extraction to its point of use. This, in turn, usually requires a large purchaser that will contract for volumes of fuel sufficient for the initial investment to be worthwhile. Israel's long experience with monopolies and the more-recent difficulties it has experienced in unwinding them made government planners averse to setting up a new one along with the introduction of a new primary fuel. This has had consequences for the introduction of natural gas into the energy economy of Israel.

The first major customer of both the domestic natural gas from Yam Tethys and the EMG gas was Israel's monopoly supplier of electricity, IEC. On July 1, 2005, IEC signed a contract with EMG for the supply of 1.7 BCM of natural gas per year for 15 years, with an option for an additional five years. This, coupled with the supply that IEC was receiving from Yam Tethys beginning in 2004, caused many to believe that the day had come when natural gas would gradually supplant coal as the sole base-load fuel for electricity generation.[7]

Options for Expanded Use of Natural Gas

As Israel looks to the future, there are several additional potential sources of natural-gas supply for Israel if demand continues to grow. A consortium headed by Delek Group and its partner, the Houston-based Noble Energy exploration and development company, continued its exploration off the coast of Israel for natural gas at the Tamar concession, located within the Matan field. In contrast to Yam Tethys, this field is located in the northern portion of Israel's territorial waters, roughly parallel with the latitude of the port of Haifa. It is, however, also further offshore and in considerably deeper waters (nearly 1,700 meters) than the Yam Tethys field. Explorations began at the end of 2008, and, in January of the next year, it was reported that explorations revealed that the formation did, indeed, contain natural gas.

These discoveries have the potential for adding a considerable domestic source of supply to Israel's energy balance. The preexploration estimates for the volume of recoverable natural gas contained in Tamar were in the neighborhood of 80–90 BCM. Reports in the press following the test drilling suggested that there might be considerably more available, perhaps twice as much.[8] This determination will need to await further exploitation of the deposit to see what amount of natural gas may be recoverable. However, the deeper waters will make exploitation of this resource much more costly than in the case of Yam Tethys. Based on the apparent suc-

6 See Appendix C for detail on the technologies involved with the transportation and distribution of natural gas.

7 "IEC spokesman Dedi Golan is confident that natural gas will soon supply Israel with 60 percent of its electricity" ("Israel and Egypt Sign Natural Gas Deal," 2005).

8 "Tamar Wildcat Finds Subsalt Gas Off Israel" (2009, p. 39). As this report was completed, the most consistent report on the size of the find put it at 142 BCM ("Dalit Reservoir Contains 15 Billion Cubic Meters of Gas," 2009).

cess of this discovery, Delek and its partners, as well as other consortia, have begun to explore other concessions lying in the waters off Israel. These efforts bore fruit in the subsequent discovery of another, albeit smaller, potential natural-gas field, Dalit, also within Israel's territorial waters.

There are also potential new foreign sources for natural gas, such as the BG Group Gaza Marine concession mentioned earlier. The agreement, which consolidated the Palestinian Authority's ownership of this natural-gas field, envisioned sales to Israel on a basis similar to that for sales within the territories of the Palestinian Authority. It is not clear that the concessionaire, BG Group, sees this as its most fruitful alternative. If the gas from this field could be directed toward the LNG-processing facilities already functioning in Egypt, it would give BG Group the option of setting up new LNG production lines with the ability to then take advantage of higher spot-market or contract prices across a wider set of potential customers. While it is not clear that this prospect has dominated the thinking by BG Group, it is the case that the negotiations between BG Group and Israel have been drawn out to date and also broken off on several occasions. At the time of this writing, there has not yet been any agreement between BG Group and any buyer in Israel, governmental or private, to contract for delivery of natural gas to Israel from the Gaza fields.

Israel may also avail itself of the LNG option, discussed in greater detail in Chapter Seven.[9] Briefly, Israel could build a facility to receive supplies of natural gas not through a fixed pipeline but via ship carrying deliveries from any supplier in the world. LNG is gas that has been pressurized and supercooled to the point at which it becomes liquid. This still does not permit transport with the same ease with which petroleum and its products may be conveyed. LNG requires highly specialized vessels and dedicated facilities for receiving shipments. LNG facilities are both expensive and potentially hazardous. This makes the decision about where to site such facilities problematic almost anywhere that there is also a center of population. This is likely to be even more problematic in Israel, since an LNG facility immediately becomes an attractive potential target for terrorist groups and for enemies in times of war.

The potential hazard may be reduced somewhat if the LNG-receiving facility is built offshore. This adds considerably to the initial capital and operating costs of such a plant. This may be a step that Israel may need to consider seriously, however. Israel's Mediterranean coastline is no more than 180 kilometers in total. The need to place such a facility away from potentially hostile borders makes this available space even less. This shoreline is also the most densely populated and developed part of the state; several of Israel's biggest cities are located on or near the sea. There are relatively few places along this shore not already claimed by industrial sites, habitation and business centers, recreational and tourist areas, or land set aside for nature preserves or military or training purposes. Those few potentially buildable spots would, of course, be adjacent to areas already dedicated to one of these other uses. The process of receiving the necessary approvals for an LNG-receiving facility next to any one of these area types is likely to be quite drawn out.

One of the important features of the trend toward LNG is that it could change some of the fundamental ground rules presently governing the market for natural gas. To the extent that LNG becomes more common and facilities for shipping and receiving it become more plentiful, the economics of regional natural-gas markets will change. On the one hand, LNG

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9 See Appendix C for a detailed discussion of the technical aspects of LNG production, delivery, and use.

increases the potential for using natural gas. Countries without current contact with natural-gas producers through the pipeline delivery infrastructure could now become receivers of natural gas in its LNG form and so become users of this fuel. This could have the effect of increasing global demand and therefore put upward pressure on prices. On the other hand, the fact that global considerations, as opposed to bilateral or regional ones, become an important factor could also affect the market.

Unlike petroleum and its refined products, natural gas is not truly a commodity that may be bought and sold on the secondary market, because of difficulties with transportation. LNG can change this. At some point, the amount of LNG produced and the facilities for its handling could become so prevalent that, for the first time, natural-gas prices would be set by a global market. This would mean, for a consuming state like Israel, a much wider potential source of supply and hence a de facto diversification of its primary-fuel base. For a supplier country like Egypt, the desirability of having a customer like Israel as a near neighbor would be reduced. A greater fraction of Egyptian natural gas could be converted to LNG and then sold to take advantage of whatever market offers the most lucrative return. Currently, owing to the initial investment cost of LNG facilities, the bulk of LNG is delivered on the basis of long-term contracts. However, the fraction being sold on the spot market, while currently small, is growing.

A final class of supply opportunities exists. It is conceivable that natural gas could come from other foreign suppliers via pipelines in addition to the existing pipeline from El Arish. The prospect most often discussed is to receive natural gas from a supplier, such as Russia, or from a source in the Caucasus or central Asia via a pipeline routed through the existing Turkish terminus at Ceyhan on the eastern Mediterranean. Given the present and prospective political relations with Israel's northern neighbors, Lebanon and Syria, this would have to be an underwater pipeline, probably to Haifa. This prospect has been the subject of discussions in recent years between the countries potentially involved. It is in the interest of all to continue these explorations and discussions.[10] That having been said, there are considerable concerns about the economic viability of such a pipeline. The costs would be potentially quite large, while the size of the potential market for natural gas in Israel alone is relatively small, especially if the supply relationship with Egypt remains intact and deliveries can achieve and be sustained at the level of 7 BCM per year. Some have suggested that the economics could be made more viable if the conduit from Turkey not only carried natural gas but also served other supply lines for other fluids, such as oil, petroleum distillates, freshwater, or electricity deliveries. This would, of course, make the engineering that much more complicated.[11] It may be difficult to make the case for such a pipeline, given the practical difficulties, in light of the alternative presented by a growing trade in LNG.

Another such possibility presents fewer economic and engineering obstacles but would have fundamental political prerequisites. The world's third-largest proven reserve of natural gas is the nation of Qatar. While a member of the Arab League and an advocate for the Palestinians in their dispute with the government of Israel, Qatar has exhibited little enmity to the state of Israel itself. In previous years, there have been informal indications that Qatar would

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[10] It is conceivable, for example, that such a pipeline could have a partial on-land leg by being directed toward the island of Cyprus. Thus, for Turkey, there would be an additional political and infrastructure-development inducement to entertain the possibility of such a pipeline.

[11] There are also possibilities of cost sharing if, for example, such a pipeline transited Cyprus.

be willing to entertain the possibility of selling natural gas to Israel. These could be via the mechanism of LNG deliveries. It is also conceivable that a pipeline could be built through Saudi Arabia to Jordan to the benefit of both Jordan and Israel.[12] It is unlikely that such infrastructure could be agreed on in the absence of a formal resolution to the outstanding issues between Israel, the Palestinian Authority, and, most likely, other Arab states.

What this brief survey suggests is that, while it is entirely possible, even likely, that Israel will be able to locate and obtain additional sources of natural gas between now and the year 2030, these additional sources will not soon be in place. Considering the location of the Tamar reserve, it is unlikely that delivery could begin much before the middle of the decade beginning in 2011. This would be true for any further domestic deepwater discoveries or, for that matter, any additional source of foreign supply. Thus, new natural-gas supplies into the system via pipeline will be available only after considerable effort and with some current uncertainty about the ultimate form of those supplies. This raises the relative attractiveness of the LNG option for Israel despite the serious drawbacks cited earlier. Other than supplies from newly discovered domestic reserves, it is the alternative least dependent on decisions made by stakeholders outside Israel and provides the greatest potential scope for flexibility and diversity in supply in an uncertain world. This proposition is analyzed at length in Chapter Seven.

Israel's Energy Balance

It is useful to provide a quick overview of how energy is generated and used in Israel. Table 2.1 shows the domestic energy balance for 2006 (the most recent year for which the Central Bureau of Statistics may legally report these data). Electricity provides a major share of end-use

Table 2.1
Israel's Energy Balance for 2006, by Primary Fuel (thousand tons of oil equivalent)

Energy Balance	Coal	Oil Shale	Crude Oil	Refinery Feedstock	Natural Gas	Total Petroleum Products	Electricity	Heat and Steam
Primary-energy supply	7,665.0	31.7	10,275.9	1,614.9	2,090.9	–831.0	–172.8	
Total primary-energy use	–7,665.0	–31.7	–10,275.9	–1,614.9	–2,085.2	9,523.6	4,096.5	
Petroleum refineries			–10,275.9	–1,614.9	–64.0	11,893.9		
Electricity generation (total)	–7,665.0	–31.7			–2,021.2	–1,512.9	4,455.7	21.1
Own use and losses						–857.4	–359.2	
Final consumption of energy					5.7	8,692.6	3,923.7	21.1

SOURCE: CBS (2008).

[12] Jordan's obligations as a recipient of gas from Egypt would need to be factored in to any such planning.

consumption of energy in Israel and, as the table shows, that electricity is generated largely by coal but with a sizable share coming from natural gas. These numbers have resulted from an increasing use of natural gas in electricity and a decreasing amount of generation coming from combustion of petroleum products.

Unlike some other countries that utilize natural gas for domestic home heating and cooling, commercial purposes, transportation, and other nonpower uses, Israel currently does not utilize this fuel for any purposes besides electric power and some industrial use by large-scale factories. The major reason is that users are confined to those that have the ability to take deliveries from the high-pressure pipeline system, which is itself still being built. INGL has not been permitted to develop the infrastructure for low-pressure delivery to smaller-scale users. The government proposes to establish a system of regional natural-gas distribution companies that will take deliveries through the pipelines operated by INGL and deliver the gas via a low-pressure distribution system to retail customers. This was still a plan in prospect at the time this research was conducted, although there were indications that it was moving forward.[13] Therefore, in much of what follows, our discussion focuses on the current major uses of natural gas, which likely will continue to claim most deliveries into the foreseeable future. Principal among these is electricity generation.[14]

Demand for Electricity in Israel

In recognition of a growing demand for electricity and the current infrastructure's inability to meet such demand, the MNI publicly announced on May 29, 2007, an expected shortage of 8,000 megawatts (MW) in the next decade in the absence of precautionary measures to alleviate it. It was therefore suggested that IEC start immediate planning for an additional 4,000 MW under the MNI's emergency plan. Among other things, the ministry requested that IEC provide it with the plans for two additional coal-fired power plants (referred to as plants D and E), each intended to produce 1,200 MW. That summer, Israel also launched its first phase of electricity-conservation plans promoting such measures as cleaning filters, closing windows, and using washing machines only when full. In January 2008, the MNI and the Ministry for Environmental Protection began a second phase of the national plan for electricity conservation through an information campaign utilizing both television and radio ads that promoted ways to reduce demand. The campaign promoted steps that included replacement of incandescent light bulbs with compact fluorescents, turning off appliances when leaving a room, setting the air-conditioning temperature to 20 degrees Celsius, and installing a timer on water heaters. The hope was that, together with additional infrastructure development, these conservation measures would help address concerns about growing demand.

There have been significant increases in per capita electricity consumption in the past two decades. Still, Israel has not moved into the first rank in this measure when compared to more–fully developed countries. This indicates the possibility of continued demand growth as

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13 At this writing, only one tender has been offered, that for the southern distribution grid, and awarded to Amisragas.

14 The major industrial firms, Israel Chemicals and Hadera Paper, have so far signed agreements for delivery of 2.5 BCM of natural gas over five years, and the Paz Ashdod oil refinery has entered into agreements to take delivery of 1.3 BCM over ten years. All deliveries are from Yam Tethys. Industrial and transportation uses of natural gas are included in the quantitative analysis.

Israel catches up to the level of consumption of the most-developed countries.[15] Peak demand in 2007 occurred in July, when load demand reached 10,070 MW, a 7-percent increase over the preceding year. The timing of the peak load switched in 1998 from the previous pattern of occurring during winter evenings. More recently, it has occurred in the summer daytime.

In 2007, IEC provided electricity to customer accounts (shown by sector in Table 2.2). While consumption increased in all areas from the previous year, consumption shares either remained constant or fell with the exception of East Jerusalem and the Palestinian Authority, which increased its share of the total by 4.5 percent.

Another way to examine the consumption data is to observe the geographic distribution across the country, as seen in Table 2.3. The greater Tel Aviv area (sometimes referred to in Israel as *gush Dan*), Jerusalem, and Haifa are Israel's main population centers, while the south, characterized by much lower population density, is the location for a sizable fraction of Israel's heavy and extractive industries. The south also is the location for major facilities of the Israel Defense Forces. These factors led to 38 percent of Israel's total electricity consumption being claimed by regions totaling just more than 5 percent of Israel's total land area.

Table 2.2
Consumption of Electricity Generated in Israel, by Sector, 2007

Customer Type	Consumption Share (%)	Consumption (millions kWh)
Residential	30.5	15,049
Commercial and public	29.9	14,766
Industrial	22.7	11,178
Agricultural	3.8	1,852
Water pumping	6.1	3,021
East Jerusalem and the Palestinian Authority	7.0	3,457

SOURCE: IEC (2007).
NOTE: kWh = kilowatt-hour.

Table 2.3
Consumption of Electricity Generated in Israel, by Geographic Area, 2007

District	Customer Accounts	Annual Consumption (GWh)	Share of Annual Consumption (%)	Share of Israel's Land Area (%)
North	384,490	9,290.7	18.8	23.3
Haifa	261,597	4,976.0	10.1	1.3
Jerusalem	265,451	6,600.8	13.4	3.0
Tel Aviv/gush Dan	527,497	7,169.8	14.5	0.8
South	944,932	21,285.7	43.2	71.6

SOURCE: IEC (2007).
NOTE: GWh = gigawatt-hour.

[15] In 2007, electricity consumption in Israel was 6,332 kWh per capita and 7,560 kWh per household, on average. This may be compared to more than 12,000 kWh per capita in the United States.

Israel's Electricity-Generating System

To meet the demand for electricity Israel relies on four primary types of fuel. In 2007, 69.5 percent of Israel's electricity was produced by coal, 3.4 percent by heavy fuel oil (known as *mazout* in Hebrew), 19.7 percent by natural gas, and 7.4 percent by diesel oil (that is, medium distillates, also referred to as *gas oil*, or *soler* in Hebrew) (IEC, 2007).[16]

As can be seen in Table 2.4, IEC plans a substantial increase in natural gas–fueled generating capacity. It projects that, by 2012, 40 percent of Israel's electricity will be produced by natural gas.[17]

As of December 31, 2007, IEC maintained and operated 17 power-station sites with an aggregate installed generating capacity of 11,323 MW. Peak demand in the same year was 10,070 MW. (On January 30, 2008, peak demand reached 10,200 MW.) Each site has one or more separate units to generate electricity. There were 60 generating units at IEC sites at the end of 2007: Twenty-two utilized steam-driven turbines and 38 gas turbines (of which six were CC gas turbines). Table 2.5 specifies the generating capacity as of the end of 2007 by the various types of generating unit, including electricity purchased from private producers.[18]

Natural Gas in Israel's Electricity-Generating System

Many of the major infrastructure investments and supply arrangements needed to establish natural gas as a significant, long-term viable source of fuel are just now being planned and implemented. As a result, Israel's efforts thus far have been primarily focused around a series of steps to increase the share of electricity generated by natural gas. Supply contracts, distribution arrangements, and increased generating capacity all are serving, however, as a foundation from which Israel can choose to rely more heavily on natural gas for electricity generation and further develop the natural-gas industry as a whole.

Table 2.4
Israel's Electricity-Generation Mix, by Fuel Type, 2007, and Estimate for 2012 (percent shares)

Fuel Type	2007 Shares	2012 (IEC estimate)
Coal	69	54
Natural gas	20	40
Diesel oil	7	2
Fuel oil	3	3
IPPs	0.6	0.5

SOURCE: IEC (2007).
NOTE: IPP = independent power provider.

[16] Unless otherwise noted, all data in this section are based on information from IEC's series of statistical yearbooks. The project team was generously provided with access to much more-detailed proprietary information on Israel's electricity-generation infrastructure for use in its modeling. In line with the conditions for use that accompanied these data, none of these inputs is reported in these pages. The discussion in this section includes only publicly available information.

[17] As is discussed in Chapter Three, in this study, we have used IEC demand projections as a baseline around which we vary assumptions to explore the implications of different demand paths.

[18] See Appendix D for a discussion of the technical aspects of operating the different types of power plants, by fuel and technology type.

Table 2.5
Israel's Electricity-Generation Capacity (MW), as of December 31, 2007

Type of Unit	Installed Capacity (MW)
Total generating capacity	11,323
Total generating units in IEC	11,297
Steam-driven power stations	6,756
Jet gas turbines	511
Industrial gas turbines	1,334
CC gas turbines	2,002
Gas turbines intended for future operation as CC	694
Generating by IPPs under company supervision	26

SOURCE: IEC (undated).

NOTE: Installed capacity represents the level of output that may be sustained continuously without significant risk of damage to plant and equipment.

IEC first began using natural gas from Yam Tethys for electricity generation in February 2004 at its Eshkol power station. The use of natural gas for electricity generation expanded to a second power station in July 2006, when the Reading power station in Tel Aviv converted to the use of natural gas. By 2007, IEC's yearly consumption of natural gas had grown to 2.695 BCM. Then, on May 1, 2008, the first natural gas purchased by EMG from Egypt began to flow to IEC's power plants. Estimates forecast annual consumption of natural gas to increase to up to 3–4 BCM in 2009.

IEC purchases natural gas from the Yam Tethys consortium under a contract that started in February 2004 and is intended to deliver 18 BCM over 11 years. The total agreement amount was set at $1.8 billion. In August 2006, an agreement was signed between IEC and the Yam Tethys Group to regulate increased hourly consumption of gas at peak demand periods, above the quantity committed to in the basic agreement. The gas to be supplied under this agreement is charged at a higher rate than in the basic agreement but still lower than the price of heavy fuel oil.

In August 2005, a contract with EMG, a joint Egyptian-Israeli company, was signed for the purchase of 25 BCM of natural gas over 15 years, at a total cost of approximately $2.5 billion. However, EMG might raise the price of the natural gas it sells to Israel, since the Egyptian government has raised its selling price to EMG by up to 70 percent.[19] Egypt's increase in prices reflects changes in the energy markets since the original negotiations began in 2000, but this move was probably also motivated by opposition members in Egypt's parliament who have attacked the government harshly for selling natural gas to Israel for what it deems to be below-market prices. The issue was taken to court, and, in February 2009, the Egyptian Supreme Court ruled in favor of continued sales to Israel (Essam El-Din, 2009).

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[19] The Egyptian government refused to disclose the exact price at which it sells its gas to EMG, which exports the Egyptian gas to Israel, saying, "There is no fixed price, but foreign gas exportation companies in Egypt agreed that the price should be adjusted to reach between $2.5 and $2.65 per million British thermal units [MMBTU]." Previously, it was estimated that EMG had purchased gas for approximately $1.5 per MMBTU (Bar-Eli, 2009a).

In the near future, a purchase agreement will have to be made with the partners of the prospective Tamar and Dalit natural-gas fields following the discovery of what may be between 90 BCM and perhaps more than 140 BCM of recoverable natural gas in Tamar and a lesser amount in Dalit. By law, Israel's Minister of National Infrastructures can require the partners in the Tamar-1 and Dalit gas discoveries—or in any other gas or oil well in Israel—to sell all of its production to Israel. The state may also control the rate of production as it sees fit.[20]

In addition to negotiating supply contracts, IEC has established agreements regarding the distribution and transport of the acquired natural gas. In February 2008, IEC renegotiated its transport agreement with INGL,[21] with a yearly cost embedded in the agreement of up to $50 million once the Alon Tavor (in Israel's north) and Haifa units begin to operate on natural gas (expected in 2009). IEC was granted the flexibility to divert up to 15 percent of the ordered natural-gas volume among its various natural gas–fired generating plants and also the right to order additional gas volume for the short term (for a full month minimum). This agreement is to remain in force for 15 years, applying to all sites to be connected to the gas pipeline.

IEC has followed government directives in converting industrial gas turbines and some of the steam-driven units that previously operated solely on fuel oil to operate on natural gas as well. As of late 2007, the Eshkol power station, with an installed capacity of 1,285 MW, was operating entirely on natural gas.[22] Two generating units at Tel Aviv's Reading power station were also converted to natural gas, with installed generating capacity of 428 MW. Together, these units generate about 15 percent of Israel's electricity. By June 2008, IEC completed the work necessary for the use of natural gas at Gezer, enabling further growth in the share of electricity generated by natural gas—first flow, and use came in the following month. The natural gas was initially used for the first 350-MW CC unit at Gezer (in the region near Beersheva) and, soon thereafter, was also used in the second such unit to be located at that site. In addition to Gezer's CC units, the plant has four industrial gas-turbine open-cycle units of 150 MW each that have been retrofitted and can now operate on natural gas. In total, the Gezer power station can generate 1,200 MW by natural gas. These additions bring Israel's share of electricity generated by gas to 30 percent.

With a looming shortage of reserve capacity caused by both the failure to begin construction on the coal-fired plant D and the failure of IPPs to come on line as had been anticipated, Israel has again looked to natural gas. In May 2008, as part of the emergency plan put in place by the government to cover the shortfall in generating capacity owing to delay in plant

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[20] According to section 33 of the Israel Petroleum Law of 1952, which also applies to natural gas,

> The minister is allowed, after consulting with the Oil Board, to require the owners of the holdings to first provide, at market prices, from the oil they produce in Israel and from oil products they produce from it, the quantity of oil and oil products the minister thinks is needed for Israeli consumption.

The law does have some limitations on the minister's powers, but, in cases of "national security or to prevent waste or to prevent dishonesty toward another [rights] holder," the minister is allowed to overrule these limitations.

[21] In 2003, the new government company INGL was founded and granted the natural-gas concession for the purpose of constructing and operating the southern part of the national gas system in Israel. According to the tripartite agreement that the government of Israel, INGL, and IEC signed in November 2004, IEC was to fund and manage the project, estimated at $249 million, which would be returned to IEC within 15 years. Up to June 2006, IEC and INGL worked under an interim contract for gas transmission. In June 2006, a 15-year contract was signed, despite the fact that IEC had reservations about a number of issues in the agreement. This contract was renegotiated and replaced by a new one in 2008.

[22] Four of the generating units at Eshkol are steam turbines with installed generating capacity of 912 MW. One additional generating unit is of the CC type, with installed generating capacity of 373 MW.

construction, IEC prepared to increase its generating capacity with the purchase of two additional gas turbines of 180–340 MW. To further address the shortage, IEC plans to build two CC units to be added to existing power plants, one to be sited at Ramat Hovav (in the south) and the other either at Hagit (southeast of Haifa) or at Eshkol. The estimate is that these units will generate between 360 and 680 MW in open cycle by 2010, and the added steam components to be completed by 2012 would bring the generation of these units to between 540 and 1,020 MW in CC.

At the time of this writing, IEC was also in the final stages of completing work retrofitting additional units to operate with natural gas, among them Hagit, Zafit (next to Kfar Menahem), and Ramat Hovav. In addition, on January 13, 2009, the cornerstone of the foundation of an NGCC generating system on the Haifa power-plant site was laid. As part of the emergency plan, IEC was instructed to install two CC units with a total capacity of 750 MW, the first of which is expected to be in operation by early 2010.

Markets and Regulation

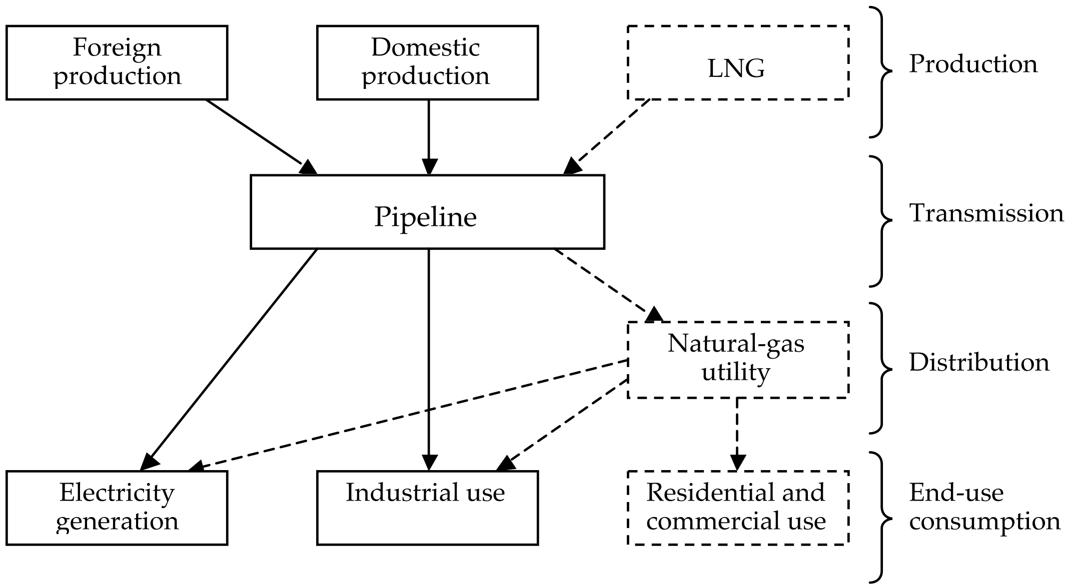
Israel's natural-gas industry is in its infancy. Many of the major infrastructure investments and supply arrangements needed to establish natural gas as a significant, long-term viable source of fuel are just now being planned and implemented.

The MNI is responsible for overseeing the development of Israel's entire energy, water, and sewer sectors, as well as the management of its natural resources (see Figure 2.2). The Natural Gas Authority works under the MNI as an executor of its policies, regulations, and rules. The Natural Gas Authority was established as the regulatory body for the national natural-gas industry in accordance with the Natural Gas Sector Law of 2002. It has been tasked with the following responsibilities:

- issuing licenses related to use of natural gas and its commerce as well as supervision of license holders
- approval of engineering specifications for the purpose of awarding building permits
- approval of tariffs and rates for sale of natural gas to end users
- coordination of the staff work in the MNI regarding natural gas
- providing permits for land use to license holders (e.g., electricity producers)
- publication of tenders and preparation of licenses
- formulation of a transportation agreement for all consumers
- setting up arrangements and determination of fees for connection of consumers to the transportation system (MNI, undated).

Figure 2.2 depicts Israel's natural-gas industry. (Owing to the early state of Israel's natural-gas development, not all functions are presently in place.) The industry can be disaggregated into four functional areas: production, transmission, distribution, and end-use consumption. Production includes the exploration, extraction, and collection of gas supplies. In the case of Israel, production can be disaggregated into gas transferred into the country via pipelines from Egypt or elsewhere, gas domestically produced from Israeli proven reserves, and imports of LNG. Transmission of natural gas is carried out by pipeline companies (of which there is currently only one) that own and operate the high-pressure pipeline capacity. Such local utilities

Figure 2.2
Structure of the Natural-Gas Industry in Israel



NOTE: Dashed lines and boxes represent industry segments and relationships that are not yet established but are likely to develop in the future.
RAND *TR747-2.2*

as may come into being would be generally responsible for the distribution of natural gas from high-pressure pipelines to customers. Finally, end-use consumption includes the use of gas for electricity generation, the overwhelming bulk of demand now and for the foreseeable future, as well as possibly increasing penetration into industrial (including transportation), commercial, and residential uses.

In August 2004, a license for the construction and operation of the transportation system was issued to INGL. The government-owned company is solely responsible for transmission of natural gas to all high-pressure gas consumers and to low-pressure consumers that consume more than 2,000 cubic meters per hour and 12 million cubic meters per year. It assesses rates for transmission, and any users meeting the set criteria may contract with it. From its inception and prospectively into the future, INGL has been prohibited from engaging in the sale of natural gas (MNI, undated). No low-pressure distribution lines have been built at this time. Therefore, currently there are no companies providing distribution services to residential, commercial, or transportation or other potential low-quantity consumers of natural gas. The only current or imminent industrial users of natural gas, besides the power industry, are firms whose use of natural gas is so great that it makes sense to take delivery through the high-pressure distribution system.

IEC has been Israel's sole organization responsible for electricity generation, transmission, and distribution. In 2003, privatization reforms were approved that will split IEC up into three private organizations, each responsible for one of the company's core responsibilities (electricity generation, electricity transmission, and electricity distribution). Previously, and again in 2005, Israel passed reforms with the intent to open the market to competition. The 2005 reforms allow private power producers to build power plants and sell electricity directly to end users.

Currently, IEC continues to generate, transport, and distribute the vast majority of electric power to consumers in Israel although the intention remains that competition will grow in the coming years with the possible dismantling of IEC. Lack of agreement between the government and IEC (and the powerful union of IEC workers) has prevented full implementation of the 2005 reforms. Further, although several IPPs operating natural gas–fired facilities were originally scheduled to be in place, with the first beginning operation in early 2009, as of now, most of these investment projects have not yet begun construction.[23]

To provide means for the reader to compare Israel's experience with other countries, we have included several short studies in Appendix F. We include short descriptions of natural-gas use in Japan and South Korea, also countries that exist as energy islands—one by reason of geography, the other by reason of politics.

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[23] The sole exception is Delek's 83.5-MW power station in Ashkelon. Also, the main use of natural gas at the Paz Ashdod oil refinery is intended to be production of electricity to be used on site by that firm. The 44-MW plant being built there will provide the 17 MW consumed by the plant annually, with the balance sold to private customers.

CHAPTER THREE

A Framework for Identifying Robust Natural-Gas Strategies

Long-Term Natural-Gas Planning for an Uncertain Future

The previous chapters laid the background for understanding the choices Israel faces in determining its future use of natural gas. This chapter and the next will describe the methodology we employed in conducting this study. Our analytical effort proceeded along two major axes. The principal axis has been to conduct a detailed, quantitative analysis using computer-based modeling of future demand, technology change, infrastructure investment, and fuel choice. Parallel to this effort, the RAND team conducted extensive interviews in Israel. In addition, we conducted several workshops to gather input from Israeli energy experts, government officials, and academic specialists. The purpose of those meetings was not only to gather useful input but also to put some of the early results from the RAND analysis before professional audiences to gain feedback and clarification. For both benefits we are grateful to the participants of these workshops.[1] In the balance of this chapter, we describe the structure of our modeling and quantitative analytical effort. The information we gained from the second (interview and workshop) axis is woven into our discussion of the analysis and its results.

The great changes in the world's energy (and economic and political) environment that have occurred since the beginning of the 21st century have brought home to most people that uncertainty about the future is now a staple of our daily life. Those responsible for planning, deciding, and implementing government policy have known this for quite some time. Those planning Israel's energy future are in an even more challenging position than most. Even a more apparently limited issue, such as deciding how best and to what extent to utilize natural gas in that future, requires looking at all alternative options for determining and meeting future demand. And these energy questions, in turn, are deeply entwined with fundamental decisions that will affect the structure of Israel's domestic society and the economy, while regional and global forces beyond Israel's control will have their own incalculable effect. Clearly, there would be great value in being capable of predicting both trends and consequences.

Considerable effort is devoted by dedicated analysts in government offices and academic institutions in Israel and elsewhere to creating detailed models to support policy decision-

[1] The formal workshops and working-group meetings we conducted for this project were held at the following venues and dates: Center for Advanced Energy Studies, University of Haifa, March 2007; Israeli National Security Council, March 2008; Energy Working Group, Samuel Neaman Institute, May 2008 (see Grossman, Ayalon, and Goldrath, 2008, for a summary of this workshop); IEC, March and May 2008; Ministry of Foreign Affairs, November 2008; and Ministry of the Interior, November 2008.

making and planning. The resulting models are ingeniously contrived tools that vastly improve the quality of such efforts, in both the public and private sectors. Such models can grow to great detail and complexity, greater than that of the models we use in this study. Yet, in a sufficiently uncertain environment, even the designers of such models would not claim that they could generate reliable predictions for a decade from now—to say nothing of the more than two decades until 2030, the period of the present study. Try as we might, we are usually not capable of creating simulations of a complex and adaptive system, such as an economy placed within a larger environment of other world economies, which will yield reliable predictive outputs. Large, detailed market and macromodels of energy economies cannot be entirely accurate in predicting even one year into the future—to say nothing of a decade or more. Viewed in this light, there is no a priori evidence that the models used in this study would necessarily perform worse than models of considerably greater sophistication. That being the case, it is worth asking what use our model or, indeed, any model of Israel's energy economy through the year 2030 can be for illuminating policy choices.

Traditional model use has been governed most often by a strategy of analysis that instructs us to develop the most apposite and accurate possible model of the system of interest, to use that model to generate predicted future states, and then to apply the tools of optimization to find the best course of action. Is this a reasonable use of an analytical model, however, under conditions of deep uncertainty, when prediction is not credible?[2] If we have optimized for one, supposedly most likely, future and the actual future turns out differently, we can hope that our previously optimal plan will still be serviceable—but we have no actual proof or theorem that this will, indeed, be the case. We might find ourselves bound on a course that is clearly deleterious to our interests, given the way the state of the world has changed from what had been expected.

This observation raises the question of whether we even ought to be interested in prediction in the first place. That is, predictions themselves are not our end goal. Rather, we wish to understand how different beliefs about the future and their relative likelihoods could affect our choice among alternative short-term actions today and how the actions we do take will affect our chances of being successful in meeting our goals in the years to come. In other words, our true interest is not so much in predicting the future. Rather, realizing that we cannot be sufficiently predictive, we seek some means to understand how we can choose today's actions most wisely in light of our long-term objectives.

The logic of the analysis we present in this chapter is that it is not sufficient to optimize strategy for one assumed set of conditions in the presence of the deep uncertainty that sur-

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2 Deep uncertainty prevails when we do not know or cannot agree on correct probabilities to assign to variables, the correct model of process and causation, or the criteria by which to evaluate and compare alternative outcomes. A number of different terms are used for concepts similar to what we define as *deep uncertainty*. Knight (1921) contrasted risk and uncertainty, using the latter to denote unknown factors poorly described by quantifiable probabilities. Ellsberg's (1961) paradox addresses conditions of ambiguity in which the axioms of standard probabilistic decision theory need not hold. There is an increasing literature on ambiguous and imprecise probabilities (Walley, 1990). Ben-Haim's (2001) information-gap approach addresses conditions of what he calls *severe uncertainty*. Fuzzy logic approaches allow beliefs to be members of different sets simultaneously, while imprecise probabilities describe beliefs with a set of different probabilities. In recent years, studies have begun to apply such approaches especially to environmental questions, such as climate change (Ha-Duong, 2003; Hall et al., 2007). Scenario-based planning methods (Schwartz, 1996) also represent uncertainty with sets of fundamentally different views of the future.

We take the phrase *deep uncertainty* from a 2001 presentation by Kenneth Arrow describing the situation that climate-change policymakers face. The precise definition of this term is our own.

rounds long-term planning and analysis. Rather, the goal should be to seek those strategies that might not be optimal in any given future but are likely to prove robust. That is, they will achieve certain minimal criteria set by planners and the larger society across a wide range of plausible future states of the world. In this case, what we need from a model is not a prediction. Rather, a model serves as an artifact that contains what we understand about critical relationships among key factors and that can then be used to generate the myriad scenarios of the future that are consistent with our current information. As we systematically vary assumptions about factors whose future values are presently unknowable, we generate an ensemble of alternative futures purposefully constructed so as to act as a test bed for helping select among policy alternatives. Rather than characterizing uncertainties at the beginning of the analysis by assigning values, assuming probability distributions, or dropping them entirely pending later analysis and updates of available information, we leave the uncertainties uncharacterized in terms of probabilities but nevertheless explicitly represent them in the model. In effect, we are now asking which uncertainties would affect our decisions today and how certain values of these presently uncertain factors might affect our choice among actions.

Elements of Robustness Analysis

Our analytical approach is based on employing a computational technique called *exploratory modeling* (Bankes, 1993). Exploratory modeling is a method for performing compound computational experiments—that is, using computers to run models multiple times to explore what range of plausible outcomes is implied by the structure of the models on the one hand and the different assumptions about future values of key variables that are consistent with our present information—or lack thereof—on the other.

This technique then allows us to bring in a strategic and policy dimension. What actions or strategies may be shown to be robust, in the sense of reliably achieving minimum threshold levels of satisfactory outcomes with respect to one or more metrics of interest, across the greatest range within the landscape of plausible futures generated by the compound computational experimental design? An analysis of this type is usually referred to as a *robust decision method*.[3] In this study, RAND researchers applied an innovative, quantitative robust decision method approach called *robust decisionmaking* (RDM). Robustness, though important in itself, is not necessarily the only desirable property from the perspective of planners and policymakers. But the concept of robustness proves to be key to making possible the systematic, rigorous analysis of policy problems not previously amenable to such inspection. Using the robustness criterion allows policymakers to understand more clearly the nature of their problem and the behaviors of its possible solutions. The goal is not to mechanize policy decisionmaking; it is to enhance our powers of observation and ability to draw insightful inferences.

There are four major components to an RDM analysis that utilizes the method of compound computational experiments to test alternative strategies across the range of plausible

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[3] The theory and practice behind the policy application of exploratory modeling is discussed at length in Lempert, Popper, and Bankes (2003). A more technical discussion of the general method may be found in Lempert, Groves, et al. (2006). A short, popular introduction for the interest of general audiences is available in Popper, Lempert, and Bankes (2005). More information on robust decision methods may be found, at increasingly technical levels of discussion, in Popper, Lempert, and Bankes (2005); Lempert, Popper, and Bankes (2003); and Lempert, Groves, et al. (2006). Another robust decision method is the Robust Adaptive Planning™ (RAP™) method developed by Evolving Logic.

futures. The first two are directly related to the inherent uncertainties whose presence makes analysis by more-traditional means infeasible. The first of these two classes represents the external uncertainties, the X factors outside the control of the planner or decisionmaker. What will be the future prices of alternative fuels? What will Israel's relations be with its neighboring states? How great will future economic growth and demand for energy be in Israel in 10 or 20 years' time? Each should be explored individually and jointly with other uncertain factors.

The second group contains those factors that different government bodies and other actors in Israel may control. What rules should be set for emissions? How much excess generation capacity should be built into the electricity market? To what degree should Israel rely on different fuels as primary-energy sources? These actions, policies, and initiatives are best thought of as individual levers (L factors). These levers are then packaged in different configurations, combinations, and sequences to produce alternative strategies. We prefer to construct strategies from such levers so that the robustness properties of the resulting strategies may be examined in detail. The uncertainty element among this class of components arises because it is difficult to determine, without prior analysis, the outcomes to which each such action or lever would give rise.

This motivates the need for a third major component. These are the measures (M factors) used to determine how close the outcomes produced by candidate strategies under particular assumptions about future conditions come to meeting policy goals and criteria for goodness. This, too, requires explicit exploration because it is rarely the case that a single measure will satisfy all parties and address all questions. For a strategy to be robust, it must prove that it performs well not only under a variety of external conditions but also according to the various values and aspirations about which we care. It is not sufficient, for example, to meet our goals for economic growth if the standards we set for environmental quality, sustainability, or even national security are seriously compromised. This aspect of robustness is among the most important when assessing public policies.

The last of the major components of an RDM application are the relationships between factors (R factors). Taken as a whole, these present an underlying model of cause and effect that makes particular actions have different outcomes depending on external conditions. It is best to be as explicit about these as about the elements that make up the other three components because they themselves often represent uncertainties about which different analysts and stakeholders may disagree. Therefore, the model part of the analytical framework (the structural uncertainty) may be made subject to exploration as are the values taken on by specific factors within the models (the parametric uncertainties).

Taken together, these four components—the uncertainties planners face, the policy tools from which they may craft strategies, the lens through which scenario outcomes are observed to assess success or failure of the strategy, and the underlying mechanisms of cause and effect—describe the policy space within which government officials may consider what is the best set of instruments to use in order to achieve the goals that have been set by the political process. This is the space within which our analysis has been set.

Table 3.1 presents the four major components in an XLRM framework. This is a simple sketch of the discussion to follow in the balance of this report. It lists, for the purpose of illustration, some of the major types of factors that will be specifically explored in the analysis to follow. The rest of this chapter discusses in detail the variables in our analysis that fall into the first two rows: uncertainties beyond the control of planners (X) and the policy levers that they might have available to them (L). Chapter Four discusses the models we built and used (R) in

Table 3.1
Components of Robust Decisionmaking Analysis, by Factor Type

Factor Type	Description	Factors
X	Exogenous (outside of decisionmakers' control)	Price path for coal Price path for natural gas Cost of carbon dioxide (CO_2) emissions Cost of fossil-fuel technology Cost of non–fossil fuel technology Availability of non–fossil fuel technology Demand for electricity Cost of efficiency improvements Administrative limits on GHG emissions Cost of capital Supply from foreign pipelines Discovery of new domestic reserves Fixed cost of LNG installation Variable cost of LNG supply Fixed cost of new domestic natural gas Variable cost of new domestic natural gas Cost of storage capacity Cost of capital
L	Levers (within decisionmakers' control)	New plant type and primary fuel National infrastructure construction Level of reserve generation capacity (policy) Share of generation capacity from coal and nonfossil fuel (policy) Dispatch order of electricity generation Administrative control of GHG emission levels Administrative control of land use Imposition of price on carbon emissions Adoption of non–fossil fuel technology and capacity Energy-efficiency enhancement Target level of reserve capacity Rate of domestic reserve depletion Level and timing of LNG capacity Fuel storage types Fuel storage levels
R	Relationships among factors	WASP package MAED LEAP system RAND natural-gas supply model
M	Measures used to gauge success	Total system costs Total fuel costs Balance of cost-sharing over generations Annual natural-gas supply requirement GHG emissions Land-use requirements Level of reserve generation capacity (actual) Share of generation capacity from coal and nonfossil fuel (actual) Depletion of domestic reserves (actual) Cost of providing a given level of supply insurance Cost of implementing supply insurance Potential unmet demand for electricity

NOTE: Each list of factors is divided into two sections. The first section of each list corresponds to the first of our two main research questions: What is a robust strategy for the utilization of natural gas in Israel through the year 2030? These pertain to the discussion presented in Chapters Five and Six of this report. The second section of each list is factors that are key to finding answers to the second question: What is a robust strategy for ensuring the supply of natural gas at the levels required to support the chosen utilization strategy? This question is treated in a separate analysis of natural-gas supply security that is presented in Chapter Seven.

greater detail. We will also provide a fuller version of the XLRM diagram for this study at the end of that chapter. Discussion of the last category, measures used to evaluate outcomes, will be discussed in detail in Chapter Six. This discussion will arise more naturally after first examining the initial results from our analyses.

Uncertain Factors and Alternative Futures

The first class of uncertain factors, the X factors largely determined by forces not under direct control of Israel's planners, will define the different states of the world that might confront Israel in the future. We identified nine such factors for the first part of our analysis pertaining to strategies for the use of natural gas in Israel. We selected these factors based on interviews in Israel and consulting the available literature to capture the main elements of the natural-gas planning problem. These factors are economic or technical in character and would affect not only choice of strategy for use of natural gas but also the outcomes that would ensue from these alternative choices. (We discuss in Chapter Seven some other external uncertainty factors that entered into the second part of our analysis, the security of natural-gas supply.)

The large number of potential values that these nine individual factors could take would create myriad combinations when taken together. This would complicate both the computational and analytical tasks without adding much value. Therefore, we sought to define an experimental design that would include representative cases of each of the major uncertain factors that we believe will be the most important aspects of future conditions that will affect natural-gas planning and policy outcomes. In the course of an RDM analysis, one can revisit the experimental design either to focus more intensely (i.e., with greater detail) on a subset of the space of plausible futures or to modify the range of plausible values.

To create our experimental design, in the majority of cases, we selected three (and, in one case, four) different values a factor might take. These factors were chosen in light of several considerations. We wanted to define a range that reflected widely differing assumptions. In addition, we wanted to reflect some of the debates, concerns, and views we gathered from interviews and from consulting the available literature. We wanted to make certain to include the base assumptions most often used in Israel, whether in the calculations of the government agencies or by private energy companies, as well as possible values that would violate these assumptions. This is an important means for discovering and testing candidate robust strategies. Finally, we sought to generate a test bed of alternative futures that would produce widely different conditions under which each strategy would need to operate. It is not computationally feasible to test literally every possible future state of the world. A robustness argument must necessarily be rooted in an inductive reasoning process rather than a more deductive approach that lends itself more easily to proofs. Therefore, a heterogeneous set of alternative future-based scenarios is necessary to build confidence that a sufficiently wide set of possibilities has been selected on which to make robustness arguments.

Each of these nine factors is listed briefly here. Generally, the first item in each list of three (or four) is a trend that would, in general, be considered favorable. The second provides a middle-range assumption about future trends. The last one (or two) alternative assumptions generally present a turn toward a direction that is less comfortable—e.g., higher price, more-restrictive regulation, greater cost.[4] In each set, one of the alternative assumptions has been italicized. This indicates those assumptions that were used to form the base-case scenario used in the initial parts of the analysis to follow.

Natural-Gas Price Base Value

- Constant price: Real prices remain constant at the 2007 IEC projection of $6.33 per MMBTU.
- *Steady increase: Real prices increase to $8 per MMBTU in 2015 and $10 per MMBTU in 2030.*
- Steady increase: Real prices increase to $10 per MMBTU in 2015 and $14 per MMBTU in 2030.

Appendix A describes in more detail how actual natural-gas prices are calculated and used in the model. Briefly, the value of this variable is used as a base number for two alternative sources of natural gas. The first of these two streams models the current deliveries arriving from Yam Tethys and from EMG—that is, for sources with infrastructure already in place.[5] The second is intended to model additional sources, such as from a newly developed domestic field, supply from a third-country supplier, or deliveries of LNG. In this case, an amortized capital charge is added to cover the costs of the new installations required. The actual price used in the model's calculations will be an average of the two price streams weighted by the shares of total natural-gas demand that originate from each source.

Diesel prices are initially set at $95 per barrel and follow the same percentage changes as for natural gas in each of the three alternative price-path assumptions.

As may be seen in Figure 3.1, the alternative natural gas (and middle distillate) price paths we consider cover a wider range than at least one set of commonly employed price forecasts. Our desire was to incorporate a range that would bracket a wide assortment of plausible price paths. Once again, the desire was not to be predictive in an area where it is not feasible to develop reliable forecasts. Rather, we wished to explore what assumptions would cause a decision to rely less on natural gas than the current level anticipated by Israel's planning authorities.

Coal Prices

- Constant price: Real prices remain constant at IEC projection of $4.01 per MMBTU.
- *Peak: Prices rise to $6 per MMBTU in 2015 and decline to $4 by 2030.*
- Steady increase: Prices rise to $6 per MMBTU in 2015 and $8 per MMBTU in 2030.

As with all of our assumptions on projected price paths for fuel, there are two line segments. The first begins with prices set at the latest annual average values for which we had data, 2006,

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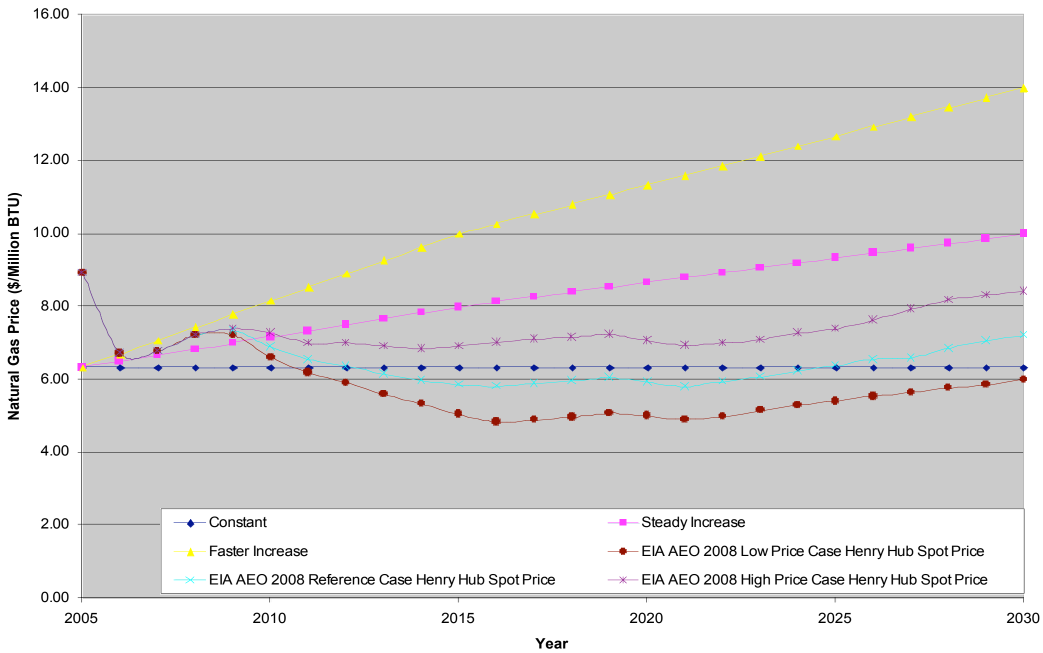
[4] The exception to this rough ordering is in the case of alternative plant capacity. For this variable, the successive assumptions are built to reflect more-extensive employment of the technologies involved, so they are not graded from favorable to unfavorable as are the others.

[5] We define a projected price path for each fuel using two line segments. The first segment defines prices from the current period to 2015 and the second from 2015 to 2030. Each segment follows a path defined by the assumptions selected for a given set of future conditions. In the case of the first, the initial price is taken from the data on current contracts for deliveries from EMG.

Figure 3.1
Comparison of RAND Modeling of Natural-Gas Price-Growth Assumptions with Energy Information Administration Natural-Gas Price Cases



NOTE: AEO = Annual Energy Outlook. EIA = Energy Information Administration.
RAND *TR747-3.1*

and rising to the value indicated for 2015. The second describes prices from 2015 through 2030.

Carbon-Emission Cost (in CO_2 equivalents)

- *No cost: There is a $0-per-tonne tax through 2030.*
- Medium: There is a $50-per-tonne tax by 2030 (linear increase beginning in 2010).
- High: There is a $120-per-tonne tax by 2030 (linear increase beginning in 2010).

Many alternatives have been proposed for internalizing the public costs that are now widely accepted to be the consequence of combustion of fossil fuels. These range from elaborate cap-and-trade systems through taxes of various types to imposing regulations and fines. We did not seek to examine these proposals in detail. But neither did we wish to ignore this increasingly important element of each nation's calculation of energy balance.

Israel is a relatively small emitter of carbon-based GHGs. Yet, as elsewhere, concern is rising for both environmental and political reasons. At present in Israel, in common with most places, there is no formal cost attached to CO_2-equivalent emissions to reflect the true cost of this activity. This cannot be presumed to continue through 2030. If not imposed directly, it is possible that Israel would face such possibilities as taxes on the carbon content of its exports or other international regimes established to halt the growth in emissions of GHGs.[6]

[6] A concern with natural gas is that any loss or spillage along the fuel stream will also result in the release of a GHG, CH_4. Some schemes have discussed applying cap-and-trade or pricing regimes to the embedded emissions in this fuel rather than

We have chosen to represent these possibilities through a simple mechanism. In some scenarios, the current zero cost for CO_2-equivalent emissions changes in 2010. In some, the ramp-up from zero cost is to $50 per tonne by 2030. In others, the price in that end year reaches what is currently viewed as the high end of the scale of proposals: $120 per tonne. Of course, this pricing need not necessarily be in the form of a direct tax. We choose to model it as such for convenience alone. The implicit assumption is that the proceeds exacted by establishing this price are directed to a government general fund.

Fossil-Fuel Technology Costs

- Low: Initial costs are 10 percent below the IEC estimate, with a 1-percent annual decline in capital costs.
- *Medium: Initial costs equal the IEC estimate, with a 0.5-percent annual decline in capital costs.*
- Higher: Initial costs are 10 percent above the IEC estimate, with no decline over time.
- Highest: Initial costs are 10 percent above the EIA AEO 2008 estimate, with a 0.25-percent annual decline in capital costs.

The costs of building fossil fuel (in our analysis for Israel, principally coal)–fired power plants rest on several factors. There may be changes in the fundamental technology that, at least in the early days, may raise capital costs while also yielding greater efficiency and lower output of pollutants. Further, as with most technologies, there is a learning effect that tends to reduce cost per unit as more units are produced. In addition, many external factors may affect costs. For example, during the first part of the decade that began the 21st century, large increases in demand in China and elsewhere significantly drove up the costs of construction materials. Therefore, in an analysis that spans more than two decades, no single assumption about price for this type of investment may be used without question.

Alternative (non–fossil fuel) Energy Technology Costs

- Low: Initial costs are 20 percent below the 2007 IEC estimate, with a 2-percent annual decline in capital costs.
- *Medium: Initial costs are at the IEC estimate, with a 1.0-percent annual decline in capital costs.*
- High: Initial costs are 20 percent above the 2007 IEC estimate, with a 0.5-percent decline over time.

The arguments about fossil-fuel technology have even more force in the case of relatively early-stage technologies, such as those involving solar and other renewable-fuel power generation. The ranges we used for this variable are accordingly wider than those for the fossil-fuel technology variable.

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solely on smokestack emissions (Bluestein, 2008). This is of greatest concern in countries where natural gas is widely used by households and other low-level consumers. This is not the case in Israel, and we have chosen to apply any pricing of CO_2-equivalent emissions solely to GHG production that arises from combustion of fuel.

Alternative (non–fossil fuel) Energy Plant Availability

- Low: Installed capacity reaches one-third the maximum by 2030.
- *Medium: Installed capacity reaches two-thirds the maximum by 2030.*
- High: Installed capacity reaches the maximum by 2030.

Using our understanding of prospective government plans, interviews, and the available literature at the time we conducted this study, we set the maximum possible installed capacity at 4,000 MW for solar-thermal power generation and 1,800 MW for pumped-storage facilities. For comparison purposes, by mid-2008, the worldwide use of solar-thermal plants in generation was slightly under 500 MW.[7] We include this as an external variable because, from the standpoint of today's planners looking at the natural-gas planning problem, it is uncertain what costs, technological changes, and other future factors will be. These could serve to frustrate the planned rate of renewable-energy investment.

Electricity Demand

- Low: Demand will be 76 billion kWh in 2030 (4-percent gross domestic product [GDP] growth, a 2-percent decrease in service- and industry-sector energy intensities, and a 0.5-percent increase in residential energy intensity).
- *Medium: Demand will be 116 billion kWh in 2030 (4-percent GDP growth, a 0.5-percent decrease in service- and industry-sector energy intensities, and a 2-percent increase in residential energy intensity).*
- High: Demand will be 165 billion kWh in 2030 (6-percent GDP growth, a 0.5-percent decrease in service- and industry-sector energy intensities, and a 2-percent increase in residential energy intensity).

This input is the derived demand for electricity given specific assumptions about underlying drivers, such as demography, economic growth, and the relative energy intensities of different parts of the economy of Israel. We worked from the demand-path scenarios developed by IEC. Of course, various policies and factors to be considered in our analysis may affect the growth and scale of demand, but this input variable may be thought of as the demand generated under ceteris paribus conditions.[8] The medium-demand scenario largely follows the pattern of the medium-demand scenario used by IEC. Our two other demand paths bracket the high and low scenarios used by IEC, as shown in Figure 3.2. This was, in part, due to not having access to the assumptions that lay behind IEC's demand-path scenarios, but also from a desire to ensure that the plausible range was bracketed by our selection of test assumptions.

We have described what underlying growth and energy-utilization intensities generated the curves we employed. While it is certainly possible to suggest other combinations of GDP

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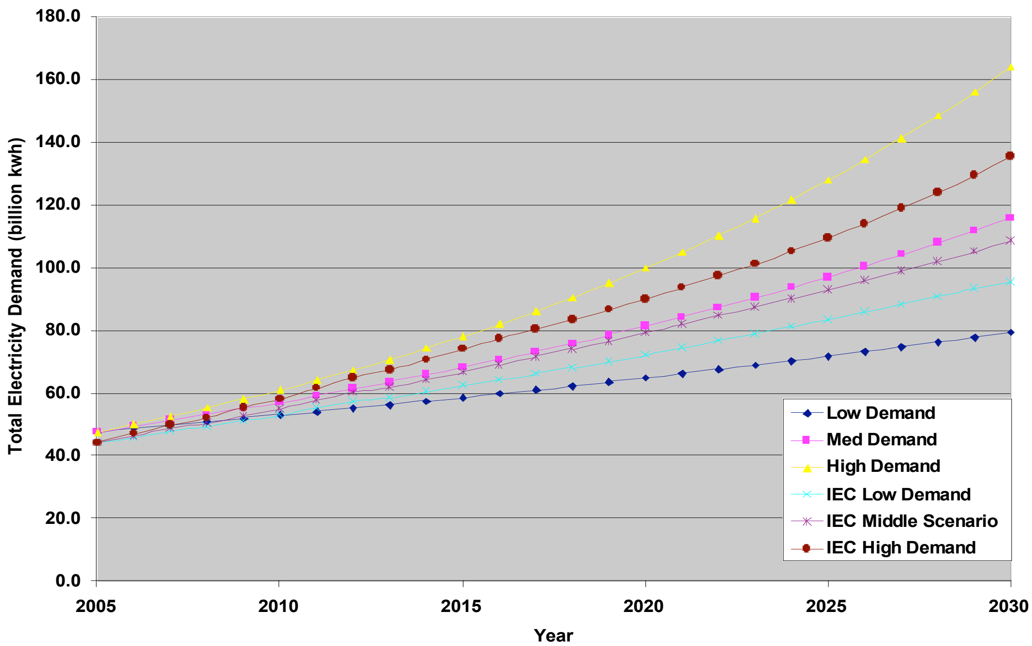
7 It should be noted, however, that there are also power plants currently at different stages of the planning, licensing, and construction processes that would add another 8,000 MW in solar-thermal capacity worldwide if all become operational. The majority of these projects are scheduled for completion by the end of 2012. One recent report projects that having 10 percent of Israel's electricity come from renewable sources in 2020 would require 3,500 MW of mostly solar-thermal and solar-photovoltaic capacity. A 20-percent-renewable standard by 2030 would require about 10,000 MW of such plants. See Mor, Seroussi, and Ainspan (2005).

8 Please see the discussion of the economic-efficiency input variable in the next section.

Figure 3.2
Comparison of RAND Modeling of Electricity Demand–Growth Assumptions with Israel Electric Corporation Demand-Growth Scenarios



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growth and sector energy intensities, the resulting demand paths would need to fall within the range we have outlined to be considered plausible looking out to 2030. Our desire to ensure a broad range of demand assumptions stemmed from the analytical philosophy and methodology of recognizing the possibility of surprise. We provide an example of one factor, among many, that could skew current demand forecasts for Israel. Note that this base demand-growth assumption may be modified, in part, by differing assumptions about efficiency gains, as discussed in the next section.

Water Desalinization. Attempts to supplement the nation's water supply through desalinization will obviously have an effect on the demand for power. The desalinization plant that services Eilat, for example, works as much as possible during the off-peak hours. At times of high demand during the summer months, however, it may work around the clock to supply the 50,000 or more cubic meters of reclaimed water demanded by its customers daily. To produce brackish water (10–17 parts per thousand [ppt] saline) from natural wells requires 1.2 kW per cubic meter.[9] Freshwater produced from seawater requires 4.5 kW per cubic meter. The costs are nonlinear; it takes ever-increasing amounts of energy to remove the last traces of salinity.[10]

[9] Technological change has brought this down from an input of more than 1.5 kW a decade ago. Further change in membrane, pump, chemical, and pipe technologies may be expected to produce incremental change, but not a revolutionary change, as long as the reverse-osmosis process remains the basis. Just pumping water from wells 200 meters deep may require a further 1 kW per cubic meter.

[10] The ultimate use of the water will also determine costs. Seawater contains about 5 ppt of boron. Desalinization will reduce this to 1 ppt. While this reduced level of boron is perfectly acceptable to humans, it will still prove unhealthy for plants. Therefore, agriculture requires a further step to remove this element from the water.

It should be noted that the energy required at peak may not all be taken from the national power grid. The water company also bases liquid-fuel generators at its desalination plants. While reducing the strain on the national power grid, such generation may, of course, entail costs that are greater than usually charged by the electric company to its customers.

The Eilat plant produces 3 million cubic meters of freshwater per year. Another desalination plant in Ashkelon can produce 100 million cubic meters. As new desalinization plants are added, even with changes in technology and increases in efficiency of production, the potential effect on demand remains large. For this reason, the demand profile of Israel through 2030 may not track as well with historical patterns of energy intensity experienced by other countries as they move through to more-advanced stages of economic development.

Efficiency Costs

- Low: Initial average cost is $0.05 per kWh, with 0.5-percent growth.
- *Medium: Initial average cost is $0.075 per kWh, with 1-percent growth.*
- High: Initial average cost is $0.075 per kWh, with 2-percent growth.

One of the actions that may be employed by the strategies we examine is to enhance efficient use of electricity and energy by various means. Such efficiency gains are attainable at a cost. We have modeled the costs of attaining efficiency gains and so reduction in demand as additional costs per kWh of electricity generated. In Chapter Eight, we discuss the example of California, which has largely been able to keep demand flat over decades despite large population increases by reducing the energy intensity of its economy and profile of energy use on a per capita basis. We arrived at the efficiency-cost assumptions by inspecting data on California in recent years. As such, the costs we have used to frame our assumptions for Israel may well prove to be on the high side. Most experts would likely conclude that California has traveled further along the efficiency-enhancement path than Israel. Typically, the easiest and least-costly actions are taken first with costs rising as greater efficiency gains are sought.

Our model does not detail what precise measures are taken to achieve greater efficiency. Public-awareness campaigns, subsidies for the purchase of more-efficient appliances, inducements to volunteer for selective brownouts, and penalties for excessive use are just some examples that have been used elsewhere. Similarly, we do not detail who ultimately pays for these efficiency improvements. Clearly, greater specificity in this regard would lead to differing rates of success, but this level of detail would be lost at the level of aggregation we use in the simulations. We presume that appropriate approaches were taken to achieve the gains realized in the model.

The costs are an important dimension in seeing how much the gain in efficiency actually is. The model calculates, for each of the three different assumed price paths of efficiency-enhancement costs, a cost for that year per kWh of electricity thus saved. This is compared to what the levelized cost of energy (LCOE) would be for electricity produced from a combustion turbine (CT) plant designed to generate power at peak levels of demand.[11] If the efficiency costs are less than this LCOE, the efficiency improvement is purchased and added as an incre-

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[11] This is a proxy chosen in lieu of the calculations that otherwise would be required to take into account all the economic factors that would be presumed to influence this decision. However, this approach suggests itself as a reasonable proxy because Israel's current emergency construction plan is building units of precisely this type.

ment to the level of efficiency gain that was realized cumulatively across the previous periods. This increment is constant and of a size that would add up to 20-percent improvement (the government's current target) by the year 2030 if this purchase is made each year. At the point at which this cost is greater than the reference LCOE, however, the efficiency improvement is not purchased, and the efficiency improvement in the economy does not proceed beyond the currently achieved level. As such, efficiency moderates the effect of the ceteris paribus demand pattern. It is an incremental effect that may place demand growth on a trajectory to be between 0 and 20 percent less than would have otherwise been the case in 2030 with unaffected growth in demand.

Greenhouse-Gas Limits

- No limit: No cap is set.
- *Medium: Cap is set at a 50-percent increase from the 2005 GHG-emission level.*
- High: Cap is set at a 25-percent increase from the 2005 GHG-emission level.

Israel is not an Annex I country in the Kyoto Protocol[12] and therefore does not have a specific GHG-emission reduction target. However, it would be inaccurate to then assume that, owing to its size and level of development, the issue of GHG emissions does not arise. There are still several reasons stemming from national self-interest, in addition to any sense of shared global responsibility, that have been moving the government of Israel in the direction of controlling such emissions. The government has committed itself to charting such a course.[13]

Several of the variables listed in this section would seem to be out of place in a list of variables supposedly external to decisionmakers' control. These would include the price set on CO_2-equivalent emissions, the amount of alternative-fuel plant that is installed, the limits set on GHG emissions, and, to some extent, the rate at which demand is permitted to grow. The reasons for doing so become clearer if we remind ourselves that we are looking at the issue of natural-gas use in Israel from the perspective of energy planners. At this time, as they work their planning problem, they have no firm information on what new policies may be put in place, what policies may be changed, and what levels will be deemed advisable by the regulators. Therefore, this ranks as an assumption that would surely affect both outcomes and viabilities of various plans but for which there can be no present certainty.

This explanation also provides the reasoning behind both including an indirect control over carbon-based emissions (in the form of a price attached to emission of CO_2 equivalents) and the more direct administrative measure of setting GHG-emission limits. We are modeling the options of a particular group of government planners who are faced with a number of administrative decisions, such as to whom they should issue licenses for power generation. Israel could, of course, choose not to make levels of GHG emissions a priority. It could institute some sort of pricing apparatus to cause the indirect costs of emissions to be internalized.

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[12] The United Nations Framework Convention on Climate Change (UNFCCC) encouraged countries to stabilize GHG emissions; the Kyoto Protocol is the associated commitment. Annex I parties are those industrialized nations that were members of the Organisation for Economic Co-Operation and Development (OECD) in 1992 or were so-called economy-in-transition (EIT) states. See UNFCCC (undated).

[13] See, for example, Ministry of Environmental Protection (2004); a statement of June 9, 2009, specifically sets out to implement the government decisions to reduce GHG emissions (Ministry of Environmental Protection, 2009).

Alternatively, or in addition to such a scheme, the planners themselves might put into place preferences for those plants that would utilize fuels or technologies that lead to fewer GHG emissions. By including both the direct and indirect measures as inputs that can take on different values or assume different states, we ensure that the set of scenario outcomes this generates will include examples of all four of the instances we have described, as well as a variety of levels at which each such policy lever could be applied.

Cost of Capital

- 5 percent.

This is a tenth input variable. During the course of the analysis, we conducted tests at several points to determine the effect that different discount rates had on scenario outcomes and analytical conclusions. We found that, while these assumptions led to sometimes-large differences in costs, they did not materially affect the central issue of natural-gas utilization strategy. Therefore, we eliminated this variable from the main analytical runs to reduce the computational load.

Policy Levers and Strategies

The second component of an RDM analysis of this type would be the actual levers available to public and private decisionmakers. These levers are under the control of the policy planners, but their effects, particularly within a sufficiently complex and uncertain environment, are themselves uncertain. It is useful to think in terms of levers or discrete actions because actual strategies will be composed of a selected number of such levers. Some may appear across all candidate strategies, others may only appear in a select number, and variation in the sequencing of actions can provide yet a further source of variation among candidate strategies. We would wish to examine the outcomes ensuing from scenarios generated by simulating the effects of applying successive strategies to a wide range of plausible future circumstances. Recursive use of this method will allow us to frame strategies with increasingly enhanced robustness properties.

The discussion to date implicitly described a set of policy levers available to Israel's planners and decisionmakers. The main elements are as follows:

- timing and choice of new power-generation plant type and primary fuel
- national infrastructure construction
- target level of reserve electricity-generation capacity
- target share of generation capacity from coal and nonfossil fuel
- dispatch order of electricity generation
- administrative control on GHG-emission levels
- administrative control of land use
- imposition of price on carbon emissions
- adoption of non–fossil fuel technology and capacity
- energy-efficiency enhancements.

Accordingly, we sought to frame the set of candidate strategies we used in this analysis based on selection, emphasis, and timing of different combinations of these levers.

A Rule-Based Approach to Strategy Formulation

Each of the candidate strategies we used for evaluation of alternatives was framed in the form of a set of rules. This is in contrast to strategies consisting of fixed energy-infrastructure investment plans. As a matter of practice, a government energy plan will most often take this latter form. That is, each year of the planning period will see particular power stations or other infrastructure constructed and brought online in accordance with a long-term plan that has been approved in the past by the appropriate authorities. There are several reasons we did not take this course for the present study.

The first reason is entirely practical. This study was conducted for the benefit of the MNI and other government bodies in Israel. While we were given access to a great deal of information in the course of the project, because of the lack of formal auspices for this study, we could not be granted access to government plans or planning processes for legal reasons. Therefore, we did not have permission to examine the most-current such infrastructure-building plans nor the competing plans over which these plans would have been selected.

The other reasons are more substantive. It would be astonishing indeed for a major national energy-infrastructure plan intended to map out investment over several decades to be fulfilled precisely as its authors originally laid out. Not even they would expect this to occur. Rather, all parties understand that the purpose of such a plan is to define broad directions and establish priorities. The plan will be adhered to as long as its assumptions prove true. As there are shifts in future demand, prices, national priorities, world developments, and unforeseen exigencies, the plan will be modified. Even though more information on the then-current state of those factors that were uncertainties when the plan was drafted will be known once specific future dates arrive, there will still be uncertainty about the values these factors will take on in the period after the plan's course correction is taken. Therefore, the practical realities dictate that the plan will continue to be referenced to emerging realities and changed accordingly, albeit not necessarily without difficulties, both substantive and administrative.

In circumstances in which change is required but insufficient information exists to make modifications based on concrete analysis (as is most often the case in the real world), rules of thumb play a large role.[14] This is the role, for example, played by hurdle rates when corporations determine priorities among competing investments.[15] Such hurdle rates are often set quite high not in the expectation that such yields will actually be realized but rather as insurance in the face of uncertainty. Experience has shown on an individual industry-by-industry and firm-by-firm basis what hurdle rate needs to be set in order to guarantee with reasonable confidence that the portfolio of actual investments will yield a satisfactory positive return.

We have constructed our strategies around such rules. In the nomenclature we used within our research team, the strategy C_50_GHG_P40_ALT, for example, adheres to the following rules:

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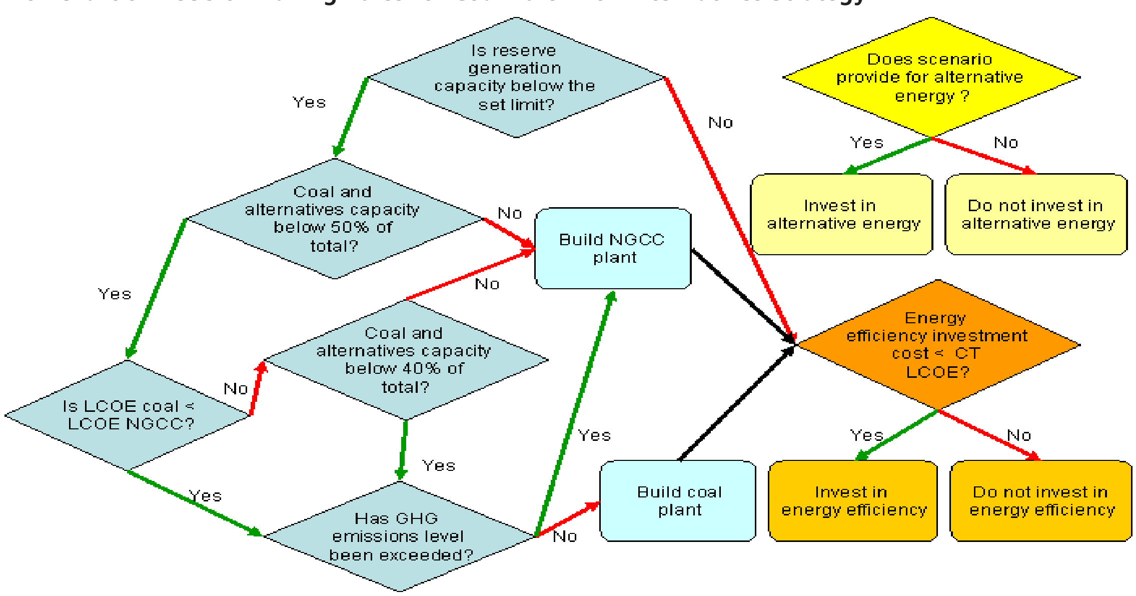
[14] Much of the work of Herbert Simon discusses how the rules of thumb are often the bases of decisionmaking in the context of insufficient information. For a practical application, see Lempert, Popper, Resetar, and Hart (2002).

[15] A hurdle rate is a threshold rate of return that a particular investment project would be expected to yield ex ante—that is, as estimated in its plan. Formal hurdle rates that are many multiples of actual historical rates of return on projects are routine.

1. If, in the year being modeled, electricity demand will exceed the reserve margin percentage of generation capacity and fraction of peak power capacity deemed acceptable according to policy, new capacity will be added by signaling construction of a new power-generating facility in the ensuing period. If none of the rules below come into force, the plant will be an NGCC power plant.
2. If the total level of generation capacity from coal and renewable fuels is less than 50 percent (50), this rule will build a coal-fired plant (C) of standard size using best available technology unless a statutory level of GHG emissions has been exceeded (GHG). If the latter condition holds, it will build an NGCC plant.
3. If the less-than-50-percent threshold condition is triggered but the GHG condition does not apply, build a coal plant if the total LCOE supplied would be less than the total LCOE from an NGCC plant at then-current prices (P). Otherwise, build an NGCC plant. Irrespective of cost, if the total generation capacity from coal and renewable fuels falls below 40 percent (40) and the GHG condition does not apply, build a coal-fired plant.
4. *ALT* indicates that this strategy will allow the construction of alternative- and renewable-fuel power stations if the scenario conditions make them available. Strategies without this property will ignore such alternatives even if present according to the scenario. This indicator also permits policies designed to enhance energy efficiency to an extent that demand in the year 2030 has been reduced 20 percent from the level it would achieve in the absence of such initiatives. The cost of such policies is itself an unknown at the time the plan is implemented and is actually set by scenario conditions.

Figure 3.3 shows the operation of this strategy in flowchart format. For the convenience of the reader, this particular strategy, one of the candidate robust strategies we examine in the analysis to follow, will be referred to in our discussion as *Coal Rule with Alternatives* or *Coal Rule_Alt*.

Figure 3.3
Flowchart of Decisionmaking Rules for Coal Rule with Alternatives Strategy



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The rules that comprise this strategy are intended to emulate those considerations through which a planning and implementation authority would go when faced either with a new need or a necessity for plan modification. There are, of course, other considerations that would enter in, such as political and financial decisions. As with the more formal infrastructure-investment planning documents, our rule-based strategies abstract from these other considerations. In essence, therefore, we are testing what set of decision rules does best in addressing a wide set of possible changed future conditions.

This line of thinking brings forth the final reason for our exploration in strategy space to take the rule-based form. Because we did not enjoy the opportunity to work directly with the MNI in forming Israel's energy plan, we needed to consider how the results from our work could still prove to be of value in the presence of an accepted national plan. We determined that our value lies in providing two forms of insight. The first, of course, is to provide the value of having a second team, operating from a different perspective but with largely the same body of available facts, to examine the role that natural gas could and perhaps should play in Israel. The second again refers back to the uncertain circumstances under which plans are framed and then unfold. When change is required and the planners at that latter date require means to navigate among changed conditions, it is our intention that the approach we have taken will provide insight into categories of actions and particular policy levers. We will have illustrated how such actions affect outcomes across a wide set of circumstances and what combinations of factors may lead to their failure. This is the raw material on which Israel's energy planners may then draw to find means to hedge around emergent problems as well as to shape their decision-making environment as well as they can in order to achieve their long-term goals.

Candidate Robust Strategies

Our approach was to craft an initial set of rather simple rule-based strategies, simulate the scenario outcomes of these strategies across a wide range of alternative futures, and then, in light of these results, modify the strategies by adding sophistication and introduce new strategy types. Those strategies whose results were completely dominated by the results of others were dropped from the set.

It is important to emphasize that the principal focus of this study is on the strategies for use of natural gas in Israel through 2030 and not on resolving Israel's energy puzzle as a whole. So, for example, several of our early test strategies envisioned the addition of nuclear power to Israel's fuel mix. However, nuclear-power generation, if at all feasible in the Israeli context, would likely occur only relatively late in our period, due to the technical, planning, regulatory, and political hurdles that must first be addressed. This option therefore did not have as much effect on the fundamental issues surrounding the use of natural gas as might otherwise be supposed.

In the analysis that we pursued, several rounds of analysis brought us to consider a set of seven candidate robust strategies. Each strategy is described in greater detail in Appendix A.

Wien Automatic System Planning (WASP) Strategy. This strategy serves as our reference strategy. It does not necessarily correspond to the current or prospective energy master plan of Israel's MNI. Rather, it is the energy infrastructure–building plan that emerges from the WASP optimization model program when WASP is given a set of assumptions on demand, costs, and technical design factors that correspond to the planning assumptions used by the

MNI.[16] As such, it alone among the candidate robust strategies is not rule based. Rather, it implements a building plan that has been developed based on a set of initial conditions and will build different types of generating capacity and other infrastructure but will do so at times set by the plan. The plan itself is designed to be optimal from a cost perspective while meeting demand and satisfying other policy constraints. However, the plan is invariant. If the assumptions on which the plan has been devised do not correspond to future realities, there is no mechanism for correction.

Coal Rule Strategy. The family of Coal Rule–type strategies carries forward a program in which new and existing coal-fired generating plants will provide the electricity base load both for reasons of cost and for the relative certainty of primary-fuel supply. Both NGCC and dual-use but largely natural gas–fueled CT facilities are used during those times and conditions in which it is economically efficient to utilize natural gas for shoulder and peak production.

The essence of the Coal Rule strategies is to preserve diversity of generating capacity both for reasons of integrity of an electricity system not tied into a larger, regional grid and for reasons of supply security. The 50-percent decision rule at the heart of this strategy reflects a current regulation limiting natural-gas use. The rule limits natural-gas use because of concerns over grid stability if the country can rely on only a single fuel. If the fuel source for a majority of Israel's plant capacity were to be disrupted unexpectedly, then system operators or automatic mechanisms may need to shut down power plants (*load shedding*), causing large-scale blackout, or risk potentially serious damage to the electricity grid. Furthermore, in the period before new domestic discoveries may be proven and developed, decisionmakers in Israel believe that relying on any single supply path for such a large portion of the country's energy requirement presents risks of a different, more strategic, character.

The Coal Rule strategy also incorporates attention to any GHG-emission cap that regulatory bodies may set. That also will force some movement away from coal to natural gas. This strategy may largely be thought of as carrying the current de facto situation of Israel forward into the future. As with all the strategies, the Coal Rule strategy maintains the reserve margin and peak capacity conditions for investing in new CC and CT capacity.

Coal Rule with Alternatives Strategy. The core of this candidate robust strategy is the Coal Rule approach. This variation has two additional aspects that will apply to the other candidate strategies that employ efficiency policies and renewable alternatives as well.

The first additional component is the availability of alternative forms of electricity generation. We have assumed that two such forms of alternative-energy sources are potentially available in the time frame of the analysis: solar-thermal plants and pumped-storage systems.[17] An important point is that, under this strategy, alternative-energy sources are built if they are available under the scenario conditions—both cost and potentially available supply of such plant are input variables. Another way of putting this is that, from the perspective of the planners, the cost and availability of these alternatives are additional unknowns. This reflects the large uncertainty that remains about technological issues, installation decisions made by other planners elsewhere (and, therefore, how and to what degree the current high prices for these innovative technologies will drop), and regulatory and land-use issues that might arise for large-scale installations.

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[16] The WASP model program is discussed in Chapter Four.

[17] Pump storage is, of course, just that: a means for storing potential energy during a prior period that may be used to generate electricity at a later time. It is not in itself a stand-alone alternative for generation in the strictest sense.

Energy efficiency is treated differently. For strategies that explicitly incorporate energy-efficiency policies, in each year, the government can invest in demand-reducing efforts that are cumulative over the analysis period. The government invests in these measures annually if they are cost effective, that is they would cost less than power that would come from installing a new natural-gas CT. Over the entire analysis period, cumulative savings of 20 percent are available if the government invests in demand reduction in every year it is eligible to do so. The analysis treats the costs of energy efficiency as a scenario variable in a similar manner to the treatment of alternative-energy costs and availability.[18]

Least Cost Strategy. The Least Cost strategy follows many of the same decision criteria as discussed for the Coal Rule family. In this instance, however, when observation of reserve margins and peak power percentages triggers a new plant-building decision, the strategy's algorithm will observe the LCOE among the available generating technologies—coal, natural gas, solar, and pumped storage—and choose the one that produces electricity at least cost. The essence of this strategy is contained in its name: Reduce vulnerability to cost risk.

Least Cost with Efficiency Strategy. Unlike the other strategies, both variants of Least Cost may incorporate alternatives because of favorable LCOE values but are not mandated to do so. This version of Least Cost, however, also has available to it policies that will reduce demand at a cost determined by scenario conditions, as is the case with the two other strategies that incorporate elements of efficiency enhancement.

Gas Rule Strategy. Like the Coal Rule strategy, Gas Rule uses the reserve margin and fraction of peak power capacity as triggers to add new capacity. It does so by adding NGCC capacity. The strategy adds natural gas–fueled CTs when the share of peak power plants declines below 20 percent of total capacity. The Gas Rule includes an option to build a coal plant in 2020 if the LCOE of a coal plant is less than the LCOE of an NGCC plant.

This strategy calls for an aggressive replacement of scheduled new coal-fired base-load capacity with natural gas–fueled alternatives. It may be viewed either as the position of strong opponents of further coal use in Israel or the de facto option the country may find itself facing if past experience in building plant D, a fourth coal-fired generating station, continues as the norm into the future. The essence of the Gas Rule strategies is to reduce emissions and hence, presumably, vulnerability to health and environmental risks.

Gas Rule with Alternatives Strategy. This strategy adds to the pure-form Gas Rule strategy the efficiency and alternative energy–generating capacity discussed above.

Table 3.2 provides a synopsis of the seven basic candidate strategies for use of natural gas in Israel.

The next chapter discusses the third component of an RDM analysis, the models that specify the relationship between policy levers, uncertain future states of the world, and measurable outcomes.

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[18] This approach has the advantage of an aggregate, simplified approach to modeling the use of energy-saving technologies. A highly disaggregate analysis of individual demand-reduction technologies applicable to the Israeli market was not available and was beyond the scope of this analysis. However, as the results of this analysis show, it would be highly valuable for future energy policymaking in Israel.

Table 3.2
The Candidate Strategies for Use of Natural Gas in Israel

Strategy	Preferred Build When More Capacity Is Needed	Conditions Under Which to Build Coal Plant	Build Renewable-Fuel Power Plants?	Invest in Efficiency Gains?
WASP	According to set plan	Called for in plan	Yes, if called for in plan	No
Coal Rule	NGCC	1a. Coal and renewables make up less than 50% of generation capacity; and b. GHG-emission limit is not exceeded; and c. LCOE coal < LCOE NGCC - or - 2a. Coal and renewables make up less than 40% of generation capacity; and b. GHG-emission limit is not exceeded.	No	No
Coal Rule_Alt	NGCC	1a. Coal and renewables make up less than 50% of generation capacity; and b. GHG-emission limit is not exceeded; and c. LCOE coal < LCOE NGCC - or - 2a. Coal and renewables make up less than 40% of generation capacity; and b. GHG-emission limit is not exceeded.	Yes, to level described in scenario	Yes, if LCOE efficiency < LCOE from natural-gas CT
Least Cost	Least LCOE among coal, NGCC, and renewables	Least LCOE	Yes, if LCOE renewables < NGCC or coal	No
Least Cost_Eff	Least LCOE among coal, NGCC, and renewables	Least LCOE	Yes, if LCOE renewables < NGCC or coal	Yes, if LCOE efficiency < LCOE from natural-gas CT
Gas Rule	NGCC	In 2020 or in 2025, LCOE coal < LCOE NGCC or renewable (i.e., maximum: 2 plants in total)	No	No
Gas Rule_Alt	NGCC	In 2020 or in 2025, LCOE coal < LCOE NGCC or renewable (i.e., maximum: 2 plants in total)	Yes, to level described in scenario	Yes, if LCOE efficiency < LCOE from natural-gas CT

CHAPTER FOUR

Analytic Platform for Evaluating Natural-Gas Strategies

In this chapter, we discuss the relationship (R) component of the XLRM analysis. These are the formal models that determine how pursuing particular actions (in our usage, choosing particular policy levers [L]) and applying them in a particular state of the world characterized by the variables outside the planners' control (X) will lead to different scenario outcomes whose desirability, from the perspective of our interests, will be assessed by a series of measures (M).

To implement this mode of analysis and apply it to illuminating Israel's choices about natural-gas use, this project built an entirely new analytical environment designed to implement the RDM approach we have discussed. We did so by using and integrating three different simulation models to analyze Israel's energy system. We then placed them within a software environment (the Computer Assisted Reasoning® system, or CARs™) designed to support and automate the large numbers of simulations required for the compound computational experiments we sought to perform. Figure 4.1 provides a conceptual overview of the relationships between these models and the environment within which we exercised them.

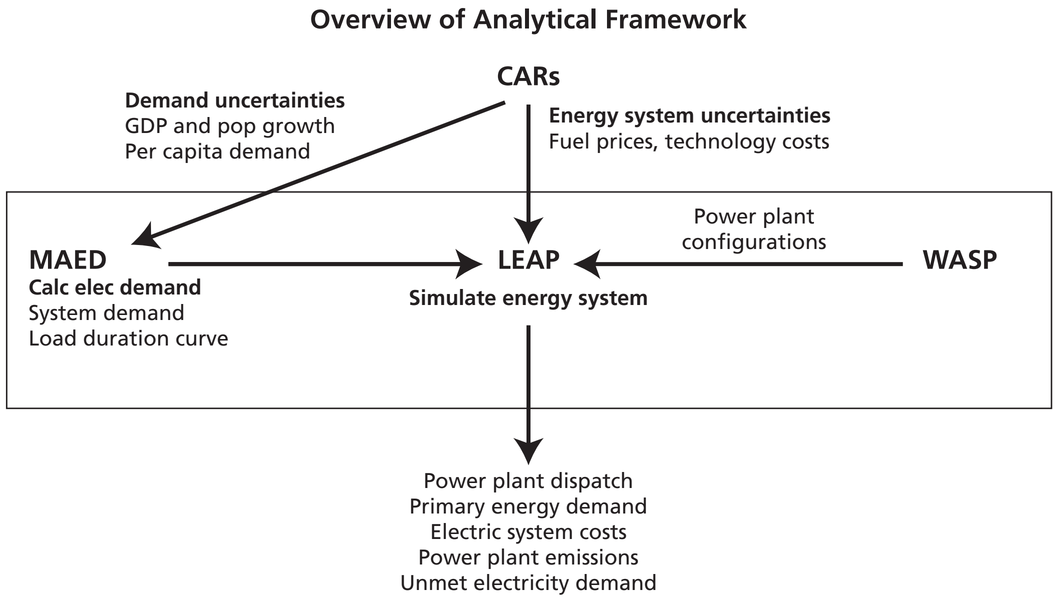
The three simulation models are the Model for Analysis of Energy Demand (MAED), the WASP package, and the Long-Range Energy Alternatives Planning (LEAP) system. The MNI in Israel employs both MAED and WASP in its long-term energy planning. The LEAP model allowed us to incorporate outputs from both MAED and WASP, translate them to the annual time step we used in our analysis, and do integrated simulation runs of different fuel paths, energy infrastructure, domestic demand factors, and external drivers and signals, such as prices.

CARs is a computer program that automates operation of the simulation models and facilitates large numbers of simulations.[1] It provides the means for using any model or modeling formalisms to run the required compound computational experiments, selecting methods for generating and examining the results of such experiments, and visualizing the output in a manner that provides integrated interaction between human operator, computational engine, and available information.

The descriptions that follow provide greater detail on the three models and the CARs software and how each was used in this analysis. Appendix A provides more-detailed descriptions of the model architecture we used to simulate the Israeli energy economy.

[1] The CARs software was developed by Evolving Logic, which provided access to it for this study.

Figure 4.1
Conceptual Diagram of Main Model Modules Operating Within the Computer Assisted Reasoning System Environment



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Model for Analysis of Energy Demand

MAED consists of two spreadsheet-based modules that project energy demand based on user-supplied information regarding assumed values for key variables, such as population growth, economic growth, relative size of different energy-consuming economic sectors, and energy intensity (energy use per capita or per unit of GDP) of different classes of energy consumers. The first model (MAED_D) projects overall energy demand for the country by aggregating demand for each major type of energy consumer. The model also estimates demand for each form for final consumption of energy (e.g., electricity, natural gas, gasoline) using user-supplied information on the share of fuel use among consumers. A second model (MAED_EL) is specific to electricity demand. This model uses the projected total demand for electricity by the MAED_D model and estimates the hourly variation in electricity demand. These estimates are known as load-duration curves (LDCs) and are used later in the analysis when simulating power-plant operation.

The International Atomic Energy Agency (IAEA) maintains these models and distributes them upon request to users in member nations. Israel's MNI currently uses these models as tools to project energy and electricity demand as an input to planning. We use projected LDCs from the MAED_EL model in several later steps in the analysis that simulate power-plant operation in Israel. The first step involves the WASP model.

The time step in MAED is very fine grained. It produces demand forecasts on a daily, even hourly, basis throughout a forecast year. We employed MAED to provide electricity-demand load curves based on various assumptions about demand. We then incorporated the results into the LEAP model of Israel's energy economy that we constructed as described in the LEAP section later in this chapter. This allowed us to make us of the detail provided by MAED to better characterize the yearly time step we used in LEAP.

Wien Automatic System Planning

The WASP model simulates power-plant dispatch[2] and calculates the least-cost additions of new power-plant capacity. The WASP model is highly data intensive, as the user must supply data on the existing power plants' operating characteristics, projected fuel costs, projected costs for new candidate power plants, and electricity-demand projections. Preparing the input files for the model is labor intensive; therefore, users typically prepare one best-case set of input values, including assumptions about presently unknown facts, and the model then uses these as the basis for its projections. The WASP model has some capacity for sensitivity analysis, but the values of the input variables cannot deviate substantially from the initial values.

The IAEA also developed the WASP model and makes it available to member countries as an aid to power-system planning. The MNI uses the WASP model in its planning and analysis and made its input files available to the project team for use in this analysis. As we detail here, we used these input files to generate one set of projections for power-plant dispatch and expansion.

The primary advantage of the WASP model is its highly detailed output from the annual power-system simulations and expansion planning. The model uses constrained optimization in the plant dispatch and dynamic programming to estimate the least-cost set of new power plants and their operation. The main disadvantage of this model is that preparing the input files is data intensive and labor intensive, which discourages running more than a few simulations.

We used the results from the WASP model to initialize and benchmark the LEAP model, which is a more simplified model that simulates the electricity system in Israel.

Long-Range Energy Alternatives Planning

Although less detailed in certain respects than WASP,[3] LEAP lends itself to multiple-scenario exploration of the outcomes that arise from differing assumptions and as the consequences of taking different actions.[4] The LEAP model is also an energy-system simulation model that performs many of the same functions as the MAED and WASP models. LEAP can estimate energy demand and hourly electricity loads using LDCs supplied by the user. LEAP also simulates power-plant dispatch and contains decisionmaking rules for determining power-plant expansion.

These functions in the LEAP model are simplified versions of the WASP model, as they generally avoid calculation-intensive optimization routines. LEAP's routines are described in greater detail in Appendix A. In summary, we use the LEAP model as a reduced-form version of the more-detailed simulation models because it is more flexible in varying input values and runs more quickly on the computer. This added flexibility and speed permits a much greater

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2 *Dispatch* covers the actual generation of power as electricity and then making the electricity available to the electricity grid from which it will eventually be distributed to end users.

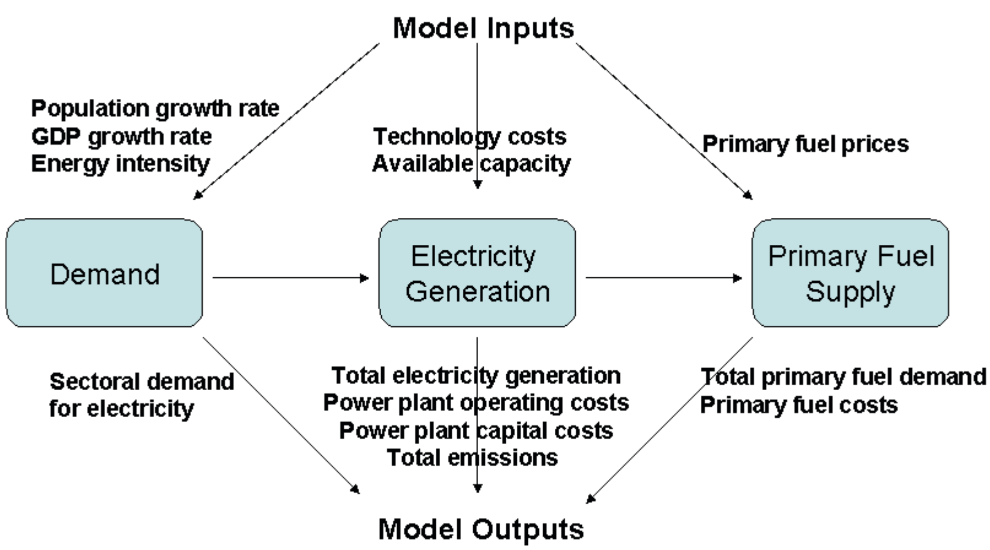
3 In fact, LEAP incorporates a great deal of technical, economic, and demographic detail and is capable of supporting the creation of highly disaggregated models of a particular country's energy economy. Where it differs is that, while MAED and WASP will provide outputs on a weekly, daily, or even hourly basis, LEAP is geared to providing outputs on an annual basis. While a limitation, this actually is a perspective of some value for an analysis designed to look out across Israel's energy future to the year 2030.

4 LEAP was developed and is maintained by the Stockholm Environment Institute.

number of simulations than would otherwise be practical and therefore creates the capability to examine the consequences of varying assumptions across broad ranges of input values while still retaining much of the analytical rigor of the more-detailed simulation models. Figure 4.2 illustrates the different portions of the LEAP model.

In this analysis, we use three modules within the LEAP model that simulate energy demand, electricity generation, and primary-fuel supply. As shown in the figure, the user supplies each module with a set of inputs (the inputs shown in the diagram are for illustration only and are by no means an exhaustive list; please see Appendix A for greater detail). The model first estimates annual energy demand and hourly electricity load based on input parameters, including demographic and economic data, as well as technical information, such as the relative energy intensities of different parts of the economy. The model then supplies this information to the electricity-generation module. This module performs two main functions. It calculates the expansion in power-plant capacity needed to meet demand over the period of analysis. The module also simulates annual power-plant dispatch used to meet the hourly loads throughout the year. With these estimates of new plant capacity and annual generation by each plant, the LEAP model calculates the capital and operating costs associated with the power-plant construction and use, primary-fuel demand, and emissions.[5] In the final module shown, the LEAP model calculates annual demand for primary fuels and the total cost for each fuel demand.

Figure 4.2
Conceptual Diagram of Long-Range Energy Alternatives Planning Model



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[5] This study takes a long-term view of planning and operation of the electricity system of Israel. We assume for convenience that new power plants come online in such a way that the criteria set by planners (such as a mandated share of average annual spare generating capacity) will be met. The implicit assumption that underlies this mechanism is that the necessary analysis, planning, regulatory processes, and construction efforts will have taken place in previous periods. Clearly, this is an assumption that works satisfactorily in the presence of broad changes in markets, technology, and demand taking place over several years. It works less well in the presence of surprise or sudden discontinuous shocks.

The modeling in LEAP was able to achieve a high degree of fidelity when compared with historical patterns because of the generous offer from IEC to provide detailed data on power-plant technology and finance. These data are proprietary in nature. Therefore, while we report output from the modeling and discuss a variety of input variables, we refrain from reporting inputs deemed confidential and provided to us on the understanding that they remain so.

Computer Assisted Reasoning System

The CARs software is an environment within which a model or scenario generator of almost any type may be placed. CARs provides a general-purpose engine for reasoning with compound computational experiments (Bankes, 1993) by offering a convenient platform for linking the numerous functions necessary to support these experiments and user interactions.

CARs is a Java™-based system that can run on a range of computer platforms and is designed to link easily to other applications. CARs can encapsulate a wide variety of sources for computational experiments (e.g., simulation models, statistical analyses, spreadsheets, neural-net training processes) and use large numbers of such experiments to support reasoning and problem solving. The technology allows us to capture both knowledge about and deep uncertainty regarding complex systems by representing infinite ensembles of plausible alternative models. The software supports reasoning about the properties of such ensembles and, hence, properties of ensembles of possible future events through tailored constellations of computational experiments whose specification is guided by user goals and reasoning strategies. In this sense, CARs is middleware technology that allows multiple-uncertainty analysis, data mining, and visualization technology to be interoperated within the methodology of RDM discussed in Chapter Three. It may also be used as the base for a rapid-prototyping system for uncertainty visualization—relying on alternative models, data structures, algorithms, and visualizations in support of evolving concepts.

In this study, we use CARs as a tool for using computer simulation models to generate a large ensemble of plausible future scenarios in which each scenario represents one estimate of the way the world works and the results that would be generated by applying one among the alternative plans for acting on the world. We then use computer search and visualization methods to help decisionmakers extract information from this ensemble of scenarios to evaluate alternative decisions. This approach is general and can reproduce a wide variety of methods of decisionmaking under uncertainty. For instance, one can lay probability distributions over the ensemble of scenarios and reproduce the results of traditional decision analysis (though sometimes less efficiently). By screening the allowable scenarios, one can also conduct a variety of types of constraint-based reasoning. However, in the presence of deep uncertainty, CARs provides a unique ability to combine a wide variety of types of information and allows users to examine a rich menu of uncertainty-management techniques, such as robust strategies, hedging strategies, and strategies that adapt over time in response to new information. In addition, the tool is designed to exploit interactive computer visualizations and thus provides a visual language—which we call a *landscape of plausible futures*—that has proven useful in eliciting from decisionmakers quantitative and nonquantitative information relevant to the analysis.

The approach uses computer simulation models to support inductive, rather than deductive, quantitative reasoning. That is, our system helps users form hypotheses about key aspects of their planning problem, such as what types of plans will be robust against a wide range of adversarial actions or what scenarios put the most stress on such plans; test these hypotheses by searching across the full range of scenarios; and then revise, as necessary, plans and hypotheses in light of the information gained by these searches. This inductive reasoning process makes extensive use of interactive computer visualizations generated by search engines run across the ensembles of models and scenarios but also draws heavily on the narrative interactive techniques of scenario-based planning. This combination of quantitative and narrative techniques can provide an analytic planning system that fits smoothly with human cognitive processes for managing under uncertainty and is ideal for supporting incremental plan formation, with interaction between human and computerized elements in plan development, evaluation, and refinement.

Detailed Exogenous, Lever, Relationship, and Measure Factor Analysis

Table 3.1 in Chapter Three provides a stylized XLRM mapping of the elements that constitute the four main elements of this RDM analysis of Israel's strategic choices with respect to the future use of natural gas. Table 4.1 provides a more detailed version after having discussed three of the four elements in detail. (The fourth component, the measures, M, used to assess scenario outcomes are treated in Chapter Six in the course of presenting analytical results.)

The factors we have shown in the table are not intended to represent an exhaustive list. They are presented because they play an explicit role in the modeling, simulations, and analysis we conducted. The table is presented as a convenient guide for the reader and a means for orientation to what may be found in the following pages.

Table 4.1
Detailed Components of Robust Decisionmaking Analysis, by Factor Type

Factor Type	Description	Factors
X	Exogenous (outside of decisionmakers' control)	Price path for coal Price path for natural gas Cost of carbon dioxide (CO_2) emissions Cost of fossil-fuel technology Cost of non–fossil fuel technology Availability of non–fossil fuel technology Demand for electricity Cost of efficiency improvements Administrative limits on GHG emissions Cost of capital Supply from foreign pipelines Discovery of new domestic reserves Fixed cost of LNG installation Variable cost of LNG supply Fixed cost of new domestic natural gas Variable cost of new domestic natural gas Cost of storage capacity Cost of capital
L	Levers (within decisionmakers' control)	New plant type and primary fuel National infrastructure construction Level of reserve generation capacity (policy) Share of generation capacity from coal and nonfossil fuel (policy) Dispatch order of electricity generation Administrative control of GHG emission levels Administrative control of land use Imposition of price on carbon emissions Adoption of non–fossil fuel technology and capacity Energy-efficiency enhancement Target level of reserve capacity Rate of domestic reserve depletion Level and timing of LNG capacity Fuel storage types Fuel storage levels
R	Relationships among factors	WASP package MAED LEAP system RAND natural-gas supply model
M	Measures used to gauge success	Total system costs Total fuel costs Balance of cost-sharing over generations Annual natural-gas supply requirement GHG emissions Land-use requirements Level of reserve generation capacity (actual) Share of generation capacity from coal and nonfossil fuel (actual) Depletion of domestic reserves (actual) Cost of providing a given level of supply insurance Cost of implementing supply insurance Potential unmet demand for electricity

NOTE: Each list of factors is divided into two sections. The first section of each list corresponds to the first of our two main research questions: What is a robust strategy for the utilization of natural gas in Israel through the year 2030? These pertain to the discussion presented in Chapters Five and Six of this report. The second section of each list is factors that are key to finding answers to the second question: What is a robust strategy for ensuring the supply of natural gas at the levels required to support the chosen utilization strategy? This question is treated in a separate analysis of natural-gas supply security that is presented in Chapter Seven.

CHAPTER FIVE

Evaluating Natural-Gas Strategies Against Uncertainties

In this chapter, we examine the candidate strategies from Chapter Three by considering the outcomes they produce when played out across a set of alternative future states of the world. Each strategy employed in a particular state of the world—that is, a particular set of assumptions about present factors whose future values cannot be presently known—results in a scenario. The set of outcomes from a particular candidate strategy across the full test bed of alternative futures provides the means for assessing the robustness of that strategy and determining where its strengths and weaknesses lie, in an absolute sense. Testing each strategy successively across the same set of alternative assumptions about future conditions allows us to draw conclusions about the relative strengths and weaknesses of each compared to the alternative strategies. In the course of this discussion, we introduce the measures we use to evaluate outcomes.

Exploring Across Strategies

In this section, we first report some results from simulating various strategies under the same base case—that is, a single fixed set of assumptions. This is intended to provide an orientation to understanding what some of the consequences of strategy choice would be. We also explore how one change in assumptions might affect these outcomes.

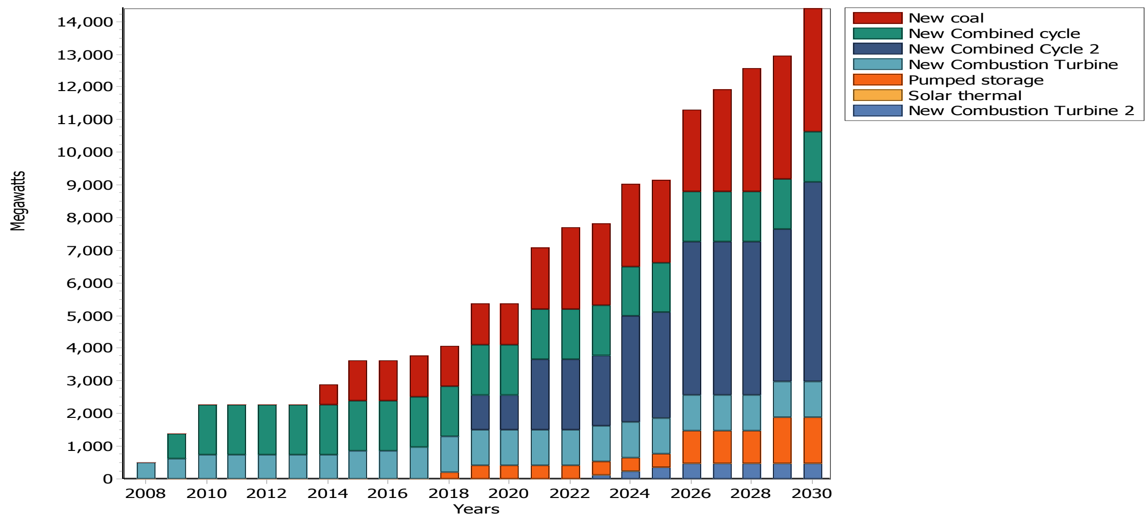
After that, we perform a similar exercise but this time capturing the results of multiple simulation runs as each candidate strategy is compared with the others across a full range of different sets of assumptions. This latter exercise provides the raw material in the next section for then doing an analysis of the vulnerabilities of each candidate scenario and drawing inferences about what a robust approach to the use of natural gas may prove to be.

Performance of Strategies in Base-Case Future

Figure 5.1 shows the results of pursuing the WASP strategy with the base-case assumptions in terms of the volume and types of electricity-generating plants constructed. Under these conditions, by the year 2030, an additional three coal-fired generating plants (with a total installed capacity of 3,780 MW) will have been added. In addition, 11 new NGCC plants (with a total installed capacity of 7,920 MW) would be required in order to meet projected demand under this scenario.[1] Pumped storage is used to balance out mismatches between relatively low-cost electricity-generation periods with times of peak demand, as are CTs.

[1] We arrive at this total for new NGCC plants by aggregating those that would be fueled by supply from Yam Tethys and the existing foreign pipeline (New CC) with those that would require new infrastructure and sources of supply (New CC 2). This corresponds to the modeling details found in Appendix A.

Figure 5.1
Additional Power-Plant Capacity Required by Wien Automatic System Planning Strategy Under Base-Case Assumptions



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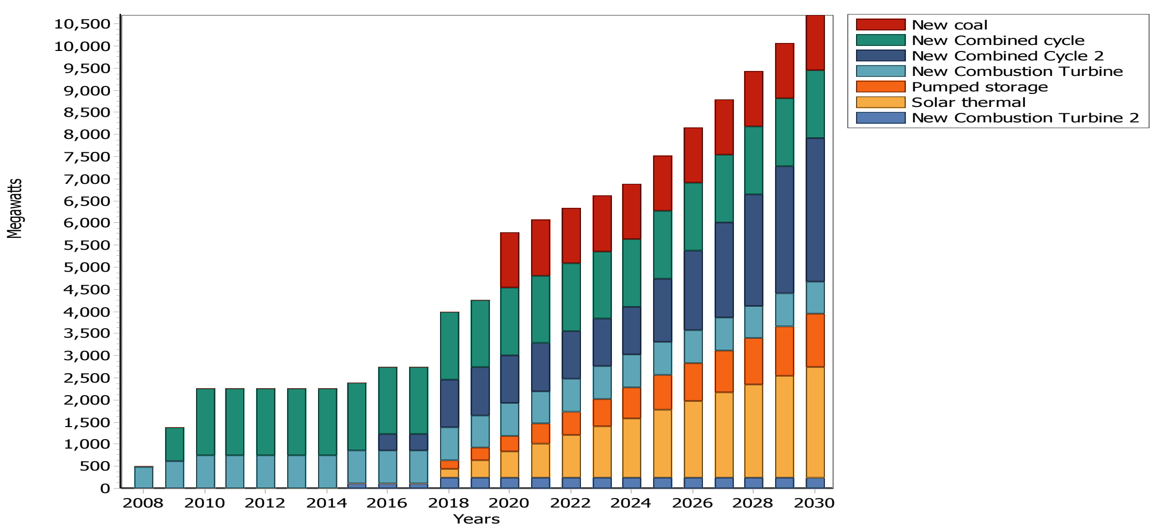
The same approach is shown in Figure 5.2, this time using the Gas Rule_Alt strategy. In this case, only one further coal plant is built in the year 2020, as the strategy permits. The balance of the nation's electricity-generation need is met largely through construction of NGCC plants. This strategy, however, also employs measures to enhance efficiency in such a way that total average demand in 2030 is 20 percent less than it would have been had no such efforts had been made. The nation also builds 2,500 MW of installed solar capacity.

Figure 5.2
Additional Power-Plant Capacity Required by Gas Rule with Alternatives Strategy Under Base-Case Assumptions

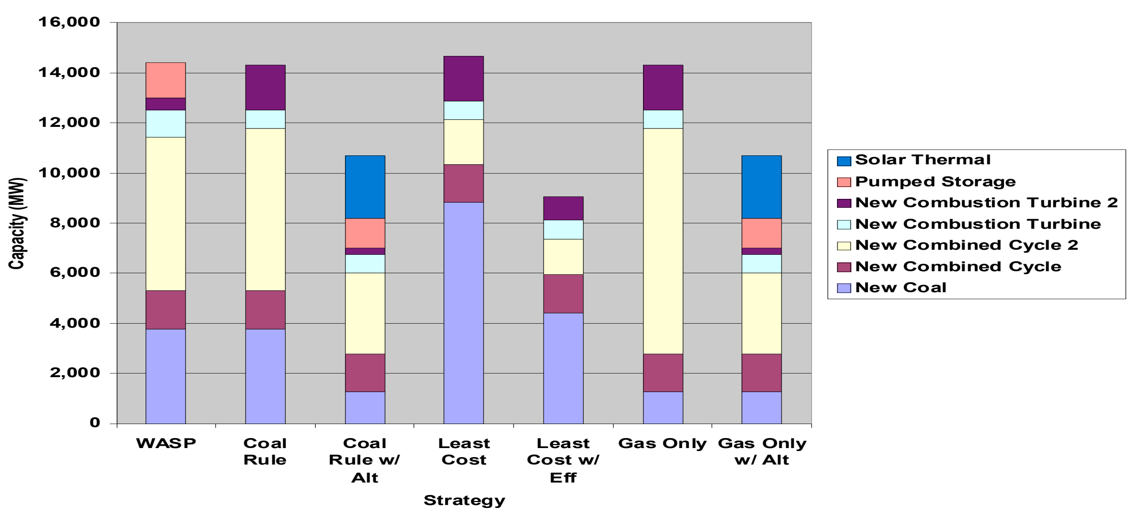


RAND *TR747-5.2*

We can examine the implications of these two and the other candidate strategies for a variety of outcomes of interest. Figure 5.3 shows the total new installed capacity between 2008 and 2030 for each of the candidate strategies under the base-case assumptions.[2] Under these assumptions, the Least Cost strategy will build seven new coal-fired plants of the standard size and no solar facilities, solely due to comparison of costs between the two. Not too surprisingly, the least new capacity will be required by those strategies that also incorporate policies to enhance overall efficiency of electricity use in the Israeli economy. The version of the Least Cost strategy that also includes efficiency measures requires only about 9,000 MW of new capacity.[3] It is interesting to note that the Coal Rule strategies require more natural gas (NGCC and CT) facilities be built than any other strategy except for the Gas Rule strategy.

There are two main components of cost in utilizing any power-generating technology: the costs for the fuel itself and the costs of building and operating the necessary plant. The costs associated with each strategy under base-case assumptions are shown in Figures 5.4 and 5.5. Figure 5.4 shows the aggregate plant costs[4] of each strategy over time. By the year 2030, the Least Cost strategy requires the greatest outlay for infrastructure, followed closely by the two strategies that envision substantial installation of a relatively costly solar-thermal plant. At the same time, the version of Least Cost that incorporates a 20-percent decrease in demand due to

Figure 5.3
New Power-Plant Capacity Installed Between 2008 and 2030 by Candidate Strategies Under Base-Case Assumptions



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2 These simulation runs take into account the new capacity called for in the emergency program introduced by the MNI in mid-2008 (see, e.g., Eliezer, 2009).

3 The other two strategies that incorporate efficiency enhancements to the same level require more installed capacity to be built. This is because, in the LEAP-model accounting system, the installed capacity for solar is discounted by one-third because of the practical limitations of that technology—that is, limited or no generation capacity on cloudy days and at night. To maintain the reserve margin mandated by policy, additional gas-fired installed capacity must be added, whether NGCC or CT.

4 The plant costs include plant construction, operation, and maintenance and cost of capital. The costs are calculated in 2008 dollars.

Figure 5.4
Aggregate Power-Plant Costs of Candidate Strategies Under Base-Case Assumptions

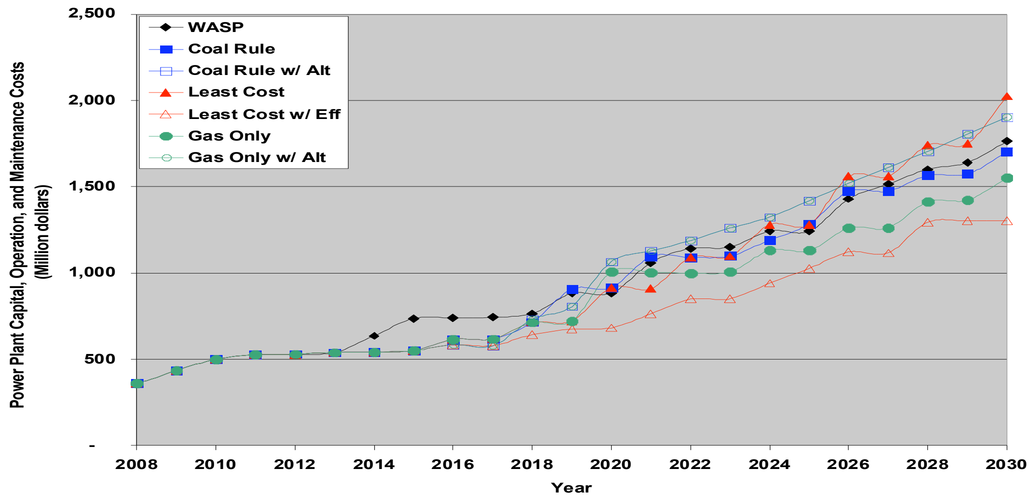

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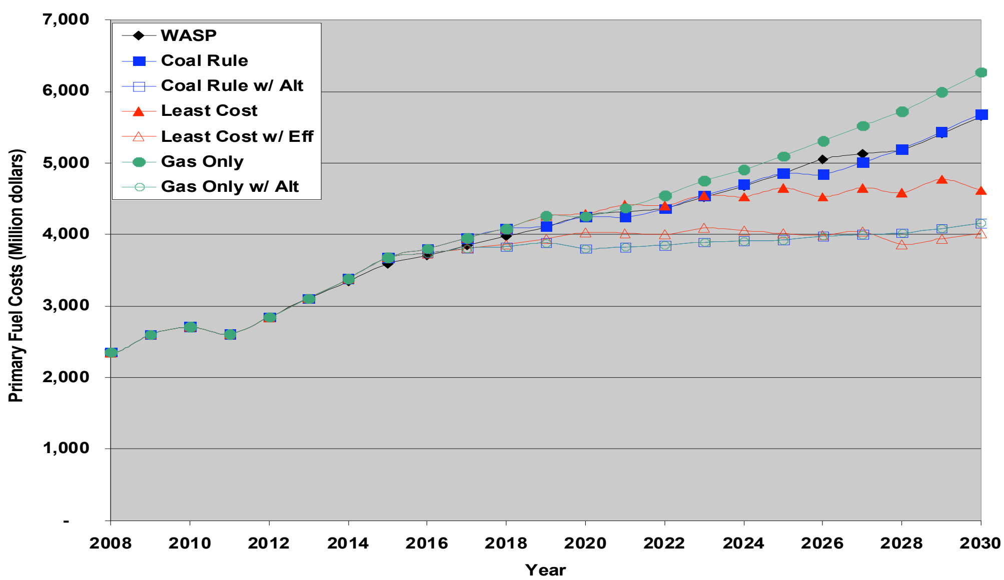
Figure 5.5
Aggregate Primary-Fuel Cost of Candidate Strategies Under Base-Case Assumptions



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efficiency gains is the lowest in terms of capital and operation and maintenance (O&M) costs. Again, this is due to the relatively costly solar alternative not being favored by the algorithm governing this strategy.[5]

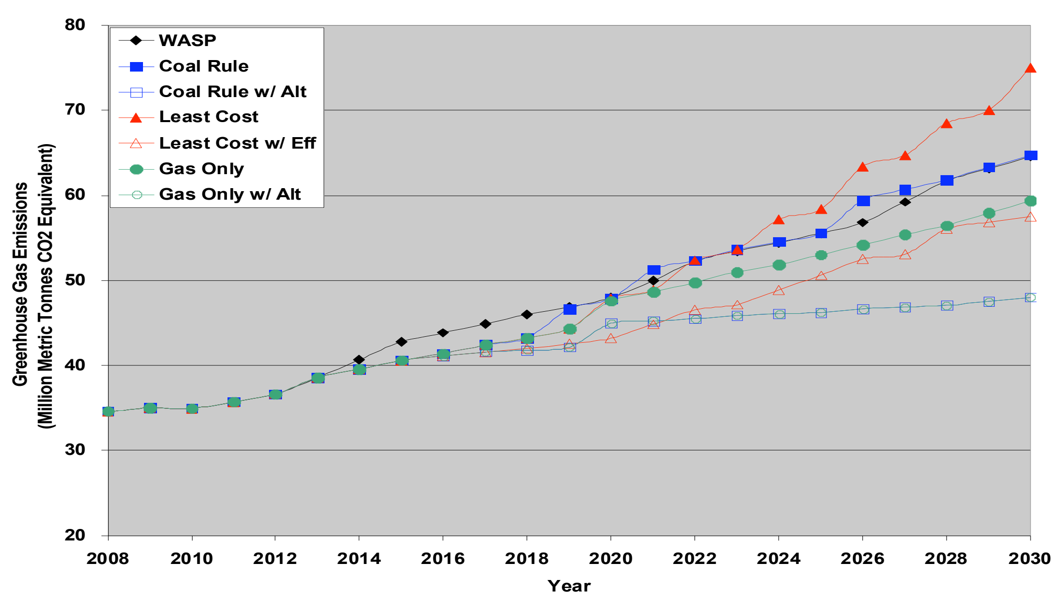
Figure 5.5 shows what the primary-fuel costs would be for each strategy under the base-case assumptions. The natural gas–intensive Gas Rule strategy would be the most expensive

[5] There are costs associated with achieving these efficiencies for each strategy that incorporates an efficiency component. These costs are reflected in the calculation shown in Figure 5.4.

when measuring this component of total cost. Both variants of the Least Cost strategy achieve the goal for which they are named because of the low expense for primary fuel they entail. And the cost savings from the solar alternatives are shown clearly by the near-second-place finish (just behind Least Cost_Alt) of the strategies that employ solar thermal. Note that fuel costs tend to dominate plant costs in share of total cost.

Overall system costs are not the sole metric by which to assess satisfactory outcomes. Part of the drive toward natural gas comes from its cleaner combustion properties. Figure 5.6 shows the outcomes with respect to emission of GHGs.[6] The Least Cost strategy can be termed so only if we ascribe no cost to the markedly greater production of GHGs and other emissions known to lead to health and environmental damages that would be occasioned by following this strategic course. From this perspective, we observe additional benefits to be gained from efficiency reductions. This metric also illustrates a greater differential between those efficiency-incorporating strategies that mandate clean alternatives for electricity generation (Coal Rule_Alt and Gas Rule_Alt) and those that will pursue such construction only if the immediate operational costs are relatively attractive or ignore such alternatives entirely (Least Cost_Eff). Finally, we note that the pure form of the Gas Rule strategy reduces the emissions of GHGs by approximately 6 million metric tons when compared to the Coal Rule strategy in its pure form. This represents a 10-percent reduction in additional GHG emission during the period 2008–2030.

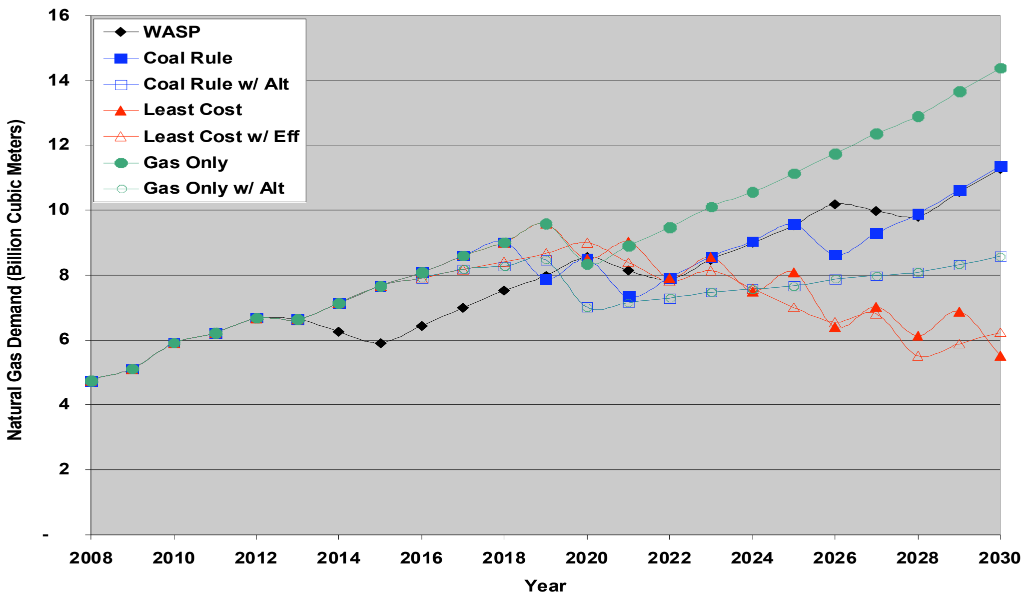
Figure 5.6
Greenhouse-Gas Emissions of Candidate Strategies Under Base-Case Assumptions



RAND *TR747-5.6*

[6] The outcomes for emissions of NO_X, sulfur dioxide, and particulate matter follow roughly the same patterns as for GHGs.

Figure 5.7
Natural-Gas Primary-Fuel Requirements of Candidate Strategies Under Base-Case Assumptions



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There is another metric of considerable interest for Israel. Figure 5.7 shows the level of natural gas that would be required under each strategy to meet its implicit primary-fuel needs.[7] Recall that the Yam Tethys reservoir is expected to be exhausted some time not long after 2012. This means that the only other existing supply source before any deliveries from newly discovered domestic reserves come online is the 7 BCM (effectively more on the order of 6.5 BCM to make allowance for some contractual swing capacity) for which EMG is willing to enter into contracts with Israeli customers. The figure suggests that all strategies would require additional supply from another source by 2017 under the base-case conditions. Only the Least Cost strategies would stay below 7 BCM in 2030. New domestic sources, supply via pipeline above the current level from new foreign suppliers, the capacity to import LNG, or some combination would be required by all strategies. The supply question will be dealt with extensively in Chapter Seven.

Performance of Strategies in High-Emission-Cost Future

The preceding discussion provides a means for orienting ourselves to the nature of the individual candidate strategies and how they would perform under one set of conditions. Of course, there is no guarantee that the base-case assumptions will bear any resemblance to the actual conditions Israel will face in the years until 2030. Quite the opposite: We would all be astonished if this were to be the case. We can get a sense of how the results might change by altering even one of the assumptions that constitute the base-case conditions. In particular, what if

7 The assumption is that natural gas would be the primary fuel for both NGCC and CT facilities, although both are dual-fuel capable, and fuel switching away from natural gas to diesel occurs when necessary. Our estimates also include natural gas utilized in other sectors of the economy, but the overwhelming bulk of demand would come from the electric-power sector during the relevant period for this study.

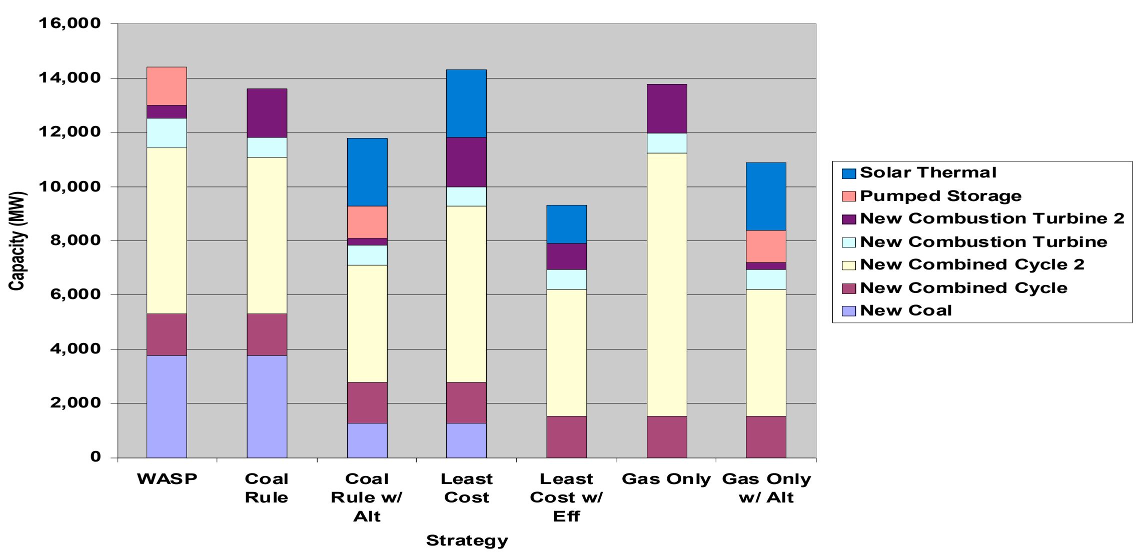
Israel were to internalize the cost of emissions from fossil fuel–based electricity generation? We model this by imposing a price on CO_2 equivalents emitted.[8] Specifically, starting from a price of \$0 per tonne of CO_2 equivalents in 2010, the price increases linearly in successive years until it reaches the level of \$50 per tonne in 2030. Further, a policy has been put in place that will limit GHG emissions from coal plants at no more than 50 percent above the 2005 level from coal-fired electricity generation.

The results in Figure 5.8 may be compared with those displayed in Figure 5.3. The Least Cost strategy shifts radically away from coal-fired facilities under the new conditions by now building only one plant beyond the three that exist today in Israel. And, whereas investment in solar-thermal capacity was not feasible under the strategy's decision algorithm when there was no cost to emissions, in the presence of a nonzero GHG-emission price, solar thermal becomes a principal component of the building plan implied by this strategy's operation through 2030.

Figure 5.9 shows the result of the changes imposed by a nonzero CO_2-equivalent emission price on the building plans ensuing from the candidate strategies. However, as before, the span from highest to lowest, while now slightly tighter, is on the order of \$700 million. At the same time, the high- and low-cost strategies are each about \$150 million more expensive than the high and low recorded when the emission price in CO_2 equivalents was held at \$0.

The implications for primary-fuel costs are much greater, as shown in Figure 5.10. First, there is a clear bifurcation into two clusters. The lower cost cluster is composed of those three strategies that include implementation of measures to enhance energy efficiencies. All the others are grouped at the higher level. The second implication is, quite naturally, higher overall energy

Figure 5.8
New Power-Plant Capacity Installed Between 2008 and 2030 by Candidate Strategies Under Base-Case Assumptions with Increasing Emission Price



RAND *TR747-5.8*

[8] This may be thought of as a tax or some equivalent scheme that would attach costs to those emission gases actually released into the environment after scrubbing by the cleaning technologies implied by the operating characteristics of existing and prospective generation plants. The proceeds from this tax or equivalent are assumed to accrue to the government general fund.

Figure 5.9
Aggregate Power-Plant Costs of Candidate Strategies Under Base-Case Assumptions with Increasing Emission Price

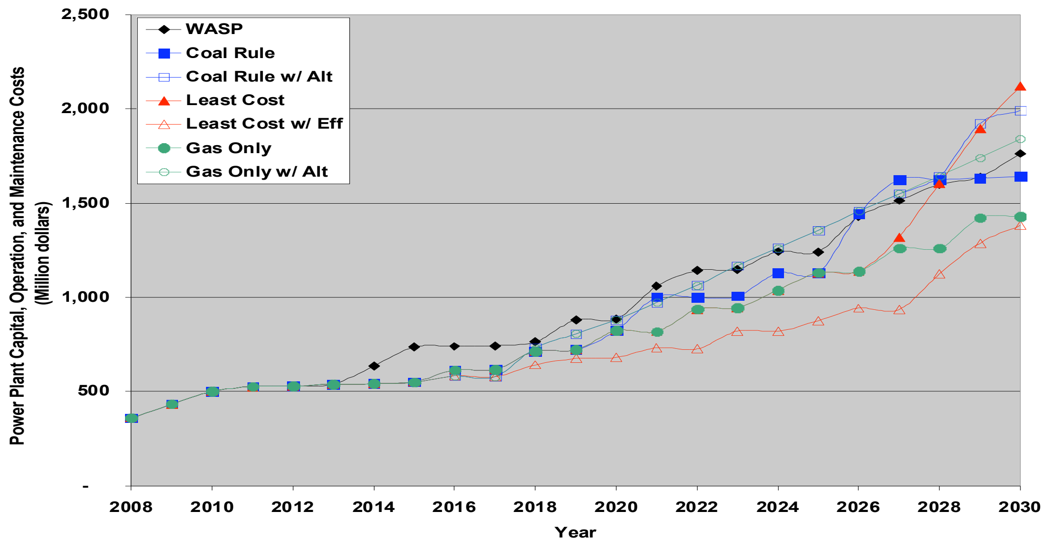


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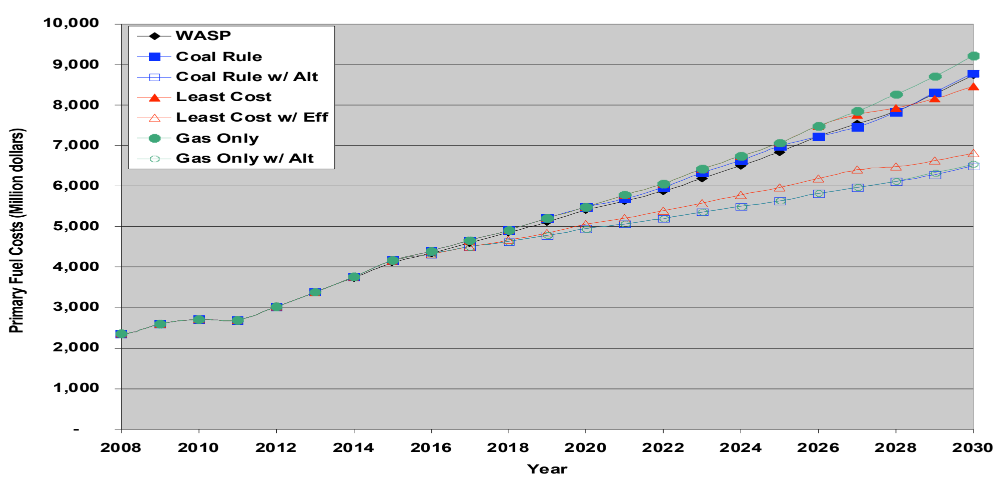
Figure 5.10
Aggregate Primary-Fuel Cost of Candidate Strategies Under Base-Case Assumptions with Increasing Emission Price



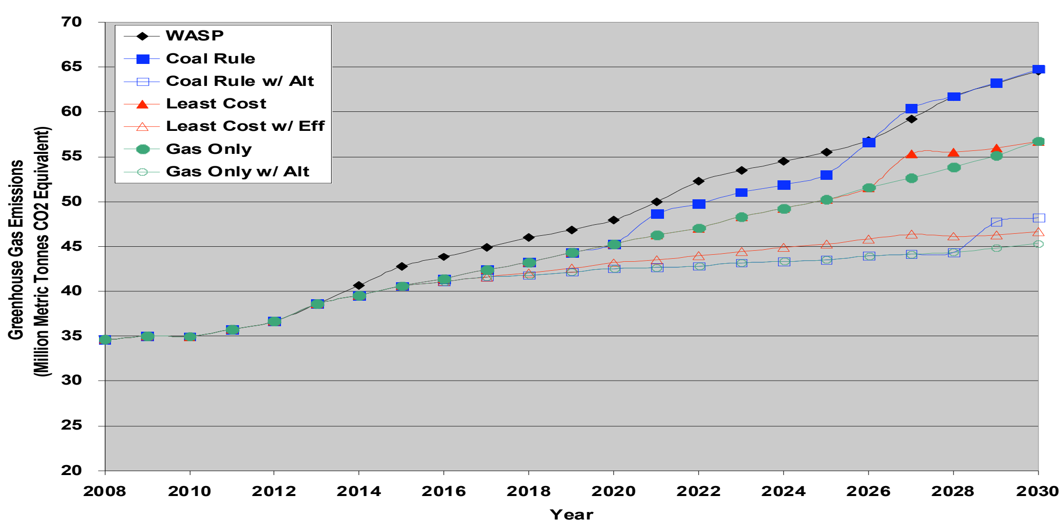
RAND *TR747-5.10*

expenses. Whereas, in the absence of a carbon price, the total of primary-energy expenditures was $6.3 billion at the high end and around $4.0 billion at the low, when a steadily increasing carbon price is imposed, the new low point is a bit higher than the previous upper bound, while the new high is in the vicinity of $9.2 billion. These differences in fuel costs, which now include the imposed price on emissions, swamp the distinction between strategies that appear when looking solely at plant costs.[9]

Of course, the purpose behind imposing a price on emissions is to introduce an incentive to reduce the level of those emissions. Figure 5.11 shows these results. The most-GHG-intensive strategies emit 10 million fewer tonnes than in the absence of a price on CO_2 equivalents. Interestingly, the emission level for the price-sensitive Least Cost strategy drops nearly 25 percent, or about 18 million tonnes.

The more-satisfactory emission outcome achieved when there is a nonzero price for emissions comes at a price itself. Figure 5.12 shows the implications for each strategy under the new set of conditions from the perspective of natural-gas primary-fuel requirements. Shifting the price relations between coal and fuels, such as natural gas, that produce fewer emission products per unit of energy or electricity generated[10] will naturally mean greater dependence on such fuels. Natural gas is no exception. Under these circumstances, even those strategies employing policies to enhance efficiency require increasing deliveries of natural gas from newly discovered domestic reservoirs, via pipelines from foreign supplies (including, potentially, the fields off Gaza), or LNG. The threshold of 6.5–7 BCM of current contracted supply in addi-

Figure 5.11
Greenhouse-Gas Emissions of Candidate Strategies Under Base-Case Assumptions with Increasing Emission Price



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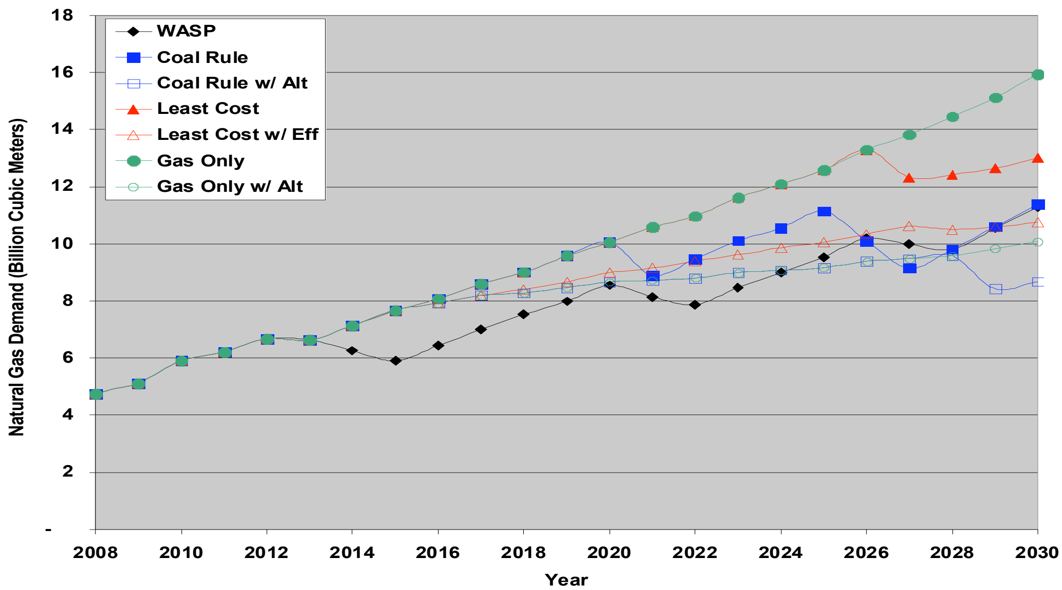
[9] We do not trace the fate of the revenue generated by such emission charges. They could be used to offset higher fuel charges on a selective basis or used for other purposes entirely. From the perspective of the consumers of electricity, in the absence of any subvention, they will appear as costs. We have treated them as such in our analysis.

A sense of the magnitude of these charges may be gained by observing the cost performance of the WASP strategy, the one building strategy that remains invariant, under the two regimes. Plant costs remain constant. Fuel costs, with emission charges, shoot up from \$5.7 billion in constant dollar terms to \$8.8 billion. The fixed nature of this strategy with no adaptive characteristics makes this an extreme case.

[10] The actual relationship between combustion-product emission and energy gained is partly based on the chemistry of the molecules involved and the limits of the technology used in practice to do the combustion. On balance, both the theoretical and the practical considerations favor natural gas over coal and other fossil fuels as a relatively low emitter of GHG.

Figure 5.12
Natural-Gas Primary-Fuel Requirements of Candidate Strategies Under Base-Case Assumptions with Increasing Carbon Price



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tion to Yam Tethys will have been passed by even the least natural gas–intensive strategy by the middle of the coming decade. This would mean that the schedule to bring new sources online would not be an insignificant matter for Israel's natural-gas strategic planning if this result held widely across scenarios.

Alternative Futures, Multiple Dimensions

The preceding discussion illustrates several points. There exists a wide band of strategies that could be followed, and each has properties that render it attractive from some perspectives while less so from others. Different assumptions about future states of the world have a considerable effect on relative outcomes. The great number of variables that define these states of the world yield many different possible combinations with differing results for each candidate strategy. Individual examination of all these combinations would prove unwieldy.

Gaining the most value from working with a compound computational experiment of the type that lies at the heart of this study requires preparing different perspectives for viewing outcomes. It stands to reason that viewing ensembles of scenarios requires adequate tools for observing the phenomena of interest. To do so, we introduce the concept of *regret*.

Ultimately, we wish to understand why one strategy should be selected instead of another. We have already suggested that the characteristic of robustness should be the key to choice. But how is robustness to be measured? This difficult question is made easier by recognizing that we usually have only a finite menu of actions from which to choose. Therefore, we are weighing strategies against each other in a relative as opposed to an absolute sense. As an initial guide, we should look for those strategies that seem to do the best against a wide set of plausible alternative future sets of conditions. That means that they perform better than the other alternative strategies we could instead have chosen to pursue.

For any one of the alternative futures and for any particular outcome that is of interest to us (e.g., system cost, level of natural-gas demand, emissions), at least one and possibly more strategies will perform the best. Had we been given complete future knowledge of what the future would be like, we would have selected this strategy or one of the ones that perform equally well according to the indicator we had chosen. Choosing another strategy that did not perform as well would have left us with some regret. *Regret* of a strategy with respect to some metric of interest may be defined as the difference between the performance of that strategy and the performance of the strategy that, in retrospect, now that we know the future values of the factors that were uncertain at the time we chose our strategy, would have been best to follow. The concept of regret therefore leads us to measure directly the consequences of choosing one strategy over another and leads to better understanding of what makes particular strategies succeed or fail when compared to the alternatives. It is a direct link to the fundamental question of what strategic course might be most robust.[11]

The first step in the direction of measuring regret and so beginning to infer robustness is to select a representative test set of futures for each strategy to confront. Chapter Four describes the nine variables we chose to represent explicitly the uncertainties that would affect the decision about how to pursue using natural gas in Israel. We also described three alternative assumptions (four, in one case) for values or trends that these variables might take in the future. These uncertainties then implicitly define a set of more than 26,000 distinctly different combinations of possible future values.[12] The future states of the world defined by some combinations of the variables are possible but perhaps not as plausible as some others. Nevertheless, we do not assign probabilities at this stage because this, too, would be to presume that we know more than we, in fact, do. Using what is in effect a uniform distribution also eliminates the need for the preliminary argument and persuasion that usually causes controversy, delay, or preemptory rejection of results even before the analysis is performed. It is important that groups and individuals with widely different perspectives on the likely course of future trends will be able to find in the simulations a representation of the reality they perceive.

The models we utilize for analysis are not simple and so require considerable run time even on modern computers. Therefore, to frame the test set of alternative futures, we take a sample from the full set of possibilities implied by the different assumptions for the uncertain variables. In this study, we employed an experimental design that selected a subset of the full set of combinations.[13] Run-time considerations led to the design choice of sizing this uniform sample of alternative future states of the world at 1,400 members.

We can now run each of the strategies we described in each of the 1,400 sets of conditions contained in the test-bed sample. The concept of regret allows us to present, in a single view, the results from the combined compound experiment we run by means of simulation-

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[11] Consider an example of two alternative strategies, A and B. Strategy A generates total system costs with a net PV of $50 billion, while strategy B under the same assumptions would entail costs of $60 billion. The regret in terms of system cost of B would be $10 billion, or 20 percent. However, B produces 25 million tonnes of emissions, while A produces 30 million. The regret of A, according to this measure, under this set of assumptions, would be 5 million tonnes, or 20 percent.

[12] That is, $3^8 \times 4 \times 1 = 26{,}244$.

[13] We used a Latin hypercube experimental design. Given a proposed number to be drawn as a sample from a larger population—in this case, 1,400—this design selects the set members so that they are evenly distributed across the multidimensional space defined, in this case, by the nine axes of uncertainty with alternative possible values we have defined for this study, as described in Chapter Four.

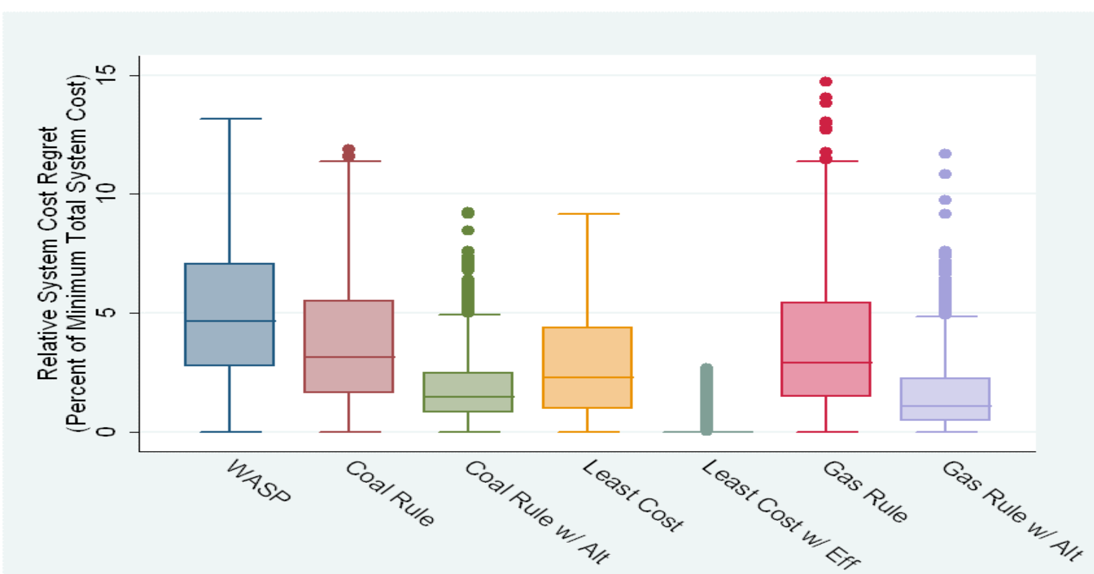
model runs. Figure 5.13 shows the regret results of running each of the seven strategies across the full set of future states of the world. The figure shows all 9,800 scenario outcomes for the designated indicator.[14] For any particular set of future conditions and any particular measure of outcome, at least one strategy among those tested would exhibit the most-successful results. This strategy has zero regret because it was clearly the best strategy for the conditions it actually faced. Any strategy that does less well than the zero-regret strategy has a measurable regret—for example, in terms of additional cost or greater emissions of GHG compared to those ensuing from operating according to the zero-regret strategy. By this means, we can compare the outcome of thousands of simulation runs involving different strategies all confronting the same large set of plausible futures and assumptions.

Figure 5.13 displays the differences in the PV of total system costs (including both the plant and fuel costs we have previously considered separately) through 2030. It shows these regret results in relative terms—that is, the percentage difference between any positive-regret scenario with the zero-regret (that is, best-case) scenario result for those same conditions. In this case, the zero-regret result would be the lowest system cost exhibited by any of the strategies given the particular assumptions and conditions that define the scenario.

As with all of the strategies, the WASP strategy was run against all 1,400 sets of future assumptions. The median result was regret on the order of $3 billion, or around 4.5 percent. The worst case for the WASP strategy shows regret of about $14 billion, or 13 percent.

A different picture emerges from looking at the Least Cost_Eff strategy. No whisker appears because there is no interquartile range: At least 75 percent of all cases exhibit zero regret. The worst that this strategy does in any scenario is to produce regret within about 2.5 percent of the low-cost strategy for that scenario.

Figure 5.13
Relative System-Cost Regret (PV) of Candidate Strategies, 2008–2030



RAND *TR747-5.13*

[14] Seven strategies each applied to each of the 1,400 sets of values and assumptions in the test set: 7 * 1,400 = 9,800.

It would be possible to look at the regret behaviors of these two strategies as displayed in the figure and conclude that Least Cost_Eff shows the most promise as a robust strategy. It yields zero regret over the majority of different sets of assumptions, and, when it does fail, it does so gracefully. Even at its worst, its performance in those scenarios is quite near that of the zero-regret strategies. This conclusion is not necessarily wrong, but there are two large considerations that must be borne in mind when conducting an analysis of this type. The first is to note that this analysis and the Latin hypercube experimental design assign no probabilities to each of the 1,400 cases and treat them as being of equal interest. However, there are some instances that prior information not contained within this analysis may well suggest have greater likelihood or are potentially of greater concern should they arise. It makes sense that any final determination of robustness should take these factors into account. If those circumstances in which the WASP-strategy system costs are low and the Least Cost_Eff costs high are deemed either highly likely or of greatest concern to planners, for example, then the superiority of the Least Cost_Eff strategy over WASP becomes less obvious.

The other major point, of course, is to note that this analysis so far has only looked at outcomes with respect to one criterion: total system cost. We soon look at other measures of successful outcomes and examine the candidate strategies for their performance in those respects as well. However, there is an issue specific to cost measures that should first be explicitly addressed.

It is usual practice to discount a stream of income and expenses that extends over several years. One dollar of revenue gained or cost incurred today is not the same as a similar dollar amount accrued in the next or succeeding years. The way to assess the overall benefit gained from such an investment stream is to calculate the PV. This calculation will reduce the value to us today of benefit we are likely to obtain in the future. Similarly, the further out potential cost may be, the less sensitive to it we are today, once discounting has been performed. This presents a problem when the period over which the activity occurs becomes so long as to approach the intergenerational. The problem is as much philosophical as technical. If we are to make decisions today that, for example, frontload benefits early on and backload costs over decades to come, in effect, we have made the decisions largely taking counsel of our own preferences while discounting those of our children's generation.

The investments in energy-sector capital stock tend to be quite large and have implications for Israel's infrastructure in decades to come. One could well ask how to enfranchise or at least consider the effect on the later generations that will—or will not—have specific types of plant and other capacity as their inheritance. The PV calculations we have used in the analysis so far were obtained by applying an annual discount rate of 5 percent. While there is no standard, this is well within the middle range of discount factors usually applied to such investments.[15] Choosing a lower rate would make the decisions more sensitive to the effect they would have in later decades. However, it is not certain what discount rate would be appropriate. Further, given the uncertainties, it is also not clear that the present generation should be saddled with costs appropriate for future conditions when we are not at all certain of what they

[15] Private communication with the Budget Office of Israel's Ministry of Finance suggests that a discount rate of 7 percent is more frequently the norm in its calculations. This reflects its interest in ensuring budget balance and making certain that the nation's capital account—its long-term investments—will not unduly burden its current accounts. Private companies will apply even higher discount rates to ensure the selection of projects with rapid payback and readily obvious results. Such higher discount rates, of course, make the preferences of the current generation even more dominant than those of later ones.

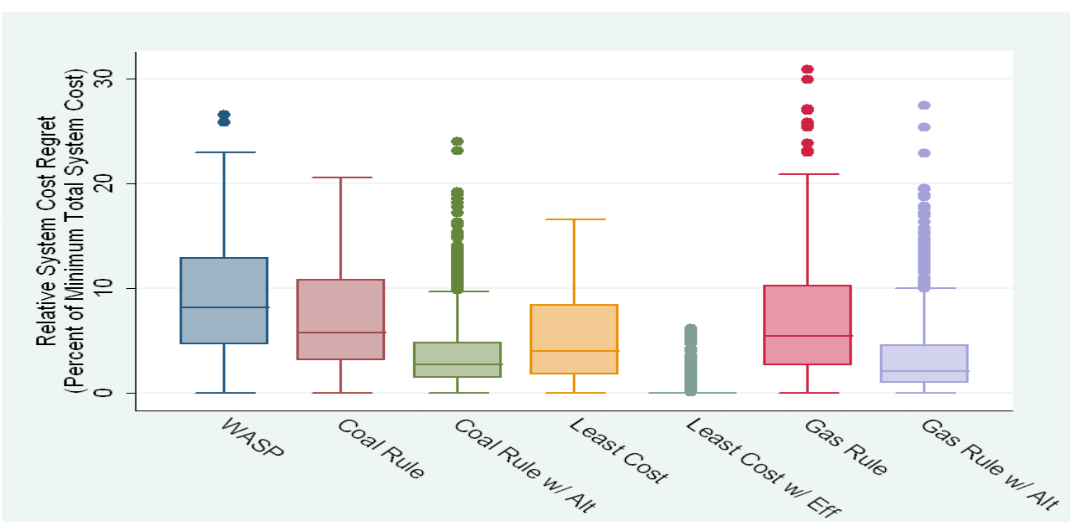
might be and what the relative abilities of this generation with present technology would be to address these conditions in comparison to the next generation and the means at its disposal.

We choose to address the issue of costs by taking the long period from 2008 through 2030 and dividing it into two unequal parts. One can imagine that the generation of planners and decisionmakers present in 2008 will be largely responsible for the consequences of its decisions over the ensuing 12 years to 2020. In the last ten years of the period, however, we would begin to see the coming into power of a new generation. Therefore, we have calculated the PV of system cost for the period 2008–2020 and for the period 2021–2030. For the latter period, a 5-percent discount rate is used, but the net income stream is discounted to the year 2021.

Figure 5.14 shows the results of doing so for the latter period. Again, we look at both the dollar-denominated regret amount and the percentage relative regret for each candidate strategy. Except for several outlier scenarios, the WASP strategy has the highest mean relative system-cost regret, followed by the regret plot resulting for the Coal Rule and Gas Rule strategies. As we shall see later on, those scenarios that would favor the former would be unfavorable to the latter and vice versa. Once again, those strategies that include possibilities for demand-efficiency enhancements and the use of non–fossil-fuel renewable generation technologies have the lowest regret, both relative and absolute, in general. Two of them, Coal Rule_Alt and Gas Rule_Alt, do exhibit some relatively high regret outliers.

What Figure 5.14 shows when compared to Figure 5.13 is that most of the large consequences and a true divergence of results among strategies occur in this last ten-year period. This was not apparent when PV was calculated across the full time period. The ranges of both absolute and relative regret are larger with some PV system-cost regrets greater than $15 billion and relative regret scores of more than 20 percent.[16] Of course, since these are rule-based strategies, later generations may elect to modify these rules or discard them for others. Indeed,

Figure 5.14
Relative System-Cost Regret (PV) of Candidate Strategies, 2021–2030



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[16] The analogous regret plots for the earlier, 2008–2020 period show no results greater than 5 percent relative regret with the large bulk of outcomes exhibiting less than 3 percent relative system-cost regret.

one of the ways to best employ a robust approach to strategy is to introduce adaptive change rules. One of the values of an analysis of this type is the ability to identify indicators that change might be required and to define and gain agreement ex ante on what form such change may take. This reasoning will be explored later in the analysis. However, it is also true that later planners and decisionmakers will be forced to live to some extent with decisions that have already been made regarding plant and fuel types. Therefore, these results should not be interpreted as irrevocable destiny, but they do represent what might be expected under varying conditions if each of the candidate strategies is carried through to the year 2030. More than do the PV results discounted over the full period, they suggest the need for some forethought and farsightedness in making the energy-infrastructure decisions of today.

Figure 5.15 shows how the strategies would perform in terms of natural-gas demand in the year 2030. The median value for all of the strategies falls in the range between 10 and 16 BCM. This is above the capacity of the 7-BCM pipeline from Egypt that is Israel's only current source of supply that also could conceivably be available in 2030, long after the depletion of the currently producing domestic field, Yam Tethys. So, in the majority of scenarios, Israel would need to develop additional supply from newly discovered domestic sources, a second pipeline from Egypt if a higher level of delivery than can be borne by the current pipeline can be negotiated, a new international pipeline for supply from some other country, or LNG facilities to make up the balance. Of course, there can be more than one additional source of supply to make up the requirement implied by this level of demand. For most strategies, a full quarter of the scenarios would require more than 15–16 BCM annually, while, for the Gas Rule strategy, this level would be 20 BCM. That is, nearly three times the current maximum contracted supply from Egypt would be required in 25 percent of the sample scenarios if that strategy was to be followed.

Figure 5.15
Annual Natural-Gas Demand in 2030

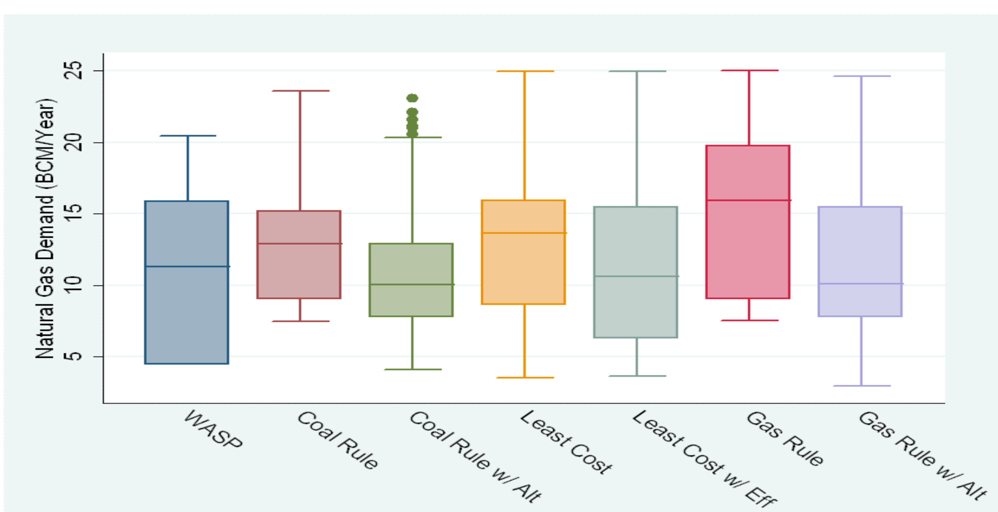

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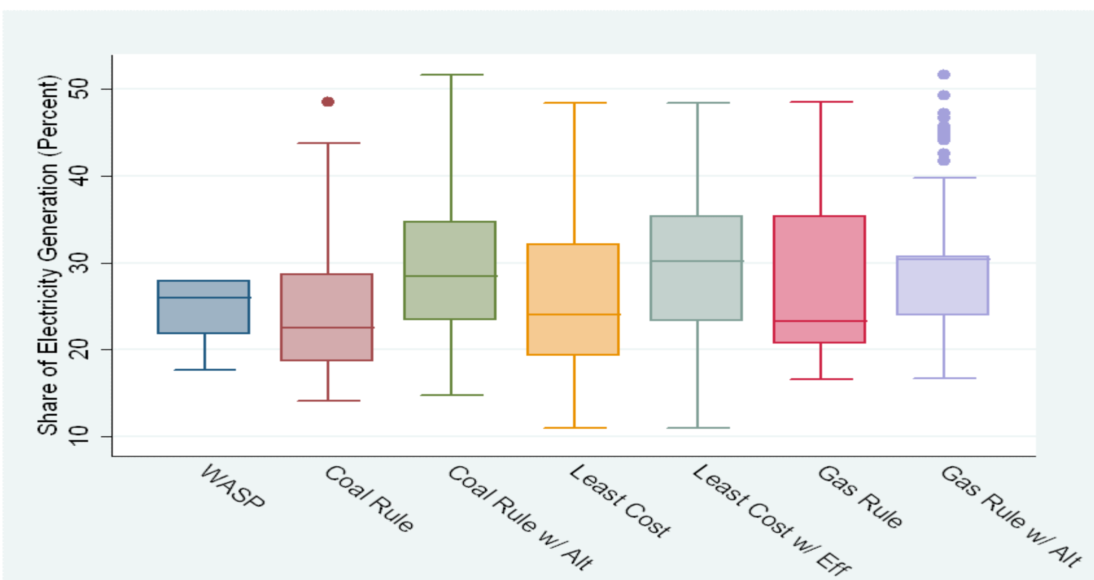
Figure 5.16 shows for each strategy the range of scenario outcomes for share of electricity generation[17] that would be fueled by natural gas received through the foreign natural-gas pipeline that exists today, assuming that the maximum per year reaches and remains set at 7 BCM. Clearly, if the supplier would consider signing contracts with Israel for more than this amount, the share would be higher. Similarly, if no additional contract beyond the current level, well below 7 BCM, is finalized or if such contracts are reneged on, this amount would be smaller. Going above 7 BCM would require expanding capacity or building a second pipeline, however. Even for the two Coal Rule strategies, the share of natural gas from Egypt in 2030 would be more than 20 percent in three-quarters of the scenarios in the sample set. Not surprisingly, the price- and condition-sensitive Least Cost strategies show the greatest range of response to differing scenario conditions. Perhaps more surprisingly, while the Gas Rule strategies do display a different pattern from that of the Coal Rule strategies, the differences when looking at the full set of scenarios in aggregate is not that great.

Part of the reason there is not greater dispersion in the patterns of use for natural gas from existing foreign supply is that we have presumed that this supply will continue to be limited by the 7-BCM-per-year cap. Gas above this amount would need to come from newly discovered domestic supply, additional foreign pipeline deliveries, LNG, or, over the short term, local storage. In Figure 5.17, all strategies show at least one scenario in which additional supply beyond the presumed 7 BCM delivery of foreign fuel imports would not be required in 2030. The vast bulk of cases, however, would call for fuel beyond what is currently contracted for in the years when natural gas from Yam Tethys is no longer available. This is true even for the strategies

Figure 5.16
Percentage of Electricity Generation in 2030 Supplied by Natural Gas from Existing Foreign Pipeline



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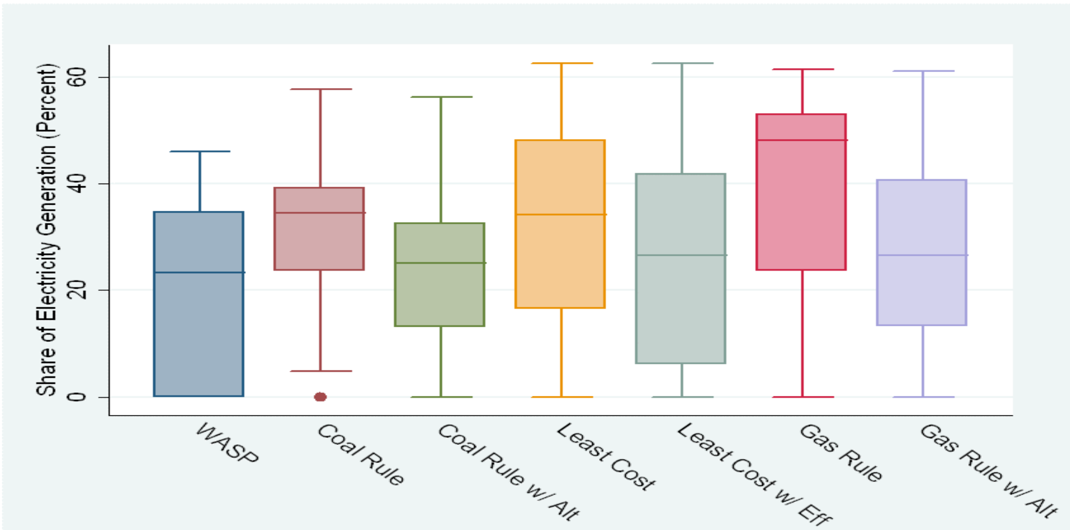
17 Note that each of the 1,400 scenarios represented in each column has its own implied electricity demand, so the actual amount of electricity that corresponds with the shares shown in Figure 5.16 will not be linear. That is, a 30-percent share versus a 15-percent share will not necessarily correspond to twice as much electricity generated.

Figure 5.17
Percentage of Electricity Generation in 2030 Fueled by Natural Gas from Sources Other Than Existing Foreign Pipeline



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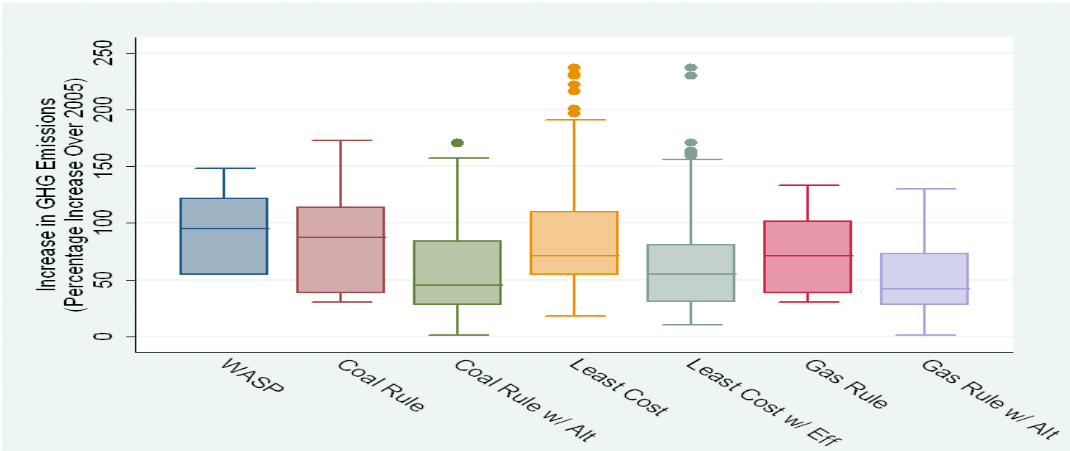
that include demand management and employment of renewable-fuel generating sources. The median scenario outcome for these three is a fairly consistent 25-percent share. Even for the WASP strategy, the median scenario's natural-gas requirement would mandate deliveries, representing 23 percent of total generation, above the 7-BCM level.

These results strongly suggest that, in almost all the 1,400 alternative futures we examined, a nontrivial share of electricity will be derived from natural gas that will need to come from a supply stream in addition to the existing pipeline. This question is considered in greater detail in Chapter Seven.

Among the calculations performed by the LEAP model is to simulate the level of various pollutants emitted during the course of a year by burning the fossil fuels required for electricity generation. Figure 5.18 shows in aggregate the scenario outcomes for emission of GHGs. The range of outcomes is wide indeed. For the Least Cost strategy in those scenarios in which there is no price attached to CO_2 emissions, pure cost considerations yield increases approaching 250 percent more than the 2005 emissions. Again not surprisingly, these levels are reached in futures in which coal is quite inexpensive compared to the alternatives. The Least Cost_Eff strategy shows a tendency toward more–environmentally sound outcomes, but, even here, fully half of the scenarios would imply GHG-emission-level increases of 60–240 percent greater than 2005. If we look only at the interquartile ranges—that is, the regions defined by the boxes incorporating those scenario outcomes within the 25th- and 75th-percentile bands—the strategies arrange themselves into two groups. On the one hand, there are those with demand-reduction policies and the potential for utilization of non–fossil fuel energy sources, and on the other are the remaining four strategies. For the former, half of the scenarios witness increases between 35 and 80 percent of 2005 levels of GHG release. For the latter, unconstrained demand strategies, no less than 40 percent in the lowest case and reaching 100–140 percent in the upper, 75th-percentile bracket of scenario outcomes. Chapter Six offers a more systematic treatment of conditions leading to success and failure for each strategy.

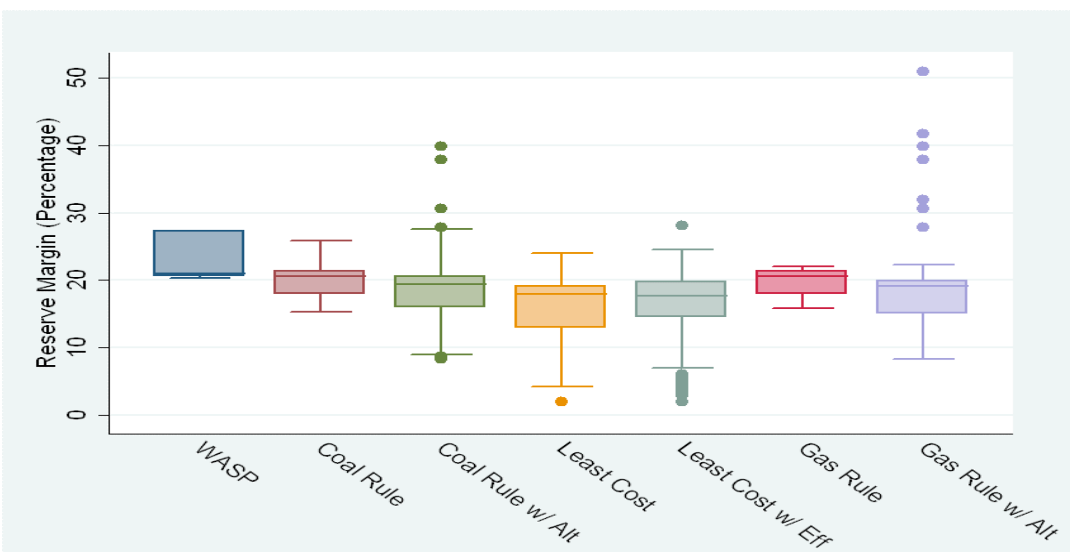
Figure 5.18
Increase in GHG Emissions in 2030 Compared to 2005 Levels



RAND *TR747-5.18*

There is one potential downside to the strategies incorporating efficiency enhancement and nonfossil alternative fuels, as shown in Figure 5.19. The algorithm in all of the strategies for determining when new capacity is added depends partly on the average reserve capacity—the excess of installed generating capacity over average demand requirement for the year. If this falls below 20 percent, it is a trigger to build new base-load plant. In scenarios in which the cost of achieving efficiency is high and the technology costs of solar-thermal plant are low, demand will continue to grow, and relatively large installations of solar capacity may be installed to meet it. LEAP discounts installed solar-thermal capacity by one-third because of solar thermal's inability to operate at night and reduced effectiveness on cloudy days. Thus, it will deter-

Figure 5.19
Reserve Margin in 2030 (percentage of installed generating capacity in excess of annual peak electricity demand)



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mine that there is less installed capacity with respect to demand than may well be the case. One can raise the question of whether this rule of thumb is fully appropriate to conditions in Israel and what means could be installed to store generated power during the day for release at night or to produce power using hybrid systems that resort to fossil fuels when the solar array is inoperable.[18] Further, Figure 5.19 shows only a snapshot of one point in time. Presumably, the low–reserve capacity scenarios occur when the solar thermal was only just recently added in periods just preceding the final period of analysis in the year 2030. Because of the rules on which these strategies are based, there would be a tendency in later years to construct additional capacity that would be required to increase the reserve capacity.

Nevertheless, the results in Figure 5.19 do hint at a potential vulnerability. Power-plant construction projects, no matter the type of plant, are large, long-term efforts. Such investment results in outcomes that are lumpy: A newly constructed NGCC plant for the purpose of this study is assumed to be 720 MW; a latest-technology coal-plant installation, 1,260 MW. The incremental addition of capacity to an energy system tends to come in large lumps. So, while a particular indicator may be used as a target for action, at any given time, its actual value may undershoot or overshoot this mark. This is what the results in Figure 5.19 reflect. If a relatively large share of Israel's generating capacity at a particular time did consist of solar thermal and, indeed, low–reserve capacity conditions occurred at the same time as extraordinary incidents that threatened the system's ability to meet demand, it could conceivably raise the risks of brownouts or even load shedding. The Least Cost strategies seem particularly susceptible, among the seven candidate strategies in this analysis, to scenarios that may lead to failure according to this criterion.

A broad finding from the results presented so far, particularly when emission outcomes are compared to the cost-regret outcomes, is that it is not possible to look at any single metric to evaluate the relative performance of alternative candidate strategies. For a problem of this complexity, it will not be obvious that any one strategy may dominate the others across the full range of indicators of importance to planners and the public that they serve. This is shown in Table 5.1, which displays for each strategy the 75th-percentile value (top), median value (middle), and 25th-percentile value (bottom) for several of the metrics discussed in this chapter. Each strategy has positive characteristics and behavior according to some measures while registering more-disappointing performance in others. This having been said, those strategies incorporating efficiency-enhancement measures and the possibility for use of non–fossil fuel technologies generally show less problematic outcomes across the various performance measures than do the others. This is despite being exposed to the additional vulnerability of uncertainty over (possibly high) cost for achieving these efficiencies and employing alternative fuel technologies.

The next chapter examines the performance of strategies in more detail by applying several specific metrics to judge scenario outcomes produced by the candidate strategies across different future conditions. Chapter Seven then begins a discussion of how a robust supply infrastructure for natural gas in Israel may be established.

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[18] Dual fuel–capable turbines may serve as backup for solar-thermal plants, and there are prospects for technological developments in solar-thermal storage during the period of the study. Also, while solar-thermal technology appears the most likely to see wide commercial use in the early part of this period, it is possible that a significant portion of the installed capacity of renewable energy could be based on photovoltaic technologies by the year 2030.

Table 5.1
Interquartile Range (75th, 50th, 25th percentile) Values for Each Strategy over 1,400 Future Scenarios

Strategy	Regret, Relative Cost, 2008–2030 (%)	Regret, Relative Cost, 2021–2030 (%)	Average Natural-Gas Demand, 2030 (BCM)	Share of Electricity Fueled by Existing Natural-Gas Foreign Pipeline (%)	Increase in GHG Emissions, 2030 over 2005 (%)
WASP	7.4	13.0	15.8	28.0	122
	4.8	7.9	11.8	26.0	91
	3.0	5.0	4.2	22.0	57
Coal Rule	5.2	10.7	15.1	28.5	118
	3.2	6.0	13.0	23.0	85
	2.2	3.2	9.0	18.5	41
Coal Rule_Alt	2.5	4.9	13.0	35.0	84
	1.9	3.0	10.0	28.4	45
	1.2	1.9	7.8	23.7	30
Least Cost	4.6	8.2	16.0	32.0	110
	2.4	4.2	13.8	24.0	73
	1.4	2.1	8.5	19.0	56
Least Cost_Eff	0	0	15.2	35.7	83
	0	0	11.0	30.0	59
	0	0	6.5	23.1	33
Gas Rule	5.2	10.1	19.8	35.7	101
	3.2	6.2	16.0	23.0	75
	2.2	3.0	8.9	20.3	39
Gas Rule_Alt	2.5	4.9	15.4	31.0	77
	1.5	2.5	10.1	30.7	43
	0.7	1.0	8.0	23.2	33

CHAPTER SIX

Seeking a Robust Natural-Gas Strategy for Israel

The Fourth Component of Robust Decisions: Measurement (M)

The need now to evaluate the success or failure of strategies based on scenario outcomes brings up the fourth and final set of factors to be explored in an RDM analysis. Having already discussed the causal (model) relationships (R), uncertainties beyond the planners' control (X), and the various combinations of possible actions or policy levers (L), we now turn to consideration of how to characterize scenario results. For this we need to select a set of metrics (M).

The preceding analysis suggests that some strategies may be more vulnerable to certain conditions than others and that they have different relative strengths with respect to performance criteria of importance to planners and to stakeholders throughout Israel's government and public. The values shown in Table 5.1 in Chapter Five suggest that no one strategy unambiguously dominates the others. There are good outcomes and bad, depending on scenario conditions and the basic tenets of each strategic course. If we are to pursue the search for strategies possessing the property of robustness, we need to be specific about what constitutes "good" versus "bad" outcomes. Then we can see where the inherent vulnerabilities of different pure strategies, such as the ones we have examined so far, or modified and hybridized strategies, might be found. Such knowledge is a crucial component for both forming and testing such hybridized or adaptive strategic frameworks.

It is rarely the case for issues that are of long-standing public discussion that there is only one measure that will prove sufficient to evaluate outcomes. We care about "guns *and* butter"—that is, public expenditure for security as well as private consumption—within a limited budget. We are interested in measures of health delivery and educational performance, but we are also sensitive to issues of cost. This is very much the case for the issue of energy policy, and nowhere more so than in Israel.

The reader should also recall that, in selecting a list of criteria for evaluating scenario outcomes, we are seeking a means to evaluate strategies for the quality of robustness that they may or may not display. For a strategy to possess robustness, the goodness or badness of its outcomes would be relatively insensitive to different states of the world in which it is pursued. Lack of robustness, on the other hand, would characterize a strategy as being sensitive to the conditions that define the state of the world and hence exhibit a certain fragility of outcomes. In this latter case, we would expect to see greater variation in the outcomes we would observe if we were to employ nonrobust strategies across the full range of future plausible states of the world.

The concept of robustness is much more closely linked to that of *satisficing* behavior rather than the optimizing behavior more often regarded as the assumed stance of decisionmaking agents.[1] In a world of profound uncertainty, most planners and decisionmakers recognize that, in practice, seeking a maximum outcome with respect to one particular set of assumed conditions may leave us too vulnerable to the possibility of other conditions actually prevailing. Under such conditions, the tendency, either formally or informally, is to define thresholds of performance that are considered to be good enough: We would be satisfied with strategies that yield at least this level of results for our various measures across a broad range of plausible scenarios. Being satisfied with meeting minimal criteria for goodness as defined by performance metrics makes it possible to adopt courses of action that are more hedged intrinsically against a wider possible set of future conditions.

The concept of defining robustness in terms of satisficing allows characterization of outcomes. If a scenario's performance falls below a set threshold according to some measure, then the scenario has led to a bad outcome. If, however, it meets or exceeds this threshold, the outcome is a good one. Those strategies, plans, and courses of action that display an array of favorable outcomes not only across many scenarios but also in terms of many or all the indicators of interest—and a characteristic of failing gracefully, as opposed to catastrophically when conditions cause criteria of success not to be met—are the type of robust strategies we seek.

Performance Thresholds

We have indicated various categories of risk that Israel (or any other state, albeit perhaps in differing rankings of priority) would seek to minimize through the application of policy tools to issues of energy balance. In evaluating the outcomes from different strategies under alternative future conditions of the world, we have sought to highlight these concerns. It is worth bearing in mind that, although the broad realm of energy policy covers a great many aspects and possibilities for both government and private action, this study focuses on strategies for use of natural gas. This somewhat circumscribed view permits narrowing the set of issues to examine but does run the risk of discussing ancillary concerns without full treatment. In the discussion that follows, we have sought to achieve a balance.

In this study, we wish to establish thresholds along four major dimensions. We distill these from the various categories of risk listed in Chapter One. These include criteria for cost, emissions and health, land use and regulation, and security, especially with regard to the supply of natural gas. These correspond to the major dimensions of risk with which we began this analysis. This is not to suggest that these alone are the criteria to which attention must be paid. However, they do permit the next, more-detailed analysis of what constitutes robustness for Israel when framing strategies for natural gas. The first three of these categories lend themselves to the framing of thresholds that serve as relatively simple proxies for many of the more-detailed concerns. The last, supply security, is more complex and will require treatment of a different character. This will be presented in Chapter Seven.

System Costs

The major use of natural gas in Israel will most likely be electricity generation. Quite simply, we would wish to avoid surprises on the total cost of the electricity produced by Israel over the

[1] The term was coined by Herbert Simon, who also described the concept of satisficing as a way to understand managerial and bureaucratic behavior within organizations (Simon, 1957).

course of years through 2030. A strategy should limit the chance that this might occur. As shown in Chapter Five, most of the variation in costs would come in the latter period, 2021–2030. Therefore, we set the following threshold: If the regret of a scenario outcome with respect to PV system costs in the last ten years of the study period (2021–2030) is less than 5 percent of the costs for the zero-regret strategy or strategies, then this is considered an acceptable outcome. If it is 5 percent or greater, the scenario outcome would be considered to be unfavorable.

Greenhouse-Gas Emissions

This criterion is useful for several reasons. GHG emissions tend to be an indicator for the full panoply of emissions from fossil fuel-combustion. There will be great variation among NO_X, particulates, and other emissions, depending on the fuel and the combustion and scrubbing technologies, but the trends will be in the same general direction. Further, there is increased global concern over GHG release as opposed to the more local concerns with other emissions. These concerns may lead to carbon taxes, trade restrictions based on carbon content calculated for tradable goods, and possibly even control regimes that may cause difficulties or at least embarrassments in the future. Given these uncertainties, it would be of potential value to have such emissions under control. Finally, although the precise health effects of pollutants emitted into the atmosphere are not precisely known, there is much agreement on the correlation between greater concentrations of aerosol and gaseous pollutants and the incidence of human health events. Therefore, a threshold on GHG emissions would also, in part, address the need to have energy solutions for Israel that reduce the extent of these impacts.

Our analysis shows that, if current population growth and energy intensity trends persist, it would be difficult and would require extraordinary circumstances for Israel to level its GHG emissions over the term of this study.[2] But it is also clear that some scenarios lead to much greater increases than others. These considerations led to establishing a threshold that considered good performance to yield an increase in GHG emissions by 2030 no more than 25 percent greater than the emissions recorded in 2005, the last year for which we had complete information. This is not in itself an overly restrictive threshold. The 2008 AEO of the U.S. Department of Energy projects a 26-percent increase for the United States during the same period in the no-climate-policy case. Nevertheless, as is discussed in this chapter, this represents a considerable challenge for Israel to meet if it continues on its present trajectory.

Land Use. Israel is a country with a land area slightly less than that of the U.S. state of New Jersey. At least 40 percent of this mass lies in the Negev desert. The population and industry both tend to be concentrated on or near the shores of the Mediterranean and Red seas and in and around Jerusalem. The total length of coastline is 273 kilometers (National Foreign Assessment Center, 2009). Land use and land-use planning are critical elements of Israeli policy. In particular, unlike some countries with greater land area, the issue of where additional power plants may be sited is not trivial in Israel.

Table 6.1 provides some sense of the scale involved. The first set of columns on the left shows a calculation of land area and generating capacity of selected natural gas– and coal-fired power plants in Israel as well as standard estimates provided by the National Energy Technol-

[2] The issue of energy intensity is crucially important but peripheral to a study focused on natural gas. Nevertheless, our examination of the data suggests strongly that the government of Israel should revisit assumptions about energy intensity and that this is perhaps the most useful aspect of energy policy to which its attention could be addressed. This point is discussed in Chapter Eight.

Table 6.1
Comparison of Land-Area Footprint of Existing and Proposed Natural Gas– and Coal-Fired Generating Plants

	Land Area at Existing Plants				Equivalent for Assumed Standard-Size Plant			Dunam/100 MW	
Plant Site	**Dunam**	**Acres**	**Total (MW)**	**No CT (MW)**	**Dunam**	**Acres**	**MW**	**With CT**	**No CT**
Hagit (NGCC)	1,020	245	1,550	1,550	455	114	720	n.a.	66
Ramat Hovav (NGCC)	200	48	555	335	249	62	720	35	60
Gezer (NGCC)	450	108	1,336	744	233	58	720	32	60
Zafit (NGCC)	233	56	578	358	279	70	720	39	65
Alon Tavor (NGCC)	142	34	583	363	168	42	720	23	39
Orot Rabin (coal)	2,024	486	2,590	n.a.	945	236	1,260		75
NETL estimates									
NGCC	405	100	560	n.a.	520	129	720		72
Coal	1,214	300	550	n.a.	2,781	687	1,260		221

NOTE: n.a. = not applicable.

ogy Laboratory in the United States.[3] The next set scales the actual figures for a plant of the standard size used in our analysis for new plant construction. The last two columns give a normalized value for dunams required per 100 MW for a standard-sized plant with the same land-use data for the actual or ideal plant appearing in that row. The figures were utilized in constructing the metric described in the following paragraphs.

The land-use metric is composed of two criteria. The first is whether the average weighted land-use footprint per 100 MW of the 2030 installed capacity required in a scenario is greater than that currently found in Israel. If so, then the scenario fails to meet this criterion.

In addition to this average-footprint criterion, the second criterion relates to the total scale of the area actually required to support the electricity-generating infrastructure that emerges under each scenario. This is an important consideration in such a small, intensely populated country. For any particular combination of future conditions defined by our nine input variables, at least one of the infrastructures resulting from applying the seven candidate strategies will require the least amount of weighted land area. We have set the threshold level for con-

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[3] Data on Israeli power plants derive from IEC and MNI sources that required reconciliation in some cases. The data shown are an attempt to capture the actual situation existing or planned for each facility. In several cases, the rated capacity of a plant site included existing or proposed NGCC plant along with CT generators also on the site. It is unclear whether the more-appropriate land-use intensity would be derived from considering the NGCC capacity alone or the full capacity likely to be available at future plant sites as well. For this reason, we report both values. National Energy Technology Laboratory (NETL) data derive from NETL (2009). One dunam, the Ottoman unit of measure still the standard used in Israel, is equal to 0.1 hectare (= 1,000 m^2).

sidering an outcome to be good as an infrastructure footprint no than more than 50 percent greater than the smallest footprint achieved by any strategy under the same conditions. This is the relative-footprint component.

A land-use footprint of power plants that is half again as big as the smallest footprint area would have a much greater effect in a small country with severely constrained land area than might be the case in other countries. However, we choose this relatively large band of acceptable outcomes within this second condition of the land-use criterion to reduce the chance that different weights from the ones we selected would lead to different assessments of scenario outcomes. The 1:1.625:13 ratio[4] we have developed to weight the quality and nature of land required for solar, natural gas, and coal projects, respectively, may be wrong. But it is most likely not far wrong, and our presumption is that alternative means for deriving that ratio would lead to results not much different from the one we have chosen. Nevertheless, the relatively large range of acceptable outcomes should provide a measure of confidence in the reliability of our categorization. We will term this form of the two-component land-use criterion as the Land Use (Relative) metric.

Although, in our analysis, we relied on the relative formulation of the second component of the land-use metric, there is an alternative framing of this criteria whose results we report as well. We do this so planners in Israel can then determine how best to evaluate the land-use implications of alternative building strategies. This latter formulation would set an absolute upper limit of newly built capacity rather than the relative threshold we chose to employ for the infrastructure land-area condition. The reasoning behind this alternative is that, at some point, the problems of permitting, land cost, alternative land-use demands, and public acceptance will become sufficient to withstand pressure for more power-plant construction. We therefore chose 8,100 MW of new NGCC-plant construction across the two decades to 2030 to be the threshold level.[5] Scenario outcomes that exceed this level would be deemed to have failed

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[4] Using the data in Table 6.1, we calculated the following relative land-use intensities: 160 dunams per 100 MW for coal, 60 dunams per 100 MW for NGCC, and 800 dunams per 100 MW for solar thermal. However, not all land areas are of equal value. Coal plants are, by preference, sited near the coast to reduce transport costs and provide access to great amounts of cooling water. NGCC may be inland but near existing or proposed high-pressure pipelines. Considerations of water use in Israel mean that NGCC plants, by preference, use air cooling. (Some experiments with use of recycled water for cooling have been conducted with mixed success.) In Israel's climate, this leads to a loss in thermal efficiency. This would be exacerbated the more such plants are sited in the hottest portions of the country, so we assume that they will be clustered in less severely warm areas. Solar thermal may be sited in areas largely unusable for other purposes. If the land area of Israel is roughly divided into coastal area, the Negev, and the remainder, the ratios for relative share of total land area are very roughly 1:13:8, respectively. From this, we derive normalized weighting criteria of 13x for coal, 1.625x for NGCC, and 1x for solar thermal, based on the most likely location of each type of plant. When applied to the raw figures, the results for weighted land-use intensity are 2,080 weighted dunams per 100 MW for coal; 100 weighted dunams per 100 MW for NGCC; and 800 weighted dunams per 100 MW for solar thermal. These are the figures we used to compare alternative 2030 power-generating infrastructure footprint intensities with those of 2008. The latter is approximately 1,600 weighted dunams per 100 MW.

[5] For a number of reasons, it is most likely that new capacity would largely take the form of new NGCC plant. Keying off the values shown in Table 6.1, we reasoned that the rated capacity for NGCC plants either currently existing or under construction is approximately 2,700 MW. Nearly all of the new capacity, except the retrofitted Eshkol, Reading, and Haifa NGCC plants sited on the coast, is inland. Although interviews suggest that it would be difficult in most cases to site additional rated capacity on existing sites already devoted to power generation, we assume that an additional 2,700 MW may be constructed at existing power stations. Finally, we allow a further 5,400 MW NGCC capacity at greenfield sites (assumed to be along already-permitted natural-gas pipelines, such as in the relatively lightly populated areas in the region north of Beersheba). Thus, a criterion constraint of 8,100 MW permits adding new NGCC capacity three times greater than the current rated capacity.

this absolute-footprint test. This formulation we refer to as the Land Use (Absolute) metric. However, we chose not to follow this course in constructing the sieve for assessing different strategies because, ultimately, we wish to compare among the choices actually available under varying conditions. We did not wish to set criteria that would be seen as selectively restrictive among generating technologies and fuels.

Energy-Supply Security

The fourth thematic area for setting criteria for scenario outcomes is security of the energy supply, which, in turn, is an aspect of energy security. This will not be treated in the same manner as the preceding three. The principal reason for this is the complexity of the energy-supply security equation. While the metrics and components of cost, emissions, and land use present their own challenges, they all yield reasonable proxy metrics for which a reasonable case of illumination and sufficiency can be made. This is less true in the case of the supply aspect of energy security. The variables encompass infrastructure for delivery and generation, fuel choice, storage, contracting forms, technology development, and a range of policies and tactics, such as fuel switching and demand management. As such, the topic is best considered in Chapter Seven, in which we turn explicitly to the question of a robust supply infrastructure.

Performance of Strategies Against Thresholds

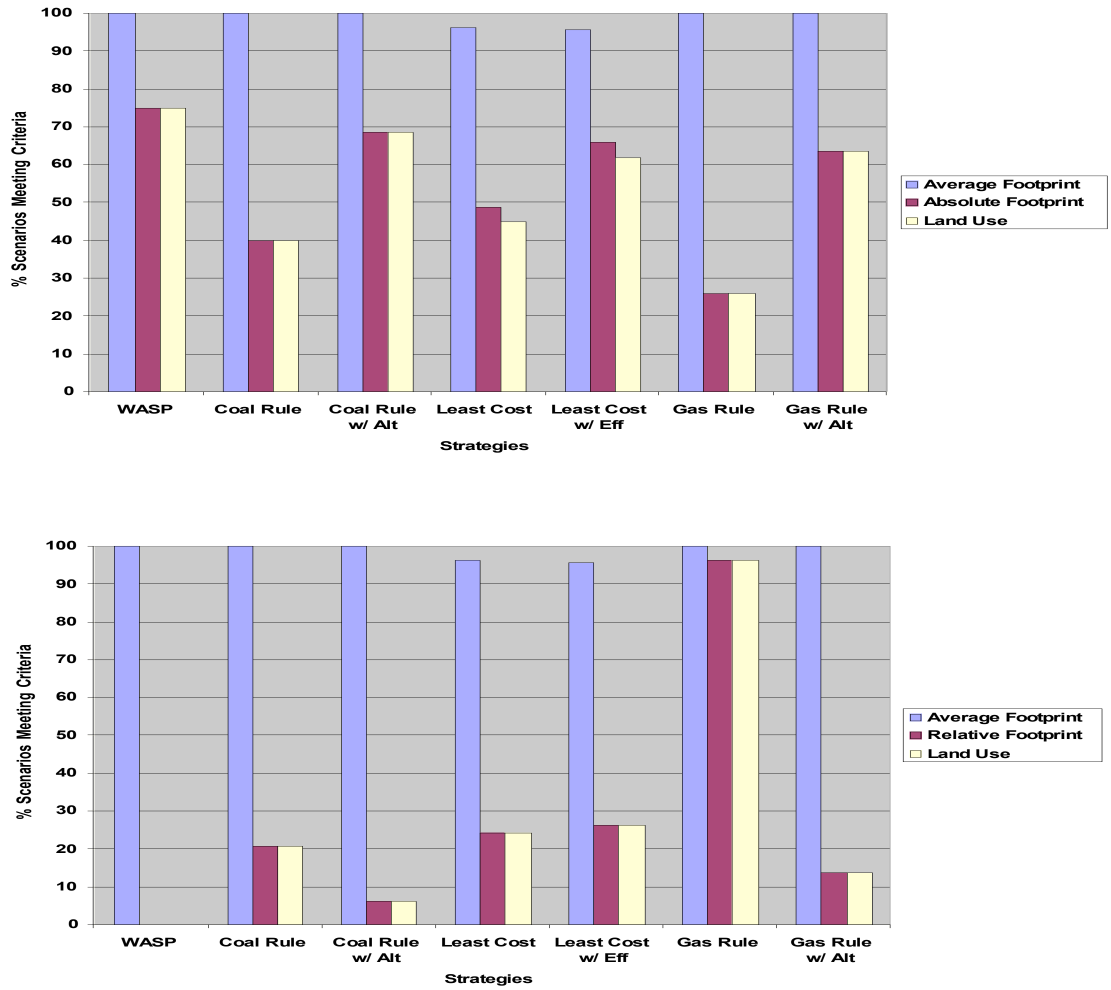
Applying the Land-Use Criteria

Figure 6.1 shows the results from applying the threshold criteria from one of the measures of interest—land use—to the set of scenario outcomes. It also illustrates how to interpret results at this stage.

The land-use criterion has two components. A scenario outcome is judged to be favorable if (1) average weighted land-use intensity remains less than or the same as that of 2005 (this is the first, average-footprint component) and (2) the land-use footprint for the electricity infrastructure that results is no more than 50 percent larger than that resulting from the strategy that yields the smallest footprint under the same conditions (the second, relative-footprint component). The lower portion in the figure shows, for each strategy, the number of scenario outcomes out of the total scenario test set, that meets the threshold for the first (average) and second (relative) component as well as the number that meets both of these components (Land Use [Relative]). For the sake of comparison, we also report, in the upper portion of Figure 6.1, what would be the result of applying the absolute criterion of adding no more than 8,100 MW of NGCC capacity (absolute footprint) as the second component of this threshold measure and the different resulting Land Use (Absolute) comprehensive measure. The average-footprint component of the land-use criterion measure remains the same in each of the formulations plotted on the two graphs.

In both versions of the results, the average land-use intensity component does not appear to present too great a hurdle. Most strategies seem to perform well with the exception of those strategies that favor massive expansion of coal-fired generation plants under some scenario conditions. Solar-thermal plants, of course, require the most land for an equivalent generating capacity among those technologies we examine. However, when we weight footprints according to land values by the scheme just described, coal-fired generation has a weighted land-use requirement much greater than that of solar thermal.

Figure 6.1
Percentage of Scenarios Meeting Land-Use Threshold Criteria



NOTE: Upper figure uses average- and absolute-footprint measures. Lower figure uses average- and relative-footprint measures.
RAND *TR747-6.1*

The second component, relative land use, causes more scenario outcomes to be unsuccessful and affects the strategies with differing degrees of severity. If the alternative formulation (absolute footprint) were used, the result would be to discard those strategies that led to great reliance on natural gas under extreme conditions. The WASP strategy carries out a fixed investment program with a large coal-fired component so is least susceptible, but it, too, experiences some scenario outcomes that fail this criterion. Those strategies that build natural gas–fired plants according to a rule-of-thumb approach and that do not permit demand management or alternative energy approaches are the most sensitive. The figure also shows the share of scenario outcomes for each strategy according to this metric that meet both criteria (Land Use) for each of the two different formulations.

We used the results of the lower of the two graphs in our analysis. This also leads to a more differentiated outcome. The relative compactness of NGCC-plant installations now makes those strategies that rely most heavily on natural gas show higher levels of success according to the relative-footprint criterion and, therefore, the combined Land Use (Relative) result. In no instance among all the scenarios could the WASP strategy meet this threshold. Similarly, those strategies that allow for and utilize large-scale solar-thermal arrays are disadvantaged by applying a relative-footprint standard across generating technologies.

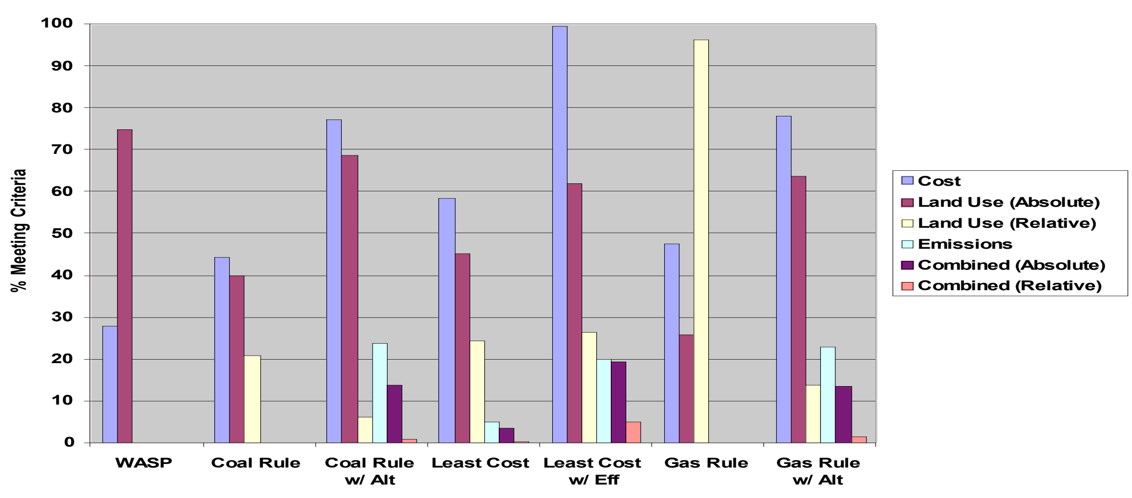
Applying Multiple Criteria

Figure 6.2 summarizes the behavior of each strategy with respect to the criterion thresholds across the full set of test scenarios. We compare scenario results against the thresholds set for the cost, emission, and land-use criteria as well as the number of scenarios that pass all three tests (Combined). We report both forms of the combined land-use criteria by showing two ways of calculating the share of scenario outcomes that meet each formulation of the two constituent thresholds. In the first instance, Land Use (Absolute) (and therefore the Combined [Absolute] result) is calculated using the absolute limit on NGCC construction. In the second, Land Use (Relative) (and therefore Combined [Relative]) uses the relative measure of land-use footprint.

As may be readily seen, across all strategies, it is the emission criterion that is the cause of the greatest share of unsuccessful outcomes, even though it does not require a reduction or even leveling of GHG emissions but permits an increase of up to 25 percent over 2005 levels. Only about one-quarter of scenario outcomes are deemed favorable according to this measure for the strategies that do the best, while three strategies do not display a single scenario under which this condition can be met satisfactorily.

The cost threshold criterion presents a more complicated view when applied to the scenario outcomes. The percentage number indicates the share of scenario outcomes for each strategy in which cost is within 5 percent of the lowest-cost strategy's cost outcome for that set of conditions. Most interesting is that, while the Least Cost_Eff strategy meets this criterion

Figure 6.2
Percentage of Scenarios in Which Each Strategy Meets Threshold Criteria



RAND *TR747-6.2*

measure in nearly 100 percent of the scenarios, the same strategy without the demand-management component (Least Cost) does so far less frequently, in only 59 percent of the scenarios.

The remaining criterion, land use, has already been discussed in detail in the previous section.

An important finding at this point is that three strategies, Coal Rule_Alt, Least Cost_Eff, and Gas Rule_Alt, consistently dominate the other four strategies with respect to each of the three criteria we have examined in detail. The results using the alternative form of the Land Use (Absolute) criterion show that Coal Rule_Alt and Gas Rule_Alt consistently match each other's performance and do best in all categories, ceding first place to Least Cost_Eff only with respect to the cost criterion. Interestingly, the addition of the energy-efficiency and alternative (nonfossil) fuel component to each of these former strategies allows them a higher share of success scenarios under the cost criterion than that displayed by the Least Cost strategy. Using the first form of Land Use (Absolute), the three strategies pass all three thresholds in 13 percent of the scenarios in the case of Coal Rule_Alt, in nearly 20 percent for Least Cost_Eff, and in 13 percent of the cases for Gas Rule_Alt.

This situation changes somewhat if we look at the same result using the filter of our preferred form of the Land Use (Relative) threshold, which utilizes the relative land-use footprint component in its algorithm. Then, the share of success across all three thresholds falls to only about 5 percent for Least Cost_Eff and less than half that, around 2 percent, for the other two leading candidates. These three still perform better than the other four strategies, even at this miserable level of performance.

So far, we have taken only an aggregate view of strategic performance by use of scenario outcomes. This level of analysis does provide some valuable insight into the strengths and weaknesses of each strategy but does so in only an approximate manner. We have looked solely at information contained within the formal quantitative analysis we performed. It is certain that Israel's planners will almost surely possess other types of information, albeit perhaps less complete or reliable than they might wish. These inputs not only will be on the substantive issues but also will convey an implicit weighting among the policy considerations involved in the natural-gas planning problem. When considering such a large set of scenarios, we need to move in a direction that will allow us to better understand precisely which conditions and which scenarios lead to the principal failure modes for each of the candidate strategies. This is a step not only toward making fuller and more discriminating use of information we possess but also to modifying strategies to shore up their defenses against possible strategic failures.

It is possible to determine, by simple inspection of the results database, what conditions lead to the outcomes shown in Figure 6.2 for the land-use and emission metrics. These are shown in the two right-hand columns in Table 6.2, which displays the scenario conditions that cause strategies to exhibit frequent failures. For those scenario outcomes that do meet the threshold set for the emission criterion, a future condition of low growth in demand is essential. This condition does not guarantee meeting the emission goal, as may be seen from the three strategies that cannot do so even when demand is relatively low. But it does appear necessary for those scenarios that meet this requirement.

A similar, but less stark, situation exists for the land-use metric. Again, it is demand that appears to be the most significant driver, but, in most cases, avoiding the highest demand projection is sufficient to ensure meeting both components of this metric. The Coal Rule_Alt and Least Cost_Eff strategies also require the most-intensive installation of solar-thermal capacity, while Gas Rule_Alt may also require the lowest-cost conditions for efficiency gains.

Table 6.2
Scenario Conditions Causing Failure of Each Strategy to Meet Threshold Criteria

	Metric		
Strategy	**Cost**	**Land Use (Relative)**	**Emissions**
WASP	Low–medium efficiency cost Medium–high CO_2 price	High demand	[Cannot meet metric]
Coal Rule	Low–medium efficiency cost Medium–high demand Medium–high natural-gas price Medium–high CO_2 price	High demand	[Cannot meet metric]
Coal Rule_Alt	Medium–high alternative cost Low–medium CO_2 price Medium–high alternative capacity Low–medium demand	High demand Low–medium alternative capacity	Medium–high demand
Least Cost	Low efficiency cost	High demand	Medium–high demand
Least Cost_Eff	(Fails in narrow range) Low demand	High demand Low–medium alternative capacity	Medium–high demand
Gas Rule	Low–medium efficiency cost Medium–high natural-gas price	Medium–high demand	[Cannot meet metric]
Gas Rule_Alt	Low–medium CO_2 price Medium–high alternative capacity Low–medium demand Medium–high alternative cost	High demand Medium demand if efficiency costs also medium–high	Medium–high demand

However, when considering behavior with respect to the cost criterion, simple inspection is no longer sufficient to understand the interplay of dynamics that determine successful outcomes. The number of variables that will affect the cost outcomes is too large for the easy recognition of patterns in the data.[6] In this case, we must utilize data-mining techniques to gain fuller insight into the information contained within the set of test-case scenario outcomes. In particular, we utilize a scenario-discovery algorithm that tests alternative sets of scenario conditions to find those that most compactly and efficiently describe the circumstances that lead to failure of each strategy.[7]

Ideally, we wish to find those conditions that then divide the set of scenario outcomes into those that meet a criterion threshold, such as minimal cost, and those that fail to do so. We evaluate a proposed set of rules for defining such failure-scenario conditions by measuring coverage (what fraction of the cases of failure to meet thresholds found in the full data set will be included in the set of outcomes produced by applying the failure-scenario conditions), density (within the set of outcomes selected by the failure-scenario conditions, how many actually truly do fail), and ease of interpretation. Clearly, those factors that would tend to increase the

[6] In addition to being unable to perceive patterns and relationships, there is also a concern that the human tendency to see a pattern where none actually exists would affect the analysis. For both these reasons, it is useful to employ analytically rigorous quantitative means for scenario discovery. See Lempert, Groves, et al. (2006) and Lempert, Bryant, and Bankes (2008) for a fuller discussion.

[7] Groves and Lempert (2007) provide a good discussion of the patient rule induction method (PRIM) algorithm and scenario discovery in general.

coverage would, in most circumstances, tend to reduce the density of failure cases within the resulting set of scenario outcomes and vice versa. The full results of this analysis of scenario failures are presented in Appendix B. A simplified version of the results showing those criteria most likely to lead to failure scenarios for each strategy is shown in the Cost Metric column of Table 6.2.

The WASP strategy is susceptible to failing to meet the cost-criterion threshold in scenarios in which the costs for achieving efficiency gains are not high and in which there is a nonzero cost for emission of CO_2 equivalents. It is clear why positive CO_2-emission pricing would be problematic for the coal-heavy WASP strategy. It may be less clear at first glance why the low cost of energy-efficiency gains may work to the disadvantage of this strategy. The point is an important one: We are measuring relative versus absolute effects. While all strategies would benefit from low-cost means for enhancing energy efficiency, they would not benefit equally. These two conditions would make strategies that seek efficiency gains and produce fewer emissions better suited to such possible futures. WASP suffers by comparison in a relative sense, since the threshold for this metric was constructed on the basis of cost *regret*. WASP tends to succeed, on the other hand, under conditions in which efficiency gains tend toward the costly end of their range, when the price of natural gas is high and coal prices are low or moderate, and GHG-emission charges are not set at the high end of their range of possible values.

The Coal Rule strategy similarly fails to meet the threshold when costs for achieving efficiency gains are in the lower range. It succeeds under conditions similar to those for the WASP strategy. Adding the alternative and efficiency policies to the Coal Rule strategy changes the conditions somewhat. Scenario conditions under which a GHG-emission price exists, natural-gas prices are not set at their lowest, and the costs of alternatives are not at their highest will tend to favor meeting the cost threshold.

As we see in Figure 6.2, the two strategies with the highest percentage of cases that meet the cost-condition threshold are Least Cost_Eff and Gas Rule_Alt. Since those two strategies each dominate their analogues that do not incorporate an efficiency-seeking component (and alternative-energy capacity in the case of Gas Rule), it is profitable to examine their cost-condition results in detail.

It is not surprising that the Least Cost_Eff strategy succeeds nearly 100 percent of the time according to this criterion. Interestingly, there are no scenario cases in which demand follows either of the medium or high demand-growth paths that see Least Cost_Eff fail to meet this criterion threshold. Base demand growth would need to be at its lowest level for a failure scenario to appear.

Half of the cases in which Gas Rule_Alt succeeds are under scenario conditions in which there is a nonzero CO_2 equivalent–emission price, base demand growth is not at the lowest level, and the cost of alternatives does not turn out to be at the high end of the range of assumptions. Almost no scenarios that include these conditions see failure outcomes when this strategy is followed. Two-thirds of the cases of failure for this strategy occur when GHG-emission prices are not set at their highest level, alternative-energy plant capacity is in the middle or high range, demand is not at its highest level, and the costs for alternative-energy technologies are middling or high. However, nearly half of the time when these conditions are met, the Gas Rule_Alt strategy leads to successful outcomes. Appendix B provides more details and an extended discussion. Table 6.3 provides a tabular synopsis of the performance of the seven basic strategies.

Table 6.3
Percentage of Scenarios Meeting Individual and All Three Criterion Thresholds

Strategy	Cost	Land Use (Relative)	Emissions	Meets All 3 Criteria
WASP	28	4	0	0
Coal Rule	44	21	0	0
Coal Rule_Alt	77	6	24	1
Least Cost	59	24	5	0
Least Cost_Eff	99	26	20	5
Gas Rule	48	96	0	0
Gas Rule_Alt	78	14	23	2

NOTE: Red indicates that the strategy meets that criterion threshold in less than 10 percent of the scenarios. Orange indicates that the strategy meets that criterion threshold in 10–30 percent of the scenarios. Yellow indicates that the strategy meets that criterion threshold in 31–75 percent of the scenarios. Green indicates that the strategy meets that criterion threshold in more than 75 percent of the scenarios.

Enhancing Robustness of Strategies

So far, we have considered the behavior of the seven strategies as originally specified. We have seen that three appear to be the best candidates for robust performance but that each possesses potential shortcomings—areas in which performance in one or more of the three criteria discussed so far could fall short. The result is a relatively low rate of success across the test bed of alternative future conditions when screened by the three measures for success used so far. The share of scenario outcomes deemed successful according to all three metrics varies from 2 to 4 percent among the three strategies. The preceding analysis provides useful information on where the vulnerabilities of each strategy lie. Using this information, we now address each of the three candidate strategies and modify them to enhance their properties of robustness as we have defined the term.

To generalize, the scenarios where the basic, rule of thumb–based strategies fail are those that have conditions not favorable to the basic strategy. Nevertheless, even when the trend becomes clear, the simple-minded application of each strategy's decision rules continues along the set strategic course. We now introduce modifications that permit learning and observation to guide midcourse changes to the strategies. We create three new strategies built on the three that fared best in the preceding analysis.

Least Cost_Eff (Modified). This strategy continues to follow the Least Cost rules and employs efficiency-enhancing measures. However, if conditions are appropriate to do so, it may choose to retire one or two coal-fired generating plants. It will do so when the LCOE of operating the coal-fueled plant is greater than that of equivalent NGCC or alternative plants. Beginning in the year 2020, when the total operating costs for the coal plant, including the payment of any GHG emission–based price or tax, is greater than the replacement costs (including the amortized investment costs) of a new plant, such a replacement may occur. A second coal plant may be decommissioned if the conditions recommend such a step, but no sooner than five years after the first plant is retired.

The analysis we have employed is at a level of aggregation (national and yearly) for which this mechanism is an adequate representation. The presumption, of course, is that the relevant authorities have gathered information on technology costs, fuel prices, and GHG-emission tax equivalents and have projected where each trajectory is trending. Plans have been made to implement the switch at the appropriate time.[8] This approach may also be more conservative than it first appears. The capital costs associated with building a new power plant are sufficiently high that it makes such a replacement economically desirable only when the costs of emissions from a coal-fired plant become quite high. And, of course, it will not occur if demand is too great to permit taking base load off-line. In addition, while the land required for the NGCC replacement plant would most likely be less valuable than that of the larger land area (and most likely coastal location) formerly occupied by the decommissioned coal plant, we presumed that the replacement would be budget neutral with respect to land costs.

Gas Rule_Alt (Modified). As with the Least Cost_Eff (Modified) strategy, there is now the option of retiring one or two coal-fired plants. In addition, because of the focus on maximizing the use of natural gas, this strategy now pays attention to the costs of introducing alternative-fuel electricity sources before doing so. If the LCOE stemming from the introduction of solar thermal and pumped storage would be greater than that of building and operating NGCC plants, it is no longer mandatory that it build that alternative-fuel capacity just because the scenario conditions make it available. Finally, beginning in the year 2021, if the LCOE from installation of natural-gas facilities is 30 percent higher than it would be if a new coal-fired plant were built instead, then the strategy ceases to employ the Gas Rule strategy–based rules and instead begins to employ the Least Cost strategy rules. The essence of this strategy still remains to exploit fully the possibility of using natural gas to fuel Israel's energy economy but now has built-in safety valves if confronted with a serious emission problem (retirement) or a cost regime unfavorable to natural gas. Figure 6.3 provides a flowchart view of this modified form of the Gas Rule_Alt strategy.

Coal Rule_Alt (Modified). The strategies of the Coal Rule family by design already have a certain level of safety-valve mechanisms encoded in their operational algorithms. These rules will select either coal- or natural gas–fired plants based on a series of criteria. Given the nature of this strategy and its principal focus on maintaining a diversified portfolio of generation technologies, we have introduced no capability for retiring coal-fired power plants as we have with the two other modified candidate strategies. The only modification we have introduced into this version of the Coal Rule approach is to make the decision about investing in alternative-fuel capacity cost sensitive. If the LCOE stemming from the introduction of solar thermal and pumped storage would be greater than that of building and operating NGCC plants, it is no longer mandatory that it build that alternative-fuel capacity.

The three modified form strategies are summarized in Table 6.4. The modifications to the original rules for the base strategy are shown in color.

Table 6.5 shows the previous results for the unmodified forms of the three strategies as well as the results of testing the three new modified strategies in each of the test scenarios and applying the same thresholds we used previously to assess the outcomes for the original set of seven strategies.[9]

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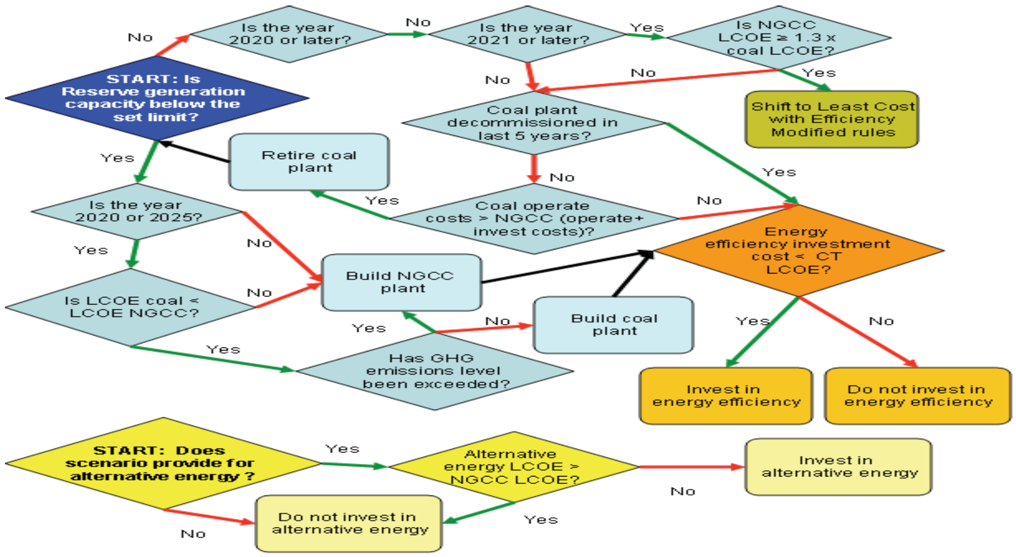
[8] This view of how the replacement process would be prepared and implemented is acceptable from a technical point of view at this level of aggregation. Those familiar with the institutional issues involved in making such replacement investments in a democratic system may find the assumption to be a heroic one when viewed through the lens of politics and bureaucratic organization.

[9] In this instance, the test set of 1,400 future states of the world was reduced to 1,265. Therefore, this resulted in an additional 1,265 × 3 = 3,795 scenarios to add to the simulations database.

Figure 6.3
Flowchart of Decision Rules for Gas Rule with Alternatives (Modified) Strategy



RAND *TR747-6.3*

The effect of introducing relatively simple modifications to the base strategies so as to permit more-adaptive behavior appears to be large. Whereas before the base form of Coal Rule_Alt was successful with respect to each of the three metrics in only about 1 percent of the cases, the success rate was enhanced twelvefold after introducing the modification. The change is even more dramatic in the case of the Gas Rule–form strategy. The combined performance across all three criteria increases from about 2 percent success across all the scenarios to36 percent. The change for the Least Cost (Modified) strategic form is less dramatic than this but still is paced at a nearly sixfold increase in success according to the combined results.

The modified form of the Gas Rule we have tested in this analysis emerges as the most interesting candidate to form the basis of a robust approach to framing Israel's natural-gas utilization strategy. It dominates or is the near equal to the other final-form strategies in the measures we have analyzed formally. It appears to balance the multiple main objectives in Israel's energy planning. It achieves this success by being less sensitive to future prices placed on GHG emissions than the more coal-intensive strategies. It produces lower emissions per unit of energy than do the others. The ability to shift to more of a Least Cost approach when conditions demand it means that this strategy never fails catastrophically with respect to costs and usually does rather well.

This last point is illustrated in Figure 6.4. It looks over the full range of test scenarios applying the latest modified forms of the Least Cost and Gas Rule strategies. In many situations, the modified Least Cost rule would lead to the Least Cost system plan. But as may be seen from the many points lining the vertical axis, the regret for following the Gas Rule in most of these circumstances is less than 5 percent, often well under that level. The highest regret is 11 percent. Similarly, we can see from the points along the horizontal axis that there exists a set of scenarios in which the modified-form Gas Rule actually bests the latest form of the Least Cost strategy, which, instead, registers some measure of cost regret in these cases. Finally, there exists a relatively small set of points forming a line extending out from the origin

Table 6.4
The Modified Candidate Robust Strategies for Use of Natural Gas in Israel

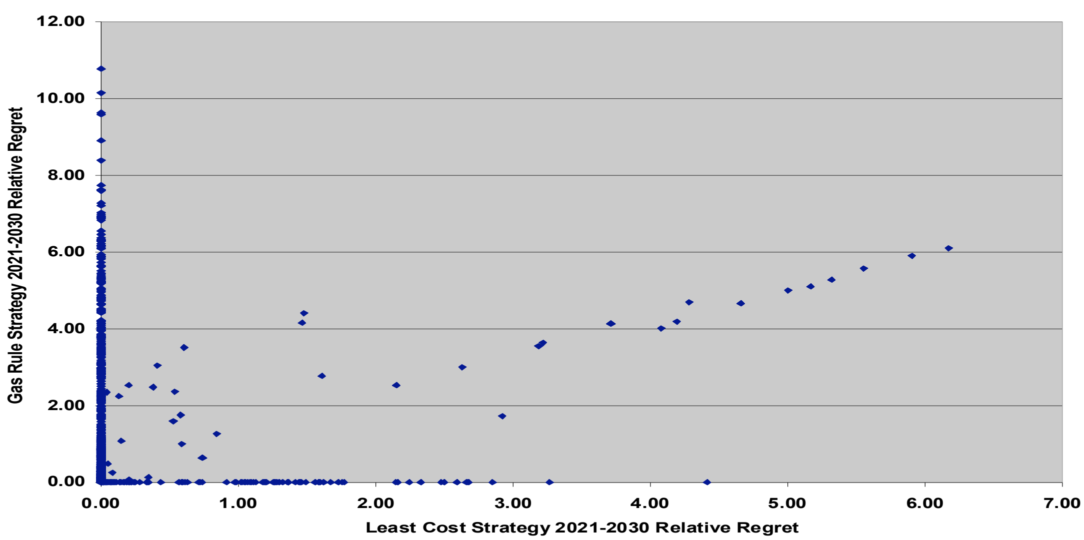
Strategy	Build if More Capacity Is Needed	Conditions Under Which to Build Coal Plant	Build Renewable-Fuel Power Plant?	Invest in Efficiency Gains?	Retire Coal Plants?	Continue to Follow Rules?
WASP	According to set plan	Called for in plan	Yes, if called for in plan	No	No	Yes
Coal Rule_Alt (Modified)	NGCC	1a. Coal and renewables make up less than 50% of generation capacity; and b. GHG-emission limit not exceeded; and c. LCOE coal < LCOE NGCC - or - 2a.Coal and renewables make up less than 40% of generation capacity; and b. GHG-emission limit not exceeded.	Yes, to level described in scenario if LCOE renewables ≤ LCOE natural-gas CT	Yes, if LCOE efficiency < LCOE natural-gas CT	No	Yes
Least Cost_Eff (Modified)	Least LCOE among coal, NGCC, and renewables	Least LCOE	Yes, if LCOE renewables < LCOE NGCC or coal	Yes, if LCOE efficiency < LCOE natural-gas CT	Yes, one in 2020 and one in 2025 if operating costs for coal > LCOE of replacing NGCC (including all investment costs)	Yes
Gas Rule_Alt (Modified)	NGCC	In 2020 or in 2025, LCOE coal < LCOE NGCC or renewables (i.e., maximum: 2 plants in total)	Yes, to level described in scenario if LCOE renewables ≤ LCOE natural-gas CT	Yes, if LCOE efficiency < LCOE natural-gas CT	Yes, one in 2020 and one in 2025 if operating costs for coal > LCOE of replacing NGCC (including all investment costs)	If LCOE NGCC > 130% of LCOE coal, will revert to Least Cost_Eff (Modified) rules

Table 6.5
Percentage of Scenarios Meeting Individual and Combined Criterion Thresholds for Unmodified and Modified Forms of Three Strategies (percent)

Strategy	Cost	Land Use (Relative)	Emissions	Meets All 3 Criteria
Coal Rule_Alt	77	6	24	1
Coal Rule_Alt (Modified)	67	31	18	12
Least Cost_Eff	99	26	20	5
Least Cost_Eff (Modified)	99	54	40	27
Gas Rule_Alt	78	14	23	2
Gas Rule_Alt (Modified)	94	96	39	36

NOTE: Red indicates that the strategy meets that criterion threshold in less than 10 percent of the scenarios. Orange indicates that the strategy meets that criterion threshold in 10–30 percent of the scenarios. Yellow indicates that the strategy meets that criterion threshold in 31–75 percent of the scenarios. Green indicates that the strategy meets that criterion threshold in more than 75 percent of the scenarios.

Figure 6.4
Relative Regret of Gas Rule with Alternatives (Modified) and Least Cost with Efficiency (Modified) Strategies with Respect to Net Present Value of 2021–2030 System Costs



RAND *TR747-6.4*

at which neither Gas Rule nor Least Cost provides the low-cost solution. This is the set of scenarios in which the modified form of the Coal Rule dominates in terms of cost. It might be noted from the slope of that imputed line that, in these exceptional instances, both modified Least Cost and Gas Rule strategies register almost exactly the same level of regret.

This modification of the fundamental Gas Rule approach still has two main vulnerabilities. It does not perform well when future natural-gas prices are high, especially when compared to those for coal and other fuels, and it requires considerable infrastructure and natural-gas consumption when demand for electricity is high or very high. Of course, this latter situation makes it nearly impossible for any of the strategies to meet all the objectives we have formalized in our analysis. These vulnerabilities can be mitigated by more permutations by introducing even more adaptive elements than we have used in constructing and modifying the strategies so far. As we have seen, a major vulnerability in the cost dimension was considerably improved through the addition of fairly unsophisticated criteria by which the Gas Rule trajectory may be shifted to following the Least Cost strategy instead. The situation of rapidly growing demand for natural gas may be mitigated by several potential shifts to substitute away from natural gas in the future. This may be toward other fuels operating on technological principles different from those available today or more-active measures to affect the shape of demand directly.

A statistical analysis of those futures in which application of the Gas Rule_Alt (Modified) strategy succeeds suggests that this 36-percent share of all cases does not represent unusual or limited cases. Table 6.6 shows these results for several sets of scenario-condition assumptions that appear in successful scenario outcomes for each strategy. It is interesting to note that, in the cases in which both the latest forms of the Least Cost and Gas Rule strategies meet all three criteria, no new coal plants are constructed. Even the successful outcome scenarios for the Coal

Table 6.6
Characteristics of Scenario Outcomes That Meet All Three Threshold Criteria, by Strategy Employed in Scenario

	Strategy			
Measure	WASP	Coal Rule_Alt (Modified)	Least Cost_Eff (Modified)	Gas Rule_Alt (Modified)
Successful scenarios (out of 1,400 futures)	0	150	343	461
Successful scenarios with new coal capacity installed	n.a.	23	0	0
Demand level (% of all successful scenarios)	n.a.	100	100	100
Low	n.a.	100	47	55
Medium	n.a.	0	53	45
High	n.a.	0	0	0
Price of natural gas (% of all successful scenarios)	n.a.	100	100	100
Low	n.a.	15	48	37
Medium	n.a.	51	46	48
High	n.a.	33	6	15
GHG limits (% of all successful scenarios)	n.a.	100	100	100
None	n.a.	23	24	26
Medium	n.a.	55	49	48
High	n.a.	22	28	26
CO_2-emission price (% of all successful scenarios)	n.a.	100	100	100
None	n.a.	37	9	11
Medium	n.a.	57	43	45
High	n.a.	5	48	44

NOTE: n.a. = not applicable. Due to rounding, not all sets of disaggregated assumptions may total 100 percent.

Rule variant in which new coal-plant construction occurs represent only 15 percent of the total of successful cases for this strategy.[10]

The conclusion we draw from our analysis to this point is not that Israel should adopt the Gas Rule plan as we have presented it as its approach to national planning for the use of natural gas. We have, indeed, shown that a plan containing the elements of such a strategy—and, in particular, its heavy reliance on natural gas—may achieve results consistent with metrics and thresholds we have set and that we presume are similar to those that the government wishes to achieve. But the principal finding at this stage is that this rather simple-minded approach within the parameters of the model we developed can meet the objective criteria set for it in nearly 40 percent of the widely ranging scenarios we have simulated. It does so with only the most limited of foresight capability and only rudimentary rules for plan switching. This suggests the possibility that a more detailed adaptive approach, adding such elements as prospective land-use planning for energy on a national level, cost tracking focusing on key elements of cost, and emission monitoring and enforcement, could be the means for constructing implementation-ready, adaptive energy solutions that would guide the utilization of natural gas and meet at least three of the four criteria we have utilized to characterize scenario outcomes.

It is not useful to pursue this in more detail at this point. This framing would best be done under conditions that could draw direct input from Israel's planners and engage them in an integrated process for determining the best ways to proceed. But we are still left with a large remaining question: What level of natural-gas supply is commensurate with all of Israel's objectives and concerns? What amount may be planned on without compromising the desire to also minimize risk that arises from the supply dimension of the nation's energy balance? We explore this issue in considerable detail in Chapter Seven.

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[10] Clearly, this outcome depends in large part on where the threshold levels are set for each of the three criteria we used. Making these more or less restrictive would change the number for each strategy that meet all criteria. Further, we have presumed no hierarchy of priority among the three criteria. If some were to be accorded more or less weight than others, particularly in the case of the emission standard, this would lead to different patterns of successful outcomes and different patterns for adding new coal capacity, among other things.

CHAPTER SEVEN

Natural-Gas Sources, Infrastructure, and Security

In the previous chapters, we have proposed candidate strategies for natural-gas utilization, tested their robustness against different plausible sets of future conditions by establishing criteria for judging scenario outcomes, and used this information to select among the original set of strategies. We then introduced modifications to the strategies for natural-gas utilization and found that we could considerably enhance robustness by adopting relatively simple adaptive rules. We used the metrics of cost, emission, and land-use requirements to judge the utilization strategies.

Underlying the issues of utilization are also concerns about the sourcing, infrastructure, and security of natural-gas supply. In this sense, there is a fourth criterion for judging scenario outcomes—namely, the sustainability of the natural-gas supply required to implement a robust utilization strategy—that is qualitatively different from those of cost, land use, and emissions. This latter criterion really requires a separate examination of strategies—this time not for natural-gas utilization but for natural-gas supply.

In the case of supply, infrastructure, and security, actions and polices do not so much lead directly to particular consequences but rather serve to raise or lower the risk of those consequences. Further, the gravity and extent of the consequences will be affected not only by whether a risky situation becomes realized in the form of an undesirable occurrence. The level of consequences will also be determined by the vulnerability Israel has to the particular occurrence in question. And this vulnerability in itself is a characteristic that can be affected by supplementary policy choices. That is, should a certain energy policy raise a risk of unfavorable occurrences, Israel may take conditional measures to offset that risk or to minimize the consequences should an unfavorable future even arise.

The discussion in this chapter addresses the issues raised by natural-gas supply. The first section provides a primer for those not familiar with the technical and economic issues and options that exist. This section will be of use to many but may be passed over by those more familiar with the use of natural gas. It does not form part of the analytical narrative. This general section will be followed by more-specific consideration of the threats to Israel's energy supply, measures to alleviate such risks, and then what types of costs these measures would entail.

Our quantitative model–based assessment of choices, strategies, and outcomes is discussed in the rest of the chapter. Again, we follow the RDM approach we used when considering natural-gas utilization. We propose four strategies, and we examine the behavior of those strategies with respect to metrics (such as cost and rate of domestic natural-gas depletion). We are then able to develop a series of trade curves to assist planners and decisionmakers based on key uncertain variables. Rather than develop a prediction for those variables and so an optimal solution, we provide a basis for determining when and for what reason one strategy should be selected over another. In our discussion, we speak of what specific actions and investments would provide a degree of insurance for the natural-gas supply that would be appropriate, what level of insurance would be advisable, and what may be done in the specific case of a sudden loss of supply of natural gas over an extended period. As before, our discussion necessarily touches on a broad perspective when discussing the nation's energy balance as a whole, but we apply particular attention to issues related to the supply of natural gas.

Fundamentals of Natural-Gas Supply and Infrastructure

Transmission and Distribution Infrastructure

So far, our discussion of infrastructure has been restricted to selection among various types of generating capacity. These, of course, are coupled with implicit decisions over fuel choice. In addition, there must also be an infrastructure to support the distribution of natural gas. This infrastructure begins with domestic pipelines that will both feed high-capacity users and possibly provide deliveries to retail distribution networks that may arise in Israel in the future if demand for natural-gas transitions from the power-production and heavy industrial sectors to other potential customers.

The main requirement of the transmission system is to meet the peak demand of its shippers that have contracts for delivery.[1] To meet this requirement, the natural-gas delivery and storage system should be designed with the most-efficient and -economical mix of pipelines to deliver the gas and storage and LNG facilities to serve peak demands. The diameter of the pipeline and its operating pressure are important factors in determining how much a pipeline can carry. The size of the pipelines often depends on the availability of storage. Hence, to design a pipeline delivery network that provides the required capacity and handles swings in supply and demand, both pipeline and storage must be integrated into the design. The right combination will allow flexibility in current operations as well as future operational expansions.

Operating the gas pipelines at full capacity is optimal for revenues. However, utilization rate (flow relative to design capacity) of pipelines is rarely 100 percent. Utilization at less than the planned levels results from temporary decreases in market demand or from shutting off parts of the line for scheduled maintenance, weather-related operational limitations, or operational accidents. These factors are important for Israel. It is a small country with little longitudinal spread. This means that the daily cycle does not permit much opportunity for load spreading. Further, the observance of the Jewish Sabbath and other holidays, with their injunction to cease all work, while not universally adhered to, have a noticeable effect on the pattern of electricity demand. The result is that swing capacity is an important issue with supply.

The starkest example is in the case of the gas pipeline carrying EMG deliveries from El Arish to Ashkelon. It was designed for 7 BCM per year capacity, in line with the decision by EMG to cap annual deliveries to Israel at this level. However, when the issue of swing is taken into account, it becomes clear that contracts can be written at most to a level of only 6.5 BCM because of the need to meet demand at peak times through a system that will accept only vol-

[1] This discussion is based largely on EIA (undated [a], undated [b]).

umes of 7 BCM total in a year.[2] There are some indications that portions of Israel's domestic distribution lines may have design capacities that could add a further choke point into the system. Therefore, pipeline design is an important policy element.

The question of swing and pipeline load is not solely one of technology. The ability to determine when natural gas will be utilized is also determined by the nature of the contract with the suppliers. The issue is what degree of swing can be incorporated into the governing contracts. If the supplier will allow a considerable rate of swing, this enhances the flexibility of use of natural gas as a fuel. A plant can be constructed with the intention of operating and consuming natural gas during shoulder and peak periods of demand, when the tariff that can be charged to consumers is high. If, on the other hand, the contract allows for only limited swing (and this appears to be characteristic of the contracts that EMG is willing to consider), this means that a natural gas–fired plant must also operate as a base-load plant. Doing so would decrease the likelihood that a potential independent market entrant would find it attractive to do so if the base-load tariffs provide insufficient margin above costs. It also increases the likelihood that Israel would rely on more-traditional fuels, such as heavy oil or diesel.

In this regard, one decision Israel will face is whether and when to build the planned inland pipeline up the center of the country that parallels the route of the undersea pipeline that already exists. We return to this point later in this chapter.

Storage of Natural Gas

The policy and actions related to the storage of natural gas and other liquid fuels that could be used to offset a stoppage in the natural-gas supply are crucial for Israel. For this reason, an extensive discussion of these issues and an examination of relevant international experience may be found in Appendix C. In this section, we touch on some of the main ideas that informed the analyses.

One of the main functions of natural-gas storage is to act as the supply-and-demand relief valve. Natural-gas storage enables backup inventory to meet seasonal demands, provide reliable service to users, and control price volatility. In addition, transmission pipeline companies use the gas in storage to maintain the pipeline system's gas flow and pressure within design parameters, thereby preserving operational integrity. This last point is important for Israel, as natural-gas deliveries from EMG via the Egyptian pipeline become more important, and is an element in the management of pipeline swing.

Stock Storage of Natural Gas. The three most common natural-gas storage sites are depleted reservoirs, aquifers, and salt caverns. Depleted reservoirs are oil or gas fields from which all commercially profitable oil or gas has been extracted. Aquifers are reservoirs bounded by impermeable rocks. Salt formations are created by leaching naturally occurring salt beds and caverns. The available geology is the main factor for determining the location, the number, and type of underground storage facility. The engineering conditions, the size requirement, and base gas requirements will determine whether and where to develop storage. The site's access

[2] At times of high demand, sections of the pipeline may be used at more than 100 percent certified capacity, because this is the minimum capacity for maintaining service and not the maximum throughput capability of the pipeline. Pipelines are engineered to withstand much greater pressures than the pressures of certified capacity. Exceeding 100 percent can be accomplished through secondary compression and line packing to increase the pressure within safe limits to increase the throughput temporarily. However, over the full year, this will not introduce much change to the point made in the discussion on swing.

to transportation-pipeline infrastructure, sources of gas production, and markets is another important element to determining the locations of storage development (FERC, 2004).

In the particular circumstances of Israel, only depleted-reservoir storage is likely to be relevant. Aquifers are strategic resources in such a water-scarce region and are unlikely to be made vulnerable to contamination or mischance. Salt domes are also not likely, for reasons developed more fully in Appendix C. Therefore, the present discussion of stock storage focuses on depleted reservoirs.

Depleted oil or gas fields are permeable underground rock formations confined by impermeable rock or water barriers. Having contained petroleum or natural gas for millions of years, depleted reservoirs are proven for storage. Furthermore, the geology and operating characteristics of a depleted field are already known. Another advantage of a depleted field is that the existing wells, gathering systems, and pipelines used earlier for oil or gas can be reused for natural-gas operations. Generally, a depleted reservoir requires 50 percent of its total capacity to be filled with base gas, leaving 50 percent of the total capacity for working gas storage.

This high base gas level means that depleted reservoirs will have relatively long injection periods. Depleted reservoirs are therefore usually cycled only once per year (Simmons and Company International, 2000). For depleted reservoirs and aquifers in northern climates, the gas is usually withdrawn in the winter season (November to March) to meet the cold-season demands and injected during the summer season. This might be reversed in Israel, where the peak now occurs most frequently in summer.

Depleted reservoirs are the easiest and least costly means of storage to develop (FERC, 2004). Therefore, if available, depleted reservoirs are the favored storage choice. The costs of storage are site specific and depend on many factors, such as the quality and variability of the geologic structure of the proposed site, amount of compressive horsepower required, type of surface facilities needed, proximity to pipeline infrastructure, and permitting and environmental issues. Other costs include holding inventory and transporting natural gas from supply source to storage facility and from storage to market. Of all cost factors, cost of base gas is one of the most expensive elements of a storage project. Tables 7.1 and 7.2 compare the cost of gas storage using depleted reservoirs versus salt caverns.

Currently, the owners of storage facilities in the United States are not necessarily the owners of the gas inside. Before 1994, the interstate-pipeline companies owned all the gas in their pipelines and storage and had exclusive control over the capacity and operations of their

Table 7.1
Average Cost for Storing Natural Gas in Depleted Reservoirs ($/MMBTU)

Cost Item	Amount
Annual demand charge	0.40
Injection fee	0.02
Withdrawal fee	0.02
Fuel	0.04[a]
Total	0.48

SOURCE: Simmons and Company International (2000).

NOTE: Storage costs vary from facility to facility and are often based on negotiated rates.

[a] 1% of a $4.00/MMBTU natural-gas price.

Table 7.2
Average Cost for Storing Natural Gas in Salt Caverns ($/MMBTU)

	Cycles				
Cost Item	**1**	**2**	**3**	**4**	**5**
Demand charge	1.00	0.50	0.33	0.25	0.20
Injection fee	0.02	0.02	0.02	0.02	0.02
Withdrawal fee	0.02	0.02	0.02	0.02	0.02
Fuel	0.04	0.04	0.04	0.04	0.04
Total	1.08	0.58	0.41	0.33	0.28

SOURCE: Simmons and Company International (2000).

NOTE: Storage costs vary from facility to facility and are often based on negotiated rates.

storage facilities. This situation changed in 1994 when Federal Energy Regulatory Commission (FERC) order 636 on open access was implemented. According to the new law, pipeline companies were required to provide third parties open access to their storage facilities. Minus the working gas capacity needed to maintain system balance, pipeline companies were required to make available for leasing to third parties a major portion of the remaining working gas capacity at each site.

We conclude the general discussion of stock storage by summing up the advantages and disadvantages of depleted-reservoir storage:

- Advantages
  - They are typically near existing regional pipeline infrastructure.
  - The fields already have usable wells and gathering facilities. This reduces the cost of conversion to gas storage.
  - The geology is well known. The fields have previously trapped hydrocarbons that minimize the risk of reservoir leaks.
- Disadvantages
  - Natural-gas storage can be quite expensive because of the need to maintain sufficient pressure within the reservoir in the form of valuable natural gas that remains unpumped.
  - Because of the nature of reservoir producing mechanisms, working gas volumes are usually cycled only once per season (extremely large storage reservoirs are the exception).
  - Often, these reservoirs are old and require a substantial amount of well maintenance and monitoring to ensure that working gas is not being lost via well bore leaks into other permeable reservoirs.

Depleted-Reservoir Storage in Israel. Israel has, until recent years, been noted for being poorly endowed with fossil-fuel resources when compared to other parts of the Middle East. Nonetheless, there has been considerable on-land exploration over the years, with several minor successful strikes of oil. This has left Israel with depleted oil reservoirs. To what extent could these be converted to storage of natural gas as Israel shifts its primary-fuel base for electricity generation away from coal and heavy fuel oil? The RAND project team did not gain sufficient access to the data necessary to come to a conclusive judgment on the storage possibilities in Israel. We report on the information we did obtain, in interviews with several sources, to indicate where possibilities may lie. This presentation must necessarily be qualitative in nature but will serve the present purpose. Only additional work can provide a full evaluation of the feasibility of these potential options.

There is a series of formations that have previously been drilled for natural gas (e.g., Zohar in the region near Arad). In addition, there is a depleted oil reservoir at Heletz inland from the coast in the region between Ashdod and Ashkelon. Several other candidates, both drilled formations and salt domes, exist in formations[3] near the Dead Sea and down the rift valley of the Arava. However, both Zohar and Heletz (and the nearby Kochav oil field) appear attractive on their face because of their proximity to existing or planned high-pressure natural-gas pipelines.

Anecdotal information suggests the Zohar formation may not have sufficient capacity to serve as a meaningful natural-gas storage facility. Further, any decision to explore the possibility of using any such depleted reservoir would need to consider the costs involved—not only for the infrastructure but also for the base gas load that would be required to build up sufficient pressure so that working gas could be injected and withdrawn as needed. Nevertheless, the possibility does exist. In view of the potential hazards of supply shortfalls, for whatever reason, in a system converting to greater use of natural gas, this is a potential insurance measure that Israel may wish to explore.

In this regard, it is also worth pointing out that the Yam Tethys reservoir will be depleted some time in the early or middle part of the next decade. The actual date will, of course, depend on the rate at which natural gas is actually withdrawn.[4] However, at that point, there will exist a massive depleted reservoir off the coast of Israel already connected to the domestic high-pressure pipeline. It is at least conceivable that this would prove to be a practical storage location for natural gas both to smooth supply during ordinary circumstances, conceivably take deliveries of LNG (as discussed in the next section), and provide a strategic reserve for the nation. Of course, any such development would depend crucially on the technical details and the actual calculation of costs to provide an informed determination of feasibility. We did not have independent access to the necessary data, and there did not appear to be a common position among those whom we interviewed. Therefore, we merely raise the possibility for further consideration later in our analysis.

Finally, it is also worth mentioning that a system of high-pressure natural-gas pipelines in itself provides a system for storage. The natural gas contained within a pipeline is not inconsiderable and could be used to affect a sudden crisis elsewhere in the system, albeit for only a very short time.

Liquefied Natural Gas and Storage. When natural gas is cooled to temperatures below –160°C, it condenses to LNG. In liquid form, natural gas occupies just 1/600 the volume of its gaseous form. With such a significant reduction in volume, large quantities of LNG can be transported in the volume of a single tanker ship. In fact, one tanker shipment of LNG can carry enough LNG to power the daily energy needs of more than 10 million homes. The lique-

[3] The desirable areas are sandstone layers that were naturally capped with limestone or other formations over millions of years that display good porosity (hence a sufficient amount of space available) and permeability (a measure of how well the porous spaces are interconnected). Too low a level of porosity or permeability would reduce the suitability of a formation for reinjection with natural gas.

[4] The experience of the latter part of 2008, for example, was that delivery problems with the pipeline delivering natural gas purchased from EMG required additional draws on Yam Tethys beyond what had been anticipated for the period.

fied form also allows for ship transportation to great distances, too costly to reach by building underground or undersea pipeline networks.

When needed to fulfill natural-gas demand, LNG is warmed, regasified, and pumped into the distribution pipelines to be used for the same purposes as conventional natural gas. A common use of LNG is for peak shaving. Peak shaving is the practice of storing gas for peak demands that cannot be met by one's typical pipeline sources. During extremely cold months or hot months or when unforeseen events arise, the demand for electricity may peak. To meet this peak in demand, utilities need a reliable source of gas that can quickly supplement the existing supply and shave peaks in demand. LNG can be a reliable source that can be stored and quickly converted to usable gas.

The costs of liquefaction plants have decreased from $600 per ton of capacity in the late 1980s to about $200 per ton as of 2001. The construction of a new 8.2-million-ton-per-year liquefaction plant could cost between $1.5 billion and $2 billion (NETL, 2005). Chartering a 138,000-cubic-meter-capacity LNG ship costs about $60,000 per day (NETL, 2005). The building and operating costs of onshore receiving terminals total upward of $400 million. Offshore-terminal construction cost is substantially higher. These terminals function as unloading, storage, and regasification facilities (NETL, 2005).

In the United States, FERC and U.S. Department of Transportation (DOT) regulations require LNG facilities to establish security patrols, protective enclosures, lighting, monitoring equipment, and alternative power sources. The regulation also requires an exclusion zone surrounding the facilities to protect adjacent sites in the event of flammable vapor-cloud release (NETL and NARUC, 2005). Leakage does not automatically lead to an explosion or fire. The combustibility and ultralow temperature of LNG, however, do pose potential hazards. The likelihood and the severity of hazardous incidents are debatable. However, experts tend to agree that the greatest potential dangers are pool fires, flammable vapor clouds, and flameless explosions.[5]

The potential hazard due to LNG spill, however, can be catastrophic. One study modeled accidental and intentional LNG spillage in order to determine the level of consequential hazard. The study estimated that the level of LNG cargo-tank breaches for intentional events, such as acts of terrorism, would be up to six times as large as for an accidental event. It was estimated that thermal hazards would occur mostly within 1,600 meters of an LNG-ship spill, with the highest hazard within 250 to 500 meters of a spill. The pool sizes for a credible spill were estimated to range from 150 meters for small spills to several hundred meters in diameter for large spills. Beyond about 750 meters for small spills and 1,600 meters for large spills, the impacts on public safety should be low (Hightower et al., 2004).

LNG is stored at atmospheric pressure in double-walled, insulated tanks. As precaution against spills or leaks, the storage tanks are generally surrounded by containment tanks, which limit the spread of an LNG spill and the potential vapor cloud. Although storage facilities can

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[5] Pool fires occur when LNG spills near an ignition source and the evaporating gas burns over the pool of spilled LNG. The resulting fire spreads as the LNG pool expands and continues to evaporate. LNG pool fires burn more intensely and rapidly than oil or gasoline fires and cannot be extinguished. The LNG must be consumed completely for the fire to die. A pool fire, especially over water, is considered the most dangerous LNG accident. In cases in which LNG spills but does not ignite immediately, the evaporating natural gas will form a vapor cloud that drifts from the spill site. Once the cloud encounters an ignition source, the cloud could explode. The third potential LNG hazard results from an LNG spill over water. The LNG could heat up and regasify almost instantly in a flameless explosion. A flameless explosion is not likely to produce a hazard zone as large as a vapor-cloud or pool-fire hazard zone (Parfomak, 2003).

be in remote locations, they are generally located near the population they serve and integrated with the local gas-pipeline network. LNG tankers unload their cargo at marine terminals, which store and regasify LNG. These terminals include docks, LNG-handling equipment, storage tanks, and interconnections to regional gas-transmission pipelines. Some terminals are established entirely offshore and connected to land only by underwater pipelines. These offshore terminal designs conveniently avoid much of the community opposition and permitting challenges that can delay or prevent the construction of onshore LNG terminals. Offshore terminals, however, may create adverse environmental impacts. Because offshore terminals use the seawater to warm the LNG, the regasification process lowers the water temperature near the terminal, potentially affecting the local ecosystem (Parfomak, 2003).

Finally, we discuss the Bishop process, which may be of importance in Israel. In a conventional terminal system, LNG is transferred as liquid into a cryogenic tank, maintained as a liquid form, and vaporized when withdrawn from the storage tank for use. In the Bishop process, the LNG is vaporized at the point of ship discharge and then may be injected into an underground storage complex or directly into the pipeline for distribution. This method obviates the need to build onshore LNG-receiving facilities and especially the cryogenic LNG-storage tanks that are the most expensive elements in a receiving facility. The ship can also be unloaded miles from the storage caverns, providing more flexibility and security (Craddock, 2003).

Using the Bishop process, a terminal with working gas storage of 16 billion cubic feet (a little under 0.5 BCM) and peak deliverability of 3 billion cubic feet per day may be feasible. These storage volumes and deliverability rates are at least twice as large as those of most conventional LNG terminals. Experiments are under way to develop systems that would increase these rates so that LNG tankers could finish unloading in one day (Korman, 2006). Environmental effects are not negligible, however. Because the Bishop process uses large volumes of seawater as the heat-exchanging medium, the fish larvae passing through the area are likely to die. This is a serious consideration and needs to be examined in light of Israel's particular circumstances. However, this may present an emerging technology that allows Israel to introduce LNG deliveries either as part of regular supply or as a system backup without the great cost and land-use controversy that either a fully onshore or offshore LNG terminal would engender.

Fuel Switching. Paradoxically, one of the best ways to provide backup storage for natural-gas facilities is not to store natural gas at all. Rather, the combustion and generation equipment that routinely uses natural gas as a fuel may be designed with a dual-fuel capability. In this case, a backup fuel, such as diesel, may be stored on-site or within available reach and used within the same plant if costs or emergencies make this expedient to do.

Dual-fuel capability and fuel switching have been the principal tools used in Israel. The government has set forth regulations and policies, such as mandating storage of 100 hours' worth of switch fuel at generating facilities of 100-MW rated capacity or greater. IEC set a rule to maintain reserves equivalent to 1.5 months of average supply of each fuel used for generation, with the exception of natural gas. The storage requirements of a fuel, such as diesel, that is liquid at ambient temperatures, are much less complex than for natural gas. Further, diesel may be transported with much greater ease if an extended period of need should arise.

Market Structure and Regulatory Policy

The shift toward natural gas as a major energy fuel is not the only transformation occurring in Israel. Among other things, the country is currently undergoing a complete rethinking of how the energy sector should be organized and what role both the private and public sectors should play going forward. As Israel attempts to promote competition in its energy sector, policymakers need to consider a number of issues that challenge an efficient development of the industry. These include the following:

- interdependencies between investments in extraction, storage, transport, distribution, and consumption that benefit from centralized planning and coordination
- public-good aspects of the physical transmission and distribution system
- energy-supply security and reliability issues that are not likely to be fully internalized by private firms operating in the industry
- economies of scale leading to natural monopolization of the production, transportation, and distribution of natural gas
- lumpiness of investments and contracts needed to facilitate natural-gas penetration
- changes in environmental externalities and risks associated with shifting energy consumption between alternative fuels
- local opposition arising from proposals to locate critical energy infrastructure near population centers
- safety concerns that private decisionmakers may not fully internalize or be capable of influencing without centralized coordination.

Because of these issues and others, many nations impose strict regulatory controls on private firms operating in their domestic natural-gas industries. This is particularly true in small nations like Israel that, due to their size, find it difficult to attract enough firms to establish a truly competitive industry.

Production. ***Foreign Supplies Through Pipelines.*** Because pipelines that bring natural gas into Israel could potentially service demand in other nations through which they pass, international coordination and investment in their construction may be sought. That said, coordinated planning and investment in an international public good of this type is likely to be very difficult, given the limited regional cooperation experienced by Israel and its neighbor nations and the dominance of other political issues.

The importation of natural gas could be conducted entirely through government-initiated contracts, through such organizations as IEC or with entirely new entities created for this purpose. Alternatively, private firms could be allowed to purchase supplies directly from foreign sources for delivery into Israel. In this case, shared access to pipeline capacity entering Israel would need to be coordinated and planned in order to facilitate the efficient use of intercountry pipelines. In the past, Israel has sought to prevent the emergence of a new monopolist in the energy sector in the form of a single purchaser for foreign natural gas. It also prohibited IEC from purchasing gas from EMG for resale in Israel for fear of enhancing the power of this existing monopoly. Rather, it has opted for having individual customers—IEC, potential IPPs, large industrial consumers, and, eventually, regional distribution companies—contract on an individual basis for natural-gas delivery. While desirable from the perspective of discouraging the emergence of monopolists on the domestic market, this policy is problematic given the nature of natural-gas markets. Since costs for the transportation infrastructure remain the dominant factor in the global market for natural gas, it is difficult for even relatively large end users to contract individually for gas deliveries because only a certain minimal level of demand over an extended contractual period will justify the investment expense this would entail.

This dominant reality has led other natural gas–importing nations to opt for a single buyer to negotiate for deliveries that may then be distributed according to some formula that addresses domestic concerns and interests.

Even if the procurement of natural-gas supplies is left for private firms and it proves feasible to actually do so, regulation of international supply arrangements may be warranted. Private firms that import and resell natural gas for profit may not internalize the full social value of securing stable rights to natural-gas supply. Regulations placing requirements on the proportion of imports obtained through short- and long-term contracts may be warranted. Furthermore, to the extent that some sources are less stable than others, import regulation may seek to encourage supply relationships with selected nations.

Domestic Supplies. The Yam Tethys reserve will become depleted well before the halfway point of the next decade. In January 2009, Noble Energy, through the Delek Group, announced the findings of its exploration of the Tamar reserve off the coast of Haifa. Initial reports suggest that Tamar appears to contain a reserve of natural gas at least the equal of predrilling estimates of 90 BCM.[6] Once operational, this reserve would provide a stable source of supply of gas for Israel that could last for many years. It would also enhance Israel's ability to secure more-attractive supply agreements with foreign suppliers by affording Israel greater flexibility when negotiating the terms of delivery.

Because the public value of domestically owned reserves is likely to exceed their private-market values due to the energy-security and reliability benefits they provide, regulating domestic extraction via quantity restrictions, taxes, or by other means may be justified. In the case of the Yam Tethys reserve, regulation of domestic extraction is likely to have limited effect, however, due to preexisting contracts for gas from the reserve. As such, our analysis largely counts the latter as having been fully accounted for.

Liquefied Natural Gas. Due to its portability, LNG is traded globally and therefore is less susceptible to market instabilities caused by events in the region. Terminals set up to accept LNG tankers must be large, and the processing facilities require sizable up-front infrastructure costs. To recoup the costs of establishing capabilities for importing and processing LNG, these facilities must be operated near capacity for many years to provide suitable rates of return to investors.

Clearly, the large question at this writing is the extent to which recoverable gas may be drawn from the newly discovered domestic reserves and in what amounts. Even should this prove to be a substantial asset for Israel, the value of an LNG facility could still be large. It could provide a source of gas should supply from Egypt or elsewhere become disrupted. It would also provide Israeli companies with greater bargaining power when they negotiate for supplies with foreign countries.

In May 2007, Israel's Minister of National Infrastructures announced that an LNG facility would require the investment of $500 million and that a feasibility study investigating different options was under way. Current plans suggest that the LNG tender would be intended to identify two companies: one that will be responsible for constructing, maintaining, and operating the facility, and one that will purchase LNG and market gas to consumers. However,

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[6] In March 2009, Noble Energy announced that preliminary exploration of the Dalit reserve suggests the possible existence of a further natural-gas find 60 kilometers off the coast of Israel at Hadera at a depth of about 3,600 meters. At the time of this writing, quantities and the quality of the gas, if present, have not been determined, but the find appears to be on the order of 15 BCM (IHS, 2009).

with the advent of plentiful natural gas from newly discovered domestic reserves, the question arises whether an LNG terminal is still desirable. The costs are very large, and the matter of siting such infrastructure within such a small state is far from trivial.

Further, while LNG is one way of providing additional energy security, LNG facilities themselves are not without risks. In Israel, as elsewhere, concerns have been raised about the environmental effects of proposed LNG facilities. Of additional concern in the Israeli context is that, because of their importance and relative vulnerability, LNG facilities are likely to be a tempting target for terrorists or more-traditional enemies in time of war. The environmental and safety issues have made the siting of LNG port facilities difficult. In many nations, siting decisions are not made without years of bureaucratic wrangling.

The question of the advisability of an LNG terminal in Israel is addressed analytically in the discussion of our modeling and simulation studies.

Transmission. In the transmission phase, gas is transported through high-pressure pipeline systems to customers that include power producers, large industrial users, and local gas utilities. Transmission companies are responsible for building, maintaining, and operating the pipeline system, combining gas supplies from various sources and routing gas to customers.

In some nations, the pipeline companies take on a marketing function by purchasing the gas they transport for resale. In so doing, they must manage a portfolio of purchase and sale contracts and finance gas transactions. This is typically facilitated through long-term contracts, which may include take-or-pay clauses and pass-through costs.[7]

Internationally, pipeline companies often fall under heavy regulation, since they have monopoly control over the pipeline infrastructure and control the gas available to downstream customers. In the United States, interstate-pipeline companies are nationally regulated in the rates they charge, the access they offer to their pipelines, and the siting and construction of new pipelines. Regulations establishing spot and futures markets and open-access transmission rights have reduced brokerage activities by pipeline companies. FERC has been established to oversee and regulate interstate energy activities in the United States. FERC has been tasked with a number of responsibilities in the natural-gas industry, including the following:

- preventing discriminatory and preferential service
- preventing inefficient investment and unfair pricing
- ensuring high-quality service
- preventing wasteful duplication of facilities
- acting as a surrogate for competition where competition does not or cannot exist
- promoting a secure, high-quality, environmentally sound energy infrastructure through the use of consistent policies
- where possible, promoting the introduction of well-functioning, competitive markets in place of traditional regulation
- protecting customers and market participants through oversight of changing energy markets, including mitigating market power and ensuring fair and just market outcomes for all participants (NGSA, undated).

[7] *Take or pay* refers to the option to defer or rescind a contractually scheduled delivery of natural gas by paying a fee, usually a percentage of the cost of that volume of gas, set in the contract.

The planners charged with developing the plan for the nation's natural-gas pipeline infrastructure wrestle with considerable challenges. The National Outline Plan (NOP) 37 interagency working group charged with planning all of Israel's natural-gas pipelines is currently developing plans for the low-pressure system that will carry natural gas to all industrial users other than those major users in a position to take the gas feed directly from the high-pressure pipelines already serving the electricity-generation sector. This issue is circular: The availability and location of the low-pressure pipelines will determine the full extent to which the economy as a whole will rely on natural gas as a primary fuel. On the other hand, demand from potential customers should inform the decisions about how such lines are routed and developed. In an environment of uncertainty, both those on the potential demand side and those planning for supply seek a signal from the other.[8]

For the purposes of the present analysis, the issue of pipeline-infrastructure costs can be dealt with in a relatively straightforward manner. The high-pressure lines currently existing and planned for Israel will probably need to be developed in full no matter which energy strategy is employed by the state. As our analysis will show, it will be difficult for Israel to meet its various goals and objectives without the use of natural gas continuing into the future. While Israel could conceivably rely solely on the present undersea pipeline, the loop connecting the Ashdod and Ashkelon energy corridors, the northern line serving the lower Galilee region, and the southern line extending toward the industries of the Dead Sea, prudence suggests the value of also building the central pipeline that will parallel the present undersea pipeline running up the coast. The cost of building such an onshore line is less than for an underwater route, but the issues of permitting and land use are vastly more complicated. Nevertheless, the possibility of supply disruption by natural catastrophe, accident, or deliberate intent would be considerably reduced by having such a pipeline in place. Further, having the high-pressure gas pipeline system fully in place as presently planned would also add to the default storage capacity represented by gas pipelines themselves. Therefore, if one accepts the finding that natural gas must be part of Israel's energy balance over the next two decades, the cost of building this high-pressure pipeline needs to be borne in all of the potential strategies considered in this study.

The low-pressure distribution system is another matter. The need to build such a system and the extent to which it is built depends almost entirely on the policy choices made by planners. The degree to which natural gas is made available directly to industry, large commercial spaces, and even, conceivably, households and other potential customers will determine how costly the low-pressure gas-delivery system will be.

Distribution. At the distribution stage, gas utilities transport and distribute gas from the major pipeline network to end-use customers. Because utilities own and operate the local distribution network, they have monopoly power over gas consumers and typically face heavy regulation. In the United States, they are regulated by state utility commissions (rather than at the national level), which oversee their rates and construction issues and ensure that proper procedures exist for maintaining adequate supply to their customers. The objectives and issues of regulating natural-gas utilities resemble those associated with pipelines, including avoiding

8 A possible alternative or supplement to a low-pressure pipeline might be the adsorbed natural gas (ANG) option. As reported in March 2009, Energtek announced the granting of a commercial license for the exploration, production, and sale of natural gas in the northern Negev region. If discovered and exploited, the firm plans on transporting the natural gas using the ANG technology combined with low-pressure, mobile pipeline systems (Energtek, 2009).

the exercise of market power, protecting captive customers that rely on a single source for their supply of natural gas, and ensuring that prices are fair and equitable.

In nearly every nation, the price of natural gas charged to retail customers is regulated. The need to regulate retail prices stems from the fact that utilities maintain a monopoly on the infrastructure that transports natural gas to homes and businesses. This is also another potential tool for policy. A government may wish to subsidize retail rates in an effort to encourage the use of natural gas—for example, to encourage the installation of appliances that use natural gas as opposed to electricity. As the industry matures, these subsidies (or surcharges) may be reduced or eliminated completely. Alternatively, the government may choose to tax electricity more heavily than natural gas, making natural gas a more cost-effective alternative for consumers.

The electricity rate in Israel is composed of fuel costs, financial costs, depreciation, wages, and other O&M costs. The main component is fuel costs, accounting for 57 percent of the total cost.[9] Israeli rates for electricity are relatively low in international comparisons. At the end of 2006, the average residential rate was about $0.11 per kWh and the industrial average about $0.09.[10]

Currently, it is not clear the extent to which natural gas will be used for purposes other than generating electricity in Israel. Ultimately, these other purposes will dictate the extent to which the establishment of formal natural-gas utilities will be needed. Should utilities be established, a regulatory structure that includes a means for setting retail prices and overseeing utility investments and performance will be established by Israel's Natural Gas Authority (previously under the MNI but now part of the Public Services Authority. In addition, due to the possibility of explosions caused by natural-gas leaks, safety regulations designed to prevent accidents will need to be established.

The Natural Gas Authority has decided to divide the country into five regions, each of which will eventually be serviced by a different natural-gas utility. At the time of this writing, the only license that has been issued was to Magal for the distribution of gas in the Arad region (MNI, undated).

Natural-Gas Customers. Electric-power producers, as well as other large customers who meet certain gas-consumption requirements, may receive gas directly from the operator of Israel's high-pressure pipeline system, INGL. These customers must currently contract directly with gas producers for natural-gas supplies. Small commercial and residential customers that might use natural gas for such activities as heating and cooking will eventually purchase gas directly from their local natural-gas utilities, although the establishment of local gas utilities is likely to take some time.

Electricity Generation. Because of IEC's dominant role in the industry, it is difficult to ensure that entrants will be able to compete against IEC. For instance, a large customer like IEC may have the ability to secure attractive supply arrangements that smaller customers may

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[9] The other shares are 11 percent for capital costs and 13 percent for depreciation, with the balance (19 percent) for operations, maintenance, and other costs (IEC, 2007).

[10] These rates may be compared to those in Hungary, a country of approximately Israel's size, that currently generates a share of its electricity from natural gas (36 percent) that is approximately the same being planned by the MNI for Israel (40 percent) (Szolnoki and Takácsné, 2009). Hungary charges more than $0.14 per kWh for residential and $0.10 for industrial users. Similarly, the analogous rates for Ireland, a country of Israel's approximate size and level of development, were $0.20 and $0.12. Israel's average rates of $0.11 and $0.09 are higher than those for the United States ($0.10 and $0.06, respectively) but significantly lower than comparable countries.

not be able to obtain. One way to reduce this concern is to establish entities that act as aggregators, procuring gas on behalf of many small firms. The price at which natural gas is contracted will affect the degree to which it is possible for IPPs to enter the market. As the price of natural gas increases relative to other available fuels, it becomes less likely that potential entrants will view the electricity-generation market as potentially profitable.

While more than 70 percent of Israel's electricity was generated by power plants using coal in 2003, that fraction has been falling as more natural gas–fired plants come online. Even so, it will remain an important component of the fuel mix required to provide electricity base load. Regulatory policies, such as emission limits, cap-and-trade programs, or taxation of CO_2-equivalent emissions have been proposed in other nations to encourage greater use of clean energy. Such regulatory practices usually encourage the use of natural gas over coal and have the potential to significantly increase the demand for natural gas in Israel by affecting the priority of different power plants in dispatch decisions and by inducing greater investment in cleaner gas-fired generators. More-extreme forms of regulation might require that all new power plants use cleaner fuels, such as natural gas.

Industrial, Commercial, and Residential Users of Natural Gas. Natural-gas use is almost entirely restricted to electricity-generation companies in Israel today. In the future, however, natural gas may be used for a variety of other purposes, including heating and cooking. In most nations, natural-gas use is regulated and priced differently for the industrial, commercial, and residential sectors.

To bill gas consumers, the natural gas that is used by individual customers is tracked using meters. Traditionally, to bill customers correctly, meter-reading personnel had to be dispatched to record these volumes. Customers were billed based on the amount of natural gas they consumed according to the difference between meter readings. However, electronic meter-reading systems are now capable of transmitting this information directly to the local distribution company. Some of these metering technologies allow utilities to charge prices that vary by time of use. These *real-time pricing schemes* can reduce supply costs by better managing demand for natural gas via pricing.

If a policy decision was made to encourage natural gas's wider integration into the Israeli economy, some form of subsidization may be useful for end-use technologies that rely on natural gas. This subsidization may take the form of rebates or discounts furnished to individuals and businesses that install technologies that utilize natural gas instead of electricity. Furthermore, many buildings will need to hook into the local natural-gas distribution system. Subsidizing these investments may be necessary in the case that a shift away from electricity to natural gas is deemed advantageous.

Sources of Risk to Israel's Energy Supply

Tables 7.3–7.5 set up an approach to evaluating strategies and outcomes according to security-of-supply criteria. Table 7.3 itemizes the different energy-supply risks for each energy source Israel uses for electric-power generation. We divide these risks into two categories: those that affect the delivery of energy supplies and those that affect the supply infrastructure itself. The remaining tables follow this classification of risks. Table 7.4 shows measures that Israel could employ to mitigate the supply risks, while Table 7.5 characterizes in qualitative terms the categories of principal costs for each vulnerability-reducing or -mitigation measure. The columns

Table 7.3
Threats to Israel's Energy Supplies

		Primary-Fuel Source					
Energy Security Threats to	**Threat**	**Coal**	**EMG Natural Gas**	**LNG**	**Natural-Gas Pipeline from Another Country**	**New Domestic Natural-Gas Source**	**Solar Thermal**
Delivered supply	Lost delivery	x		x			
	Supply withheld		x		x		
	Contract dispute	x	x	x	x		
	Embargo			x			
Supply infrastructure	Port inaccessible or unavailable	x					
	Import pipeline unavailable		x		x		
	LNG terminal inoperable			x			
	Receiving facility inoperable		x		x	x	
	Undersea pipeline unavailable		x			x	
	Domestic pipeline network damaged		x	x	x	x	
	Blockade	x		x			
	Power plants damaged	x	x	x	x	x	x
	Transmission capacity unavailable	x	x	x	x	x	x

in the tables display the main current and potential future primary-energy supply sources. These sources include imported coal, natural gas supplied by EMG through the pipeline from Egypt, natural gas supplied through an LNG terminal, natural gas supplied through a pipeline from some country other than Egypt, new domestic sources of natural gas beyond Yam Tethys delivered by pipeline from offshore reserves, and solar power supplied from solar-thermal arrays placed in the Negev and other marginal areas.

Risks to Delivered Energy Supplies. The risks to delivered energy supplies could include geopolitical or contractual disputes that would cause a supplier to withhold deliveries or push prices sharply up to levels greater than in countries with which Israel competes economically. To put it differently, the supply risk faced by Israel is not solely an issue of obtaining adequate quantities of fuels; prices that would lead to economic shocks are also a concern. Israel may also fail to receive energy supplies due to factors outside of the supply relationship, such as pirating or storms that prevent a delivery. An important note for this analysis is that we assume that only imported energy is subject to the risks noted in Table 7.3. While a domestic energy supplier could fail to uphold a supply contract, energy consumers would have recourse through Israel's judicial system. This situation sharply contrasts with a supply relationship with a for-

Table 7.4
Measures to Address Threats to Israel's Energy Supplies

		Primary-Fuel Source					
Measures to Address Threats to	Measure	Coal	EMG Natural Gas	LNG	Natural-Gas Pipeline from Another Country	New Domestic Natural-Gas Source	Solar Thermal
Delivered supply	Find new supplier	x		x			
	Renegotiate contract	x	x	x	x		
Supply infrastructure	Coal storage	x					
	Natural-gas storage —local —reservoirs		x	x	x	x	
	Transport from second port	x		x			
	Flex-fuel capability		x	x	x	x	x
	Diesel import capacity or storage		x	x	x	x	
	Use reserve capacity in remaining plants	x	x	x	x	x	x

eign supplier, in which recourse for relief in the case of one party breaking a contract is much less certain.

Given that imported energy sources are more vulnerable to failed deliveries than domestic sources, a key distinction between the imported sources is whether the energy source is a commodity actively traded on international markets or a fuel directly imported through a point-to-point connection. Coal, oil (including refined-petroleum products), and LNG fit into the first category, while natural gas supplied through pipelines comprises the second category. The relationship between suppliers and physical infrastructure differs across these categories, and these differences affect the measures Israel can use to manage the supply risks.

With the current reliance on coal, oil, and distillates for the bulk of Israel's energy needs, the problem of possible denial is reduced. All of the necessary inputs are available from multiple sources at world market prices. Even if no supplier to Israel resorts to use of the natural-gas weapon by withholding supply in pursuit of political gains, having limited channels of supply for a possibly large relative share of Israel's primary-fuel requirements still represents a risk, whether from natural or other causes.[11] For commodities like coal, oil, and LNG, Israel

[11] This is also true for other fossil fuels to a certain extent. While they may be theoretically available at global market prices, as a practical matter, they still must be brought into specific ports containing sometimes-unique facilities. If these facilities are not available for some reason, theoretical availability will be trumped by circumstances. Further, there are needs for different types of petroleum distillates at different places and different times. Effective local shortages could transpire.

Table 7.5
Cost of Measures to Address Threats to Israel's Energy Supplies

		Primary-Fuel Source					
Costs of Measures to Address Threats to	**Cost**	**Coal**	**EMG Natural Gas**	**LNG**	**Natural-Gas Pipeline from Another Country**	**New Domestic Natural-Gas Source**	**Solar Thermal**
Delivered supply	Change contract and spot price	x	x	x			
	Political capital and diplomacy		x		x		
Supply infrastructure	Coal storage costs	x					
	Natural-gas storage costs		x	x	x	x	
	Transportation costs	x		x			
	Flex-fuel costs		x	x	x	x	
	Oil-pipeline opportunity costs and diesel storage costs		x	x	x	x	
	Higher plant-maintenance costs	x	x	x	x	x	x
	Potentially lower reliability						x
	Opportunity cost (i.e., depleting own natural reserves)					x	

is subject to the risks of disrupted, stolen, or lost deliveries because of storms, accidents, or piracy or as a result of contractual disputes. However, these latter events are limited in the risk they present because they affect only one or a small number of shipments. Contractual disputes could conceivably occur over a longer time frame and affect multiple deliveries. Yet, the supply-delivery risks for these energy sources are still limited because Israel would usually have recourse to enter into new contracts with other suppliers or buy on spot markets. An important note is that, while LNG is sold on spot markets, making up temporary shortfalls by spot purchases may be difficult at times and expensive. Some LNG is sold on spot markets, and this fraction of total sales is increasing, but spot sales still represent a relatively small market share relative to that represented by the oil and coal spot markets. Furthermore, only a limited number of ships are equipped to transport LNG. Contracting for one on short notice may be difficult. Therefore, LNG supplies are not currently as fungible as those for coal, petroleum, or

However, most of these particular cases involve transportation fuels or manufacturing inputs in which natural gas is not likely to play a large role. Hence, we do not dwell on these aspects in this research.

distillates. Nonetheless, an LNG terminal still provides an option for purchasing from several suppliers under some future conditions. This clearly offers some bargaining advantages in comparison to a direct pipeline connection.

In Tables 7.3–7.5, we distinguish between two natural-gas sources supplied through a pipeline: the existing pipeline carrying EMG's natural gas and a second, hypothetical pipeline delivering natural gas from another exporting country. Proposals have been made both for a pipeline through Turkey that delivers natural gas from Russia and for another through Jordan carrying natural gas from one or more Persian Gulf states. The threats to delivered supply from either of these sources would consist of the source country simply withholding supplies, a transiting country disrupting the supply, or supplies being halted by the exporter because of contractual, as opposed to political or other, disputes. Substituting another supplier or buying on the spot market are not options in a dispute with the exporting or transit countries. Because of Israel's direct connection to the supplier through the pipeline, Israel would be forced to negotiate with the exporting or transiting country in the case of any disputes. While the bilateral energy-supply relationship through a pipeline poses energy-supply risks, Israel can use several options to improve its negotiating position in any contractual disputes. In the section "Measures to Address Risks" later in this chapter, we describe these options in greater detail.

Risks to Energy-Supply Infrastructure. Each energy source shown in Tables 7.3–7.5 requires a dedicated infrastructure to deliver and receive energy imports as well as distribute the supply within Israel. Most of this infrastructure consists of large facilities that could conceivably be potential targets of attacks. This vulnerability to attack is a risk over and above malfunctions that can occur during normal operation, such as pipeline breaks or downed transmission lines. The risks from attack or malfunctions are distinct, but we discuss in "Measures to Address Risks" the notion that many of the measures used to mitigate malfunctions can also address the vulnerabilities from attacks.

Israel receives coal at the receiving terminals in Ashkelon and at Hadera's power plants. Coal is offloaded from ships and transferred for storage at the coal-fired power plants located nearby. Because the coal is consumed at power plants near the receiving terminals (and does not, therefore, require an extensive distribution network), the terminals are the primary infrastructure risk with this energy supply. In addition, unless both terminals are unavailable simultaneously, the second terminal could supply some additional import capacity in an emergency.

Israel currently has two natural-gas sources (EMG's deliveries originating in Egypt and domestic reserves at Yam Tethys), but prospects exist for several other sources. All natural-gas supplies share a common domestic high-pressure pipeline infrastructure, but the individual sources also have unique infrastructure facilities associated with delivering the natural gas into this domestic distribution system. For the natural-gas pipeline from Egypt to Ashkelon, the critical infrastructure consists of the undersea pipeline coming from Sinai and the receiving facility in Ashkelon in addition to Israel's domestic pipeline network. A second pipeline from an exporting country would likely have similar infrastructure requirements. A disruption to either the import pipelines themselves or the receiving facilities could threaten the entire flow of natural gas from such sources, whereas interruptions in the domestic distribution network (if completed as planned with a certain degree of redundancy)[12] can be isolated.

[12] Specifically, there are plans to construct an onshore pipeline parallel to the existing offshore pipeline that runs up the Mediterranean coastline. This pipeline would be underground and generally track the course of the north-south infrastructure corridor currently used by Israel's toll Highway 6.

LNG supply requires a receiving terminal, onshore storage tanks, a regasification installation, and connection to the domestic pipeline network. In an onshore facility, all of the functions are generally located at a single site. In an offshore facility, all of the infrastructure to regasify the LNG is located offshore and then connected to the supply network with a pipeline. Under either of these options, the LNG terminal itself is vulnerable to an attack along with the domestic pipeline network.

Any new, offshore natural-gas source would have a similar infrastructure configuration to that for the natural gas purchased from EMG. An undersea pipeline would deliver supplies from the offshore reserve, come onshore at a receiving facility, and then enter the domestic distribution network. All of these facilities present potential vulnerabilities.

Israel currently has a small (100 KW) solar-thermal power plant at Samar, north of the Red Sea port city of Eilat.[13] Proposals exist to considerably expand power from this energy source in the largely desert-climate southern part of the country. The power plants would be relatively secure from a direct attack because they are spread over a wide area. Such damage as might be inflicted could be repaired with relative ease. Furthermore, if Israel developed a large capacity for solar-thermal power, it would likely occur at several sites. While the plants may not be concentrated in one location, they would be connected through the transmission grid to deliver the electricity to the centers of demand in the northern part of the country. Therefore, this energy source is as potentially vulnerable as others through the transmission lines built to bring the electricity northward into Israel's population centers.

Measures to Address Risks. Measures to address potential risks include risks both to delivered supply and to the infrastructure through which supply is received and distributed.

The measures to address energy-supply risks for energy sources that are traded on commodity markets differ from those for primary fuels imported through a pipeline. For supplies traded on commodity markets, Israel can find a new supplier (either by contract or on the spot market) or renegotiate the supply contract. For energy imported through pipelines, the options are more limited. Israel can renegotiate the supply contract or use diplomacy to enforce provisions of the existing contract; however, Israel has no flexibility to find another supplier.[14]

As shown in Table 7.4, major contracts for supply of energy are always subject to negotiation. The degree of diversity in Israel's supply affects the country's bargaining power in negotiations. In general, as a particular energy source increases its share in meeting total energy demand, Israel becomes more vulnerable to consequences from disruptions in supply of that fuel and loses bargaining power in negotiations with suppliers. This correspondence is not perfect. No matter how low the dependence on coal becomes, it is not at all an easy process to shift coal-fired plants to other fuel types (fuel switching). There are other circumstances in which facilities are dedicated to relying on supply of a particular fuel—in transportation applications,

[13] The MNI has issued tenders for solar-thermal and photovoltaic plants at Ashalim and the Negev for a total capacity of 250 MW. Planning is under way for additional facilities in the Timna Valley and Tel Arad. A solar-photovoltaic test array is located at Sde Boker, a 5-MW installation of solar-photovoltaic generators is planned near the Arava Institute for Environmental Studies in Ketora, and there are smaller projects under way in such locales as Yotvata, Katzrin, and Drigat.

[14] In this analysis, we assume (1) that domestic energy sources are not prone to supply disruptions from events outside of Israel or (2) that any such disruptions represent qualitatively different circumstances from those occasioned by foreign import.

for example—and so also have limited means for fuel switching.[15] Risk is mitigated for fuels traded on global markets because Israel can, in most circumstances, negotiate a new contract with another party or buy on the spot market.

Of primary interest, then, are the energy sources that tie Israel to a particular supplier. This currently means the natural gas imported through pipelines. For these sources, as their share of total energy increases, Israel loses bargaining power relative to the suppliers. Diversifying supplies of energy can improve Israel's position relative to any given foreign supplier; however, the composition of the remaining energy supply is still important. If a second supply of natural gas is through a pipeline, then Israel may still be vulnerable if the exporting (or transit) countries decide to withhold energy supplies simultaneously. A second supply of natural gas through an LNG terminal would potentially improve Israel's bargaining position with foreign suppliers because, over a longer time horizon, Israel can increase the size of the facility to offset potential declines in supply through any one pipeline. Finally, an additional domestic natural-gas source also enhances Israel's bargaining power with other natural-gas suppliers because Israel can also use this source to offset any declines or interruptions in natural gas imported through pipelines.

Events that pose risks to the supply infrastructure include disruptions that may stem either from intentional acts or from unintentional and natural occurrences. To mitigate risks to this supply infrastructure, Israel can develop storage facilities to buffer a supply shortfall while the infrastructure is being repaired, use spare capacity at other facilities when possible, and use flexible infrastructure that can operate using several types of fuel.

Several options exist to offset disruptions in the supply infrastructure for the natural gas supplied through pipelines to Israel. Local storage capacity for switch fuels, such as diesel at natural gas–fueled power plants, can help plant operators maintain the power supply during short-term disruptions to the supply system. A large, independent domestic storage site, such as the oil-storage reservoirs developed for Israel's current domestic reserves, can help offset a longer-term disruption from foreign supply pipelines. Flex-fuel capability, currently a requirement for natural gas–fueled power plants, allows plant operators to switch to petroleum-based fuels without affecting plant operation.[16] Consequently, local diesel storage at power plants and within the system can be used when plants have flex-fuel capability. Finally, Israel currently has a pipeline connecting the Mediterranean and Red Seas that is used primarily for oil transport (not domestic consumption). In an emergency, a parallel, existing pipeline could be used to supply refined products to Israel's power plants.[17] Table 7.4 shows that these mitigation measures overlap across all the sources of natural gas and that stored fuels can be used to offset shortages in any of the natural-gas sources. Finally, stored backup fuel can also help Israel's negotiating position with foreign fuel suppliers, as these stored fuels reduce the country's vulnerability to supply cutoffs.

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[15] In the case of petroleum distillates, we speak only of their use in energy supply. When used as inputs to industrial processes, the degree of flexibility is even less than it would be for using them as fuel for combustion and power generation.

[16] The current regulatory requirement is that power-generation plants with a rated capacity of 100 MW and above must store 100 hours' worth of reserve or alternative operating fuel on site.

[17] Such use would, of course, have implications for the industrial processes that require deliveries of petroleum distillates as inputs to manufacturing. The closer this pipeline is to capacity utilization, the greater the potential economic and other effects from secondary disruptions.

Solar-thermal power developed in the Negev is vulnerable to a transmission-line failure that would prevent transporting the electricity from this source to Israeli population centers. Electric-power system planners typically address this type of contingency by maintaining enough power-plant reserve capacity in the remainder of the system to offset a transmission-line failure. This contingency should be addressed as part of system-reliability planning for the Israeli electricity system, and this planning would also cover an intentional act to isolate solar-thermal energy.

There is a final family of measures that can be used to address crises in energy supply. These would not so much seek to replace lost supply as to reduce or otherwise manage demand. This can take several forms depending on the severity and expected length of the crisis. Clearly, there are limitations to how much demand could be reduced without causing undue economic harm to the economy or placing individuals at hazard. There are also questions about the means by which such cutbacks could be achieved (e.g., persuasion, inducements, decrees, penalties) and how much preparation would be required beforehand. But, in any consideration of measures to address surprise conditions that would affect supply, demand-side actions may also play a part. By their nature, such measures would play a role in each cell of Table 7.4. They have been excluded to focus on the unique aspects of the individual primary-fuel streams.

Costs of Contingency Measures. Table 7.5 characterizes the principal costs of potential measures to mitigate energy-supply risks. For imported supplies, the costs are the difference in price between the new contract or spot-market price and the existing supply contract. For the energy supplies for which this is not an option, Israel may have to expend nonfinancial resources in negotiations between suppliers connected through the pipeline. These could include political capital used in the diplomacy or other concessions that are needed to resolve the dispute holding up energy supplies.

For the energy-supply infrastructure, each of the measures discussed has an associated cost. Developing storage for natural gas or diesel fuel is potentially quite costly, as would be completing a parallel, onshore, domestic high-pressure natural-gas pipeline. However, Israel may need to invest in storage in any case to help manage seasonal fluctuations in demand. The incremental costs of additional storage, once sites are identified and permitted, may be relatively small when compared to their value in preventing energy shortages.[18] An additional potential cost would be the incremental cost of dual-fuel capability at gas-fueled power plants. The costs of using the existing oil pipeline to import diesel fuel in an emergency would include the upgrades needed to supply the capacity needed plus the opportunity costs of the oil trade displaced by the emergency fuel. Finally, when using natural gas from domestic sources in excess of planned quantities, this would lead to more rapid depletion. This would reduce the ability to be insured against future disruptions as well as decrease bargaining power when negotiating prices for supply from other sources.

Again, on the demand-management side, the costs would depend very much on the means used to achieve reductions in demand, the depth of those reductions, and the length of time they would need to be in place. Here, as in many other areas, taking active measures in the absence of crisis and as a matter of policy to enhance the efficiency of energy use in all sectors of the Israeli economy would likely yield large payoffs. Such measures would reduce the level of energy required to sustain economic growth and so in themselves reduce vulnerabili-

[18] In keeping with the level at which we have conducted our analysis, we leave aside the question of how the costs, benefits, and management of such storage infrastructure should be shared between the public and private sectors.

ties to energy-supply shocks. They would also provide the government and the energy-system authorities with useful information on what energy demand–reduction measures work and at what cost. These data can be used as a basis for more-restrictive demand-reduction plans to be used in the case of emergency.

Discovering Robust Supply and Infrastructure Strategies

After the qualitative discussion of energy-supply security in general, we now turn to quantitative assessments. Before understanding what policy stance would be appropriate, it is important to know what the costs of not taking action might mean. In other words, this problem could be viewed as one of determining appropriate insurance procedures and levels of costs: How much is Israel willing to spend to avoid different types and magnitudes of consequences? How prepared does Israel wish to be in advance against the types of contingencies we have discussed?

To approach these issues, we constructed a further model based on our previous analyses of alternative future patterns of Israel's natural-gas use and the behavior and requirements of the various strategies for meeting demand, now adding the possibility of sudden shortfalls in supply. This model is described in fuller detail in Appendix E, under "Model Documentation." The purpose is to support exploration of answers to three main questions:

- What infrastructure is required to meet Israel's long-term natural-gas demand?
- How much does a given strategy deplete the recoverable gas that may be obtained from the Tamar, Dalit, or other possibly new domestic deepwater (DDW) reserves?[19]
- How robust is any supply strategy to changes in future deliveries of natural gas delivered from foreign-import pipelines?

Note that this approach is not designed to discover the best approach to achieve comprehensive energy security across all fuel-supply streams. Rather, we use it to assess the amount of risk that may be represented by increasing dependence on natural gas under several sets of conditions. In particular, the analysis we present assesses four different strategies for natural-gas infrastructure development and assumes that new gas supplies could come from two different sources: the Tamar and Dalit reserves or other DDW sources and an LNG terminal.[20]

[19] The depletion of any new natural-gas deposits under the control of Israel will most likely not occur by 2030, the end date of this study. However, the strategies that will shape the period beyond 2030 will be chosen and put in place well before that year. We explicitly call attention to the depletion indicator to reduce, to some degree, the end-of-the-world aspect of our analysis.

[20] We proceed on the assumption that it is the recently discovered relatively DDW reserves that are likely to be the main domestic supply in the period to 2030. This is because of the size of the total combined discoveries. However, Tamar, which presents the larger prospects, is in relatively deep water and will require large fixed investment (and therefore favorable contract terms) for its exploitation. (Dalit would likely follow similar terms, since it would be developed by the same group of firms and represents a significantly smaller reserve.) Alternatively, the natural gas could come from some currently unproven reservoir, but then it is not likely that fuel from these sources will begin to flow by 2015. Gaza Marine would provide a considerably smaller potential supply than is currently in prospect for the Tamar find and would require further negotiation with BG, but it is relatively accessible (at 650 meters deep) in nearby offshore waters, compared to the greater distance and depth of any Tamar exploitation. (This is still much deeper than the current domestic reservoirs for Yam Tethys, lying in 220 meters of water.)

The strategies vary in choosing how to build and operate this infrastructure. Once we have performed this analysis, we are then able to address the question of how much insurance Israel might seek to provide for itself in light of the costs that would be entailed.

Four Candidate Strategies

The four strategies differ in the emphasis placed on drawing natural gas from DDW reserves and from a domestic LNG terminal.

The DDW Only strategy tries to supply all future gas demand from the Tamar, Dalit, or other such reserves that may be discovered and exploited.[21] The Joint DDW/LNG option appears as two different strategies. The two versions simultaneously build supply capacity at the DDW reserves and construct an LNG terminal, but they differ in how they operate them. In the Joint DDW/LNG (LNG Priority) strategy, natural gas is supplied first from the LNG terminal up to its capacity, and then any residual demand is supplied from DDW sources. In the Joint DDW/LNG (DDW Priority) strategy, the converse is true. Finally, the DDW Then LNG strategy first builds capacity at the DDW reserve up to a limit and then builds an LNG terminal at a later time. In this strategy, once both DDW and LNG supply chains are operational, deliveries also come first from DDW wells. The four strategies are shown in Table 7.6.

In the simulation modeling, the decision to build capacity is triggered by observing that next-period demand exceeds current supply capacity or that an emergency margin that has been set by policy has declined below a target level. In the model, we assume a limited degree of foresight so that planners can accurately predict what demand will be in the next period. The emergency margin is an amount of capacity in excess of actual demand that could, if necessary, be available to be used in a supply emergency to meet a sudden shortfall.

The model was used to evaluate supply-strategy cost, rate of depletion, and reliability for several different levels of demand over the period to 2030. We selected six representative natural-gas demand paths from among the scenarios in the test set used for the prior utilization analyses in Chapters Five and Six. Each of the scenarios we selected runs the Gas Rule_Alt

Table 7.6
Characteristics of the Four Candidate Natural-Gas Supply Strategies

Strategy	Builds LNG Terminal?	First Relies on Supply from
DDW Only	No	DDW
Joint DDW/LNG (LNG Priority)	Yes, immediately	LNG
Joint DDW/LNG (DDW Priority)	Yes, immediately	DDW
DDW Then LNG	Yes, when needed	DDW

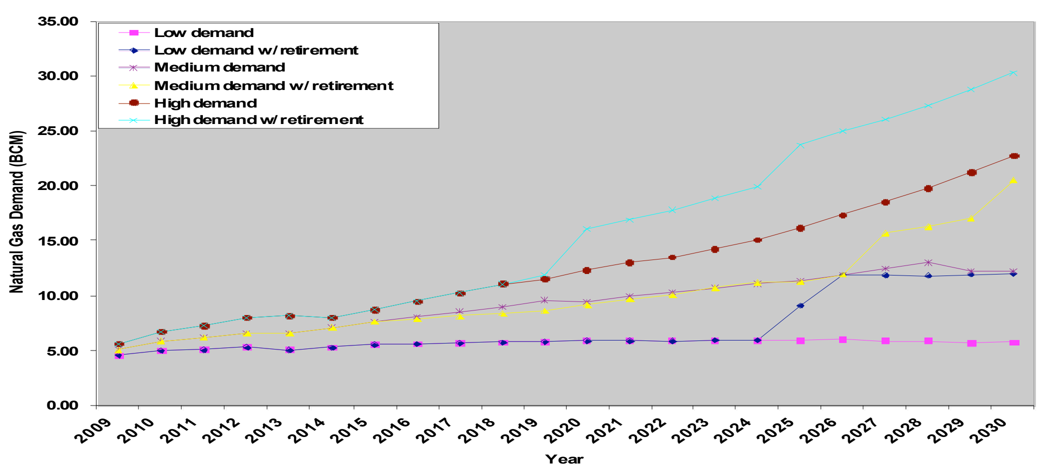
We are more specific about the supplementary source for natural gas—namely, LNG. This is because the supply of LNG is analytically dissimilar to the other potential sources. While the infrastructure costs may be large, they are smaller than for a deepwater exploitation lying some distance offshore. On the other hand, the per-unit price for the fuel itself is likely to be burdened by the upstream development costs of its supplier. For our present purposes in calculating cost of insurance, this makes LNG qualitatively different from gas coming from domestic sources, Gaza Marine, or other foreign pipeline.

[21] At the time of this writing, it is still not clear what the store of recoverable natural gas might be in these reserves or whether it is likely to be joined by subsequent discoveries in the same or nearby fields under the jurisdiction of Israel. Therefore, planners may also use our analysis to assess what alternatives may be available depending on how Tamar, Dalit, and other possible sites develop in the coming years.

(Modified) infrastructure-build strategy against a set of conditions selected to elucidate the types of infrastructure configurations needed to satisfy different levels of demand. These are not intended to be representative of a most likely scenario. The scenarios were selected to fit into six different regimes that have qualitatively and quantitatively different implications for the requirements that a natural-gas supply infrastructure would need to meet. Similarly, the Gas Rule_Alt (Modified) strategy quite frequently is the most natural gas–consuming of the three modified form alternative strategies when run against the test set of alternative futures. At the same time, inclusion of the option to build non–fossil fuel electricity-generation facilities as an integral part of this strategy helps highlight the importance that such capacity may hold for issues of concern, such as reduced vulnerability to supply shocks, beyond the obvious value in reducing emissions.

The first level is represented in Figure 7.1 by two scenarios, each of which has low demand of natural gas throughout the time to 2030. The first of these reaches a level of demand no more than 7 BCM by that year. The only current natural-gas import supply source Israel has is the pipeline delivering natural gas purchased from EMG. The current understanding is that contracts from this source will be capped at 7 BCM per year, the design capacity of the pipeline.[22] Given this initial source of natural gas, an important analysis is how Israel's new supplies can complement the gas delivered from this import source or substitute for it if, for some reason, this supply was not forthcoming. In addition, we have included a scenario that sees low natural-gas demand but also a sharp rise in demand at the end owing to the retirement of one or more coal-fired power plants. This is a more stressing case because of the need to expand capacity to maintain supply adequate to serve that sharply increased demand.

Figure 7.1
Six Test-Set Scenarios Selected to Represent Different Levels of Future Natural-Gas Demand Under the Gas Rule with Alternatives (Modified) Strategy



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22 As noted before, in the absence of significant storage to moderate supply and demand imbalances during peak and lax times, as a practical matter, the amount of actual contracts written would need to total no more than approximately 6.5 BCM.

In the lowest-demand scenario, natural-gas demand slowly rises from below 5 BCM per year to no more than 6 BCM in any year through 2030. In this scenario, the low demand for natural gas results from low demand for electricity, successful energy-efficiency programs that moderate demand by 20 percent, and the construction of a new coal plant. Under the conditions in the low-demand scenario that sees coal-plant retirements, natural-gas demand follows a similar path until 2025, when demand begins to increase by approximately 5 BCM per year after retiring one or more of Israel's existing coal-fired power plants.

The next important level is represented by those scenarios that require supply of 7 to 15 BCM of natural gas per year. Our model allows complete flexibility in how to designate new supply systems. In the analysis presented in the preceding chapters, we presumed an LNG terminal with an initial design capacity of 5 BCM that Israel could expand up to 8 BCM per year. Given this figure, this sets 15 BCM per year as another important threshold: Up to 8 BCM of natural gas could come from LNG in addition to the maximum of 7 BCM from the import pipeline. If the pipeline delivered less than 7 BCM, then gas from newly discovered domestic sources would be needed to replace this shortfall, possibly up to the full 7 BCM. Again, we select two such scenarios, one with a steady increase in demand and one forced to higher levels by plant retirements.

The next range of natural-gas demand scenarios would require 15–22 BCM per year to satisfy demand by 2030. Assuming that natural gas supplied from new domestic sources can be supplied at the same level as the full capacity of deliveries from the EMG source (7 BCM), the maximum amount from all three supplies is 22 BCM. This is the case with the scenario we have called High Demand in Figure 7.1.

We see a pattern in the medium-demand scenarios that is similar to those in the time path of the low-demand scenarios, albeit with a greater average annual increase in the level of demand. In the high-demand scenario, natural-gas demand exceeds 20 BCM per year by 2030. In this scenario, moderate growth in electricity demand leads to rising demand for natural gas. This demand increases in 2026 and 2030 with the retirement of existing coal-fired power plants.

The last scenario is the one within our test bed set of scenarios requiring the most natural gas. This is representative of a small class of scenarios in which natural-gas demand is above the 22 BCM threshold. This highest-demand scenario shows a time path that results in the highest natural-gas demand level reached in any alternative future within the test set. This occurs when high demand for electricity is combined with coal power-plant retirement, an unlikely but not impossible future state of the world. Given the assumptions described in our discussion of different natural-gas fuel paths on the capacity of each source of gas supply, scenarios with demand greater than 22 BCM will require larger capacity facilities or additional sources of natural gas. This fourth source could be a second LNG terminal, new domestic capacity beyond that currently anticipated from Tamar and Dalit, possibly new capacity from the current pipeline import source, or a new pipeline source of imported natural gas. New shallow- or deepwater discoveries in addition to Tamar and Dalit would be an example of the first, while establishing supply from Gaza Marine, Turkey, or another supplier in the Middle East would be examples of a new import source. The defining characteristic of this scenario is that the currently proposed sources and capacities will be insufficient for the long-run demand, based on the assumptions used in this analysis.

These scenarios were selected to illustrate the types of infrastructure configurations that might be needed to supply gas demand at different levels. We point out that these are not intended to be typical scenarios. Quite the opposite: At both the high and low ends, the pattern of natural-gas demand is atypical. Similarly, while one scenario in each pair of the low- and middle-demand scenarios yields 2030 levels of natural-gas demand that are representative of many other scenario outcomes, they, too, introduce stress because of the sharp rise experienced in certain years due to plant retirements. Other scenario outcomes resulting in the same 2030 levels of fuel demand do so by following smoother paths. These paths were chosen deliberately to explore how severe the consequences might be for a sudden disruption in a major source of primary-fuel inputs to Israel's energy economy. It was important to represent both types in the resulting database of scenario outcomes.

Trade-Offs Between Domestic, Foreign Pipeline, and LNG Supply Sources

The success of the Tamar and Dalit reserve exploration for offshore natural gas raises the question of whether the significant expense and difficulty of building an LNG receiving terminal are now worthwhile (Bar-Eli, 2009b). The LNG terminal for which tenders were to be issued in July 2009 would clearly be of considerable value if Israel's sole source of an increasingly important fuel were to be a pipeline from a country with which it had fought five wars in living memory. If the domestic natural-gas resource proves to have the amount of recoverable gas that early reports have mentioned, it becomes more of a question whether this LNG terminal should receive the priority attention it had in the past.

This is a difficult question to answer at this stage because so much rests on the remaining unknowns about the volume of recoverable gas from Tamar and Dalit and the costs of that recovery. Our project team had no access to these data because the preliminary analyses have not yet even been offered for tender, much less performed. In the absence of such information, we sought to examine, in broad terms, what alternative costs might be. It is our intention to provide Israel's policymakers with a preliminary assessment of various strategic options building on the analysis we have discussed in this chapter.

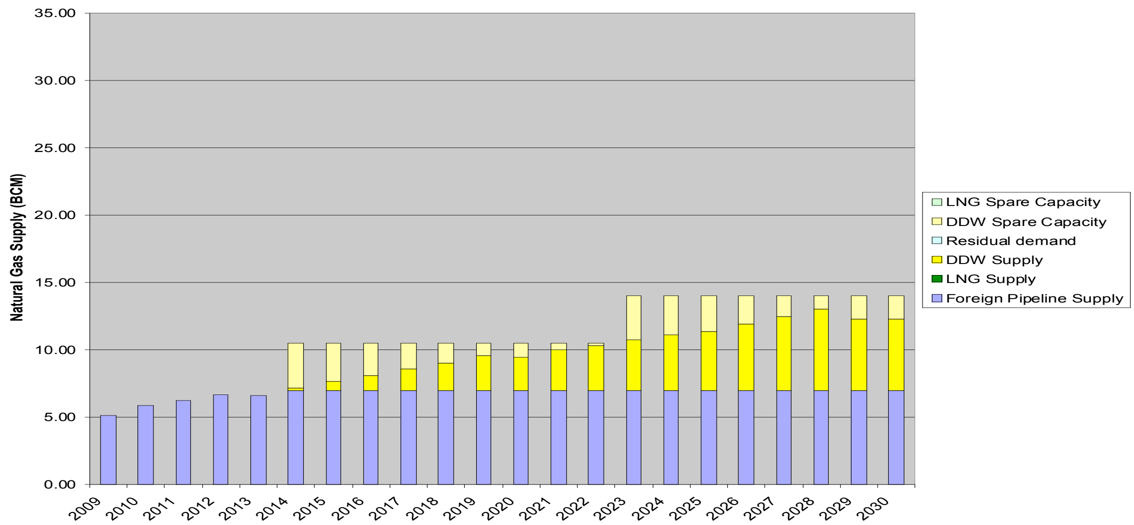
Specifically, we address ourselves to three further questions that will provide part of the answers to the core questions we posed at the beginning of this chapter:

- Does Israel need LNG, and, if so, when?
- How do different strategies for supplying natural gas vary with respect to possible costs, the degree to which the newly discovered domestic reserves would need to be depleted, and the reliability of supply?
- What measures could Israel take to insure against harmful consequences arising from disruptions in supply from foreign sources?

On the first question, our analysis perhaps not too surprisingly shows that this depends very much on assumptions about the future demand for natural gas in Israel, the size of DDW reserves, and the scale of deliveries from foreign pipeline sources. We can illustrate this by looking at two scenarios that vary in the level of expected pipeline deliveries arising from sales of natural gas by foreign pipeline.

Figure 7.2 shows where supplies would need to come from if the pipelines from foreign sources deliver 7 BCM per year through 2030, demand follows the medium growth path described, and Israel follows the Gas Rule_Alt (Modified) utilization strategy. Under these circumstances, about 60 BCM would need to be drawn from DDW reserves to meet demand through 2030. Capacity would need to be built out to approximately 7 BCM per year, and this

Figure 7.2
Sources for Meeting Israel Natural-Gas Demand to 2030 with Annual 7 Billion Cubic Meters from Eastern Mediterranean Gas and Oil: Medium-Demand Path and Following Gas Rule with Alternatives (Modified) Strategy



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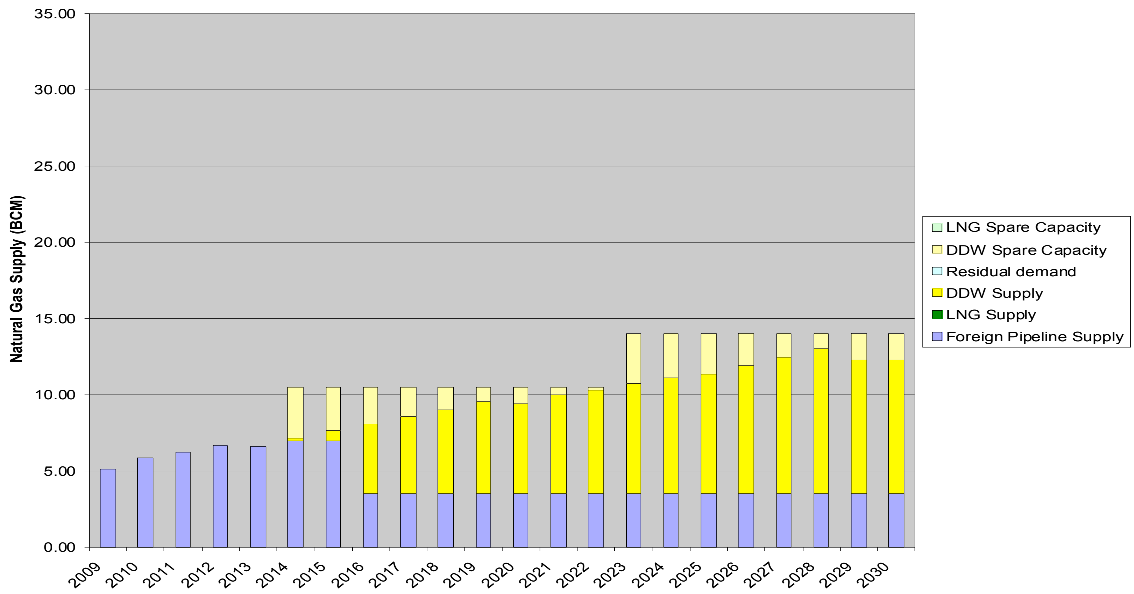
would not leave much DDW spare capacity if the 7 BCM from the foreign source should fail to be delivered for some reason.

Figure 7.3 shows the same situation, but this time assuming that foreign-pipeline deliveries only come in at 3.5 BCM each year, half the design capacity of the current pipeline to Ashkelon. In this case, the DDW sources would need to deliver more than 10 BCM per year, thus requiring greater initial capital expenditure. These reserves would need to provide 112 BCM or be supplemented with other sources up to this amount. However, note that the additional reserve capacity that we have assumed at this level would more adequately cover shortfalls in foreign supply, in part because these are at only half the previously assumed level.

The publicly available information suggests that, during a large part of the first year of operation, actual pipeline deliveries from EMG that began in May 2008 fell a good deal short of meeting the contracted levels. If we now assume a rate of delivery that is halved again to 1.7 BCM per year, the size of the initial contract under which gas is being delivered to Israel, the need for the DDW resource becomes even greater if not supplemented by an alternative source of supply. Under these terms, the total supply from Tamar and its prospective counterparts would need to be about 135 BCM to the year 2030. The annual volume of delivery from these sources would need to be more than 14 BCM by that year. Note, however, that, given the increments for infrastructure building, we have assumed in this analysis this would leave a surge capacity in the domestic reserves on the order of 2–3 BCM per year. This means that should the EMG source fail entirely, the reserves under the control of Israel would be sufficient to meet the shortfall at this relatively low level of foreign supply volume. The more natural gas is drawn from the foreign-supply pipeline, the less Israel's own reserves are depleted, but the greater the possible consequences of shortfall because of a lack of means to make up for the missing deliveries.

Figure 7.3
Sources for Meeting Israel's Natural-Gas Demand to 2030 with Annual 3.5 Billion Cubic Meters from Eastern Mediterranean Gas and Oil: Medium-Demand Path and Gas Rule with Alternatives (Modified) Strategy

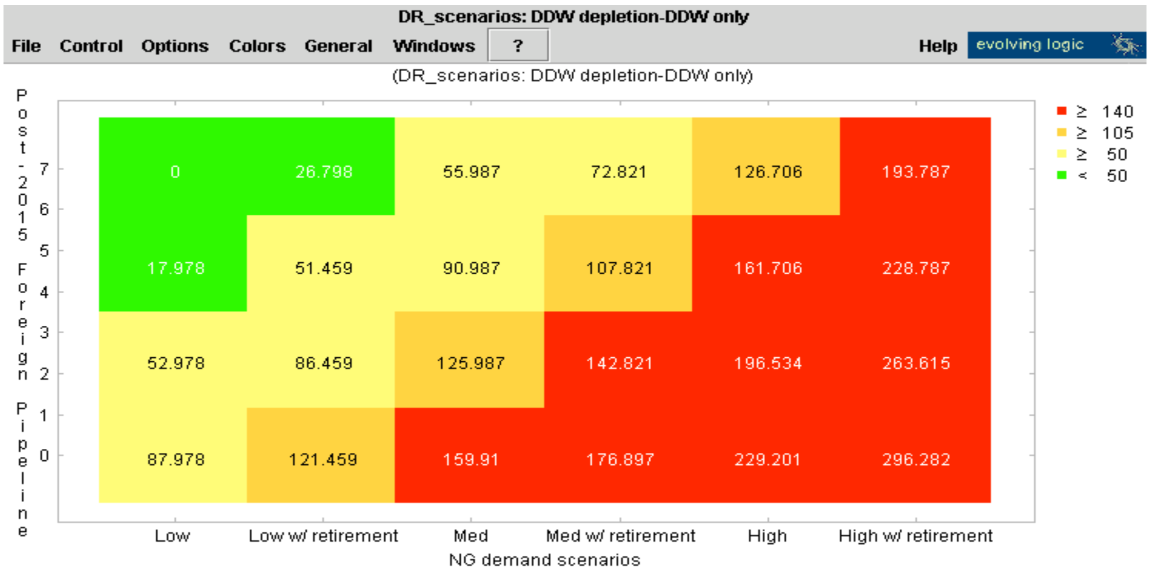


RAND *TR747-7.3*

Note that all of the results we have discussed so far pertain to the case of medium demand and without the additional stress of coal-fired power-plant retirements as in some of the other scenarios. We can obtain a better sense of how different assumptions might affect outcomes by examining Figure 7.4, which applies the DDW Only strategy to 24 different cases. The figure shows the cumulative supply required from DDW sources through 2030 if we look across the different demand paths of the seven test scenarios (the horizontal axis) as well as the level of deliveries received from foreign pipelines during the period after 2015 (vertical axis). In this case, we have looked at four evenly spaced levels—namely, 7.0, 4.67, 2.33, and 0.0 BCM per year. Therefore, this figure allows us to view a selection of 24 scenarios that differ only in the two variables whose assumptions we explore. The right-most column, presenting outcomes from scenarios in which demand is high and emission requirements force retirement of coal-fired plants would appear to be unlikely to occur. We include it to provide a better feel for how volume of supply from domestic sources is affected by changing assumptions.

The columns representing other assumptions about demand and retirements forced by economic or environmental considerations are more germane. A sense of the scale implied by these results may be gained by considering that the infrastructure required for recovery and transportation of natural gas from DDW reserves could be in place by the middle of the next decade. If the 90-kilometer pipeline from Tamar to shore was built to carry 7 BCM per year, over the 15 years until the end of our study period in 2030, this could transport 105 BCM. Therefore, even in the case of medium demand and no plant retirements, the supply of natural gas from EMG would need to remain consistently at the high end of the import volume assumptions for these two combined sources to prove adequate to Israel's needs. Any shortfall from the import-pipeline source, failure to reduce the energy intensity of economic sectors in Israel, unexpected obstacles to introducing renewable-energy sources at economically viable

Figure 7.4
Natural-Gas Deliveries from Domestic Deepwater to 2030: Gas Rule with Alternatives (Modified) Strategy Under Differing Assumptions About Demand and Deliveries from Foreign Pipeline Source (total volume in BCM)



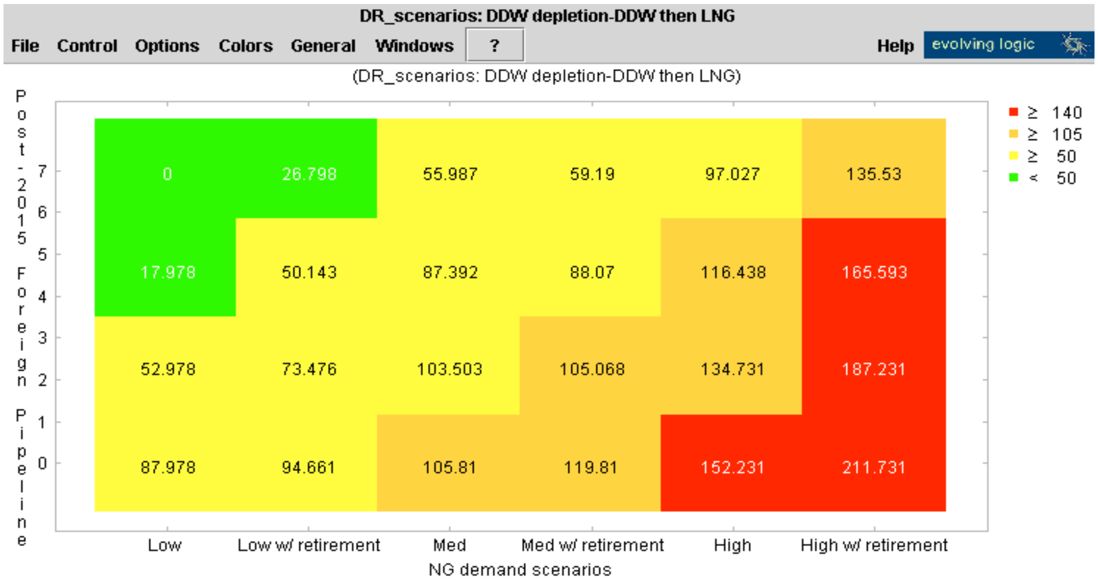
NOTE: The color thresholds are set at subjective levels. We chose 105 BCM as one threshold because this represents the stock accumulation from a volume of flow that equals 7 BCM per year for 15 years. It is also in the range of the preexploration and initial posttesting estimates of Tamar's capacity (90–142 BCM). The others are designed solely to assist comprehension and comparison among the figures.
RAND *TR747-7.4*

prices, or need to retire existing coal-plant capacity would severely tax the supply system. In the face of these exigencies, assuming that the government has determined that it is the appropriate policy to service this level of demand, in the absence of other sources of supply, the remaining alternatives would be much more-rapid depletion of the DDW reserves—assuming the necessary levels of recoverable natural gas are present—and greater costs for infrastructure. We return to the issue of costs later in this chapter in more detail.

Strengths and Weaknesses of the Four Candidate Supply Strategies

If we suppose that the decision was taken not to rely on DDW Only and instead to go forward with development of an LNG terminal in Israel, as we have seen there are several alternative strategies, of which we identified three above. In Figure 7.5, we have applied the DDW Then LNG strategy. That is, in the immediate future, natural gas from DDW sources is brought online in 2015 and the installation of LNG is postponed until an annual flow of 7 BCM from DDW wells is no longer adequate to meet demand. Of course, any reserve capacity from DDW development to cover possible shortfalls will have dwindled to near zero before this date. This may be seen to alleviate a good deal of the stress placed on DDW sources alone in the previous examples. Only in the case of medium demand, coal power-plant retirements, and low levels of foreign delivery do the demands on this reserve rise above the notional 105 BCM that we have suggested as a means for gauging different outcomes. At the same time, the amount of reserve capacity available under many of these conditions becomes quite small at certain criti-

Figure 7.5
Natural-Gas Deliveries from Domestic Deepwater to 2030: Domestic Deepwater Then Liquefied Natural Gas, Gas Rule with Alternatives (Modified) Strategy Under Differing Assumptions About Demand and Deliveries from Foreign-Pipeline Source (total volume in BCM)



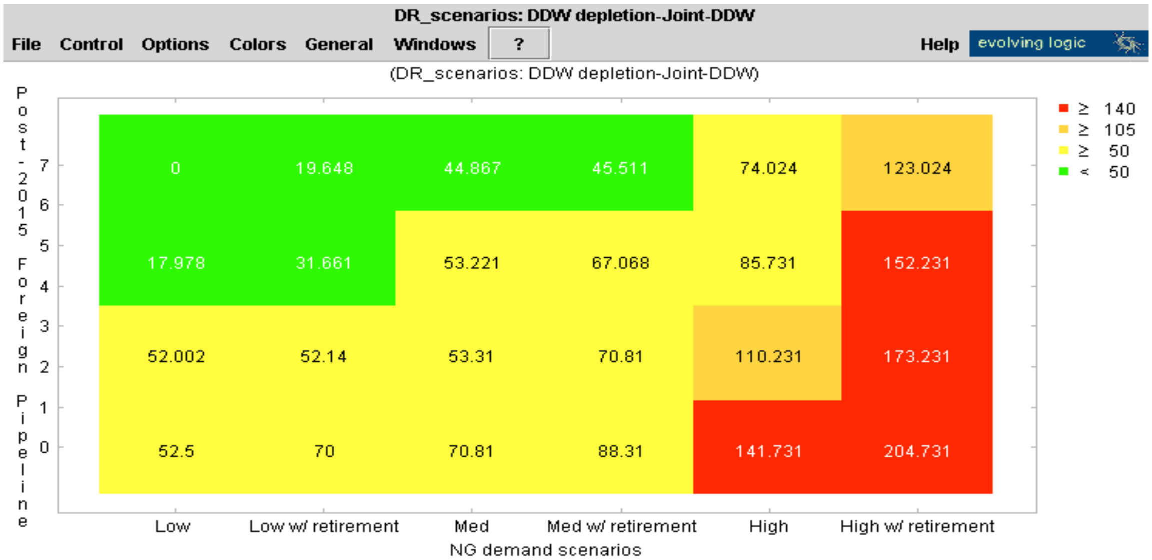
RAND *TR747-7.5*

cal points in the time series when compared to the possible need to make up if any shortfalls in supply from other sources were to occur.

The other choices we examined were the paired strategies in which DDW fields and an LNG terminal are both developed roughly contemporaneously. In the first instance, we suppose that, though both developed, the emphasis is placed on first taking deliveries from the domestic resource. This is shown in Figure 7.6. The depletion rate and overall volume of gas required are lower than in the previous views. For example, we can look at the scenario of medium demand (the yellow rectangle), 2.33 BCM from foreign pipelines after 2015, and all other factors held consistent with the examples discussed so far. We now assume that an LNG terminal with an annual capacity of 5 BCM would come online in 2016 and that this capacity would be expanded to 8 BCM in the year 2027. The draw on DDW reserves would not exceed 4 BCM in any year and depletion over the course of the entire period to 2030, as shown by this rectangle, would be slightly more than 53 BCM. Again, variations in other variables that are being held constant or pursuing a different energy-infrastructure strategy would lead to different outcomes.

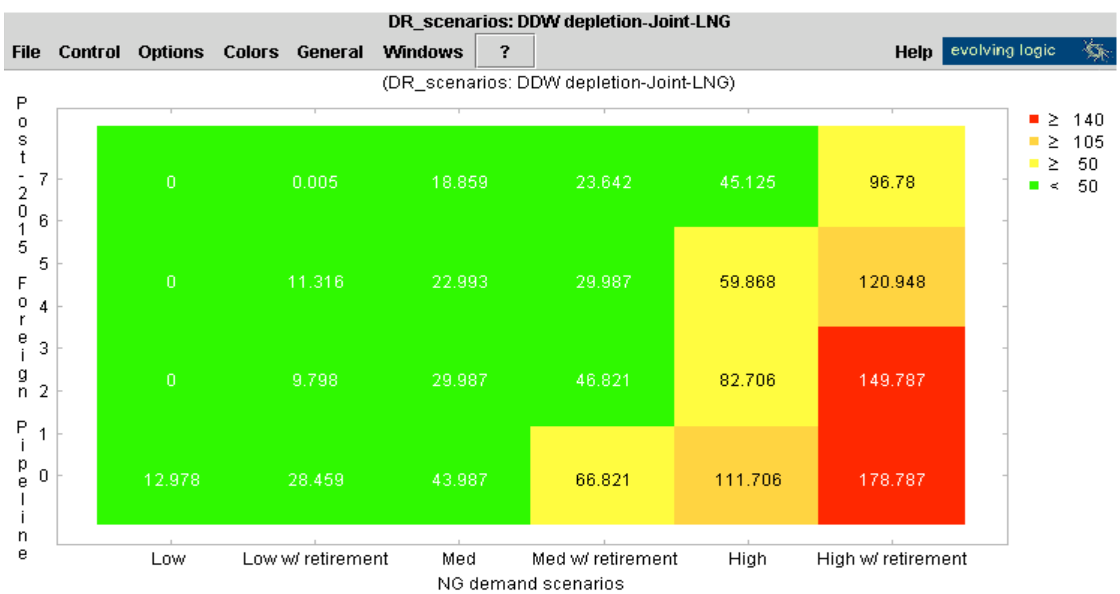
Finally, we consider the form of the joint development strategy that seeks to preserve the domestic reserves by giving preference to the use of LNG. These results are shown in Figure 7.7. Solely from the perspective of security of supply, this provides the greatest set of options for Israel. It also supports a policy in which the domestic reserve is largely kept as a buffer and is drawn on to supplement natural gas brought in from other sources, whether pipeline or LNG. The capacity of the LNG facilities can be the same as we have assumed so far (and described in Appendix E), initially 5 BCM per year and shifting to 8 BCM in the latter period, but this

Figure 7.6
Natural-Gas Deliveries from Domestic Deepwater to 2030: Joint Domestic Deepwater/Liquefied Natural Gas (DDW Priority) Strategy, Gas Rule with Alternatives (Modified) Strategy Under Differing Assumptions About Demand and Deliveries from Foreign-Pipeline Source (total volume in BCM)



RAND *TR747-7.6*

Figure 7.7
Natural-Gas Deliveries from Domestic Deepwater to 2030: Joint Domestic Deepwater/Liquefied Natural Gas (LNG Priority) Strategy, Gas Rule with Alternatives (Modified) Strategy Under Differing Assumptions About Demand and Deliveries from Foreign-Pipeline Source (total volume in BCM)



RAND *TR747-7.7*

capacity is fully utilized each year. Rather, it is the domestic reserve that provides the security against supply disruptions with a capacity for surges in its own deliveries to Israel.

The results so far are summarized in Table 7.7. It shows some of the salient points that occur under the assumptions we have so far adopted.

There are several initial inferences that we may draw from Table 7.7:

- The DDW Only strategy is insufficient unless long-term demand remains low and deliveries from foreign-pipeline sources exceed 3.5 BCM a year.
- For higher levels of demand, an LNG terminal is needed in addition to DDW natural gas. If gas supplies from foreign sources remain uncertain, the Joint DDW/LNG (LNG Priority) strategy will add reserve capacity to meet most potential shortfalls from foreign pipelines. Furthermore, prioritizing LNG use saves the DDW reserve as a strategic national resource.
- If a supply near 7 BCM from foreign pipelines is fairly certain, then the DDW Then LNG approach can meet demand and postpone the high capital costs associated with building an LNG terminal.
- As natural-gas demand nears 20 BCM, gas supplies may not meet demand if foreign pipelines do not deliver 7 BCM. Under the assumptions in this analysis, supplies cannot meet demand, even with the full supply from foreign sources, when demand exceeds 22 BCM.

Table 7.7
Synopsis of Natural-Gas Supply Model Results by 2030 Applying Gas Rule with Alternatives (Modified) Strategy Across Scenarios with Four Levels of Demand

Level of Demand	DDW Only	Joint DDW/LNG (LNG Priority)	Joint DDW/LNG (DDW Priority)	DDW Then LNG
< 7	Meets total demand High depletion of DDW if foreign = 0	Meets total demand Large underutilized capacity unless foreign supply declines to zero Low depletion of DDW	Meets total demand Large underutilized capacity unless foreign supply declines to zero Moderate depletion of DDW	Meets total demand High depletion of DDW if foreign = 0
7–15	Possible unmet demand High depletion of DDW if foreign < 7 BCM	Meets total demand High utilization LNG capacity if foreign < 7 BCM Low depletion of DDW	Meets total demand Low utilization of LNG capacity if foreign > 0 Moderate depletion of DDW	Meets total demand Low utilization of LNG capacity unless foreign = 0 High depletion of DDW
15–22	Unmet demand unless DDW > 8 BCM/yr High depletion of DDW when foreign < 7 BCM	Possible unmet demand if foreign < 7 BCM High utilization of LNG capacity Lowest depletion of DDW among strategies	Possible unmet demand if foreign < 7 BCM High utilization of LNG capacity unless foreign = 7 BCM Moderate depletion of DDW	Possible unmet demand if foreign < 7 BCM Unused LNG capacity in some years High depletion of DDW when foreign < 7 BCM
22+	Large unmet demand High depletion of DDW	Unmet demand without new source High utilization of LNG capacity Moderate depletion of DDW	Unmet demand without new source Moderate utilization of LNG capacity High depletion of DDW	Unmet demand without new source Moderate utilization of LNG capacity High depletion of DDW

Examining the Costs of Candidate Supply Strategies

Security of supply is not the only concern that matters. Issues of cost are central to the decision over supply strategy. An LNG terminal is an expensive investment difficult to justify solely as a backup reserve or insurance policy against shortfalls from other supply sources. The investment makes sense only if one anticipates the need of LNG to meet a portion of demand. On the other hand, once the investment has been made and an LNG infrastructure is in place, it does become an important element of planning to consider how the existence of this capacity within Israel could enhance robustness by avoiding the worst consequences of possible sharp discontinuities in supply. Therefore, it is worthwhile considering the early construction of such a facility if it is likely to be required anyway. The balance of this chapter explores whether this is the case in Israel.

As expensive as LNG development would be, the costs of developing a natural-gas field in deepwater 90 kilometers from shore may be even greater. In broad terms, this sets up an interesting trade-off. Both of these approaches are massive undertakings financially. With LNG, the fixed investment portion is most likely smaller than that for DDW sources, while the marginal costs of the fuel supply would probably be larger. The price at which natural gas is delivered would need to allow the supplier to recapture his own expenditures upstream of the delivery to Israel. In broad terms, DDW supply would present the opposite case. Once the fixed cost components are in place, the marginal cost to produce and deliver the natural gas would probably be less than would be the case for LNG on an equivalent energy basis.

The number of variables that enter into a decision of how to ensure Israel's natural-gas supply make this a perplexing decision. In the analysis so far in this chapter, we have examined only a very few particular sets of such assumptions. We now once more scan across many scenarios to come to a better understanding of where the balance of cost and benefit may lie. Once again, we utilize the natural-gas supply model discussed in this chapter and employ an experimental design to select a sample set of 5,000 alternative possible future sets of conditions to generate the scenarios that we will examine.[23] In this initial set, we derive these scenarios by varying assumptions about

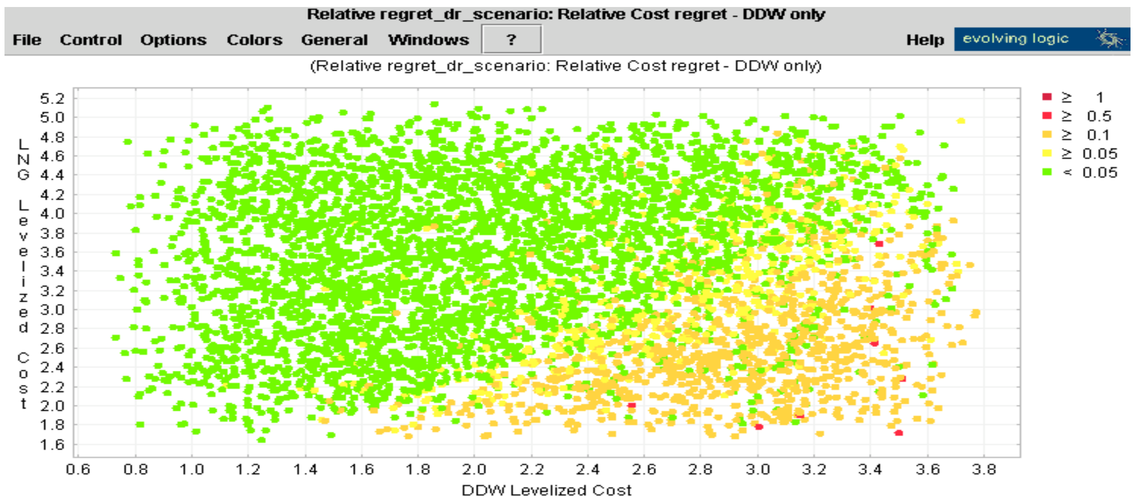
- demand for natural gas
- the fixed and variable costs associated with fuel coming from DDW and LNG sources
- the discount rate
- the amount of natural gas supplied from foreign pipelines.

We then examine the outcomes by running each of the four supply-insurance strategies against each alternative set of future conditions defined by the assumptions used for the various uncertain input factors.

An example of the results may be seen in Figure 7.8. This view shows a plot of cost outcomes for the DDW Only supply strategy. To make comparisons on a level field, the axes show a span of assumptions about the particular costs in U.S. dollars per MMBTU that stem from the fixed and variable costs of DDW or LNG sources that are being varied in the 5,000 test-

[23] Running four different strategies against 5,000 different states of the world provides us with a set of 20,000 scenario outcomes to examine.

Figure 7.8
Relative Total Cost Regret of Domestic Deepwater Only Strategy Plotted Against Variable Liquefied Natural Gas and Domestic Deepwater Levelized Cost Assumptions Under 5,000 Scenarios (percent deviation from minimum cost result)



RAND *TR747-7.8*

case alternative futures.[24] Each dot represents the outcome of one scenario in which DDW Only is run against that scenario's set of assumptions. Again, the relative regret of the cost-metric outcome is the principal measure. We can see, therefore, that, in situations in which DDW natural-gas costs are in the middle or lower range or LNG costs are relatively large, the DDW Only approach is very often either the least cost or very close to being so. Only in the lower-right section, where DDW natural-gas costs are high and the LNG costs are low do the regret results begin to grow. Even so, there are relatively few scenarios in which these are greater than 50 percent and at least as many in which the outcomes are still colored green.

The limitation of the result shown in Figure 7.8 is that we see only the direct costs of supply without any formal provision for having in place some reserve up to a level set by policy. For each of these scenarios, any excess reserve of DDW capacity that might be able to make up the shortfall in the case of a supply failure is present solely because the level of actual demand has not yet achieved the design volume of the infrastructure that has been built to develop the DDW fields from which natural gas is being drawn. No capacity has been built with the express intention of providing some buffer for supply irregularities from other sources. To conduct an accurate comparison of costs, we need, once more, to consider what level of supply assurance is desirable and what this capacity may cost.

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[24] See "Deriving Assumptions on Future LNG and DDW Natural-Gas Pricing" in Appendix E for details on how the ranges of costs unique to specific natural-gas sources were compiled. For LNG, this cost ranges from USD 1.60 to USD 5.00 per MMBTU. For DDW-sourced natural gas, the range is USD 0.70 to USD 3.75 per MMBTU. This is distinct from the market price of natural gas, which will be determined by these fundamental costs, the state and development of global or regional markets in natural gas, regulatory and administrative policies in Israel, and the industrial organization of the domestic market for natural gas and other liquid fuels. This simplification provides a fundamental analytical framework that can be modified with the inclusion of greater detail and less-restrictive pricing assumptions.

Adding a Reserve Capacity to Natural-Gas Supply

There are a number of ways that a reserve capability may be added to Israel's infrastructure to reduce the consequences of a shortfall in natural-gas supply. One of these is, of course, to build the capacity to permit a potential surge in supply from other supply sources. This would entail building out the capacity to supply DDW deliveries beyond what might otherwise be specified if no emergency capability was considered, to add LNG or other natural-gas supplies to the source mix, or some combination of the two approaches. We have discussed the possibility of using depleted reservoirs to store natural gas for emergencies, but the information available to us suggests that this would be quite expensive. The need to retain something on the order of half the volume of gas in the reserve to maintain pressure for recovery of the other portion creates a large cost threshold if this is intended to be solely an emergency reserve.[25] It is more likely that emergency stores would be kept in the form of diesel as a switch fuel that may be diverted to power plants designed to be dual-fuel capable. But this is not an inexpensive proposition either in the amounts that might be required for meeting a shortage of more than short duration.

There are two other approaches to insurance that are less technical fixes than matters of policy choice. They, too, would have costs associated with them. One is to reduce the reliance on foreign sources of supply if this is the major concern for possible longer term (that is, more than a few months' duration) supply disruptions. If this is deemed, based on information available to policymakers, to be potentially the most vulnerable source of supply, then reducing its share in the primary-fuel mix would reduce the need for backups to a potentially large supply shortfall. Clearly, if the alternatives are natural gas or other fuels coming from other sources that carry higher direct and indirect costs for Israel, the desire to limit dependence on foreign sources would need to be weighed against both the degree to which this is viewed as a potential source of risk and the costs of insuring against such risk.

The final policy recourse is to make a conscious decision about what level of insurance against supply shortfalls to seek. Focusing for the moment on natural gas as a fuel for electricity generation, the government or operators of the generation system may make a decision about what portion of the natural-gas supply that comes from sources deemed to be potentially risky it would wish to insure by making certain of backup supply sources. Making certain of 100-percent backup ability would be one choice. However, the decision could also be made to provide only on-hand backup for 85 percent of the portion of the electricity-generation fuel mix deemed to be at risk—or any point in between. The bet would be that the remainder could be made up through demand management or other emergency measures.

We once more examined the performance of the four approaches to building out natural-gas supply to the year 2030 against each of 5,000 alternative specifications of future conditions. This time, however, we included several new inputs with varying assumptions relating to supply insurance policies and their cost. There is now a variable specifying what level of insurance is desired. This amount was represented by the share of electricity generation accounted for by natural-gas supply from foreign pipeline sources. It varied between 85 and 100 percent

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[25] This obstacle becomes less binding if the reservoir was designed to be an integral part of the management system for the routine supply of natural gas to Israel. The technical requirement would still exist, but this cost may then be viewed as part of the fixed cost expense of establishing such a reservoir and evaluating the benefits accordingly. Additionally, it is conceivable that CO_2 may be recovered from fuel combustion and injected to help provide the necessary pressure balance. These and similar considerations lie beyond the level of discussion in this report.

in specifying the level of reserve capacity that would be necessary to replace loss of this supply source. There are also variables indicating whether the policy opts for natural gas, diesel fuel, or no storage capacity.

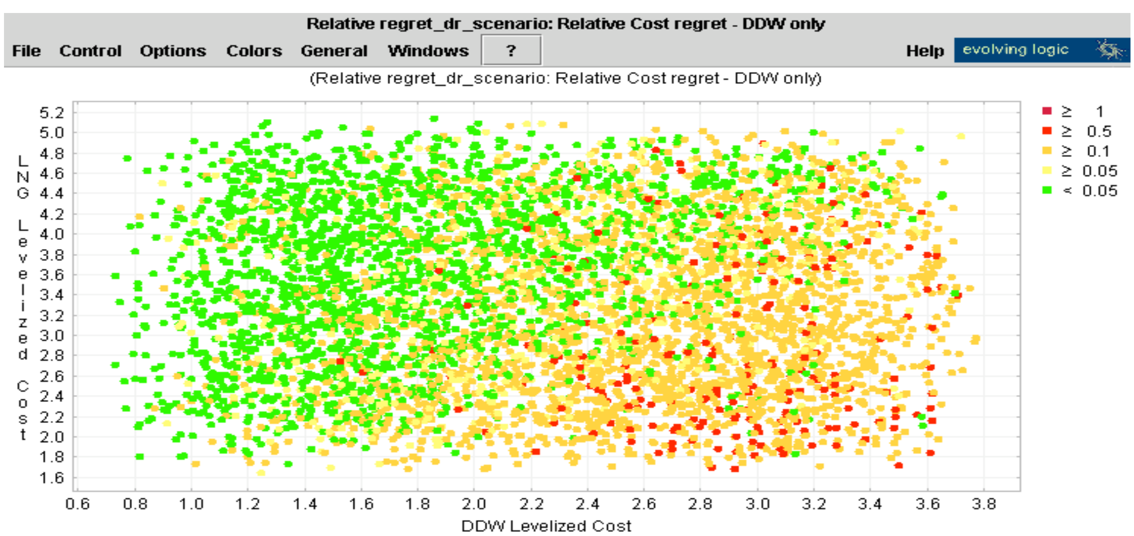
Given this mandate for a reserve supply, the principal means for achieving it was to first look to excess capacity in either the DDW or foreign supply-pipeline systems. To the degree that this proves to be insufficient to meet the required level of reserve set by the policy variable in each scenario, two additional sources would come into play. The first of these was storage of diesel fuel. Depending on the scenario conditions, this expedient may or may not be employed. If so, the size of this reserve is determined by the requirements defined by policy and excess DDW and LNG capacity at the time. The cost of diesel storage also tracks a range of alternative assumptions. Finally, there is a similar capability to store natural gas in depleted reserves. The volume of storage varies from 0 to 3 BCM and the potential costs of that storage also vary.

Figure 7.9 shows the results of the same DDW Only strategy across 5,000 scenarios but this time including a variable policy for reserve capacity described fully in Appendix E. It may be compared with the similar plot in Figure 7.8. It now shows a less clear zero-regret or low-regret (green dot) dominance by the DDW Only approach in large regions of this space.

Among the four different supply strategies, the one that shows the greatest breadth and prevalence of zero regret is Joint DDW/LNG (DDW Priority), as shown in Figure 7.10. It is clear in this view, however, that there is an important sector of low DDW premium cost and correspondingly high cost for LNG that causes this approach to do less well with respect to cost. Interestingly, the instance of extreme-failure scenarios (relative regret is 50 percent or greater) is more concentrated for this strategy. They are spread more widely, albeit in approximately the same number, in the case of DDW Only.

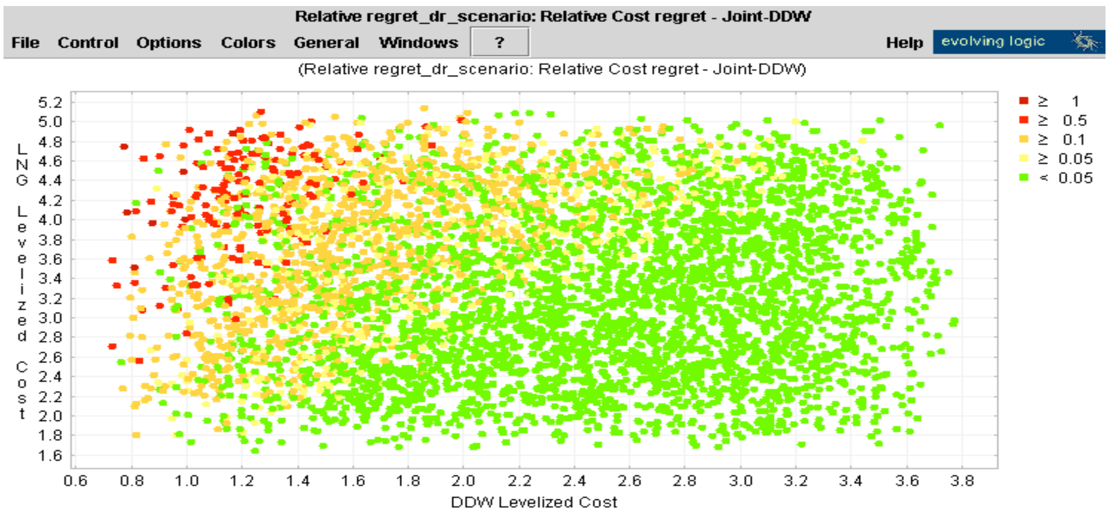
It is interesting to compare the results shown in Figure 7.10 with those in Figure 7.11. This, too, is a strategy that builds out the DDW supply path but also introduces LNG at an

Figure 7.9
Relative Total Cost Regret of Domestic Deepwater Only Strategy Plotted Against Variable Liquefied Natural Gas and Domestic Deepwater Levelized Cost Assumptions Under 5,000 Scenarios Including Costs Associated with Ensuring Supply (percent deviation from minimum cost result)



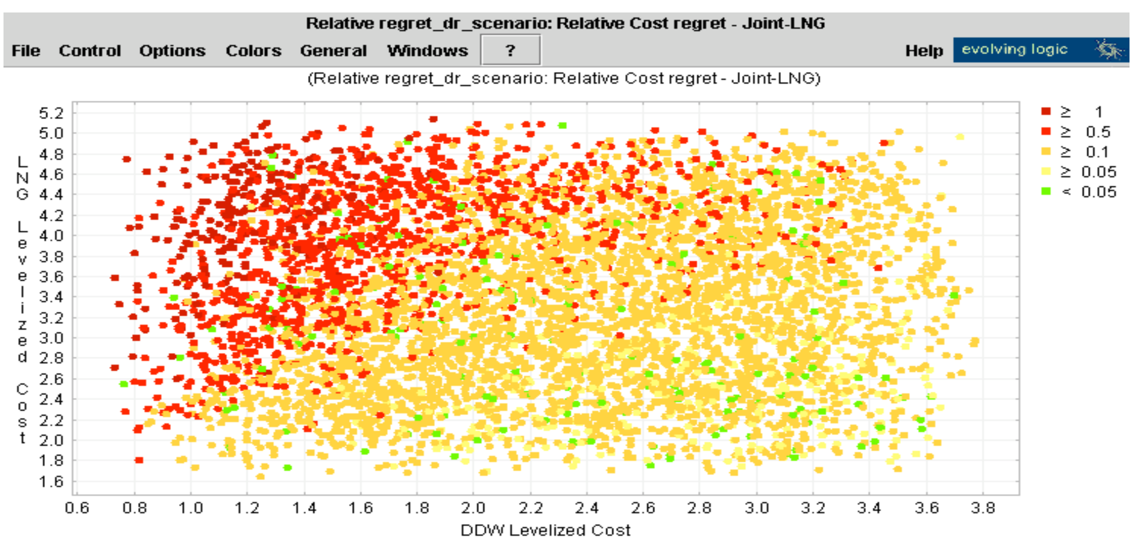
RAND *TR747-7.9*

Figure 7.10
Relative Total Cost Regret of Joint Domestic Deepwater/Liquefied Natural Gas (DDW Priority) Strategy Plotted Against Variable Liquefied Natural Gas and Domestic Deepwater Levelized Cost Assumptions Under 5,000 Scenarios Including Costs Associated with Ensuring Supply (percent deviation from minimum cost result)



RAND *TR747-7.10*

Figure 7.11
Relative Total Cost Regret of Joint Domestic Deepwater/Liquefied Natural Gas (LNG Priority) Strategy Plotted Against Variable Liquefied Natural Gas and Domestic Deepwater Levelized Cost Assumptions Under 5,000 Scenarios Including Costs Associated with Ensuring Supply (percent deviation from minimum cost result)



RAND *TR747-7.11*

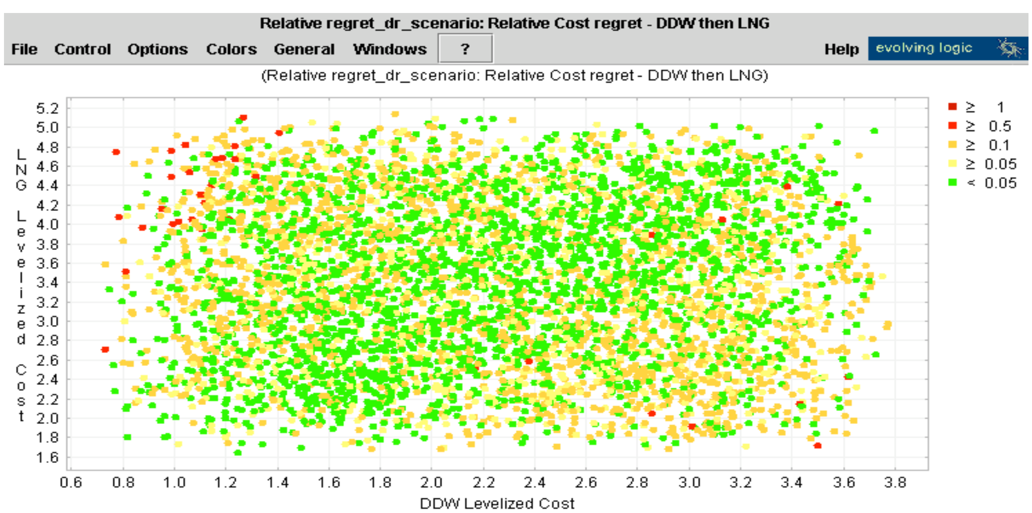
early stage. The difference is that the emphasis is on preserving the local reserve by making more-immediate use of LNG. Given the assumptions about relative costs shown in the vertical and horizontal axes of the figures, this turns out to be an unsuccessful strategy with respect to cost throughout most of the very wide region of price assumptions shown. There are almost no cases in which this strategy is preferred from the cost perspective. In fact, it fails most seriously in the region that would govern if current trends hold true—namely, that of relatively inexpensive (in terms of the levelized costs we have been using as a yardstick) domestic natural gas and rather more-expensive LNG.

In Figure 7.12, we show the same view for the DDW Then LNG approach. We do so for more than just the sake of completeness. Here we see that, throughout the landscape, not only do scenarios exist with relatively favorable outcomes with comparatively little regret, but there are also chances for no-regret scenarios. While extreme regret (50 percent or more) is not common, scenarios with considerable (10 up to 50 percent) regret are. Depending on the level of risk bearing that Israeli policymakers are comfortable taking on and, of course, performance in other relevant dimensions, this figure suggests that, at least from the perspective of the cost-regret measure, the DDW Then LNG strategy shows aspects of robust behavior. It may not dominate in any region the way the first two strategies we examined do, but it could—with a bit of fine tuning—probably be made to be successful in terms of meeting this criterion throughout the full range of possibilities we have examined in the realm of relative fuel costs. We return to this strategy and discuss it in more detail in the final section of this chapter.

Applying Multiple Criteria to Assessing Supply Strategies

Now that the costs of insurance have been included, we can examine how the four approaches behave with regard to several criteria. In the balance of the chapter, we consider three main measures. In addition to the costs of supply, we examine rates of depletion of DDW reserves and supply reliability as criteria.

Figure 7.12
Relative Total Cost Regret of Domestic Deepwater Then Liquefied Natural Gas Strategy Plotted Against Variable Liquefied Natural Gas and Domestic Deepwater Levelized Cost Assumptions Under 5,000 Scenarios Including Costs Associated with Ensuring Supply (percent deviation from minimum cost result)



RAND *TR747-7.12*

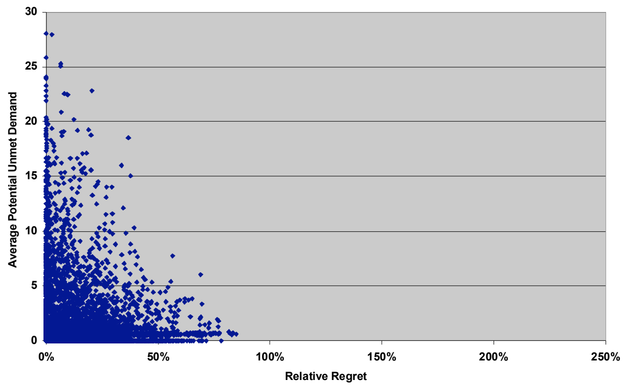
Figure 7.13 provides one view for assessing trade-offs among metric criteria for each strategy. Again, each dot represents the unique scenario outcome that results from applying a specific strategy to a set of assumed conditions. The horizontal axis shows the relative regret for cost as we have discussed above. The vertical axis shows the potential unmet demand for electricity caused by a cutoff of foreign natural gas. This is a proxy for a reliability of supply metric. Recall that each scenario now includes a policy decision about what level of risk to accept as a trade-off for reducing the cost of supply backups. This may be between zero and 15 percent of the portion of electricity generation that is fueled from foreign pipeline sources. Therefore, any point in the plots shown in Figure 7.13 that is above 15 percent indicates unambiguously that the conditions of the scenario were such that the strategy could not meet its minimal target point.

Ideally, a robust strategy would show most of the outcome points stacked in the lower left corner of each plot. In this instance, there will always be a dispersion found between 0 and 15 percent on the vertical axis because of the policy being modeled in different scenarios. Of the four plots, the fourth, showing the results for DDW/LNG (LNG Priority), is perhaps the most troubling. While the performance with respect to reliability is not at all bad, the number of high relative cost-regret outcomes is troubling. The plot showing results for DDW Then LNG appears to be the least troubling from the cost perspective but does not behave particularly well in meeting the reliability measure.

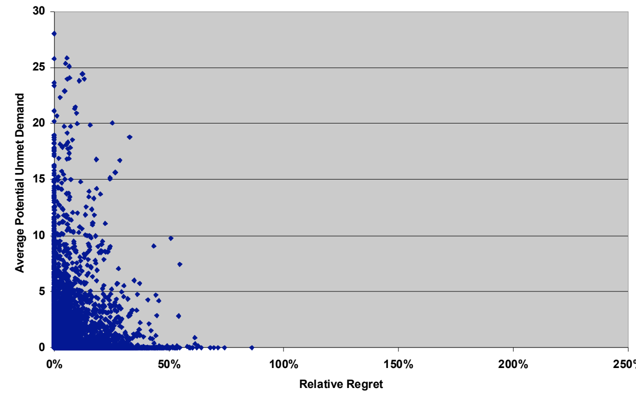
In many ways, the most interesting plot is again that for DDW/LNG (DDW Priority), the third plot. A great deal of the weight of points has massed along both axes with less in the field between the axes when compared to the other three. What this suggests is that this approach to ensuring supply, developing DDW wells and LNG facilities jointly while drawing most heavily from DDW sources during the early period, presents interesting opportunities for adaptive behavior by operators and government officials. As more information is gathered and the signposts pointing toward what the actual values of currently unknown variables might be, this strategy permits fine tuning supply to achieve several policy goals. The results shown in the figure stem from applying fairly simple policies in a rigorous and inflexible manner. With active monitoring by government and industry, the results in the DDW/LNG (DDW Priority) plot at least suggest that the system of supply could be tuned in such a manner as to manage the trade-offs gracefully under actual circumstances. This would suggest that it would be possible to bring the actual results quite tightly in toward the vertical axis to achieve the target level of acceptable risk while not incurring excessive regret over total cost.

We can expand on this point by taking a different view of the same data. In the analysis in Chapter Six, we established a threshold for each criterion of interest to assess whether a scenario outcome was acceptable. Again, strategies that achieve this minimal threshold across many alternative future states of the world and across several measurement criteria are termed as being more robust than those that fail to do so. In this case, as in Chapter Five, we set the cost threshold as being within 5 percent of the lowest-cost (zero-regret) strategy for that set of conditions. The threshold for DDW depletion we set at 105 BCM through the year 2030 by nominating 7 BCM per year for each year 2015 through 2030 as an acceptable rate for depletion of the domestic resource. And for the criterion of being able to meet demand for natural gas, we deem those scenario outcomes that achieve the target level in the 85- to 100-percent range that apply to that scenario as being successful. If that target level is not met and electricity cannot be supplied at the target level, the outcome is considered a failure.

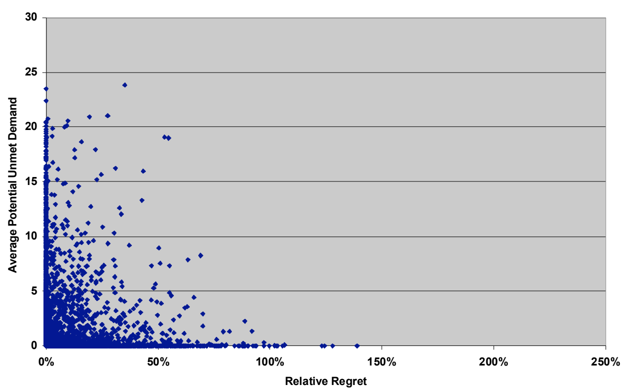
Figure 7.13
Relative Regret and Average Potential Unmet Demand of Candidate Supply Strategies Under 5,000 Scenarios Including Costs Associated with Ensuring Supply (percent)



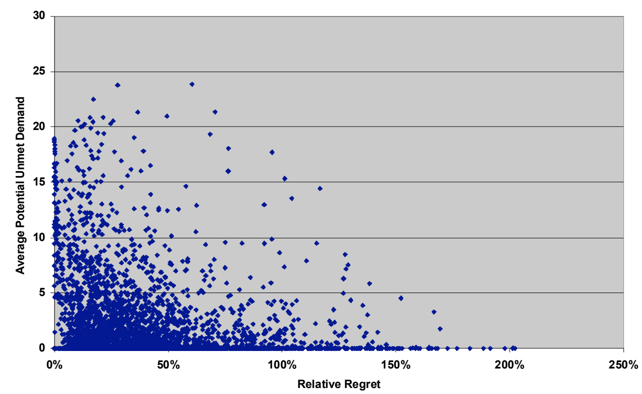
A. DDW Only



C. DDW/LNG (DDW Priority)



B. DDW Then LNG



D. DDW/LNG (LNG Priority)

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The results are shown in Figure 7.14. For each of the four approaches, we calculate the share of scenario outcomes that meet the individual criterion threshold as well as the share of scenarios in which the strategy meets all three thresholds. Because measures for supply backup are now mandated by the model algorithms, each achieves the target level of potential unmet demand in something under 90 percent of the cases. Those strategies that rely the most on natural gas from DDW sources run the greatest risk of failing to meet the depletion measure. The Joint DDW/LNG (DDW Priority) approach does best most often both in terms of cost and in meeting all three criteria. It does so in almost 45 percent of the scenarios.

When these strategies do fail, how gracefully do they do so? That is, how often is the failure a large one? Figure 7.15 provides an aggregate overview of this aspect of performance. As before, we deem being below the target level of electricity supply to be an important failure. We now look for failures in the cost dimension by seeking cases in which the relative regret is greater than 50 percent. Similarly, we calculate the scenarios in which DDW depletion is more than 140 BCM, a level of drawdown that either might not be sustainable or could leave the nation without resources in the absence of new sources of supply or new discoveries that can be brought to production before the end of the period. For the last criterion, we now count scenarios in which, for any one year, the unmet demand due to a supply shock is greater than the risk level (0–15 percent of the electricity demand fueled by the failed supply source) set by the policy for that set of scenario conditions.

Under these thresholds for detecting major failures, the Joint DDW/LNG (LNG Priority) approach exhibits very high-cost relative regret in more than one out of every four of the 5,000 scenarios. Otherwise, it does the best on the other two criteria. The DDW Priority version of the Joint DDW/LNG approach dominates the remaining two strategies (the left-most two in Figure 7.15) in the depletion and supply-reliability dimensions of performance and is beaten only by DDW Then LNG in the share of scenarios showing large cost regret.

Figure 7.14
Percentage of Scenario Outcomes Meeting Relative-Cost, Domestic Natural-Gas Depletion, and Supply-Reliability Criteria

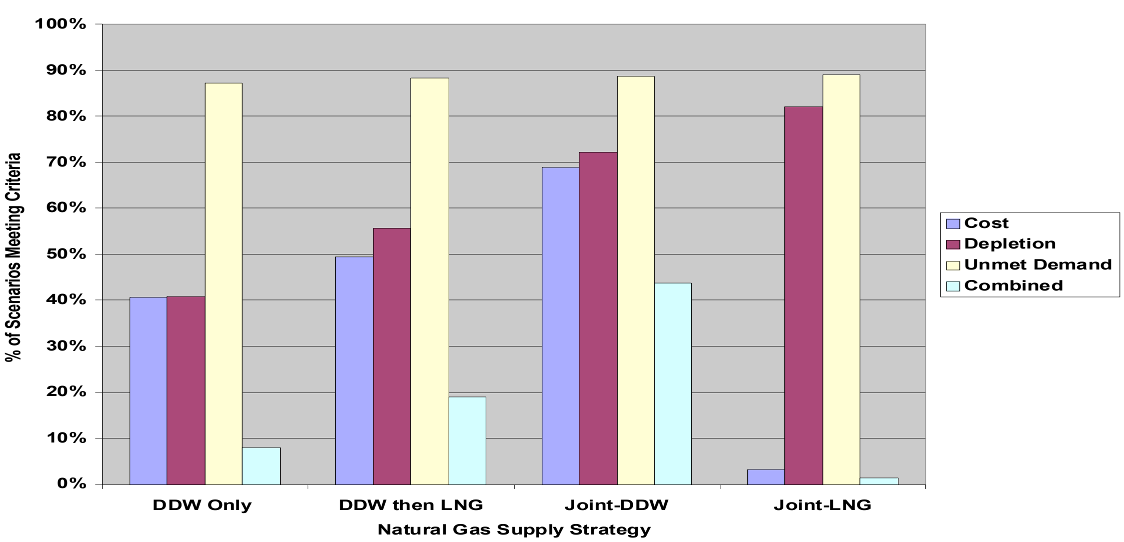

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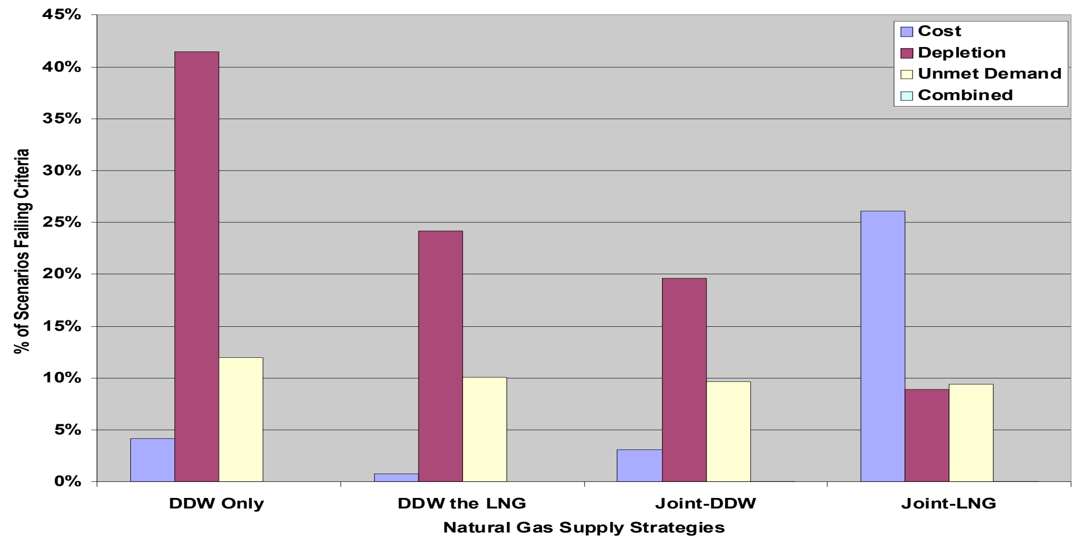
Figure 7.15
Percentage of Scenario Outcomes with Large Failures to Meet Relative-Cost, Domestic Natural-Gas Depletion, and Supply-Reliability Criteria



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As before, we note that this analysis treats all scenarios equally. It also does not weight the relative importance of the three criteria for assessing successful outcomes. With regard to the individual scenarios, it may be that the failure cases are under conditions either deemed to be relatively unlikely or that might be readily susceptible to other actions by the government to offset their risk. On the other hand, risk-averse planners may choose to put greater weight on the likelihood of scenarios that could lead to large failures. Similarly, the relative importance of each of the three criteria in determining which course to follow is a fundamental decision of policy. Weighing the value of maintaining an undepleted domestic reserve or the absence of blackouts versus determining the appropriate size of total costs and distributing them across generations can be done analytically but only in conjunction with input by those in a position of authority to make the policy choices. Similarly, these basic and relatively inflexible strategies could be subjected to the same incremental modification we used for the natural-gas utilization strategies. This would prevent, for example, excessive reliance on diesel storage when this would not be economically prudent. But the basic results shown in Figures 7.13–7.15 provide an initial assessment of the main strengths and weaknesses of the broad alternatives that Israel faces.

As in Chapter Six, we also employed data-mining scenario-discovery methods on these results to make certain that the apparently visible results were confirmed by more-quantitative methods. This was indeed the case. Showing the relative premium (that is, fuel path–specific) cost for both DDW and LNG sources is appropriate because these factors are the key drivers in determining scenario success for a given natural-gas supply strategy. When it comes to the depletion of domestic natural-gas reserves, the level of demand and the extent to which natural-gas supplies are received by pipeline from foreign sources are the key determinants of the rate and eventual level of depletion.

When we used this method to find those factors that lead to successful outcomes in being prepared to deal with potential unmet demand, we found an interesting result. Not surprisingly, those scenarios in which diesel storage was used as a backup and a positive reserve margin was maintained fared the best. But another crucial factor is to choose some level of insurance less than 100 percent of the potential loss in generation from foreign-pipeline fuel sources. It is difficult to meet the 100-percent criterion, as well as quite expensive. But if some level in the 85- to 95-percent range is chosen, it allows any shortfall to be met in most instances, does not drive the policy costs to unacceptable levels, and probably leaves sufficient room for dealing with the shortfall through demand management and other means, if a deficit were to occur. This analysis also made clear that the lowest-cost solution in balancing between maintaining a reserve margin and retaining a diesel storage capacity depends very much on the relative costs between the two. That is, while it is clear that both are important components of a strategy to provide a measure of supply security to Israel, it is also clear that recommendations must be made in cooperation with the planning authorities who are in the best position to make more-sophisticated assessments of these costs for the specific case of Israel.

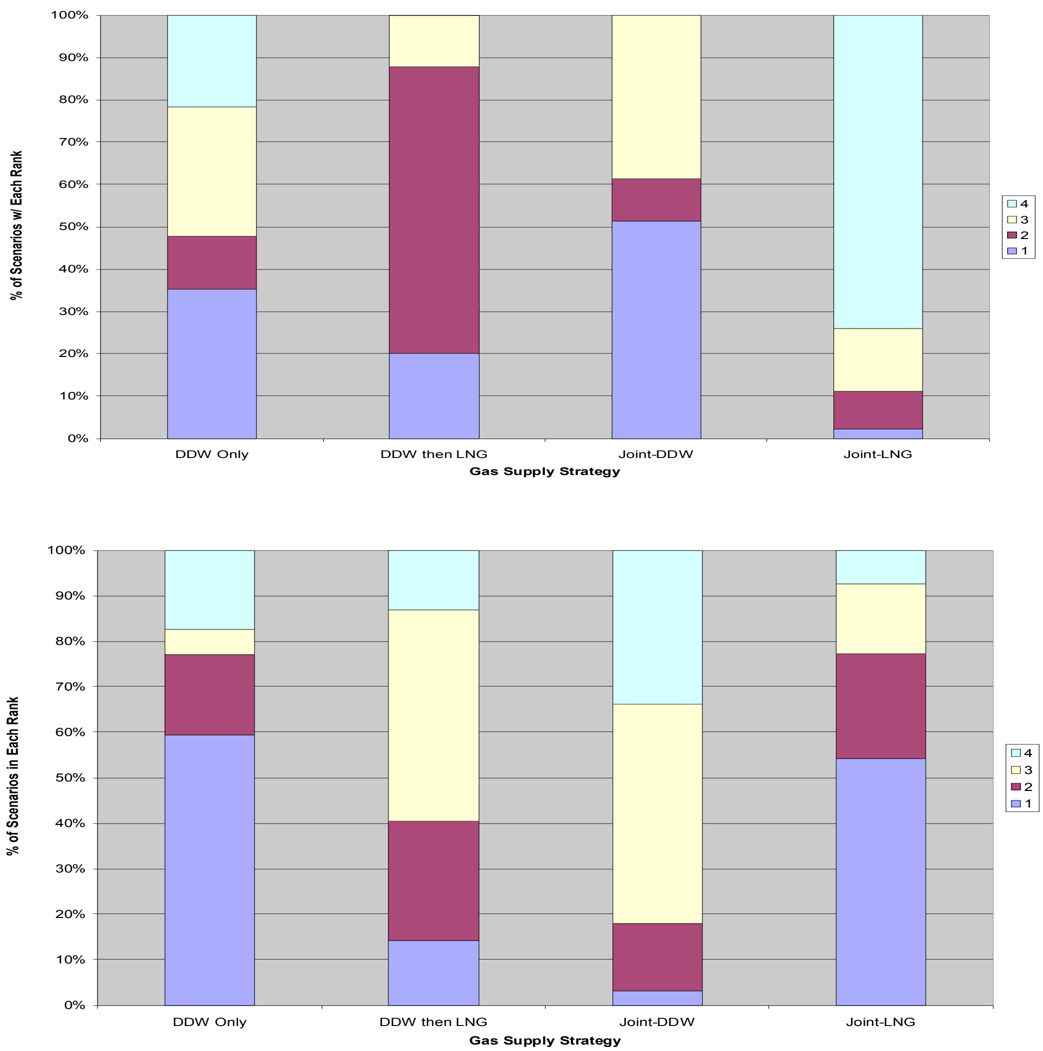
The Key to Supply Robustness

We can take several further steps in the direction of providing analytical support to policymakers at this point. We have suggested that the issue of security for the natural-gas supply is one of risk bearing. It is complicated by an inability to assign meaningful and credible probabilities to the occurrence of a major, sustained supply disruption, whether from intentional or unintended causes. Within the parameters of the analysis we have presented so far, we can address two further questions. If there is a need to actually make use of the supply-security assurance measures built into our supply strategies (e.g., excess capacity, fuel storage, fuel switching on a large scale), how do the strategies compare? And what would one need to believe was true about the likelihood of a major, sustained disruption to motivate a decision to switch from choosing one of the four approaches for erecting a natural-gas supply chain to choosing another?

Figure 7.16 provides a first approach to answer the questions we have posed. The two panels display a variation on the concept of regret, the means by which performance is measured relatively among a group of alternative strategies. This recognizes that, for any particular set of circumstances, at least one of the different approaches to supply will achieve the best result with respect to whatever metric is being used. This time, we use a ranking approach. In the top panel, we compare the total cost of the systems built under different scenarios and assess how often each strategy does the best for a particular scenario and how often it places second, third, and last.[26] It might be best to think of this as the cost of planned supply with the cost of a supply insurance policy included. The bottom panel ranks each alternative in the case that planned supply fails in the manner described in our analysis, requiring that the emergency supply measures must, indeed, be implemented. It ranks the cost of this additional supply alone. To continue with the insurance analogy, this may be thought of as a deductible paid by the insured in the case that the event insured against actually occurs. To come in first among the four approaches in the upper panel is to pay the lowest total cost of natural-gas

[26] We chose this approach because, with the limited information available at this stage (e.g., whether we should model an onshore LNG facility or one offshore), we used wide bands of assumptions, particularly with respect to costs. In addition, the simple algorithm we use in this model is not at all foresightful. The model moves forward with implementing its plan even though a human planner might have taken into account events likely to occur in future periods. Therefore, some of the regret levels are quite high in selected cases. This ordinal approach provides us with insights similar to those we obtained earlier from the more direct assessment but without running the risk of actual quantitative regret measures being unduly influential on current thinking about policy and choices.

Figure 7.16
Percentage of Scenarios in Which Net Present Value Cost Outcomes for Four Supply Strategies Rank First, Second, Third, and Last



NOTE: 1 = lowest cost; 4 = highest cost. The top figure shows the total cost of the system with insurance measures at the planned level of supply. The bottom figure shows the cost of providing unplanned supply in the case of supply shortage.

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supply, including the costs of insurance. To rank fourth is to do the worst. The same holds true in the bottom panel, although, in this instance, ranking is done solely on the basis of the deductible—the actual costs incurred in meeting demand due to a supply shortfall.

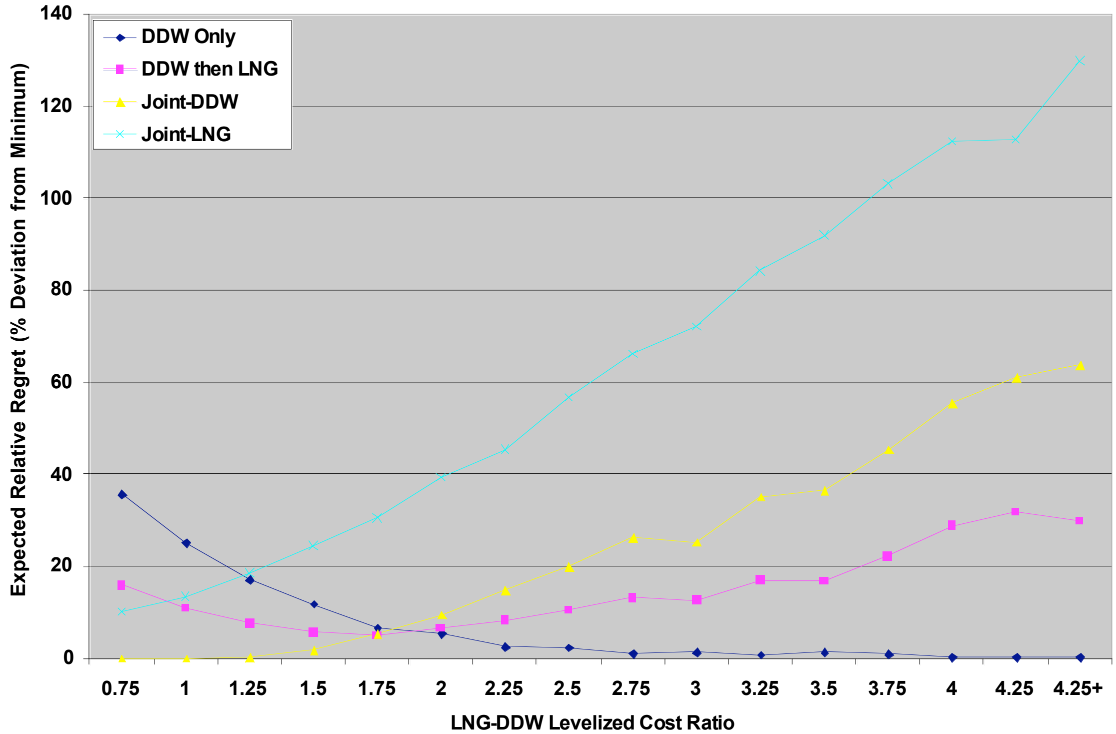
To generate the results shown in the figure, we imposed a one-year shutoff of all supplies through foreign pipeline sources in 2025. This was also the year in which several coal-fired power plants were retired under several of the demand scenarios we used for this analysis. Recall that the test set of scenarios used in this chapter's supply analysis uniformly applies the Gas Rule_Alt (Modified) natural-gas utilization strategy that emerged from looking across the natural-gas utilization scenarios defined in Chapters Four, Five, and Six. Therefore, the supply cutoff occurs under stressing conditions, since we assume the most natural gas–intensive utilization strategy. The trade-off that Figure 7.16 portrays is stark in some cases. Whereas the Joint DDW/LNG (LNG Priority) strategy rarely turns out to be the lowest cost in terms of the total system of supply, it is above the 50-percent mark and places a near second overall when it comes to how often it achieves the lowest cost of providing an alternative supply of natural gas in the case of an emergency disruption. The other form of the Joint DDW/LNG strategy, the one in which natural-gas supply is first drawn from DDW reserves and LNG at first serves primarily as backup and only gradually grows as a source of normal supply, shows precisely the opposite behavior. The most consistent in terms of performance is the DDW Then LNG strategy, which achieves the 20-percent mark both in the number of scenarios in which it provides the lowest system and insurance costs and in the number in which it provides the lowest emergency-supply costs. Interestingly, there are relatively few scenarios in which this strategy places last in terms of emergency cost and none in which it does so in basic system costs.

This analysis is illuminating, but it invites several questions. The first, of course, is the issue of relative magnitude. It is one thing to come in last place under circumstances in which the cost of emergency supply—the deductible in the insurance-policy analysis—is relatively small even at its most costly. It is quite another if this now represents, as it does in several of our test scenario cases, a significant fraction of the total supply and system costs over the full period. The second question brings us back to the issue of probabilities: Under what circumstances should Israel opt for relatively low-cost insurance against an event that may have low probability of occurring, and when should it consider making a more substantial investment in ensuring supply continuity against circumstances that might place great strain on the nation's energy balance and then, perhaps, impinge on its freedom of action in other spheres of activity?

An examination of the relative costs of both the core (normal supply system and backup capacity) and deductible (actual one-year emergency supply) components makes clear that, while the latter may sometimes be of considerable magnitude when compared to the former, what drives both streams of cost is the relative size of the LNG cost premium, the portion of cost that is laid on what is assumed to be a common commodity cost for the natural gas, when compared to that for DDW-derived natural gas. This observation of cases was confirmed by performing the quantitative scenario-discovery methodology already described. Therefore, the core issue becomes less a question of how well each strategy will perform under varying assumptions about the probability of a yearlong supply-disruption event occurring. What distinguishes the four strategies is how well they will perform under varying assumptions about the relative average costs of LNG natural gas compared to gas drawn from DDW reserves across the period.

This point is demonstrated in Figure 7.17. We look across the full set of scenarios obtained by running each strategy against each of 5,000 alternative sets of assumptions about future conditions. For each of the resulting 20,000 scenarios, we calculate the total cost stemming from the supply infrastructure with whatever insurance measures have been included in a scenario, the normal cost of natural-gas supply, and the emergency costs in response to a one-year cutoff from foreign-pipeline supply in the year 2025. These results are then sorted according to the ratio of LNG-to-DDW premium costs that make up part of the assumed conditions for that scenario simulation. Then, within each such $0.25-wide segment of LNG/DDW cost, for each strategy, we average across the total cost values for that strategy when that ratio of prices prevails. From this, we derive an expected relative regret for that strategy when faced by conditions represented by that price ratio. On this basis, we may then answer the question, what would be the expected regret from strategy A if the price ratio were x?

Figure 7.17
Expected-Cost Relative Regret with One-Year Foreign-Pipeline Cutoff of Four Natural-Gas Supply Strategies as Assumptions About the Liquefied Natural Gas/Domestic Deepwater Premium Cost Ratio Vary



NOTE: Because of the wide ranges of assumptions, particularly over costs, that we had to use to frame the analysis, the error bars around each point can sometimes be large. This view incorporates scenarios that include high demand assumptions as well as low. There are also different policy decisions regarding storage being modeled in the group of scenarios whose cost outcomes are averaged at each point. This need for averaging is what causes us to characterize the y-axis as expected relative cost regret. It is still the case, however, that the key drivers of price, demand, and foreign natural-gas pipeline supply tend to move in the same direction for each scenario. Therefore, cases of overlap between the error ranges that we could draw around each point in the graph are less significant than might at first be supposed. If the other key drivers were held constant, these points would tend to shift in the same direction, and the error ranges would decrease.
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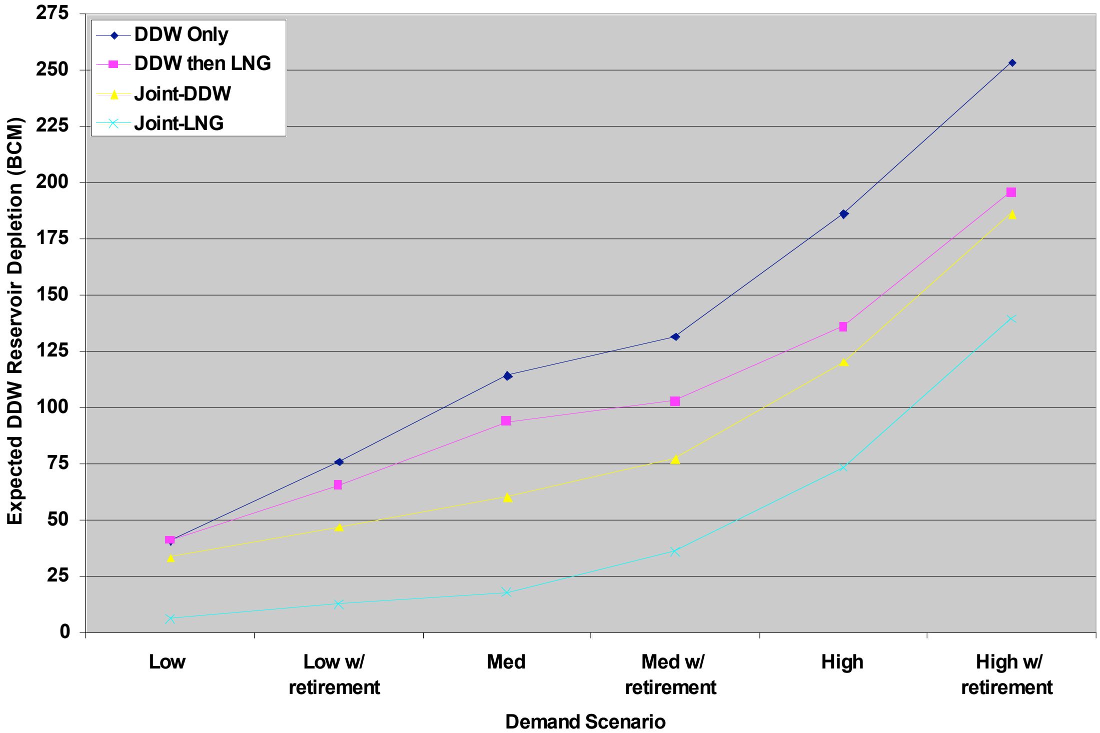
What the figure makes clear is that the choice among different supply strategies in order to minimize expected relative regret depends crucially on assumptions about the relative price ratio of natural gas from the two principal sources we have analyzed. This makes explicit that the choice of one strategy over another is a reflection of what one would need to believe was likely to prove true about this ratio over the period to 2030. If cost were to be the only consideration (and continuing, as we have done so far, in not delving into the details of who and by what means these costs are to be paid), then choosing the Joint DDW/LNG (DDW Priority) strategy would imply a belief that the LNG/DDW cost ratio will be at the extreme lower end on average. On the other hand, opting for the DDW Only approach would require holding the belief (and placing the bet) that this ratio will instead trend toward the high end of the range.

From this perspective, the behavior of the DDW Then LNG strategy is quite interesting. If one had certain knowledge about what the price ratio of interest would turn out to be, there is almost no level at which this would be the optimal (that is, minimum expected cost regret) strategy. If we were to make assumptions or create a best-guess forecast of the likely ratio of fuel-stream prices and then attempt to minimize costs by our choice of strategy, the only one that probably would never be selected—except for a narrow band somewhere in the 1.75–2.00 range—is DDW Then LNG. However, if we truly did not have strong confidence in being able to predict this average ratio over the entire period but instead viewed the likelihood of each value level as being uniform (and we are sensitive to the risk of quite disastrous outcomes), it is DDW Then LNG that suggests itself as a candidate robust strategy. Although it is rarely if ever the strategy that provides minimum cost under the prescribed conditions, it almost always runs second best throughout the range, and its failure tends to be more graceful in terms of cost than the other candidates.

This does not necessarily lead to an endorsement of the DDW Then LNG supply approach for Israel. For one thing, Figure 7.17 shows results for only one particular experiment, a one-year shutoff in foreign-pipeline supply of natural gas. For another, we have looked at issues only of cost. There is also the question of what is passed on to future generations beyond the year 2030 and the potential value of the security that comes from possessing a domestic natural-gas reserve that may be drawn on when need arises, whether stemming from market conditions, regional developments, or unexpected occurrences.

Figure 7.18 encapsulates scenario outcomes with respect to the issue of depletion in a manner similar to the one used for expected relative regret with respect to cost. This time, the question is, to what extent would any DDW reservoir be depleted by 2030 if a given strategic course is followed? Whereas, in the discussion of cost differentials, it was price ratios that proved the key drivers, in this instance, quantitative scenario identification shows that it is the level of demand that proves key. We now look at expected depletion across the range of natural-gas demand scenarios we have selected for the energy supply–security analysis in a manner analogous to the prior example. Several things become clear. First, we see a clear ranking of alternatives with no crossover switching of the type we observed earlier with respect to cost. Second, the cost-versus-depletion metric trade-off we have noted before is made clear when this ranking is compared with the cost trajectories shown in the prior figure. Third, the DDW Then LNG strategy is by no means the most favorable when measured in this dimension. Given the way it is defined, at low levels of demand, it is largely similar to the DDW Only approach. At high levels of demand, it tends toward Joint DDW/LNG (DDW Priority). This shows that, when demand for natural gas is high, the *then* for LNG that is implied in the DDW Then LNG approach comes sooner. This also suggests a certain inherent adaptability in this approach, but it does imply an assumption that there exists a sufficient reservoir of DDW resource and that a somewhat rapid depletion will not cause undue prejudice to Israel's ability to meet its various goals, including passing along to the next generation sufficient means to sustain the economy and society. Once again, we do not show the error ranges around each of the points in the graph because, once again, the principal key driver not shown in this view—in this case, the magnitude of loss of natural-gas supply that would stem from a one-year cutoff from foreign-pipeline sources of supply—tends to affect all the curves in the same direction. One final point is that, most likely, if we were to allow the possibility of utilization strategies other than the Gas Rule_Alt (Modified) strategy implicit in the six representative demand scenarios we have used in this analysis, in the highest-demand region of this figure, the depletion would likely be tempered by the building of a second LNG installation or the construction of a coal-fired plant, depending on other circumstances.

Figure 7.18
Expected DDW Reservoir Depletion of Four Natural-Gas Supply Strategies with Respect to the Level of Natural-Gas Demand (BCM)



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There are several ways in which policymakers could regard results such as those presented in Figures 7.17 and 7.18. The first would be to provide decisionmakers with a description not only of what concrete trade-offs among strategies and outcomes they face but also an understanding of what drives the differences between approaches, where each succeeds and fails, and a means to visualize the dynamic change that would come from adopting different sets of assumptions. More directly, a political decision could be made about priorities among different objectives. Were cost the main concern, for example, a determination could be made about which strategies are the most satisfactory, given differing assumptions about the value of key factors, and we could then look to the issue of DDW-reservoir depletion to select among the remaining candidates. A more quantitative approach could be obtained by weighting the value of different objective measures and then observing the behavior of different strategies with respect to this weighted average as one looked at the alternative assumptions about the possible value of key factors.

The nature of the horizontal axes in these figures also deserves some thought. It may well be that the government would have available—or could possibly obtain—alternative sources of information that might modify the uniform distribution of likelihood that is implicit in the views presented in the figures. Further, some of the factors, such as growth in demand, may be amenable to shaping actions by the government that could be put in place to be utilized if future developments turn in a direction that is unfavorable to a selected strategic course. In addition, governments and their leadership deal not only with the problem of ascertaining facts but also with varying degrees of risk aversion to certain outcomes. If there were a strong aversion to embarking on a potentially high-cost course, this would tend to skew the effective decision space toward one end of the spectrum of choice implied by the full range along the horizontal axis. In the trade-off between cost and depletion, if the latter becomes less of a worry in the face of additional discoveries of recoverable natural gas from domestic sources, the former can be made to weigh more heavily. To the extent that the latter remains a concern, it will probably continue, as in the past, to constitute the major issue with increasing the utilization of natural gas in Israel.

As a final point, we note that, while analytics may help inform a policy decision, in the end, the actual policy will result from political processes, political discourse, and the trade in political capital. This is as it should be. What is valuable about views such as those shown in Figures 7.17 and 7.18 is that they provide a framework for establishing what ought to be the appropriate political trade space. Various constituencies' and stakeholders' interests must be taken into account. But the eventual resolution of these interests into a political course of action may now be informed by illustrating what trade-offs are involved and what compromises ought to be acceptable.

This latter point is true for our analysis of supply and supply security in general. In the analysis in this chapter, we have outlined and demonstrated an approach for weighing the issue of supply security in the decision over how far and in what manner to rely on natural gas in Israel. We have drawn insights and quantified several of the most-important trade-offs to be reconciled. It seems clear, for example, that reliance in the extreme cases on single sources for natural gas raises the possibility of outcomes that would not be acceptable. We have not drawn more-definitive conclusions for several reasons that stem from the same source: Ultimately, the decisions may come only from the policy authorities of the state of Israel, given the set of value preferences they decide to adopt and impose.

Our analysis necessarily had to include quite wide ranges of uncertainty over key assumptions. We have no access to the cost estimates Israeli planners face, proposed construction plans, a few key technical details, or the resolution of commercial issues, such as how costs are to be borne and in what manner passed along to Israel's natural-gas consumers. This is not to say that all of these details currently exist even within the government of Israel. But in the absence of any indications about which variables may weigh most heavily in the nation's counsels or what ranges may safely be narrowed, we were forced to treat all points in the ranges as equally important. Running the same analysis with more narrowing of these ranges—for example, in the choice of discount rate or costs for diesel-fuel storage—would result in more-conclusive findings.

But even if we were in a position to do so, this, too, would not allow us to frame specific recommendations for policy because, in a realm of multiple criteria, the solution would depend, in part, on how different metrics for success are weighted. We have, for example, treated the cost and supply-reserve criteria to be of equal weight and importance. Further, there is the issue of which risks are considered potentially most serious, perhaps for reasons that extend beyond the narrow confines of the nation's energy balance, and what degree of risk bearing or risk aversion the government is willing to accept. Again, the approach and tools we have illustrated in this chapter should be able to provide more-definitive policy implications with the inclusion of input from the planners, analysts, and policy officials of Israel. Within these limitations, we have provided baseline findings that may become a starting point for the type of discussions and policy decisions that only Israel can make for itself.

CHAPTER EIGHT

Conclusions

In the course of this study, we have developed tools and presented initial findings to assist Israel's planners in framing policies for utilization and supply of natural gas that will also be consistent with the larger interests of Israel's people and government. The models, tools, and findings we generated are intended to assist in the observation of the often-complex interactions between a large set of key factors, many uncertain and unknown, and in managing change toward a positive future in the face of these unknowns.

We have taken a rule-based approach to framing adaptive strategies for both the use and supply of natural gas. We have developed test strategies designed to illustrate the result of taking well-defined approaches or applying concrete decisionmaking rules. We then assessed the outcomes against a short list of objectives. This process was designed to discover those elements of such plans that appear to provide robustness to the strategies of which they are a part. Robustness, in turn, enhances the chances of yielding positive results even when confronted with a wide range of plausible future conditions. Many of the trade-offs between strategies and outcomes go beyond technical considerations. They involve policy choices—for example, determining the relative shares of cost-bearing between the current and future generations or deciding between the willingness to build out capacity requiring considerable natural-gas supply and foreign-source dependence and the willingness to accept a higher level of carbon emissions per unit of energy consumed to reduce dependence. Provided with a clear set of preferences that can come only from Israel's government, the analysis we conducted can be calibrated to provide direct support to decisionmakers based on their concerns and preferences.

We have demonstrated the application of these tools to provide an objective, fact-based analysis of whether Israel should shift to large reliance on natural gas, how it might best do so, and what factors would most affect the decisions that should be made in the early stages. We did so from the outside looking in. This has both advantages and disadvantages. It allowed us to approach the decisions that Israel faces with a clean slate, to hold a dispassionate view and employ a sensibility based on experience working with similar questions in other nations. At the same time, it clearly would be advantageous to work directly with Israel's relevant planning agencies on this problem, to receive fuller access to their planning processes and information sources, and to bring greater detail to both the framing of questions and the search for solutions. Our compromise has been to work toward developing an analytical framework that is extensible and that could be easily amplified by further input from those formally charged with the task of planning and developing Israel's energy future. We feel that we have now provided a useful platform for doing so.

In the course of our analyses and interviews, we arrived at several findings. This gave us a unique perspective, but we do not claim that we had available the information possessed by, or access to discussions occurring within, the government of Israel. It is possible that several of our analytical findings would be modified in light of these additional inputs. Therefore, these should be viewed not as conclusive but as indicative findings. They suggest the most-fruitful avenues for Israel's planners to investigate in greater detail using the tools we have created.

The principal inferences we drew from our work are as follows:

- Demand management is Israel's first line of energy security.
- Israel should reconsider its current system and adopt a two-stage planning process for decisions on expanding generating capacity. Israel should use current planning techniques to make decisions on capacity additions through 2015. However, for the period beyond 2015, a new major assessment of future demand and needs should be initiated, as well as processes that will be inherently more flexible and adaptive. In particular, the decision to initiate construction should be separated from the planning process. Steps should be taken now to put that planning process in place.
- Shifting to the use of natural gas on a large scale can be made consistent with meeting goals, such as maintaining economic, human, and environmental well-being, without running excessive risks in such areas as the security of energy supply, provided that appropriate insurance measures are put in place.
- Israel may primarily invest in NGCC power plants drawing supply from the existing foreign pipeline and potential new offshore supplies.
- Israel should take delivery of contracted volumes through its existing foreign pipeline and consider new contracts up to the current physical maximum available, if this natural gas is competitively priced. It should do so even if offshore domestic supplies materialize. This will conserve the Israeli resource and create a means to evaluate appropriate pricing for delivery of the domestically available natural gas. It should not seek to go above these levels of delivery from this source for reasons of supply security and to ensure a wider range of supply sources.
- Israel should prepare implementation (e.g., planning, regulations, site selection, design, contract formats) for an LNG terminal. It may issue tenders to facilitate this preparation but could delay investment and construction until after efforts have been made to exploit newly discovered domestic sources of natural gas.
- Israel needs to maintain a diversified mix of fuels for generating electric power. Despite higher current costs, Israel should also invest in solar-thermal electric power plants or use solar thermal to preheat steam for fossil fuel–fired power plants.
- Israel should review the current administrative guideline on the minimum threshold for electricity generated by coal. Further, the threshold should possibly be expanded to include other indigenously available, relatively secure means of generation, such as solar.
- The Israeli government should regulate the wholesale and retail prices of domestically produced natural gas on the basis of the cost of imported gas and to ensure an attractive rate of return for domestic producers.
- Israel should guard against disruptions in natural-gas supplies by storing sufficient quantities of diesel, not natural gas, to smooth possible future supply disruptions.
- Israel should complete construction of the inland natural-gas supply pipeline, parallel to the existing offshore coastal pipeline, to ensure adequate capacity and system redundancy in case of transmission disruptions elsewhere in the system.

We will discuss these findings at greater length in this chapter.

The analyses we performed could be extended and made more detailed. The principal value this study offers in its present form is an understanding of what constitutes favorable future environments for Israel and, perhaps more importantly, to understand in precise terms what factors would lead to futures that are undesirable in light of Israel's goals and interests. We have demonstrated what actions and means would be to Israel's greatest advantage in achieving an energy future that reduces its people's exposure to vulnerabilities and risks. The following suggestions for the nation's planning process emerge from our analysis:

- Israel's process for planning and permitting is based on individual projects. The planning and permitting is initiated by the intention to carry forward specific construction. Thus, its national energy planning consists of planning and approving a list of specific projects. A planning process based on observation and well-defined priorities and goals and that is advanced by means of rules designed to implement preapproved flexible responses to updates in the available information through monitoring of both domestic and world conditions can provide greater robustness against the uncertainties that Israel faces in several dimensions that are important in its national life. The simple, mechanical rules we used in this study did well enough. Introducing more-sophisticated versions of these rules while adding human foresight and coordination of actions into the mixture should make this finding even truer in practice.
- We have illuminated the detailed characteristics of strategies and actions that can enhance the robustness of Israel's energy plans, specifically with regard to the use of natural gas, when facing an uncertain future. We have quantified the dynamics of various trade-offs that planners face and provided an indication of where well-hedged positions among the various goals and measure of interest may be found.
- Either explicitly or implicitly, three types of information are inherent in our presentation. The first of these are *signposts*. Not knowing what the future may bring, we have analyzed those aspects of future conditions that would present the greatest challenges to specific aspects of the energy-planning process in Israel. We have also sought to understand which values that these factors might take would prove to be of a magnitude to threaten successful outcomes. These signpost factors may be monitored and observed in practice for early indications of conditions that may prove either favorable or unfavorable to outcomes. Table 6.2 in Chapter Six provides an initial listing of potentially troubling developments for each of the utilization strategies we examined. This would be the basis on which a specific set of signpost indicators may be developed. We will make available to Israel's planners the complete database of our findings, only summarized in this report, for more-detailed scrutiny.
- There are two other types of information we have elicited in the course of our analysis. For each strategy we tested, there are situations in which continuing to follow the rules can lead to unsuccessful outcomes if not subject to further modification. Inevitably, during the course of implementation, both hedging and shaping actions will be required. *Hedging actions* are those that provide some level of recourse or insurance against too unfavorable consequences against conditions or surprises the future may hold. *Shaping actions* are those active measures taken to enhance the likelihood that conditions will remain or will become conducive to the plan that is to be followed. In the balance of this report, we call

explicit attention to several measures that would constitute hedging or shaping actions that were implicit in the analysis and tools we have provided.

In the remainder of this chapter, we elaborate on several of the points we have listed here.

Demand Management Is Israel's First Line of Energy Security

The most effective shaping action Israel could undertake is to institute policies that will enhance the efficiency of Israel's energy use, especially for electric power. We examined the consequences of three plausible paths of electricity-demand growth.[1] We found that a large share of the scenarios we generated can meet all of the conditions we established for determining favorable scenario outcomes, yet almost all of the failure scenarios occurred when growth in demand was high (see Table 6.2 in Chapter Six). Even with important new discoveries of domestic natural gas offshore, the amount of this fuel required to meet demand in the most energy-hungry futures raises questions about where the necessary fuel will come from. In addition, the relatively modest criterion for achieving success in controlling emissions of GHGs is very difficult to achieve even for natural gas–intensive strategies under high–demand growth conditions. This criterion becomes almost impossible to achieve for those strategies that envision some further growth in use of coal-fired generation to maintain energy diversity.

Israel is not a very efficient user of electricity or of energy in general.[2] This means that there are potentially meaningful gains to be had for relatively low cost. Greater enhancements would come at greater cost through some combination of public investment in infrastructure (e.g., smart-grid information systems that permit time-of-day pricing and other measures), incentive programs to match private investment, or increasing costs to retail customers. We call attention to the experience of the state of California since the first energy shocks of the early 1970s. Since that time, a variety of measures have kept overall electricity demand level on a per capita basis (see Figure 8.1). With only slight variation, the figure shows that California has had no change in overall per capita energy intensity since the mid-1970s.

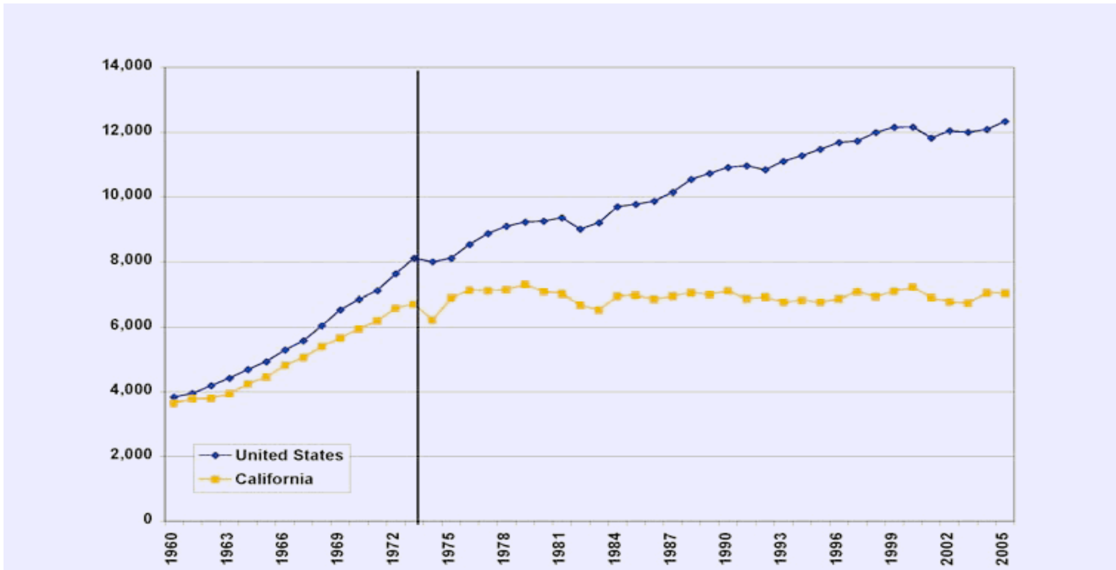
Israel is not California. The gap in economic development between California and Israel remains, although it was greater in the 1970s than it is today. Neither was the flattening of California's electricity intensity necessarily solely due to formal policies. Other factors, such as shifts in economic activities, also played a role. At the same time, California has a similar climate in the main population centers, patterns of economic activity are converging, and, like in Israel, population growth has been rapid.[3] During the period when California's growth in per

[1] The middle range is based on the same assumptions used by IEC as its baseline. Our low-demand path assumes the same level of average GDP growth as the middle range but incorporates more-favorable decreases in energy intensity in services and industry along with a slower rise in residential energy intensity. Our high-demand path follows the same trajectory of change in energy intensities in the various sectors but posits an average of 6-percent growth in GDP versus the 4-percent assumption of the middle path. Our intent was to provide three different patterns of demand that would likely bracket the most plausible range of possibilities to the year 2030.

[2] See, for example, Yehezkel and Robbas (2008) as well as Eco Energy's Israel Energy Master Plan (2005–2025) [in Hebrew] on economic conservation policy (Sverdlov et al., 2003).

[3] In 1970, California's population was 20 million and had reached 33.9 million by the year 2000, an increase of 70 percent (California Energy Commission, 2007). This is less than the 110 percent experienced by Israel in the same period but certainly places it in the same category as locales that have experienced large population gains.

Figure 8.1
U.S. and California per Capita Electricity Demand, 1960–2005



SOURCE: California Energy Commission (2007).
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capita electricity consumption was near zero, during the period 2000–2006, Israel's electricity demand per capita has grown at an average annual rate of 1.3 percent. In the 20-year period from 1971 to 1991, this average rate of growth was 1.8 percent per year. And, during the period of greatest population growth, 1991–2000, not only did population grow absolutely, but electricity use per person increased by more than 6 percent each year.[4]

Some circumstances peculiar to Israel may push up demand—for example, the potential desalination needs that Israel may face—particularly in the face of greater water scarcity with climate change. For any current industrial technology for desalinization, energy equals fresh water. Another is demand from territories under the control of the Palestinian Authority that take deliveries of electricity from Israel's grid. The Palestinian Authority intends to make provision for its own energy supply, but practical considerations make it most likely that present conditions will continue during at least the first part of the period to 2030 regardless of any change in political arrangements. While power delivered to businesses is metered in the areas of the Palestinian Authority, delivery to households is not, for all practical purposes. One consequence of enhanced political stability leading to more economic development in the Palestinian-controlled areas of the West Bank and in Israeli-controlled East Jerusalem has been a sharp upward turn in electricity demand (IEC statistical reports, various years). Clearly, metering and billing according to use would affect demand. However, there may well be local political or practical considerations that would limit the interest of the Palestinian Authority to

[4] These rates were derived by comparing Israel's MNI and IEC statistics on total electricity *supply* with its Central Bureau of Statistics' time series on total population. This leaves a question of how much power was directed toward the Palestinian population in the areas of Gaza and the West Bank. These consumers outside Israel proper are not included in the official tallies of Israel's population. Since these power supplies are included in the total while the consumers of this electricity are not included in the denominator, we expect the intensity statistics to be skewed toward higher values.

see such changes introduced. This, too, could prove a source of upward pressure on the Israeli electricity grid in spite of demand-control and efficiency-enhancement measures that may be implemented in Israel proper.

We can examine the data from our simulations to provide some quantitative indicators of the value to Israel in reducing demand and how much effect doing so could have on matters of interest to both the public and planners. We consider two of the main measures: the PV of total system cost and emission levels for CO_2. For the system-cost metric, we consider three time horizons: 2008 to 2030, and then the two subperiods, 2008 to 2020 and 2021 to 2030, in keeping with our prior analysis. To isolate the effect of changes in electricity demand on system cost and emission levels, we identified scenarios in our simulation database in which the only difference in conditions is the demand for electricity. From these matched cases, we are able to calculate the elasticity of system costs and emission levels with respect to electricity demand trajectories that result in different consumption levels in 2030. These elasticity estimates represent the percentage change in the metric of interest with respect to a 1-percent change in the energy consumption levels in 2030.

Table 8.1 summarizes the results for the WASP and the three modified-form rule-based strategies.[5] The results suggest that all four strategies perform similarly, on average, in this respect, regardless of the time horizon. For instance, based on our mean estimates of the elasticity of system cost between 2008 and 2030, a reduction in electricity demand that results in 1 percent less electricity consumption in 2030 will cause a 0.57- to 0.58-percent decrease in the PV of system cost over the 2008–2030 time period under all the strategies when all other conditions are held equal. As the table suggests, in the 97 matched cases, the 2008–2030 system-cost elasticity tends to vary somewhat, ranging from a low of 0.41 for the WASP strategy to a high of 0.74 for all strategies except the Coal Rule strategy. When we look at the system-cost elasticity estimates for the 2021–2030 period, we see that the elasticity estimates are larger, while the estimates for the earlier 2008–2020 period tend to be smaller.

When looking at the percentage change in 2030 CO_2-emission levels generated by a 1-percent change in 2030 electricity demand, we see that reductions in the rate of electricity-demand growth will have a greatest effect, in terms of the average percentage change, on CO_2 emissions under the Least Cost strategy. Based on the mean estimates for the Least Cost strategy, a 1-percent reduction in 2030 electricity demand will cause emissions to be 0.79 percent lower in 2030. The emission elasticity estimates observed in the data vary considerably, however, ranging from a low of 0.41 for the Coal Rule strategy to a high of 1.25 for the Least Cost strategy.

As is suggested by Table 8.1, all the estimates tend to vary nontrivially in the data, so focusing on the average effect may not be appropriate. That being said, it is interesting to note that the WASP strategy, the one strategy that admits no deviation from the set path, will show less of a system response to drops in demand on average than do each of the strategies designed to operate in an adaptive manner to changing conditions and revealed circumstances. These latter strategies also have a wider range of responses. This, too, suggests that, under active management by Israel's planners, strategies of the form that have been constructed for this analysis—that is, designed for flexible and adaptive response—could be tuned to achieve the more desirable end of the effect spectrum.

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5 For ease of presentation we do not provide the full names of these final form strategies, e.g.: "Gas Rule with Alternatives Modified."

Table 8.1
Percentage Change in Net Present Value of Total System Cost for Varying Periods and of Carbon-Dioxide Emissions in 2030 with Respect to a 1-Percent Change in 2030 Electricity Consumption (based on 97 matched cases)

Elasticity	WASP	Coal Rule	Least Cost	Gas Rule
System cost, 2008–2030, 2030 electricity consumption				
Mean	0.57	0.58	0.58	0.58
Standard deviation	0.08	0.07	0.08	0.07
Minimum	0.41	0.48	0.46	0.46
Maximum	0.74	0.72	0.74	0.74
System cost, 2008–2020, 2030 electricity consumption				
Mean	0.36	0.37	0.37	0.37
Standard deviation	0.05	0.06	0.07	0.06
Minimum	0.27	0.28	0.28	0.28
Maximum	0.45	0.51	0.52	0.51
System cost, 2021–2030, 2030 electricity consumption				
Mean	0.82	0.83	0.83	0.83
Standard deviation	0.11	0.07	0.09	0.08
Minimum	0.57	0.69	0.72	0.72
Maximum	1.07	1.00	1.04	1.11
CO_2 emissions, 2030, 2030 electricity consumption				
Mean	0.63	0.75	0.79	0.74
Standard deviation	0.07	0.12	0.18	0.14
Minimum	0.56	0.41	0.50	0.44
Maximum	0.70	0.98	1.25	1.05

Enhancing efficiency would have a large effect even on the narrower question of the level of natural-gas use for which to plan. *Steps taken to affect this factor of demand are among the highest-payoff actions that the government of Israel could take in the realm of energy policy.*

A Diversified Fuel Mix Enhances Robustness of Strategies—at a Potential Price

In the analysis we presented in Chapter Seven on security of the natural-gas supply, we used the Gas Rule_Alt (Modified) strategy as our test natural-gas utilization strategy. We did so for two reasons. The first, as we had stated, was that, among the natural-gas utilization strategies we examined, through our iterative process of winnowing and modifying, this was the candidate that appeared most to suggest the quality of robustness we had been seeking. The second reason was that this strategy could potentially exhibit among the largest demands for natural gas. It represented a stressing natural-gas utilization test case and so a challenge to the four natural-gas supply insurance strategies we wished to test.

The fundamental thrust of the Gas Rule strategies is that natural gas be made the cornerstone fuel for generating electricity in Israel over the next two decades.[6] In its most detailed final form, this strategy presumes that Israel will adopt policies to enhance the efficiency of electricity consumption. It also presumes that Israel will build the maximum level of renewable (nonfossil) fuel plants consistent with both availability and the underlying economics of doing so. Finally, the strategy embodies a safety valve in the form of an option of switching to a Least Cost–type approach should conditions warrant such a switch. Table 8.2 reproduces a portion of the results we showed in Tables 6.3 and 6.5 in Chapter Six. It compares three adaptive natural-gas utilization strategies, as well as the fixed-form WASP baseline strategy against the criteria we had chosen to assess their performance. As before, the table shows the percentage of scenarios, among all those created by running each strategy, across the full test set of 1,265 future states of the world, in which each strategy succeeded in crossing the threshold required to fulfill minimum criteria for successful performance.

The emphasis on natural gas in the Gas Rule_Alt (Modified) strategy should not be understood in isolation from the rest of Israel's electricity-generation and energy system. Only the heavily modified form of the strategy achieves an appropriate level of apparent robustness. Simply adding natural-gas facilities without other measures could easily be cause for future regret. The final form of the Gas Rule that we examined implies that *Israel should seek a diverse set of primary-fuel types*. Natural gas is present in successful scenarios, but so is coal, diesel for backup and peak generation, and, importantly, as much non–fossil fuel technology as the system can take on, given the realities of cost and availability. This is a point we would like to

Table 8.2
Percentage of Scenarios in Which Each Modified-Form Strategy and the Wien Automatic System Planning Strategy Meet the Metric Criterion Thresholds

Strategy	Cost	Land Use (Relative)	Emissions	Meets All 3 Criteria
WASP	28	4	0	0
Coal Rule_Alt (Modified)	67	31	18	12
Least Cost_Eff (Modified)	99	54	40	27
Gas Rule_Alt (Modified)	94	96	39	36

NOTE: Red indicates that the strategy meets that criterion threshold in less than 10 percent of the scenarios. Orange indicates that the strategy meets that criterion threshold in 10–30 percent of the scenarios. Yellow indicates that the strategy meets that criterion threshold in 31–75 percent of the scenarios. Green indicates that the strategy meets that criterion threshold in more than 75 percent of the scenarios.

[6] They place emphasis on building NGCC power plants for both base and shoulder load generation. In the modified final form of the strategy, there is an option of adding one coal-fired plant if conditions (such as emissions, demand, and cost) warrant, while retaining the option to retire one or two such plants if other conditions prevail. See Figure 6.3 in Chapter Six for a flowchart of the Gas Rule_Alt (Modified) strategy decisionmaking rules.

emphasize: *Implementing policies that maximize both efficiency improvements and utilization of non–fossil fuel alternatives makes as great a difference to final outcomes as any choice of base fuel*.[7]

Accelerating the Use of Non–Fossil Fuel Alternatives Is Especially Critical for Israel

The issue of diversity of fuel types comes up repeatedly in our analyses: Overreliance on any particular fuel enhances the chances that an undesirable constellation of conditions could lead to serious regret across one or several dimensions about which the planners and people of Israel care. This is true for both the utilization (Chapters Five and Six) and supply (Chapter Seven) of natural gas. In contrast to the shaping strategy of increasing energy efficiency, diversification of fuels provides a hedge against potential risk. This hedge may come at a price in terms of other criteria, such as costs and perhaps emissions of GHG, but not necessarily so, especially if Israel may rely more on alternative fuels and energy sources.

Our analysis shows that an indifference to costs when seeking to use renewable fuels may lead to serious failures. Along with high demand levels, programmed investment in non–fossil fuel electricity generation when the objective conditions clearly did not warrant such projects was a major contributor to substantial cost regret. But this is largely an artifact of the deliberately simplistic approach displayed in some of the earlier forms of our rule-based strategies. The planners of Israel are more than capable of detecting the signs that the technology and economics in the market for alternative energy are not fulfilling their hoped-for promise and can establish limits for prudent investment. We find that the risks of failing to exploit the potential of this avenue for building the nation's energy infrastructure are greater than the likely costs of doing so.

Natural gas will be a good fuel for Israel in meeting its needs for the immediate and longer-term future. Our analysis repeatedly shows, however, that overreliance leads to vulnerabilities in several dimensions. Israel must continue to accelerate its exploration of non–fossil fuel alternatives to provide a robust foundation to its renovated energy infrastructure.

Plan for an Adaptive Course

In addition to the individual elements of the Gas Rule_Alt (Modified) strategy, the overall effect is inherently flexible and adaptive. It is this combined property more than any single element that provides it with the means to prevail and be successful across a wide range of future conditions. This suggests a useful approach to planning the construction of Israel's future energy infrastructure.

Planning always relies on basic assumptions. When it becomes clear that these assumptions are no longer valid, plans become subject to review and change. However, gaining consensus that change is required, or even that fundamental assumptions require review, is difficult.

[7] We note in passing that hybrid facilities where solar-thermal energy can be used to produce relatively low-temperature steam that may then be passed into a gas-fired unit is most efficient for use in generating electricity and may be of special importance within Israel. Similarly, the hybrid approach can be extended to ensure supply of electricity at night or in the absence of sufficient sun.

Interests become vested; government bureaucracies may be focused on other, more immediately pressing issues; thorough reviews are timely and costly and chew up agency resources; and the changes that are made may often have more of an ad hoc character than would be desirable under ideal circumstances. We find that Israel's current processes for planning, evaluation, and permitting are too restrictive and do not take fullest advantage of opportunities for adaptive approaches. We recommend that Israel explore how it may be possible to lay out goals and guidelines, criteria for success, and rules for the road as short-term decisions need to be taken. Most important, explicit statements are needed about the indicators that are to be monitored and the basic courses of action that will be taken depending on the values that these indicators may take in the future.

A planning process that seeks to provide both flexibility and utility to Israel should be focused on preparing adaptive changes that may be introduced into actual energy-infrastructure build plans when conditions require them. This involves working to establish criteria for choice and evaluation procedures to apply rather than focusing planning processes on a case-by-case approach for individual infrastructure decisions. This would involve a change in current practice that would separate the acts of planning, evaluating, and even permitting from the actual construction of facilities. Anticipated changes that may or may not be implemented would need to be prepared in advance. To be sure, any one portion or action intended to be part of an overall infrastructure-construction program would need to be considered on its merits taking full account of effects on localities. But it is possible to do so while ensuring that tactical decisions are taken from a strategic perspective.

Adaptive and flexible approaches to planning sound fine in principle. It is not just in Israel that the challenge of doing so in actual practice appears daunting. This is why one principle of our work was to build for Israel the first-generation suite of tools that would allow Israeli planners to do so. It may well be that Israel cannot afford *not* to build some of the key elements of the adaptive approach into its planning systems.

Figure 8.2 illustrates a typical scenario in which a strategy was headed for an unsuccessful outcome. This scenario has as one of its conditions high levels of demand for natural gas. The utilization strategy is one of the simpler, less adaptive unmodified forms we initially examined. Operating under simple rules, the strategy continues to be implemented. While it is not guaranteed that, in actual practice, the trend of increase in natural-gas demand would be as unambiguously clear as in this example, a sophisticated system of signposts and signals could be put in place to warn that natural-gas consumption is following a high-growth trend that had previously been identified as problematic. Such indicators would provide time for corrections to be made. However, this can work only if the necessary plans and expedients—such as building a new, modern, clean-type coal plant—have already been developed. Adaptation is not only a matter of signals; it also entails meaningful and timely response to those signals supported by action-based preparation.[8]

As a practical matter, Israel might do well to consider a two-step approach to its planning for energy. The first step would be to plan for the period to 2015 in a traditional fashion. At the same time, a set of signposts, flexible responses, and archetypal plans could be prepared within a comprehensive planning framework. Then, as 2015 (or a similar target date) draws close, these materials may be used to fashion the plans, policies, and procedures for the fol-

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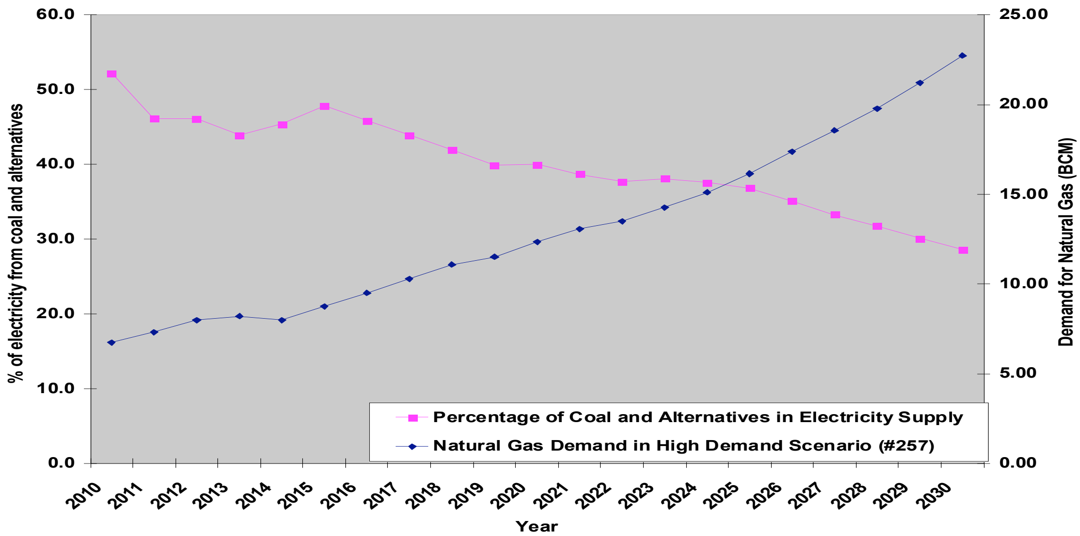
[8] See Figure 6.3 in Chapter Six for a representation of a rule-based adaptive strategy.

Figure 8.2
Demand for Natural Gas and Percentage of Generation from Coal and Renewables, 2010–2030: Feasibility of Strategy Adaptation Under Unfavorable Conditions



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lowing period. This incremental approach can be further divided into smaller time periods as appropriate and comfortable within the planning institutions.

Regulatory Issues Affect Natural-Gas Planning and Are Affected by Analytical Outcomes

We are aware that many decisions over regulatory policy for natural-gas supply and demand are being actively debated within Israel. Our analysis was intended to comprehend large trends and so focused on aggregate outcomes on a year-by-year basis. Deriving more-definitive implications for regulatory issues would require more-detailed analysis and modeling. We therefore offer the following inferences we drew from our work as a guide to what implications our analysis may have for these discussions.

Regulation of Domestic Natural-Gas Production and Pricing

The recent natural-gas discoveries in Israel suggest that domestic natural gas is likely to play a significant role in Israel's energy future. But, because there are few firms with the ability to produce natural gas from domestic reserves, concerns over market power are likely to warrant regulation of pricing by domestic producers. Regulations limiting the way in which domestic natural gas is priced are likely to be important. The price of domestic production should be tied to the cost of procuring gas from international sources and should allow domestic producers to obtain a reasonable rate of return so as to promote their participation in the market and encourage exploration and development of new domestic reserves. In addition to promoting the efficient setting of natural-gas prices, pricing regulation can also ensure that small and large buyers face similar access to natural-gas supplies so as to promote greater competition in downstream markets.

Our analysis also suggests that some governmental input on the rate at which gas is extracted from domestic reserves may be warranted on economic and energy-security grounds. We draw this inference from concern for potential too-rapid depletion at a time when the actual amount of economically recoverable natural gas that may exist in domestic reservoirs is unknown. By law, Israel's Minister of National Infrastructures can require the owner of any gas or oil well in Israel to sell all of its production to Israel. The state may also control the rate of production as it sees fit.[9] While this law does not necessarily lead to the implementation of regulations, there may be good reasons to exert this authority with respect to natural gas.[10] These regulations may specify minimum or maximum production rates as well as the maintenance of minimum reserve requirements by domestic natural-gas producers.

Environmental Regulation

Because natural gas produces less pollution than other fossil fuels when burned, more-stringent environmental policies are likely to promote a shift toward natural gas and other low- or non-polluting forms of electric-power generation. The traditional approach to environmental regulation used by most nations involves the development of regulatory standards, such as requirements for use of renewable-energy sources, without specifically targeting the carbon or other pollutant intensity of different sources. But there are other reasons, not directly environmental, for Israel to consider the desirability of such policies. These include, for example, contributing to a general desire to draw closer to the European Union (EU). To the extent that the energy profile of Israel's economy more closely resembles those of the member states of the EU, this may enhance the chances of achieving this desire and could conceivably be of value more directly if, for example, the EU were to begin assaying the carbon footprint of tradable goods produced or traded within the EU space. Israel has been well served in ways that may be difficult to quantify by an international perception of becoming a leading technological nation. It is difficult to say how this perception may be affected by disparate comparison with the nation's energy infrastructure.

In Israel, as elsewhere, there is debate over whether to adopt and how best to design market-based environmental policies. Among these are proposals to tax fuels based on their carbon content. While economists generally view a carbon tax as the most efficient means of reducing CO_2 emissions, carbon-tax proposals have often faced significant political opposition. While this point continues to be argued, in contrast, most cap-and-trade proposals, such as the EU Emission Trading System, are generally viewed as more politically feasible. They also focus on emissions rather than original carbon content so could enhance the push for sequestration technologies. It is possible that they may actually be less efficient because they usually

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[9] According to Section 33 of the Israel Petroleum Law of 1952, which also applies to natural gas,

> The minister is allowed, after consulting with the Oil Board, to require the owners of the holdings to first provide, at market prices, from the oil they produce in Israel and from oil products they produce from it, the quantity of oil and oil products the minister thinks is needed for Israeli consumption.

The law does have some limitations on the minister's powers, but, in cases of "national security or to prevent waste or to prevent dishonesty toward another [rights] holder," the minister is allowed to overrule these limitations.

[10] These powers may be less dispositive in practice than they first appear to be in theory. There is nothing in the law, for example, that compels the reserve actually to be developed and its products offered for sale if its owner feels that the conditions under which it is forced to do so may be less advantageous commercially than might be the case in the future or with the exertion of some gentle bargaining pressure.

can address only large, stationary emission sources and therefore bypass smaller and mobile sources, but there may be other benefits largely stemming from the creation of market-driven mechanisms for trade and capture of benefits from large efficiencies. Should Israel's electricity sector become more competitive in the future, market-based policies for addressing environment concerns should be among the options considered by regulators.[11]

Land-Use Policy

The integration of natural gas into Israel's energy mix is already well under way. It will continue to require additional investment in new natural-gas production, pipeline, storage, and electricity-generation infrastructure. Limits to natural-gas use are not likely to come from the supply side. The principal supply sources for the period to 2030 may amount to something on the order of 5–10 BCM per year from domestic offshore reserves, conceivably another 8–10 BCM per year in the form of LNG, up to 7 BCM from EMG, and possibly a contribution from the Gaza Marine reserve or from domestic shallow-water sources. Most of these alternatives are still prospective, and some may yet founder on several technical, economic, or practical obstacles once planning for implementation begins. There is also the question of whether drawing on what may be limited reserves at an accelerated rate is in the nation's best interest. But it is clear that, to support the implied level of capital investments in a timely and efficient manner, transparent licensing and permitting regulations should be developed for exploration and production activities and building pipelines and natural gas–powered generation plants.

Perhaps the most important stance that could be taken by those charged with the crucial function of land-use planning in Israel is to recognize beforehand the contingent nature of much of the planning that needs to go forward from this point. There are several evolutionary paths that might be desirable to follow depending on what conditions and needs unfold in the future. In order not only to be in a position to react to these conditions but also to exploit the opportunities they will present, it would be advisable to have ready the means to elaborate on basic preplans and quickly flesh them out in light of the contingencies of the future. This is not the most comfortable of positions in which a planner can find him- or herself, but being in a position to implement once the relevant signposts indicate the direction of needed response appears to be an important capability for Israel to nurture and enhance.

Israel Should Guarantee Sufficient Storage to Smooth Future Supply Disruptions in the Short Term

Several conclusions that we drew from our analyses were different from what we had supposed before we began our efforts. One of these is that Israel can be given the means to ensure that its supply of natural gas will be reasonably secure even as it becomes a major component of the nation's fuel mix. Prudent planning can considerably reduce the risk stemming from fixed sources of supply of natural gas because of the large investments in pipelines or terminals. The fuel mix needs to be carefully tuned with foresight to emerging trends, transitions, and future needs. Israel must have provision for storing standby supplies of switch fuels in amounts that will provide a meaningful cushion against sudden shortfalls in supply. However, the cost of storage need not be made onerous. With coordinated planning of changes in infrastructure,

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[11] In our analysis, we remain agnostic on whether this is done formally as a tax or as part of some more indirect scheme.

such as plant retirements, and more-detailed tuning of supply-security planning than we incorporated in our modeling, a reasonable level of insurance can be achieved at costs that are not likely to prove excessive.

Another presumption that needed to be set aside once we had conducted our analysis was the need for introducing LNG as soon as possible in Israel. The analysis in Chapter Seven suggests that there is a case to be made for deferring the decision on constructing an Israeli LNG terminal until more is learned about other sources of supply and the scale of domestic need. The crucial factor is the relative cost of LNG and natural gas that may be obtainable from domestic deep- or shallow-water sources. Therefore, the appropriate course is partly determined by knowledge or beliefs regarding such costs in the future. These costs could vary considerably with location of any LNG terminal (onshore or offshore), the costs of recovery of domestic reserves, and the developments in the international market for natural gas. Nevertheless, a decision to exploit domestic reserves first and then add LNG when and if it appears that there will be a future need can lead to satisfactory outcomes with respect to cost, depletion, and security of supply under many plausible sets of future conditions. Preparations for the LNG terminal may be made and approved in advance, permitting more-rapid implementation if the relevant signposts indicate that it would be expedient to do so.

Israel needs reasonable levels of standby reserve capacity at power plants and for central storage to smooth possible jolts to the supply system. There must also be means for transportation of both primary and standby fuels. Considering the level of penetration natural gas is likely to make in Israel through the year 2030, *an inland high-pressure natural-gas pipeline needs to be built* to transport the volume of natural gas likely to be required, to provide some degree of redundancy in means for supply, and to provide more capacity for in-line storage. Similarly, Israel should consider how existing or prospective lower-volume pipelines that are part of other systems could provide the necessary switch fuels at time of peak loading or unexpected discontinuities in the supply of natural gas.

These measures constitute important hedges to the strategy of seeking high levels of natural-gas use within Israel.

Review the Future Role for Coal from a Total System Perspective

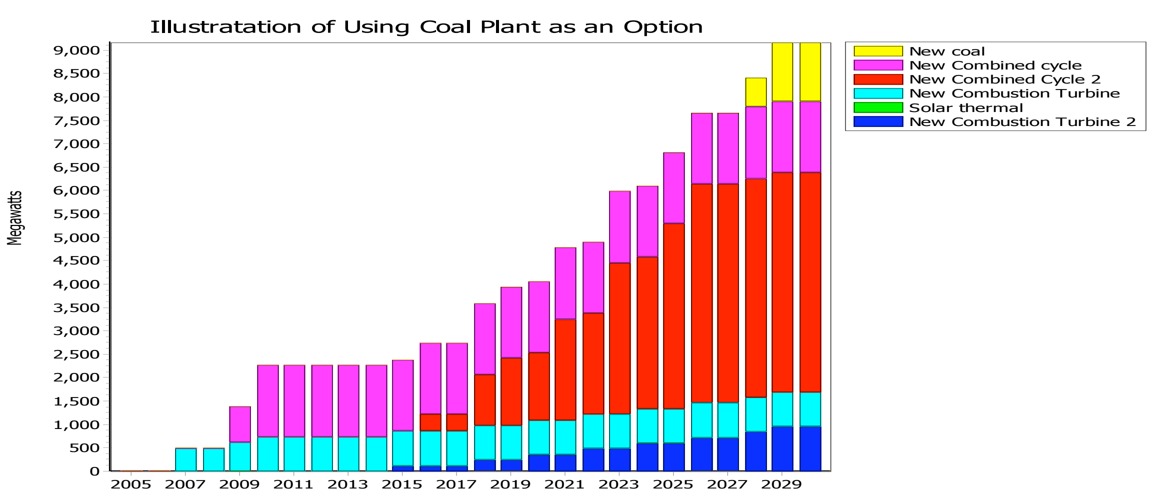
It has been our understanding that Israel currently has in place an administrative guideline that the level of generation capacity supplied by coal-fired plants should not fall below 50 percent. To the extent that we were able to determine the value of this rule in the course of our analyses, we suggest that two amendments be evaluated in more-detailed analyses. From the standpoint of security of energy supply, this administrative rule could be framed to also include the share of non–fossil-fueled generation capacity. These are sources that would be difficult to cut off should unfriendly forces wish to do so and so could mediate those concerns stemming from a national-security perspective. The second change would be a willingness to consider a lower standard if only coal is to be covered by the guideline. Clearly, this would assist Israel in meeting its goals for limiting or reducing its emissions of CO_2 and other GHGs. The question is whether this places the entire electricity-supply system in jeopardy, potentially leading to load shedding, brown outs, or even complete system shutdown in the worst case. As total system capacity increases, the share stemming from coal could decrease without appreciably increasing the likelihood of system shutdown. This, however, is a matter for close consultation between the government, the technical experts at IEC, and other potential electricity providers. There needs to be enough reserve capacity in the system to cover, at a minimum, the catastrophic loss of the largest generation plant. Now and in the foreseeable future, these will be the coal-fired plants providing base load. Nevertheless, as more natural-gas plants come online and as new domestic supplies of natural gas become available and can be made secure to a standard we have discussed in previous chapters, the fraction of generation capacity presented by these plants will decline. We recommend that Israel undertake a detailed study of the questions of how much reserve capacity and of what type may be required. We have developed the tools that would allow Israel's planners to do so.

As an illustration, our database of scenario outcomes included 97 cases in which the option to install a coal plant in 2020 under the Gas Rule_Alt (Modified) strategy is exercised. As a general rule, these scenarios have in common that coal is relatively cheap and that the strategy switches to the Least Cost strategy later in the period. One such case is illustrated in Figure 8.3. It demonstrates how cost considerations might suggest installing more coal capacity at a later date with state-of-the-art technologies. This action might also suggest itself as an expedient in cases in which demand for natural gas requires active management for other reasons.

As with our other findings, this result is more indicative than conclusive. We were not able to examine in detail the potential for load shedding and the resulting consequences in the case of catastrophic loss of base load when a large proportion is to be provided by natural gas. We recommend this as an area for more-detailed follow-up by Israel's planners using the tools we have provided.

We close as we began. In the course of our work, it has been our intent to provide tools not only for beginning the process but also for highlighting those turning points and key factors that could affect outcomes and turn them from less favorable trajectories to those of most advantage to Israel's people and government. It is both our hope that we have done so and our desire to provide the support that can help see the job done.

Figure 8.3
Scenario in Which New Coal Capacity Is Added in Later Period (MW cumulative new installed capacity)



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APPENDIX A

Model Structure and Analytical Framework

This appendix illustrates and describes the functions within the LEAP model (shown in Figure A.1) in greater detail. The actual equations used in the LEAP software to perform its calculations may be found in SEI (undated). Our discussion here details the nature of our use of LEAP to build a model of Israel's energy and power sector.

Major LEAP Modules

Energy Demand

In this analysis, we disaggregate energy demand into three sectors: residential, industrial, and service. Within each of these sectors, the model estimates demand based on primary factors, such as GDP, population, and energy intensity. The figures in this appendix illustrate the calculations for each sector.

Figure A.2 illustrates the demand estimates for the residential sector.

The model estimates residential energy demand by projecting the number of households and multiplying them by the projected energy demand per household. The projected number

Figure A.1
Conceptual Diagram of Long-Range Energy Alternatives Planning Model

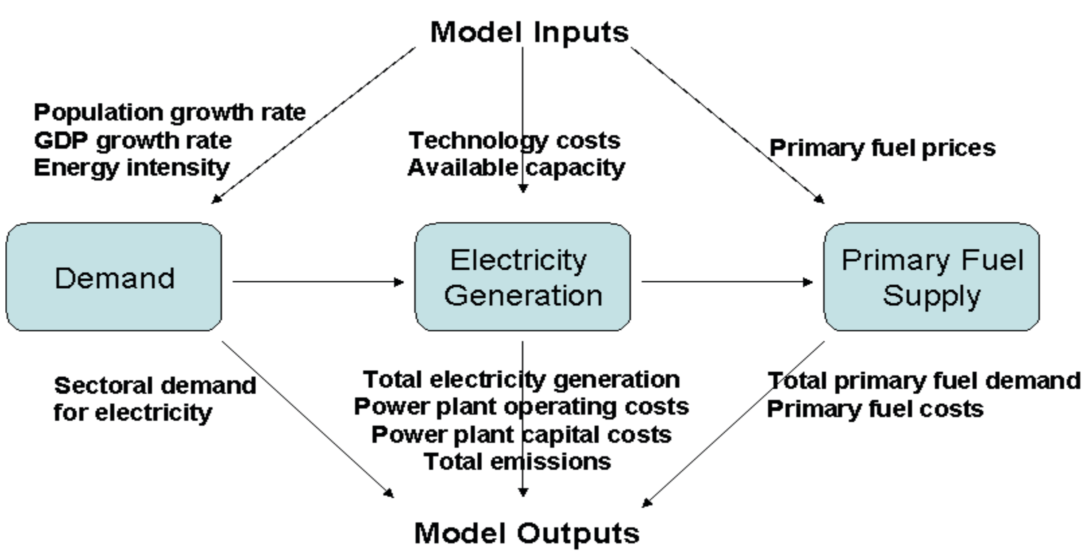

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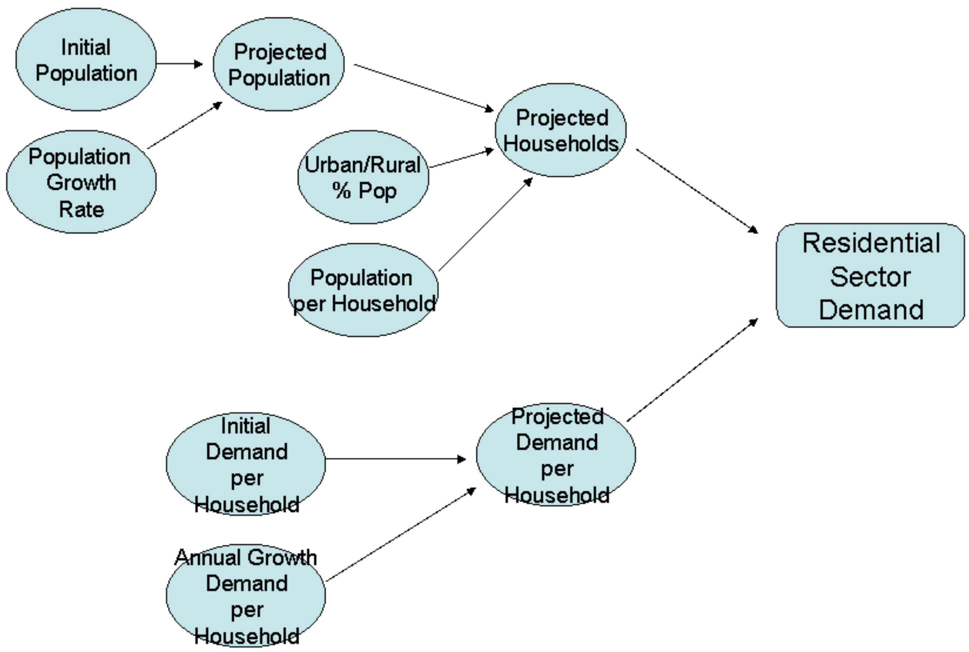
Figure A.2
Influence Diagram of Residential Energy Demand Estimates



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of households in the residential sector is based on projected population, share of urban and rural population, and people per household and uses the following relationship:

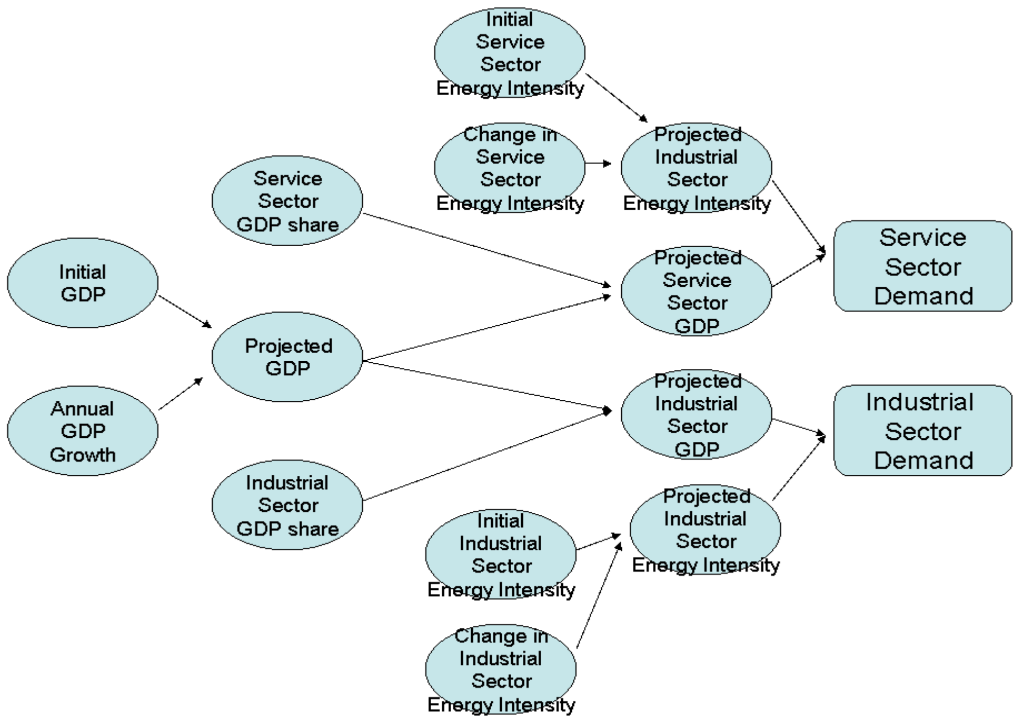
$$\text{total households} = \frac{(\text{total population} \times \text{rural share of population})}{\text{rural persons per household}} + \frac{(\text{total population} \times \text{urban share of population})}{\text{urban persons per household}}.$$

This functional form is also used in the MAED model, and we use data from the Central Bureau of Statistics for the values of rural and urban population share and the number of people per household. The projected demand per household uses the observed value for 2005 based on IEC data and an assumed annual growth rate that is varied in the analysis.

The industrial- and service-sector demand calculations determine demand in these sectors by projecting GDP in each sector and multiplying by each sector's projected energy intensity. Figure A.3 illustrates these calculations.

The estimates begin with projected GDP over the analysis period. We project GDP using observed 2005 GDP and assuming an annual growth rate that varies in the analysis. We then

Figure A.3
Influence Diagram of Industrial- and Service-Sector Energy-Demand Estimates



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estimate the share of industrial- and service-sector GDP as a share of total GDP. Multiplying these values gives the projected GDP for each sector. Following the method described earlier for residential energy intensity, we use observed energy intensity in each sector and assume an annual rate of change to project this value over the analysis period. Finally, by multiplying the projected GDP and energy intensity, we estimate annual electricity demand for each sector. As noted for the residential sector, this model structure follows the functional forms used in the MAED model.

Table A.1 displays the initial values used in the demand module.

Electricity-Sector Module

The electricity-sector module in the LEAP model estimates power-plant dispatch and capacity-expansion planning. This module takes the estimates of annual electricity demand from the demand module, estimates the hourly load in each year, calculates whether the system needs new capacity to meet demand, and simulates the power-plant dispatch used to meet hourly load. Figure A.4 illustrates these components of the power plant–dispatch calculation.

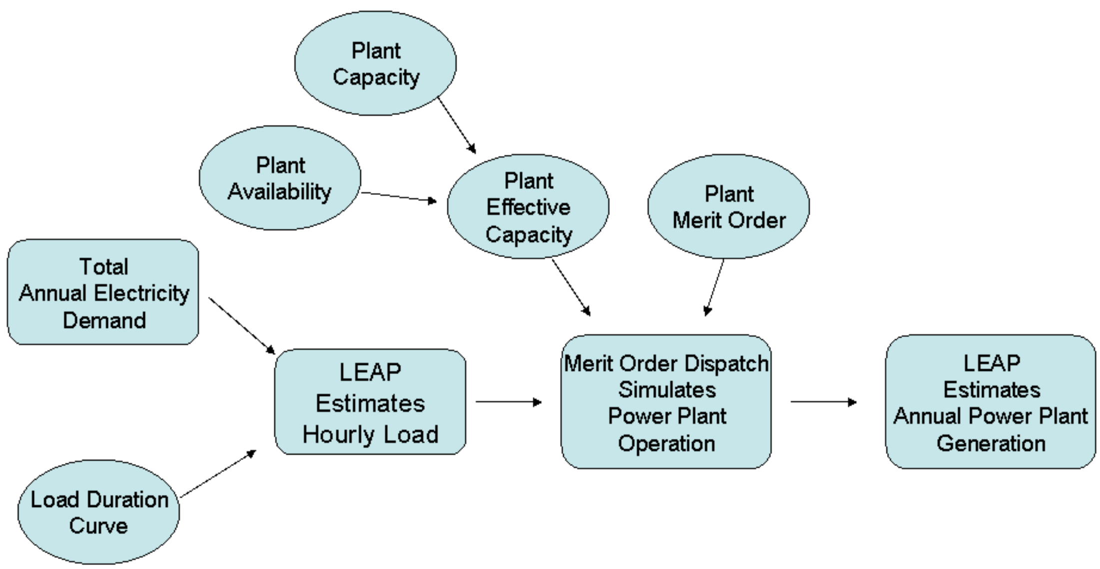
The power plant–dispatch simulation begins with the annual demand estimates from the demand module and an LDC entered by the user. The LDC specifies the distribution of hourly load across all hours in a year. In this analysis, we estimate an LDC with the MAED model because this model contains highly detailed analysis on hourly, daily, weekly, and seasonal variation in demand. Then we use this LDC in the LEAP model. Given the total demand

Table A.1
Initial Values Used in the Demand Module

Measure	Value
Initial population (million people)	6.9
Urban/rural population share (%)	92/8
Persons per household (urban/rural)	3.4/6.1
Residential energy intensity (kWh per household)	7,139
Industrial-sector GDP (%)	25
Industrial-sector energy intensity (kWh/$GDP)	0.64
Service-sector GDP (%)	75
Service-sector energy intensity (kWh/$GDP)	0.137

SOURCES: Central Bureau of Statistics except for residential energy intensity, which came from IEC annual statistical reports.

Figure A.4
Schematic of Electricity-Generation Module: Power-Plant Dispatch



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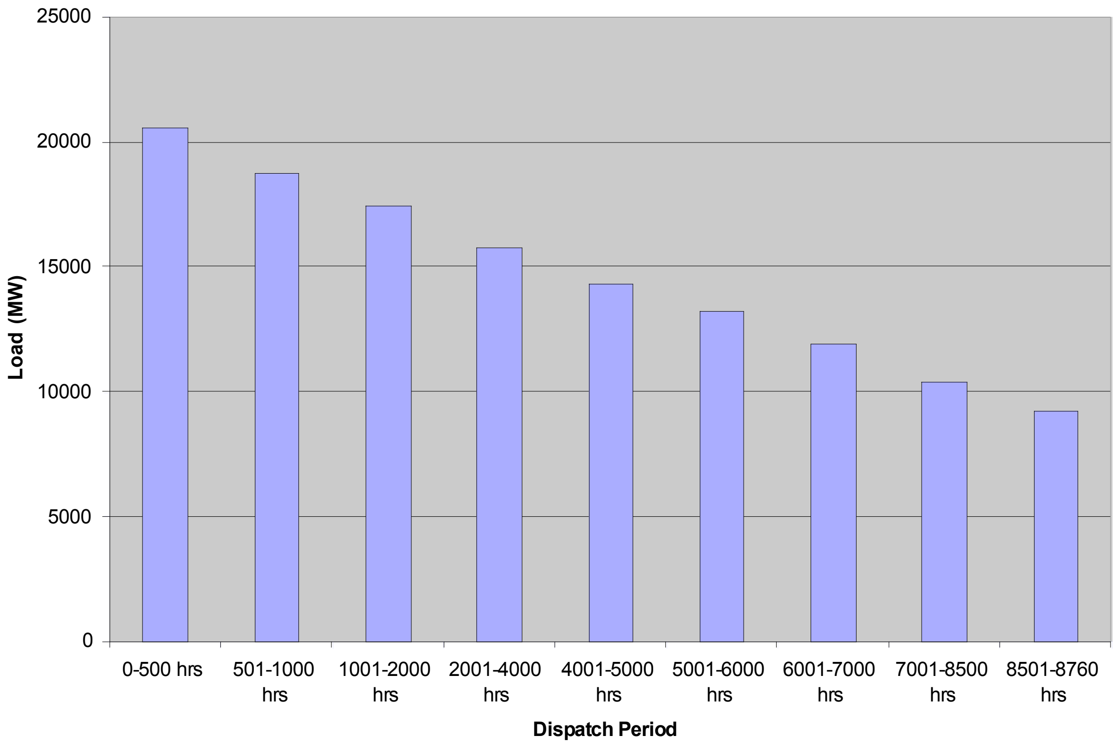
estimate and LDC, LEAP estimates the hourly variation in load for each year in the analysis. Figure A.5 illustrates one example of LEAP's estimated hourly load for 2030.

Figure A.5 shows a discrete representation of the hourly variation in load in 2030 from an alternative future incorporating our medium demand growth assumption. The nine columns represent different levels of load during the year (one nonleap year has 8,760 total hours). The first column represents electricity load during the 500 hours of the year with greatest demand. In this example, for 500 hours in the year, electricity load exceeds 20,000 MW. The second column (hours 501–1,000) is the load during the next 500 hours with the second-highest level

Figure A.5
Illustrative Example of Hourly Load (MW)



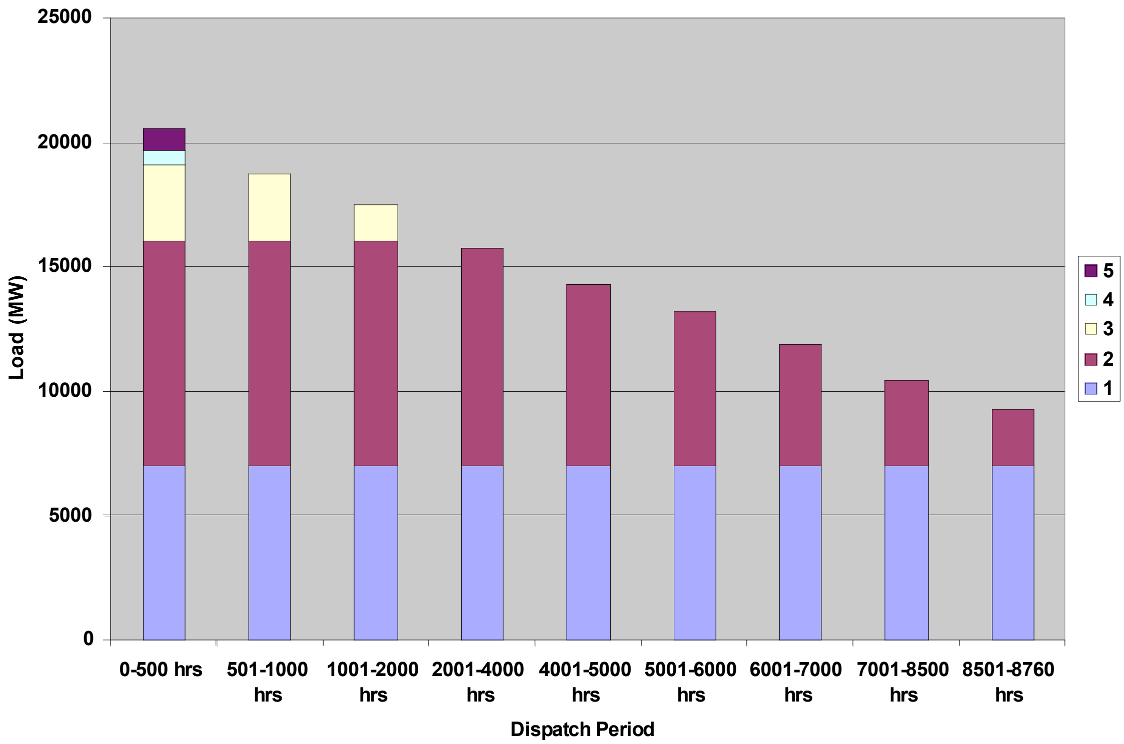
RAND *TR747-A.5*

of demand. The remaining columns show successively lower levels of load and the number of corresponding hours. An important point is that the hours represented within each column are not necessarily contiguous. Israel experiences peak electricity demand on the hottest days of the summer and coldest days of the winter. Therefore, the first column represents hours from both of these peak periods.

The next step of the simulation is to dispatch the power plants in the system to meet demand for electricity over the entire year. In this analysis, we have selected a merit-order dispatch as the simulation method. In this method, the user selects the order in which power plants are used to meet load during each time period. The model uses plants with the lowest merit order to meet load until reaching the maximum capacity of plants with this merit order. The model then uses plants with successively higher merit orders to meet remaining demand. For plants with the same merit order, LEAP uses the plants in proportion to the amount of capacity. Figure A.6 illustrates how the LEAP model uses the merit-order dispatch.

Figure A.6 shows the same level of demand displayed in Figure A.5, but now each column shows the power plants used to meet each increment of demand. Power plants with merit order 1 (depicted by the blue, lowest portion of each column) supply approximately the first 7,000 MW of electricity supply and are operated at a consistent level the whole year. Power plants with a merit order of 2 supply the next increment of supply. In the 2,000 hours of the year with highest electricity demand, these power plants are run at full capacity and at lower capacity during the other periods. The figure also shows that the power plants with a merit

Figure A.6
Illustrative Example of Merit-Order Dispatch (MW)



RAND *TR747-A.6*

order of 3 are operated in only about one-quarter of the hours in the year. Finally, the peak power plants, with a merit order of 4 and 5, operate only in the hours of highest demand.

The merit-order designations aggregate both existing power plants and new capacity added during the simulation. As an overview, existing and new coal plants are in the first merit order. New and recently constructed CC plants have a merit order of 2. Older, less efficient CC plants have a merit order of 3. Israel's older, oil-fueled steam plants that were recently converted to burn natural gas have a merit order of 4, as do new CTs. Finally, the lowest-efficiency CTs have a merit order of 5.

This merit-order dispatch is not the only option for simulating power plants and differs from other simulation models, including the WASP model. Other simulation models, like WASP, use constrained least-cost optimization to simulate power-plant operation. In this type of simulation, the model dispatches power plants based on the lowest variable costs subject to constraints stemming from transmission capacity, emission limits, and other regulatory limits. The LEAP model can simulate plant dispatch strictly on the running (variable) costs of the power plants but does not allow the user to place any constraints on the simulation. When we used this method, we found that the projected generation from each power plant did not match observed values very closely. The model dispatched low-cost power plants for a greater share of total demand than had occurred in actual operation. The merit-order dispatch described here is based primarily on power plants' variable costs and therefore performs similarly to a constrained optimization but requires far less computational effort.

Power-Plant Expansion

As noted in the previous section, a second important function of the electricity-sector module is to estimate additions of new capacity in base-load and peak power capacity. In this analysis, we use several different decisionmaking rules to specify when to make the capacity-expansion decision and how to choose between technologies. The section discussing the particular strategies we analyzed describes these decisionmaking rules in detail. At this point, we describe how the LEAP model makes these estimates in more-general terms.

In each time period, the LEAP model evaluates whether new capacity is needed. In this analysis, we use two different criteria for base-load capacity that vary depending on the investment strategy. The first criterion is when the reserve margin drops below 20 percent. The reserve margin reflects the amount of spare capacity available that is available to be used if an unexpected outage occurs at a power plant within the system. The reserve margin is calculated by the following relationship:

$$\frac{\text{Effective capacity} - \text{peak demand}}{\text{peak demand}}.$$

In this relationship, effective capacity is a power plant's nameplate capacity weighted by its maximum availability, which is the maximum percentage of hours in a year that the plant can operate.

Another criterion used in the investment strategies is the percentage of total generation supplied by natural gas coming through the pipeline from Egypt. Israeli decisionmakers have concerns over this energy supply because it is supplied through a single pipeline that could fail unexpectedly for a variety of reasons.

For peak power capacity, the model uses the share of peak power capacity of total capacity to trigger new investment in peaking plants. The analysis assumes that CTs and pumped-storage plants are used to peak power supply.

In each period, the model evaluates these criteria to determine whether new base-load or peak capacity is needed. Figure A.7 shows this as a decision node. If no new capacity is needed, then the LEAP model simulates power-plant dispatch in that year. If new capacity is needed, then the model decides what type of plant to invest in using several different criteria that vary depending on the investment strategy.

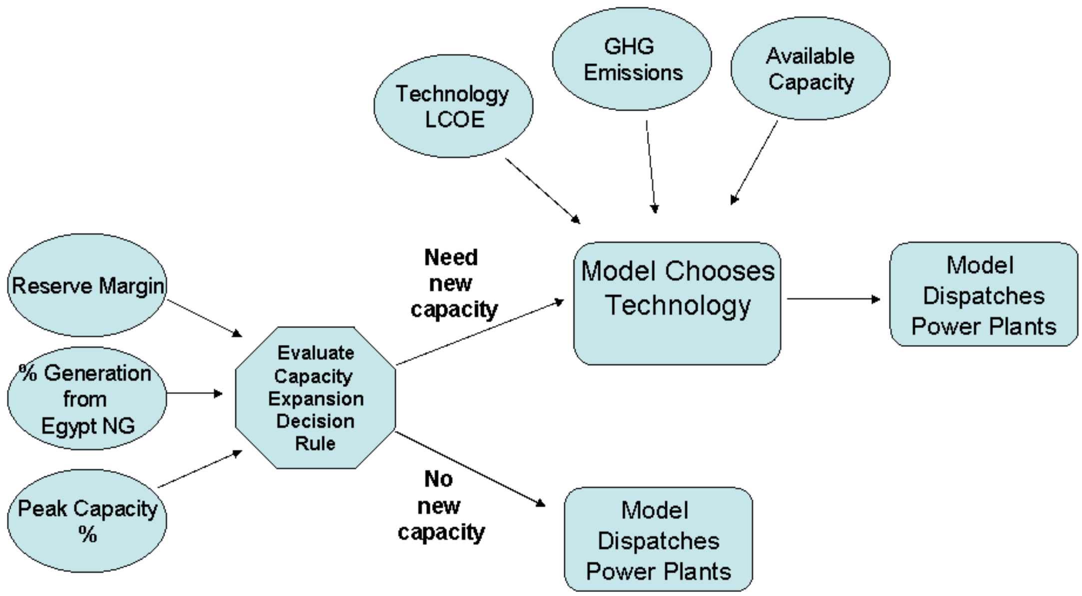
For base-load capacity, the model can consider the LCOE of the different technologies, potential limits on certain technologies based on emission limits, and limits on the total availability of certain technologies. For peak power capacity, the model considers the LCOE of each technology and limits on the availability of pumped storage.

Finally, after adding new capacity based on the decisionmaking rules described in the section on strategies, the electricity-sector model simulates power-plant dispatch.

Transmission and Distribution

The LEAP model contains a module (excluded from Figure A.4) to account for transmission and distribution losses. The total losses are set at 4 percent, which is based on observed values from the IEC Statistical Report (2007).

Figure A.7
Schematic of Electricity-Generation Module Plant-Expansion Decision Criteria



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Primary-Fuel Demand

After estimating annual generation from each power plant, the LEAP model calculates primary-fuel demand. Figure A.8 summarizes this calculation.

Figure A.8 shows that LEAP uses the annual generation of each plant, its fuel share (some plants can use multiple fuels), plant heat rate (energy consumed per kWh of electricity produced), and primary-fuel energy content (energy per unit of primary fuel). LEAP estimates the primary-fuel demand with the following relationship:

$$\text{Plant generation} \times \text{fuel share} \times \frac{\text{plant heat rate}}{\text{fuel energy content}}.$$

Plant generation is an output of the plant dispatch, while the remaining factors in this calculation are assumptions in the analysis. The conditions under which RAND was granted use of the detailed data on individual generation facilities in Israel precludes us from displaying the assumed values for all of the power plants in the analysis.

Finally, the relationship estimates fuel demand for each power plant. LEAP aggregates demand across all of the power plants and primary-fuel types for each year in the analysis.

Pollutant Emissions

The LEAP model estimates power-plant emissions using plant emission factors for each power plant and pollutant. The emission factors reflect the amount of pollution per kWh of electricity produced in each power plant. Figure A.9 shows components of the emission estimates.

Figure A.8
Schematic of Electricity-Generation Module: Primary-Fuel Demand

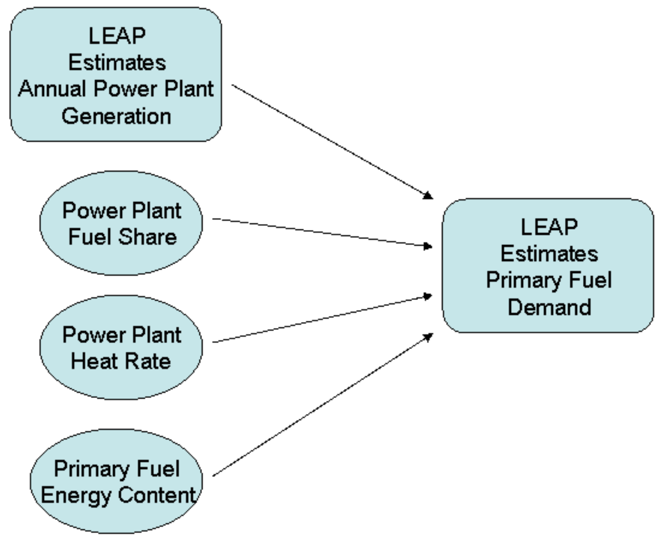

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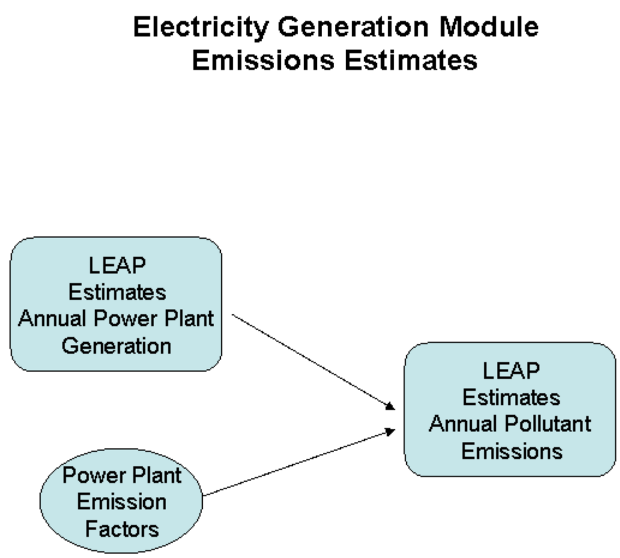
Figure A.9
Schematic of Electricity-Generation Module: Emission Estimates



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Again, LEAP uses the power-plant generation estimates from the plant dispatch calculation and multiplies these values by the power plant's pollutant-emission factor (pollutant emissions per kWh of electricity produced). The pollutant-emission factor is an assumption in the analysis. We use observed values for existing power plants based on data obtained from IEC through the MNI. For new plants, we use estimated values for each technology, and these data were also supplied by the MNI based on IEC data. Due to the conditions to which we agreed for their use, these are data that we are not at liberty to display.

Electricity-Sector Investment Strategies

The analysis assesses seven different investment strategies for the electricity sector. The strategies fall into four different general categories that we named WASP, Coal Rule, Gas Rule, and Least Cost.

WASP Strategy

This strategy corresponds with the projected investment path given by the WASP model described earlier when using the MNI's cost and demand assumptions. One of the key results in this projection is the addition of three new coal plants. This strategy adds a coal plant in the three following time periods: 2014–2015, 2021–2022, and 2027–2028. The total capacity of new coal plants is 3,780 MW (in MNI's assumptions, one coal plant has a capacity of 1,260 MW). The WASP strategy also adds 1,400 MW of pumped-storage capacity beginning in 2018. The remaining new capacity used to meet growing power demand is a combination of CC plants fueled by natural gas and CTs used for peak loads. The model adds new CC capacity to maintain a reserve margin of 20 percent and increases CT capacity to maintain peak-load capacity at 20 percent of total capacity.

Coal Rule Strategy

Among our four basic strategy types, Coal Rule–type strategies are similar to the Gas Rule type. The primary difference is that, when there is a need for new generation capacity, the Coal Rule strategies add new coal facilities if the fraction of electricity generation from coal and solar-thermal power plants supplied with natural gas from the Egyptian pipeline falls below 50 percent. This decisionmaking rule reflects a current regulation in Israel limiting natural-gas use. The rule limits natural-gas use from this single source because of concerns over grid stability. If the fuel source for a majority of Israel's plant capacity was disrupted unexpectedly, then system operators may need to shut down power plants, causing large-scale blackout, or risk potentially serious damage to the electricity grid. Furthermore, this rule also reflects the belief among some decisionmakers in Israel that relying on a single country for such a large portion of the country's energy supply is inherently risky.

In this analysis, the Coal Rule strategy applies this 50-percent rule to building new coal plants but adds two conditions. If GHG emissions exceed a user-specified limit, then Israel suspends building new coal plants. Furthermore, if the cost of a new CC power plant is less than that of a new coal plant, then a new CC plant is built until the fraction of Egyptian-supplied natural gas–based generation reaches 60 percent.

The first condition applied in this rule reflects potential climate-change policies enacted in the future similar to a policy enacted in California Senate Bill 1368. This legislation required that all new power plants built have lower GHG emissions than a CC power plant fueled by natural gas. This legislation essentially prohibits building new coal power plants in the state.

The second condition reflects potential scenarios in which relatively low natural gas prices result in lower electricity costs for CC plants than for coal plants. Under these scenarios, the Coal Rule strategy allows additional gas-fired generation and reflects the concerns that decisionmakers and the public may have in building coal plants when a lower-cost option is available.

A third component of the Coal Rule strategy is the availability of alternative-energy sources and energy efficiency. This analysis assumes that two alternative-energy sources are potentially available in the time frame of the analysis: solar-thermal plants and pumped storage. Solar thermal is assumed to have six hours of storage capacity and would produce during the daytime along with other base-load technologies. Pumped storage is used to supply power during peak periods and competes with CTs. The analysis assesses one strategy excluding these options and a second including these options. An important point is that, under this strategy, alternative-energy sources are built when they are available and the analysis varies the cost and potential available supply.

Energy efficiency is treated differently. In each year, the government can invest in demand-reducing efforts that are cumulative over the analysis period. The government invests in these measures if they cost less than power from a new CT. Over the entire analysis period, a cumulative savings of 20 percent is available if the government invests in demand reduction in every year. In the analysis, we vary the costs of energy efficiency. This approach has the advantage of an aggregate, simplified approach to modeling the use of energy-saving technologies. A highly disaggregate analysis of individual demand-reduction technologies applicable to the Israeli market was not available and was beyond the scope of this analysis. However, as the results of this analysis show, it would be highly valuable for future energy policymaking in Israel.

Finally, the Coal Rule strategies maintain the reserve margin and peak capacity conditions for investing in new CC and CT capacity. We apply these conditions to all the strategies.

Gas Rule Strategies

The Gas Rule strategies use the reserve margin and fraction of peak power capacity to add new capacity. When the reserve margin decreases below 20 percent, the strategy adds natural gas–fueled CC capacity. The strategy adds natural gas–fueled CT when the share of peak power plants declines below 20 percent of total capacity. Both Gas Rule strategies include an option to build a coal plant in 2020 if the LCOE of a coal plant is less than the LCOE of a CC plant.

The strategy including alternatives and efficiency adds solar-thermal and pumped-storage capacity up to the maximum amount available. The maximum amount available is treated as an uncertainty in the analysis. Energy efficiency is treated the same as in the other strategies. If the cost of demand-reducing measures is less than the LCOE from a natural gas–fueled CT, then the strategy invests in the measures that, in aggregate, can decrease electricity demand in 2030 by 20 percent.

Least-Cost Strategies

These strategies follow rules for triggering investments in new plant that are the same for the Coal Rule and Gas Rule strategies. As the name implies, however, this rule is agnostic as to which type of plant to build. Its sole criterion is to build a plant with the lowest LCOE among coal, gas, and, if made available under the conditions set by scenario assumptions, solar thermal (with pumped storage). There are two basic versions of Least Cost, according to whether the strategy may also invest in efficiency improvements according to the criteria already described for the other strategies.

Table A.2 summarizes each of the strategies and the components within them.

The expansion criteria refer to the criteria used to invest in new capacity. The reserve-margin criterion adds new base-load capacity when the reserve margin declines below 20 percent. The gas percentage adds new coal capacity if the fraction of electricity generation supplied by coal and alternative energy sources declines below 50 percent. The GHG-limit condition limits building new coal plants when GHG emissions reach a constraint that is varied in the uncertainty analysis. The component for alternatives and efficiency add these resources as an option. In the Coal and Gas Rule strategies, alternatives are automatically added in the strategies with this component. With the least-cost strategies, the decision to add alternatives is still based on their costs. The decision to invest in efficiency depends on their costs in all of the strategies including this option.

Modified Strategies

Table A.2 also reflects the fact that, after several iterations of the analysis, we added several components to a set of strategies noted as modified. We made the revisions to improve the performance of each of the three best-performing strategies of the previous vintage according to the multiple criteria used in the analysis. The first revision involved making the decision to invest in alternative technologies in the Coal Rule and Gas Rule strategies based on cost competitiveness. In the revised strategies for the Coal Rule and Gas Rule, solar-thermal capacity

Table A.2
Summary of Electricity-Sector Investment-Strategy Components

	Components			
Strategy	Expansion Criteria	GHG Limit	Alternatives and Efficiency Available	Coal-Plant Retirement
WASP	Reserve margin			
Coal Rule	Gas percentage, reserve margin	Yes		
Coal Rule_Alt	Gas percentage, reserve margin	Yes	Alternatives, efficiency	
Coal Rule_Alt (Modified)	Gas percentage, reserve margin	Yes	Alternatives,[a] efficiency	
Gas Rule	Reserve margin			
Gas Rule_Alt	Reserve margin		Alternatives, efficiency	
Gas Rule_Alt (Modified)	Reserve margin		Alternatives,[a] efficiency	Yes
Least Cost	Reserve margin	Yes	Alternatives[a]	
Least Cost_Alt	Reserve margin	Yes	Alternatives,[a] efficiency	
Least Cost_Alt (Modified)	Reserve margin	Yes	Alternatives,[a] efficiency	Yes

[a] Decision was based on cost competitiveness.

is built when its LCOE declines below the LCOE for a natural gas–fueled CT. This criterion was set on the assumption that CTs will be the marginal resources during a large majority of the periods when solar-thermal plants produce electricity. This change was made to improve the cost performance of these strategies. In the prior versions, they added capacity from solar-thermal plants up to a capacity limit without consideration of relative costs.

An additional revision to the Least Cost and Gas Rule strategies was the option to retire the existing coal power plants if they become uneconomical. In scenarios in which the operating costs of the existing coal plants exceed the LCOE of NGCC plants, the revised strategies will retire the plants. In the scenarios, the situation occurs only with the highest–CO_2 price scenario and relatively low natural-gas prices. The model is programmed to allow this option first at one of the Orot Rabin coal plants, beginning in 2020. Then, the option to retire the Ruthenberg plant becomes available in 2025. The options were separated into two different periods to avoid triggering the unlikely event of retiring all of the existing coal-plant capacity at the same time.

A final revision applies to the Gas Rule strategy. This revision allows the Gas Rule strategy to deviate from its initial path and follow the Least Cost strategy when the relative costs of following the Gas Rule strategy exceed a specified threshold. The goal of this revision was to reduce the number of scenarios in which the costs of the Gas Rule strategy exceed the 5-percent regret threshold used in the analysis on the cost objective. With the revision, the Gas Rule strategy will switch to follow the Least Cost strategy when the LCOE of NGCC plants exceeds the LCOE of a new coal plant by 30 percent. This trigger was set after observing in earlier results that the scenarios with high relative costs for the Gas Rule strategy are scenarios with significantly higher costs for CC plants than for new coal plants.

Computer Assisted Reasoning System Environment

The CARs software automates the running of simulations in the LEAP model. CARs varies the input values to the LEAP model, runs a simulation, and then records the outputs. After running the number of simulations specified by the user, CARs maintains the input and output values in a database. The runs are automatically scheduled with the user first describing an experimental design or a type of visualization that is desired.

Table A.3 shows the input values used in the model simulations.

Outputs

LEAP creates a complete set of output data on an annual basis. These data are presented in great detail. When using CARs to drive multiple successive runs of LEAP, we could, in principle, collect all the partial outputs. As a practical matter, this would have vastly increased individual model run times. We chose, therefore, to limit the set of output variables we collected in the CARs databases that were produced as a result of the compound computational experimental simulations we ran using LEAP. Table A.4 describes the outputs.

Specifications of Alternative Conditions Used in the Analysis

In the uncertainty analysis, for each of nine uncertain variables that we determined most affect Israel's future electricity system, we specified a set of three different alternative assumptions (four, in the case of one variable). The nine uncertain variables are coal prices, natural-gas

Table A.3
Input Variables for Long-Range Energy Alternatives Planning Model

Variable Type	Variable	Description
Energy price: We define a projected price path for each fuel using two line segments: (1) from the current period to 2015 and (2) 2015–2030. Initial (2005) price taken from MNI electricity-sector data.	2015 coal price	Specifies the price path for coal from the initial period to 2015.
	2030 coal price	Specifies the coal price in 2030 and defines the second segment of projected coal prices, 2015–2030.
	2015 EMG natural-gas price	Specifies the price path for natural gas from the initial period to 2015, assuming domestic (e.g., Yam Tethys) sources and existing EMG pipeline.
	2030 EMG natural-gas price	Specifies the natural-gas price, delivered to the terminal, in 2030 and defines the second segment of projected natural-gas prices, 2015–2030.
	2015 2nd-source natural-gas price	Same as for EMG price but sources assumed to be either LNG or DDW reserves discovered in January 2008. Includes a variable for the amortized costs of an LNG plant or extraction and pipeline facility for DDW reserves.
	2030 2nd-source natural-gas price	Same as for 2015 but for 2015–2030.
	2015 diesel price	Same as for coal and natural gas but for diesel fuel, for 2015.
	2030 diesel price	Same as for 2015 but for 2015–2030.
	CO_2 price	Specifies the price of CO_2 emissions in 2030. The model introduces this tax in 2010 and increases it linearly until the final value in 2030. It increases the cost of fossil fuels proportionately to their emission intensity.
Power-plant technology costs: Each technology has an initial cost based on estimates obtained from IEC through the MNI, then annual cost change describes costs over the analysis period. A separate path for energy efficiency includes demand-reducing technologies for residential, commercial, and industrial sectors.	Coal-plant initial cost	
	Coal-plant cost, % change	
	CC-plant initial cost	
	CC-plant cost, % change	
	CT initial cost	
	CT cost, % change	
	Solar-thermal plant initial cost	
	Solar-thermal plant cost, % change	
	Pumped-storage plant initial cost	
	Pumped-storage plant cost, % change	
	Efficiency initial cost	
	Efficiency cost, % change	

Table A.3—Continued

Variable Type	Variable	Description
Energy demand: First estimates annual electricity demand (economic activity x energy intensity [which is number of households x household demand]), then uses LDC to estimate hourly load.	GDP growth	Uses observed GDP in the initial period based on Central Bureau of Statistics data. Defines annual growth in GDP over the analysis period.
	Population growth	Uses observed population in 2005 based on Central Bureau of Statistics data, then varies future population growth. Changes annual rate of growth in population.
	Industrial-sector energy intensity, % change	Ratio of industrial-sector GDP per unit of electricity consumed. Uses the observed value based on data from Central Bureau of Statistics and varies it based on a long-run annual percentage change.
	Service-sector energy intensity, % change	Same as industrial-sector change but for service sector.
	Residential-sector energy intensity, % change	Annual household electricity consumption. Uses an initial value from IEC observed data, then varies using an annual percentage change.
Alternative energy: Varies availability of solar-thermal and pumped-storage plants	Pumped-storage plants	Individual plants are assumed to have 200 MW of capacity; up to 9 plants available by 2030. Values based on MNI data used in the WASP model.
	Solar-thermal plants	Individual plants are added incrementally, with maximum of 4,000 MW of capacity. Values drawn from IEC and MNI data and solar-power experts in Israel.
Financial	Discount rate	Set constant at 5%

prices, CO_2 prices, fossil-fuel technology costs, alternative-energy technology costs, energy-efficiency costs, alternative-energy capacity, energy demand, and GHG limits. The scenarios selected for the analysis cover a wide range of the uncertainty for each of the variables. The following section describes each of the specifications.

Coal Prices. The coal-price scenarios start with the price of coal in 2005 at $4.01 per MMBTU, delivered. This is based on IEC data. The three scenarios cover different paths for the future price of coal delivered to power plants in Israel:

- constant price: Real prices remain constant at IEC projection of $4.01 per MMBTU.
- peak: Prices rise to $6 per MMBTU in 2015 and decline to $4 by 2030.
- steady increase: Prices rise to $6 per MMBTU in 2015 and $8 per MMBTU in 2030.

In the first case, real coal prices remain constant over the analysis period and represent a scenario in which world coal supply keeps pace with long-term demand. In the second case, in which coal prices peak in 2015 and decline, the scenario corresponds with a future in which near-term coal demand grows faster than supply, and, by 2015, long-term supply can match demand. This scenario could occur if nations that are significant energy consumers continue to

Table A.4
Outputs from Long-Range Energy Alternatives Planning Model

Output	Description
Power-plant costs	Annual O&M costs (based on MNI estimates) and amortized capital costs (uncertain) for each power plant in the model.
Fuel costs	Annual costs of primary fuels consumed to produce electricity. The model calculates this output based on estimated fuel consumption and the price of each primary fuel.
Energy-efficiency costs	Annual costs of efficiency programs used to reduce electricity demand. They are the product of total electricity savings and the price of efficiency.
Unmet electricity demand	Any unmet electricity demand for each hour in the simulation.
Annual peak demand	Uses projected total annual demand and a user-defined system LDC.
Reserve margin	Estimated as (effective capacity [which is nameplate capacity x plant availability] – peak demand)/effective capacity.
GHG emissions	Estimated for each plant using estimated emission factors from MNI data.
Primary-fuel requirements	Total annual natural-gas demand met through deliveries via the existing natural-gas pipeline from Egypt and through natural gas from potential new sources, as well as other primary fuels.

use coal for a considerable portion of their demand in the near term but a competitive alternative reduces demand over the latter portion of the time horizon. In the third case, coal prices rise steadily over the entire time period. This scenario represents a future in which coal demand grows consistently more quickly than supply, resulting in increasing prices. This scenario could occur if coal liquefaction becomes competitive with other liquid fuels or if carbon capture and sequestration becomes a competitive technology to reduce CO_2 emissions. In these situations, coal's value as an energy source to produce electric power and transportation fuels increases because technologies exist to mitigate its GHG emissions and it becomes a viable alternative to petroleum-based transportation fuels.

In EIA's 2008 AEO, delivered coal prices in 2008 are $1.88 per MMBTU. In the reference case, the price of coal declines slightly to $1.82 per MMBTU in 2030. In the high-coal-cost case, delivered coal prices in 2030 are $2.76, which is approximately a 50-percent increase over the time period. In the low-coal-cost case, they decrease to $1.29 per MMBTU, which is a decline of more than 30 percent. In our scenarios, the steady-increase scenario assumes a higher percentage increase in the delivered price of coal to account to a future in which coal prices rise higher than most analysts project today. The remaining scenarios either hold the price of coal constant or show prices returning to current levels after rising.

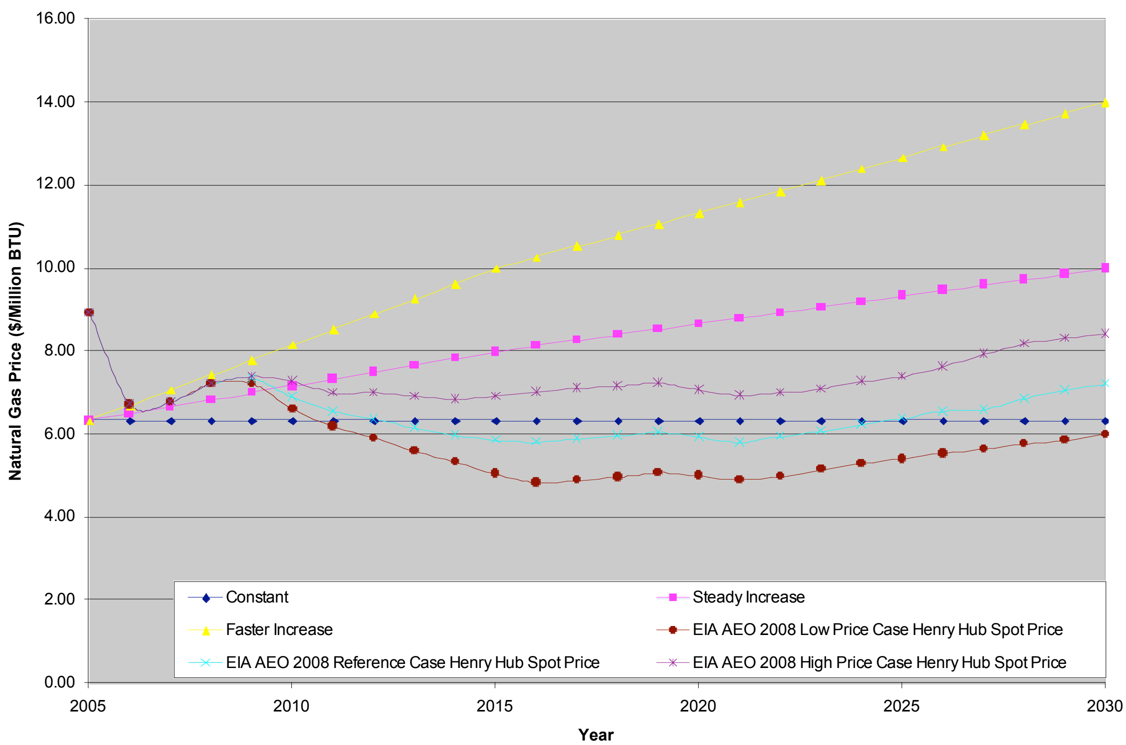
Natural-Gas Prices. The analysis considers a similar set of price paths for natural gas. These prices reflect the price of natural gas for amounts in excess of Israel's initial contract with EMG. This contract delivers 1.7 BCM per year at a price of $2.75 per MMBTU. The uncertainties being represented in the analysis are the price of the current contracted levels of natural gas when this contract expires in 2015, the possible new price that may result from renegotiated contracts, and the price for any natural gas in excess of the original amount from foreign sources, DDW reserves, or LNG delivery. The natural-gas prices do not include the amortized cost of any new DDW or LNG facility. The initial assumed price for this supply of natural gas is $6.33 per MMBTU, which is based on a projection by IEC. We then consider three different price paths for this uncertainty:

- constant price: Prices remain at $6.33 per MMBTU.
- steady increase: Prices increase to $8 per MMBTU in 2015 and $10 per MMBTU in 2030.
- faster increase: Prices increase to $10 per MMBTU in 2015 and $14 per MMBTU in 2030.

In the first scenario, real natural-gas prices remain constant at the initial level, and this reflects a situation in which Israel remains a preferred customer and the long-term supply of natural gas remains balanced with demand. In the two remaining scenarios, natural-gas prices increase at different rates. These both correspond with scenarios in which demand for natural gas grows faster than long-term supply. This could occur if natural gas becomes an increasingly preferred substitute for coal-fueled power plants in Israel. Furthermore, if nations that are significant energy consumers pursue policies that encouraged natural gas as a substitution for petroleum-based transportation fuels, as has been proposed in the United States, then demand for this energy source could grow substantially. Finally, if investment in new supplies cannot keep pace with demand, then prices could continue to rise over the long term.

Figure A.10 compares the natural-gas price paths assumed in this analysis to projections by the DOE EIA in the 2008 AEO. The AEO considers several different energy-price scenarios, and the graph shows their projections for the spot price of natural gas at the Henry Hub

Figure A.10
Comparison of Natural-Gas Price Scenarios with Annual Energy Outlook 2008 Projections



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under low-price, reference-price, and high-price scenarios. We show this projection for the Henry Hub spot price because it is used as a reference in many long-term natural-gas contracts.

The EIA scenarios share a similar general trend to the price-path alternatives we utilize in the analysis, but the magnitudes vary. EIA projections assume that natural-gas prices will generally decline from the recent high levels in 2007 and early 2008. Then, starting in about 2015, increasing long-term demand will lead to rising prices. In EIA's high-price scenario, the spot price reaches just above $8 per MMBTU by 2030. In the reference case, this price exceeds $7 per MMBTU in 2030, and, in the low-price case, the Henry Hub spot price is $6 per MMBTU in 2030.

EIA's price projections in the low-price and reference case decline below the constant-price scenario used in the analysis but meet or exceed it by 2030. EIA's high-price case lies between the constant price and steady price scenarios. The faster-increase scenario reaches prices considerably higher than the EIA projections.

A couple of notes are important to consider when comparing these projections. The first is that the Henry Hub spot price does not include the transportation cost of shipping LNG cargo to Israel. A second note is that EIA has consistently revised its energy-price projections upward in recent years as energy prices steadily rose from 2003 to 2008. Of course, with the economic recession that began in 2008, energy prices dropped considerably by late 2008. However, if the global economy recovers relatively quickly and natural-gas demand returns to the rate of growth before the recession, then high energy prices are possible again.

Finally, in all of the scenarios, prices for diesel and residual fuel oil follow the same trends as oil, and natural-gas prices are strongly correlated. The initial price of diesel fuel (*soler*) is $95 per barrel and for residual fuel oil (*mazout*) is $64 per barrel. Both of these values are based on IEC data supplied by the MNI. In all the scenarios, the price of petroleum products follows the same percentage changes as natural-gas prices.

Carbon-Dioxide Price. In our analysis, we consider scenarios in which Israel applies a CO_2 charge to fossil fuels used in power plants. Israel is a signatory to the Kyoto Protocol but is currently considered a developing country under the terms of the agreement. Currently, developing countries are not required to make emission cuts; however, this condition may change, as this agreement is under renegotiation. Furthermore, as Israel considers closer ties with the EU, one possible condition could be stronger measures to address the country's GHG emissions, which could include a tax on its emissions or the imputed carbon content of exported goods. We consider the three following scenarios for this uncertainty:

- no price
- $50-per-tonne tax by 2030 (linear increase from 2010; $12.50 in 2015)
- $120-per-tonne tax by 2030 (linear increase from 2010; $31.30 in 2015).

The first scenario is no price, which could occur if Israel uses another policy instrument or takes no measures at all to curb emissions. In the second scenario, a CO_2 tax is adopted in 2010 (starting in 2011) and increases linearly to $50 per tonne by 2030. The third scenario follows the same conditions but increases to $125 per tonne by 2030.

This broad range of CO_2 prices reflects the considerable uncertainty in how Israel may choose to address its GHG emissions and the future costs of reducing emissions. In a recent study, Aldy (2007) summarizes results from energy-economic models at the Massachusetts Institute of Technology (MIT) and EIA on the costs of proposals to reduce GHG emissions in the United States. He found that CO_2 prices ranged from \$15 to \$100 per metric tonne of CO_2. The large range in prices reflects the differences in current proposals over the stringency of the emission targets. In the scenarios considered in this analysis, the \$50-per-tonne price is near the middle of the range of results in Aldy (2007) and reflects an emission target near current levels. The scenario with high CO_2 prices represents a more stringent target for emissions near levels from the early 1990s and a suboptimal policy for implementing the limits on emissions. The analyses by MIT and EIA surveyed in Aldy (2007) assume a cost-effective, economy-wide emission-reduction program, and any less-efficient policy would result in higher costs. While our scenarios are specific to Israel, this range of costs cited for analyses in the United States is still relevant because it reflects assumptions about the costs of emission-abatement technologies that are available in global markets.

Fossil-Fuel Power-Plant Technology Costs. In this analysis, we consider three different fossil-fuel power-plant technologies: supercritical coal-fired power plants, NGCC power plants, and dual fuel–capable CTs. The first two technologies are designed to meet base-load electricity demand, and CTs typically serve peak demand.

In our scenarios, we use the estimated capital costs for each technology provided by the MNI and then vary the initial costs to account for current uncertainty in the cost of constructing power plants. We also vary the rate for change in the future technology costs. We assume that costs decline or remain constant, reflecting that future innovation and efficiency gains can reduce the costs of these technologies, even though they are considered mature technologies. IEC's estimated costs for the overnight[1] capital costs for each technology are \$1,150 per kW of installed capacity for a coal plant, \$650 per kW for a CC plant, and \$380 per kW for a CT. We constructed four scenarios to capture the uncertainty in these costs:

- low cost: Initial costs are 10 percent below the IEC estimate, with a 1-percent annual decline in capital costs.
- middle cost: Initial costs are at the IEC estimate, with a 0.5-percent annual decline in capital costs.
- high cost: Initial costs are 10 percent above the IEC estimate, with no decline over time.
- highest cost: Initial costs are 10 percent above the AEO 2008 estimate, with a 0.25-percent annual decline in capital costs.

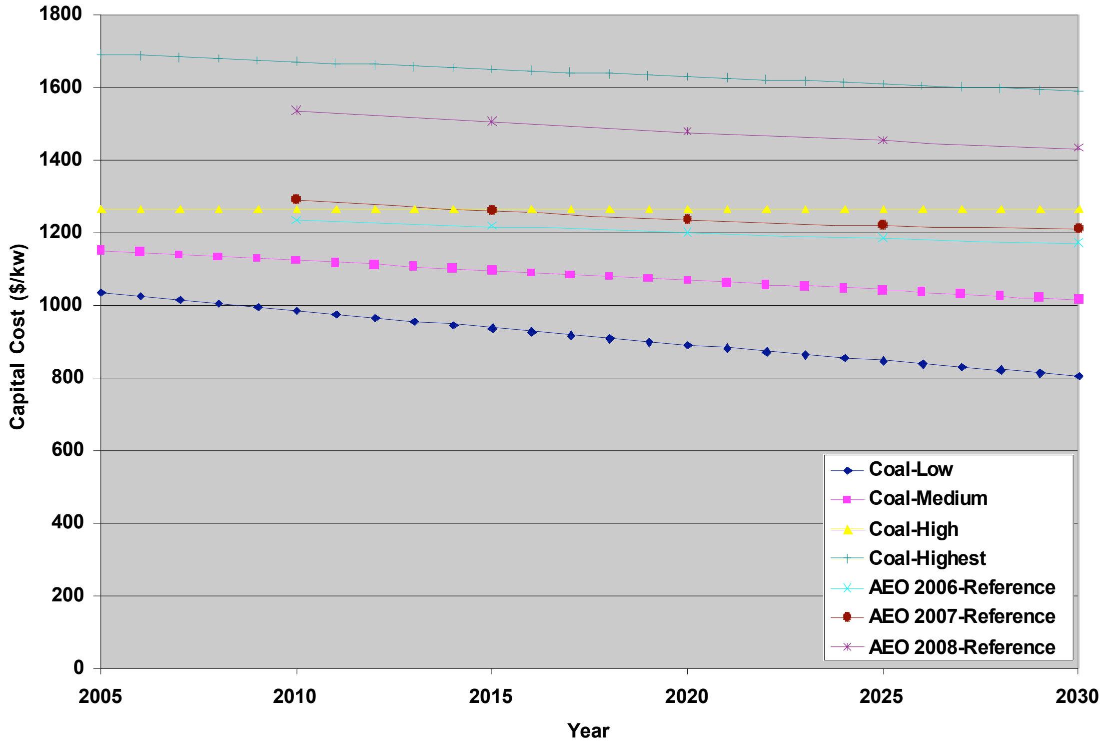
We include four, rather than three, alternative assumptions for this uncertain variable to reflect the release by EIA of the AEO 2008. This report substantially revised upward the capital cost estimates of new power plants, largely to reflect bottlenecks that had appeared in construction in the previous years. In some cases, the AEO 2008 raised capital cost estimates from previous reports by more than 20 percent. In the final, highest-cost scenario, we assume initial capital costs 10 percent greater than the AEO 2008 and the same rate of annual decline in costs of 0.25 percent.

Figure A.11 shows how these cost assumptions compare with the EIA's estimates in recent AEO reports for coal-fired power plants.

The first four lines shown in the legend are the three coal-fired power-plant technology-cost scenarios used in this analysis. In the low, medium, and high scenarios, initial costs in the analysis period vary above and below \$1,150 per kW and decline at varying rates over time.

[1] That is, the costs if a plant could somehow be built overnight and so not include charges for financing.

Figure A.11
Comparison of Assumed Coal-Plant Costs with Recent Energy Information Administration Annual Energy Outlook Estimates



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The highest case assumes initial capital costs 10 percent above EIA's estimate and declining at the same rate.

The three remaining lines in the graph show the EIA AEO reference-case estimates from 2006, 2007, and 2008. We show these three values because EIA has consistently revised its coal-plant cost estimates upward. In the 2006 AEO, the total overnight capital costs for a coal plant built in 2010 were $1,233 per kW. In the 2007 AEO, this value increased to $1,290 per kW, and the 2008 AEO considerably raised capital costs, to $1,534 per kW. EIA raised the construction cost for new power plants in part due to rising costs for raw materials and engineering expertise. A recent NETL (2007) report on fossil-fuel power-plant technical characteristics estimated the capital costs of a new coal power plant at $1,534 per kW, which EIA has used for its estimated coal-plant capital costs.

Comparing the scenarios used in this analysis with EIA's and NETL's estimates shows that the high-cost case used in this analysis is similar to the cost projections in the 2006 and 2007 AEOs. The estimates in the 2008 AEO by NETL are about 15 to 20 percent higher than the high-cost case. The graph shows that the "highest" cost scenario incorporates these revised assumptions and includes some additional contingency costs to account for potentially higher costs than estimated by EIA and NETL.

In its estimate of coal-plant costs, NETL assumes a new greenfield site in the midwestern United States. In Israel, a new coal plant is most likely to be developed near the coastline because of the need for cooling water and access to a port to receive coal. Plants sited further inland would incur higher costs to deliver the coal and cooling water. For these reasons, the costs of developing coal plants in Israel could potentially exceed U.S.-based estimates.

An important uncertainty remains how the recent economic recession will affect power-plant costs. Rapid growth in demand for power and power-plant construction led to the recent cost increases. In the near term, these costs may decline as construction activity slows. However, the longer-term trend will depend on how the global economy responds to the current downturn.

We followed a similar process in developing cost estimates for new CC power plants, and Figure A.12 displays the assumed capital costs for new CC power plants in each scenario.

In this analysis, the medium-cost scenario uses an overnight capital cost of $650 per kW of installed capacity, which was the projected cost provided by the MNI. In the scenarios, we vary this initial cost by 10 percent and then allow these costs to decline over time at differing rates. As in Figure A.11, the three remaining lines in Figure A.12 show EIA's cost estimates in the three most recent AEOs. As with coal-plant costs, EIA revised its cost estimates upward in each successive year, with a considerable increase in 2008. For 2010, EIA's estimates range from $565 per kW to $706 per kW. In the scenarios used in this analysis, 2010 costs vary from $568 per kW to $715 per kW. By 2030, the estimates span a wider range. EIA's estimates range from $502 per kW to $634 per kW. In the scenarios for this analysis, the costs vary from $455 per kW to $715 per kW.

As another reference, the NETL report on fossil fuel–technology characteristics estimated the capital costs of CC power plants at $554 per kW, which is on the lower end of the range of estimates for plants constructed in the early portion of the analysis period. Figure A.13 compares capital cost estimates for CTs.

Figure A.12
Comparison of Capital Costs for Combined-Cycle Power Plants

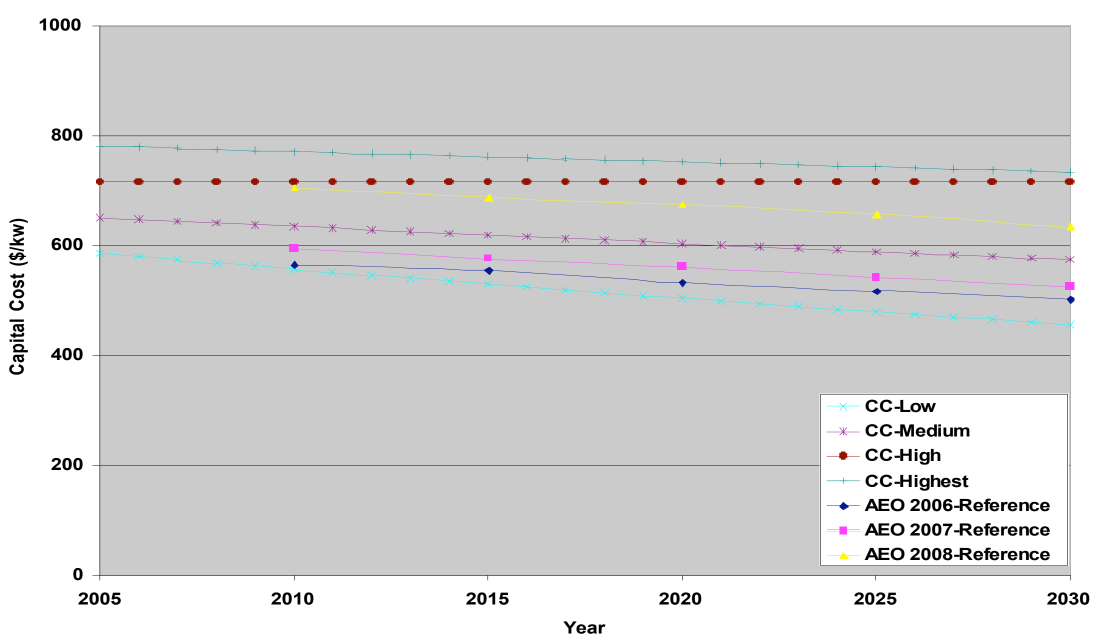

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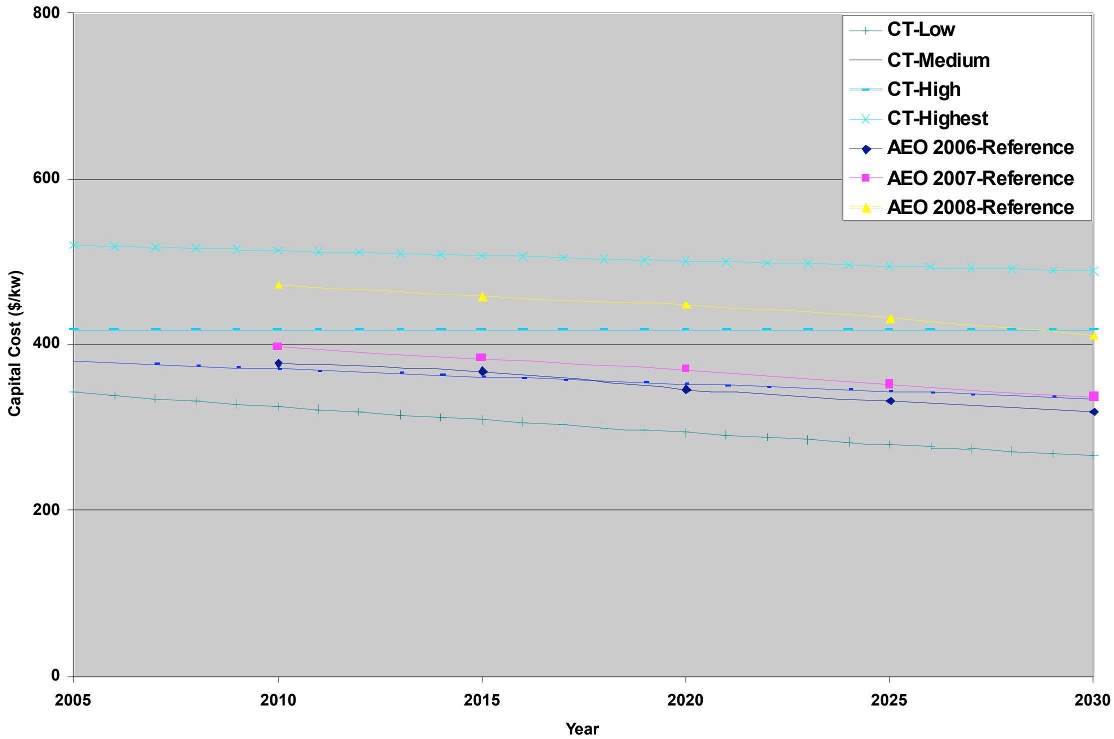
Figure A.13
Comparison of Capital Costs for Combustion Turbines



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For this technology, in the medium-cost scenario, we use an overnight capital cost of $380 per kW, which was the projected cost provided by the MNI. As in Figures A.11 and A.12, the three remaining lines show EIA's cost estimates in the three most recent AEOs. As with the other technologies, EIA revised its cost estimates upward in each successive year, with a considerable increase in 2008. For 2010, EIA's estimates range from $378 per kW to $473 per kW. In the scenarios used in this analysis, 2010 costs vary from $332 per kW to $418 per kW. By 2030, the estimates span a wider range. EIA's estimates range from $320 per kW to $412 per kW. In the scenarios for this analysis, the costs vary from $216 per kW to $418 per kW.

Alternative Energy–Technology Costs. In our analysis, we consider two alternative-energy technologies: solar-thermal power plants and pumped-storage plants. Solar-thermal plants utilize an intermittent energy source (solar energy); however, the plants have the capacity to store energy for up to six hours. Therefore, electricity from the plants can be expected to substitute for power from CT plants and CTs. Israel is currently developing a 50-MW pilot plant to test this technology and has proposed developing up to 4,000 MW if the results from the pilot plant are favorable.

- low: Initial costs are 20 percent below the IEC estimate, with a 2-percent annual decline in capital costs.
- medium: Initial costs are at the IEC estimate, with a 1.0-percent annual decline in capital costs.

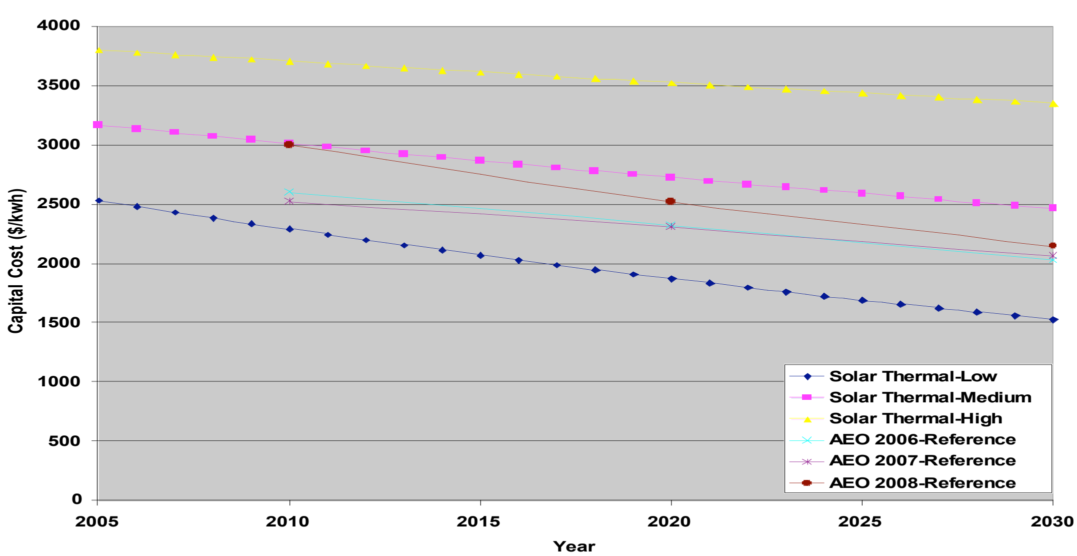
- high: Initial costs are 20 percent above the IEC estimate, with a 0.5-percent decline over time.

Figure A.14 shows that we assume a wider range of capital costs for solar-thermal power plants than for conventional fossil-fuel technologies. The wider range accounts for the large degree of uncertainty of developing these power plants in Israel. Solar-thermal power plants are under construction in several locations throughout the world. There are currently utility-scale projects under way in the southwestern United States and Spain. Even with these developments, it is still a relatively new technology. Israel is currently building a pilot plant that will be used to evaluate the technology. Until this plant is finished and can operate for several years, this technology still entails a high degree of uncertainty. For this reason, we assumed a wider range of capital costs but also a higher rate of cost decrease. Because the technology is still in an early stage, rapid learning can occur as more power plants are built globally, leading to faster declines in costs over time.

In our scenarios, we use IEC's estimate of capital costs for the medium-cost scenario and then allow for a range of initial costs 20 percent lower and higher. The figure also shows EIA's cost estimates in the AEO 2006, 2007, and 2008. The figure shows that EIA raised its cost estimates over time but not to as high a degree as for several of the fossil-fuel technologies. The low- and medium-cost scenarios bound the range of EIA's cost assumptions. We still allow for a scenario with higher costs because EIA may underestimate the capital costs of this technology. As noted earlier, solar-thermal plants still remain in a precommercial stage, and research on the accuracy of cost estimates for precommercial technologies indicates that the actual costs of developing first-of-a-kind plants most often exceed initial estimates (Merrow, Phillips, and Myers, 1981).

In this case, solar-thermal power already has seen early plants built, so some experience exists. Power plants were already built in the late 1970s and early 1980s, and a new generation

Figure A.14
Comparison of Capital Costs for Solar-Thermal Power Plants



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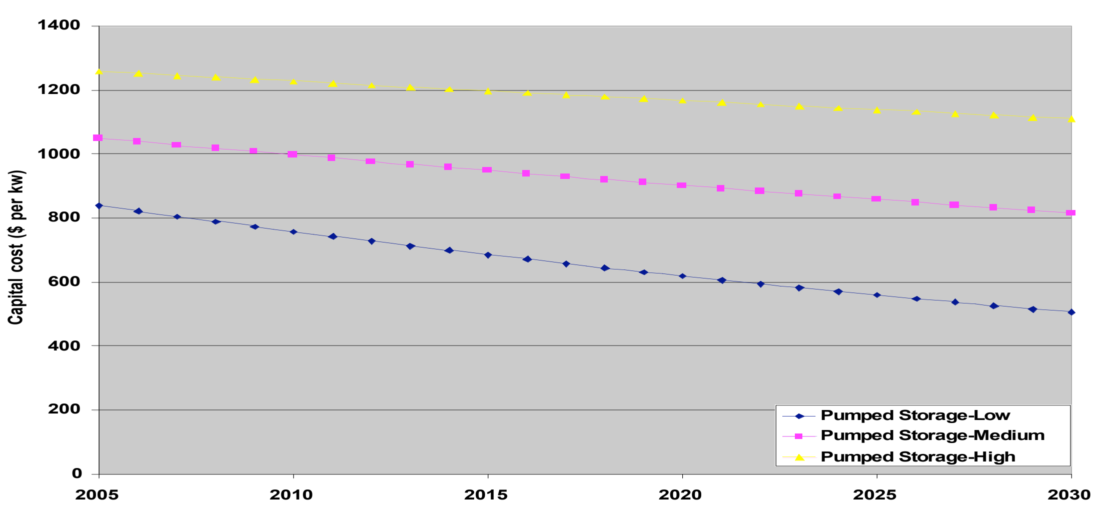
of plants is under construction in several global locations noted as well as the pilot plant in Israel. Given the limited experience with this technology, especially in Israel, a scenario including a relatively high cost contingency of 20 percent is warranted, and this is reflected in the high cost shown in the figure.

The second alternative technology considered in the analysis is pumped-storage plants. Pumped-storage plants can vary in their design, but the general principle is that the plant pumps water into a reservoir during off-peak hours. During peak hours, the plant releases the stored water and generates electricity with a hydroelectric turbine. By its design, it is a peak-power technology that is a mature technology. No pumped-storage plants currently exist in Israel, so the costs of developing this technology in Israel is uncertain, as is the total potential capacity of this resource. For these reasons, we have allowed for a relatively wide range of capital costs, and Figure A.15 shows the capital-cost assumptions for pumped-storage plants.

In the medium-cost scenario, we use IEC's estimate of $1,050 per kW as the initial cost, and the two other scenarios vary this cost by 20 percent. EIA does not include pumped storage in its options for new capacity, and we, therefore, have no cost estimates to compare with the IEC estimates. In the next uncertainty, we also vary the availability of alternative-energy capacity.

Alternative-Energy Plant Capacity. In our strategies that include alternative energy (see "Electricity-Sector Investment Strategies" earlier in this appendix for more detail on how these technologies are incorporated into the analysis), the available capacity of alternative energy is an uncertain factor that we vary. This uncertainty exists because of an inability to forecast future supply-and-demand relationships for manufacture of plant capacity, the vagaries of land-use planning and permitting, decisions made by other branches of Israel's government that may affect investment decisions in this field, and experience with prior placements of such plant in the setting of Israel, which may indicate that the potential for further installations is greater or less than initially supposed. Both of the technologies have a maximum available capacity. The maximum potential for solar-thermal capacity is 4,000 MW by 2030. As noted

Figure A.15
Pumped-Storage Power-Plant Capital-Cost Assumptions for Each Scenario



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already, this is a significant increase for a technology that is currently in a precommercial state. For this reason, we consider scenarios with a lower level of maximum capacity, at 800 MW and 2,500 MW. The 800-MW scenario represents modest growth in solar-thermal capacity after Israel finishes building and operating its first set of pilot solar-thermal plants. The 2,500-MW scenario assumes the same level of solar-thermal capacity used in a recent benefit-cost analysis of solar thermal in Israel (Mor, Seroussi, and Ainspan, 2005). The scenario with maximum solar-thermal capacity represents rapid development of this technology after Israel gains early experience from building pilot plants.

For pumped-storage power plants, we assume a maximum capacity of 1,800 MW based on an IEC assessment of the potential for adding nine 200-MW pumped-storage plants. We consider scenarios with one-third and two-thirds of the maximum capacity.

Energy-Efficiency Costs. In three strategies, investing in energy efficiency is an option to reduce demand and decrease the need for new power supplies. In these strategies, Israel invests in energy efficiency when it costs less than the LCOE of a natural gas–fueled CT. The savings in a given year are cumulative over the analysis period up to a maximum of 20 percent if energy-efficiency investments are made every year.

The uncertainty for energy-efficiency investments is their costs. We model the average costs of efficiency investments in each year. We assume three different scenarios with varying initial costs and growth rates. We assume that efficiency costs increase over the analysis period because of rising marginal costs. As Israel invests in greater energy efficiency, the incremental cost of each investment rises because the country invests in the low-cost opportunities initially and new investments are successively more expensive.

In this analysis, we are assuming that the energy-saving investments are in new residential construction, retrofits to existing housing, new commercial buildings, retrofits to new commercial buildings, and some potential for energy saving at industrial sites. The increasing cost functions imply that the investments utilize existing technologies with rising costs at higher levels of capacity. A possibility that we have not incorporated is a significant new innovation that would considerably reduce the costs of energy efficiency. While this is a possibility, the evidence indicates that Israel has considerable opportunities to utilize existing technologies to reduce energy demand, as this has not been a high priority of the government or energy planning agencies since the country's significant investment in solar hot-water heating beginning in the late 1960s.

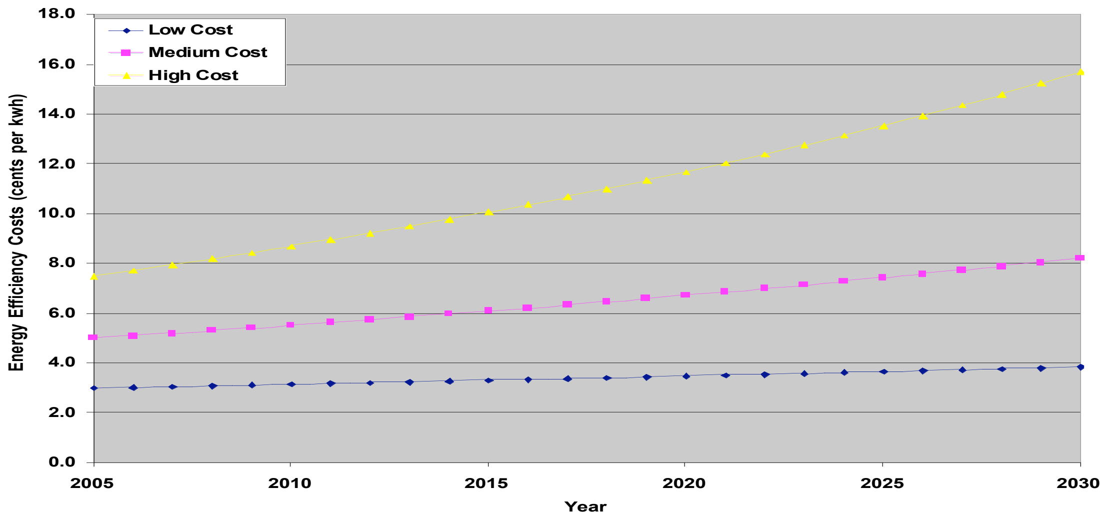
As noted, we use three different scenarios for initial efficiency costs and growth rates, which are the following:

- low: Initial average cost is $0.03 per kWh, with 1 percent growth.
- med: Initial average cost is $0.05 per kWh, with 2 percent growth.
- high: Initial average cost is $0.075 per kWh, with 3 percent growth.

Figure A.16 illustrates the costs of energy efficiency over the analysis period for each scenario.

The figure shows that the costs of efficiency investments span a wide range. In the low-cost scenario, initial efficiency costs are $0.03 per kWh and rise slightly to just under $0.04 per kWh. This scenario reflects a large potential for energy savings available at low cost, which a recent engineering-economic study in the United States suggests is plausible (Creyts et al., 2007). Some estimates of the costs of electric utility–mandated energy-efficiency programs in

Figure A.16
Average Cost Curves for Energy-Efficiency Investments



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the 1990s also found the costs of saving electricity in this range (Nadel, 1992; Fickett, Gellings, and Lovins, 1990; Nadel and Geller, 1995; Eto et al., 1995; Gillingham, Newell, and Palmer, 2006).

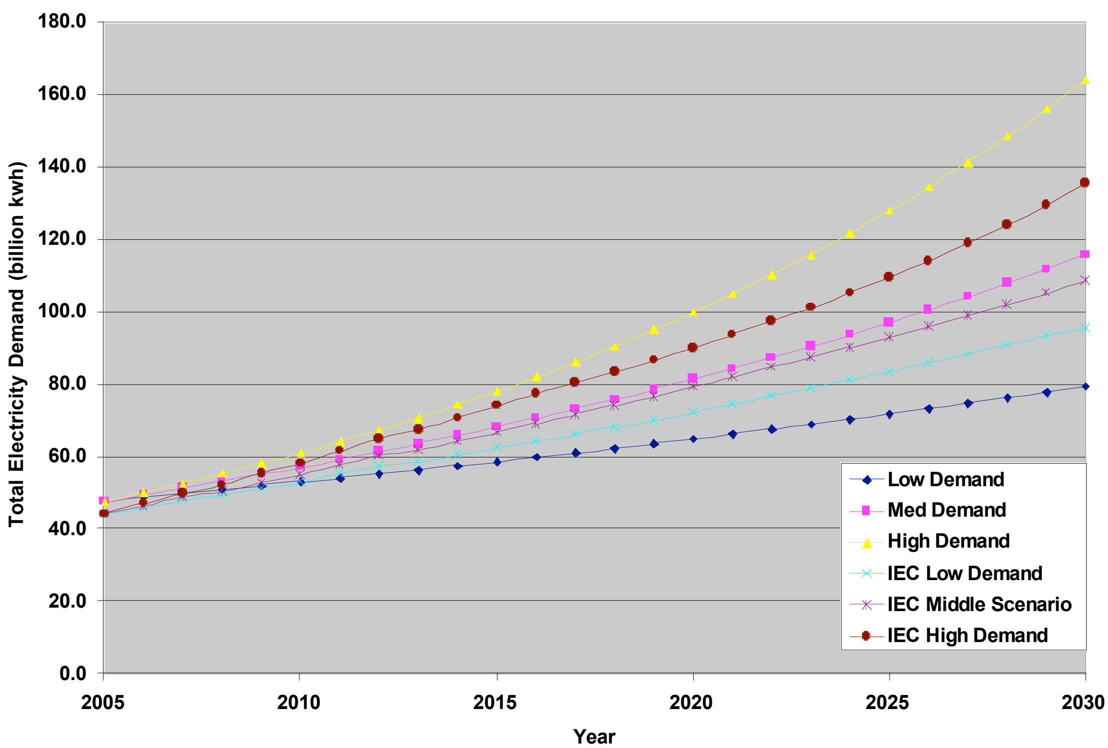
The annual reports for utility efficiency programs provide another reference on the costs of energy efficiency. The annual reports for 2007 (the most recent year available) on energy-efficiency programs at California's investor-owned utilities (IOUs) showed that the utilities spent between \$0.0003 and \$0.037 per kWh saved, even after several decades of investment in energy-saving technologies. An important note is that these estimates include only program expenditures by utilities and did not incorporate additional customer spending needed to purchase energy-saving devices. The reports do include the estimated total spending by the utility and customers, which was 30–40 percent greater than utility expenditures, but did not normalize these figures by estimated savings discounted over the lifetime of the device. As another reference on the additional costs incurred by consumers, Gillingham, Newell, and Palmer (2006) double their estimated cost of energy savings to account for these costs based on the findings of Joskow and Marron (1992).

Other studies indicate higher costs for energy-efficiency programs, and we have included two other scenarios with higher costs. In the medium-cost scenario, initial costs are \$0.05 per kWh and rise to more than \$0.08 per kWh. In the high-cost scenario, initial costs are \$0.075 per kWh and rise to almost \$0.16 per kWh. Economic literature mandating utility energy-efficiency programs in the 1980s and 1990s found several examples with efficiency costs in the range bounded by the medium- and high-cost scenarios (Joskow and Marron, 1992; Loughran and Kulick, 2004). These studies found that many of the engineering-economic studies suggesting very low costs exclude some of the costs borne by consumers and utilities. In addition, in many cases, the energy-saving technologies did not perform as projected. Finally, some utilities overestimated the energy savings from energy-efficiency programs by not accounting for customers that received incentive payments but would have installed energy-saving devices even without the incentive.

Because of the considerable uncertainty about the future costs of saving energy, we have assumed a wide range of energy-efficiency costs in the analysis, which we bound with the scenarios used in the analysis. Furthermore, our cost estimates are based on studies and programs at U.S. utilities. The applicability of these estimates to Israel is an additional uncertainty, and, for these reasons, we have assumed a wide range of costs in the analysis.

Demand. We assume three different scenarios for energy demand that span a wider range of potential demand than IEC's projections and find that the results are very sensitive to this uncertainty. Our scenarios are based on variations in three key components of energy demand, GDP growth, and the energy intensity of the residential, service, and industrial sectors. We have calibrated the MAED model to IEC's base-case projection, and this is the medium-demand scenario. In this scenario, the average growth rate of GDP is 4 percent, the energy intensity of the service and industrial sectors declines by 0.5 percent per year, and per-household demand rises by 2 percent per year. We then varied the energy intensities downward to estimate a low-demand scenario that is driven primarily by greater energy efficiency. The high–energy demand scenario is driven by a 6-percent annual GDP growth rate and no improvements in energy efficiency compared to the medium-demand scenario. The following list shows the assumptions within each scenario, and Figure A.17 compares the scenarios with IEC's demand projections:

Figure A.17
Comparison of Israel Electric Corporation Demand Projections and Those Used in This Analysis



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- low demand: 4 percent GDP growth, 2-percent decrease in service- and industrial-sector energy intensity, and 0.5-percent increase in residential intensity
- medium demand: 4 percent GDP growth, 0.5-percent decrease in service- and industrial-sector energy intensity, and 2-percent increase in residential intensity
- high demand: 6-percent GDP growth, 0.5-percent decrease in service- and industrial-sector energy intensity, and 2-percent annual increase in residential intensity.

The first three projections in the legend are the low-, medium-, and high-demand scenarios used in this analysis. The next three are taken from a set of scenarios provided by IEC. The figure shows that the medium-demand scenario used in this analysis corresponds closely with IEC's middle scenario. The high-demand scenario in this analysis exceeds IEC's high-demand scenario by approximately 15 percent, and the low-demand scenario is about 15 percent lower than IEC's low-demand scenario. The demand scenarios were selected to test how the different strategies would perform across a broad range of demand conditions and not on judgment of the likelihood of these scenarios. For these reasons, we chose a wide range of possible demand scenarios that exceeded the range of IEC's assumptions.

Greenhouse Gas–Emission Limits. In the final uncertainty for which we test variable assumptions in the analysis, we model potential constraints on coal power plants based on emission limits. With the Coal Rule and Least Cost strategies, if GHG emissions reach the limits, then no new coal plants are built. This policy is similar to a policy passed in California that requires all new power plants to have GHG emissions below those of a natural gas–fueled CC plant.

With this policy, we treat the constraint as an uncertainty. Under the first scenario, developing coal plants under the Coal Rule and Least Cost strategies is an uncertainty. The remaining scenarios vary the constraint at 25 percent and 50 percent above 2005 emissions.

Table A.5 shows the variables used as inputs to the electricity generator–dispatch module in the LEAP model and the data source we used to obtain the values. The merit order is the relative order in which the generator is used in the system dispatch. These values were determined based on estimates of variable costs from the WASP model. Nameplate capacity is the combined capacity, in megawatts, of the generating units at the power station. Maximum availability is the percentage of the total number of hours in the year the plant is available after accounting for planned and unplanned outages. The capacity credit is the fraction of nameplate capacity counted in reserve margin calculations. Heat rate is the fuel consumption per unit of electricity output. Variable O&M cost is the O&M costs that vary with plant output, and the fixed O&M cost is the O&M costs that are incurred independent of plant output. The emission factors calculate the amount of emissions produced per unit of fuel consumption.

Discount Rate. This variable is also subject to alteration in our model. We conducted simulation runs that varied this input. However, while these variations had a considerable effect on cost estimates for scenario outcomes, we found few (if any) instances in which changes in this variable affected choice among strategies. Therefore, for the main analysis, we fixed the discount rate at 5 percent and did not configure CARs to change this variable for simulation runs. The implications of this choice are discussed extensively in Chapter Five.

Table A.5
Power-Plant Operating Variables Used in the Analysis

Power-Plant Variable	Data Source
Merit order	Determined from WASP output
Nameplate capacity (MW)	MNI (with permission of IEC)
Maximum availability (%)	MNI (with permission of IEC)
Capacity credit (%)	MNI (with permission of IEC)
Heat rate (kcal per kWh)	MNI (with permission of IEC)
O&M cost ($/MWh), variable	MNI (with permission of IEC)
O&M cost ($/MWh), fixed	MNI (with permission of IEC)
CO_2 emissions (kg per tonne)	MNI (with permission of IEC)
NO_X emissions (kg per tonne)	MNI (with permission of IEC)
SO_2 emissions (kg per tonne)	MNI (with permission of IEC)
PM_{10} emissions (kg per tonne)	MNI (with permission of IEC)

NOTE: kcal = kilocalorie. MWh = megawatt-hour. kg = kilogram. SO_2 = sulfur dioxide. PM_{10} = particulate matter with particles no larger than 10 micrometers.

APPENDIX B

Results of Scenario-Discovery Analysis

Success- and Failure-Scenario Conditions for Unmodified Strategies

We employed PRIM to identify and characterize the clusters of future states in which each candidate strategy exhibits high regret (Friedman and Fisher, 1999). PRIM is a data-mining algorithm designed to generate a set of low-dimensional boxes in higher-dimensional data containing regions in which the value of a particular function is large (or small) compared to its value outside these boxes. It aims to optimize both the classification accuracy of boxes and their interpretability.

Tables B.1 and B.2 show the results from the PRIM scenario outcome–discovery analysis. Table B.1 presents the results of searches for conditions that define scenarios in which failure to meet the cost-criterion threshold becomes more likely for each scenario. Table B.2 shows the conditions that are the most favorable to scenario outcomes from each strategy that will meet or better this threshold.

It is often the case that one can find different sets of conditions that will change the coverage and density characteristics of the set of scenarios that conform to these conditions.[1] In some cases, two such proposed conditions may be related by changing the thresholds of a given factor or by adding additional factors to the conditions.[2] Some condition rules, however, are composed of entirely different factors. In Tables B.1 and B.2, it may be seen that, for some strategies, one set of conditions and rules was sufficiently superior to any alternative to make the latter of no interest. In some cases, however, as many as four alternative rules contain information of interest to planners. These are reported in successive columns proceeding from left to right.

In the case of the WASP strategy, the scenarios with outcomes that fail to achieve the cost threshold tend to be those in which the costs for achieving efficiency gains are not high (< 2) and in which there is a nonzero cost for emission of CO_2 equivalents. These two conditions capture nearly two-thirds (coverage = 0.64) of the failure scenarios for this strategy with respect to the cost threshold while giving a density of 88 percent. It is clear why this should be so, since these two conditions would make strategies that utilize efficiency gains and produce

1 The coverage statistic measures the number of bad (or good) outcome scenarios captured as a share of the total such scenarios in the full data set. The density statistic describes the fraction of scenarios in the set, defined by the proposed conditions that are actually bad (or good) outcome scenarios.

2 The order of the condition thresholds is also important. Scenario discovery is a peeling process, in which the algorithm automatically adds or discards successive conditions, depending on how they affect the resulting coverage and density statistics. Thus, the first condition in a set usually has the most effect, followed successively in order by the additional conditions in that set, which have a decreasingly important effect.

Table B.1
Results of Scenario-Discovery Analysis for Conditions Causing Failure to Meet Cost-Criterion Threshold

	Condition Set								
Strategy	**1**			**2**			**3**		
WASP	Efficiency costs	<	2	Natural gas	<	2	Efficiency costs	<	2
	CO_2	>	0	Alternative-energy technology costs	<	2	Demand	>	0
							Coal	>	0
	Coverage	0.64		Coverage	0.2		Coverage	0.07	
	Density	0.88		Density	0.54		Density	0.69	
Coal Rule	Efficiency costs	<	2	Efficiency costs	<	2	Natural-gas price	<	1
	Demand	>	0				Demand	>	0
	CO_2 price	>	0						
	Natural-gas price	>	0						
	Coverage	0.42		Coverage	0.49		Coverage	0.03	
	Density	0.83		Density	0.58		Density	0.5	
Coal Rule_Alt	Alternative-energy technology costs	>	0	CO_2 price	=	0	Natural-gas price	=	0
	CO_2	<	2	Coal price	<	2	Alternative-energy plant capacity	>	0
	Alternative-energy plant capacity	>	0	GHG limit	>	0			
	Demand	<	2	Natural-gas price	>	0			
				Efficiency costs	>	0			
				Fossil-fuel technology costs	<	3			
	Coverage	0.66		Coverage	0.12		Coverage	0.18	

Table B.1—Continued

Strategy	Condition Set 1			Condition Set 2			Condition Set 3		
Coal Rule_Alt (cont'd)	Density	0.51		Density	0.68		Density	0.36	
Least Cost	Efficiency cost	<	1	Efficiency cost	<	2			
				Demand	>	0			
				Natural-gas price	>	0			
				CO_2 price	>	0			
	Coverage	0.63		Coverage	0.23				
	Density	0.98		Density	0.52				
Least Cost_ Eff	CO_2 price	=	0						
	Demand	=	0						
	Efficiency cost	=	1						
	Coal price	<	2						
	Natural-gas price	>	0						
	Coverage	0.86							
	Density	0.17							
Gas Rule	Efficiency cost	<	2	Efficiency cost	<	2	CO_2 price	<	2
	Natural-gas price	>	0	Demand	>	0	Demand	>	0
				GHG limit	>	0	Coal price	<	2
	Coverage	0.75		Coverage	0.07		Coverage	0.06	
	Density	0.72		Density	0.4		Density	0.26	

Table B.1—Continued

	Condition Set								
Strategy	**1**			**2**			**3**		
Gas Rule_Alt	CO_2 price	<	2	CO_2 price	=	0	Alternative-energy technology cost	>	1
	Alternative-energy plant capacity	>	0	Coal price	<	2	Coal price	<	2
	Demand	<	2	Natural-gas price	>	0	Fossil-fuel technology costs	<	3
	Alternative-energy technology cost	>	0	Fossil-fuel technology costs	<	3			
	Coverage	0.68		Coverage	0.18		Coverage	0.05	
	Density	0.53		Density	0.49		Density	0.17	

NOTE: The number following a named variable refers to alternative assumptions for scenario elements as reported in Chapter Three and Appendix A. In each case, 1 corresponds to the middle alternative in the range of three, the one we have nominated as the base-case assumption in the earlier part of the analysis. The 0 case is the first one in the series of alternative assumptions for each case, generally less restrictive and more favorable than in the case of the 1 assumption. The 2 case represents the last in the list of three alternative assumptions under each such factor, generally the most stringent or least favorable one. Only the fossil-fuel technology factor has a fourth assumption, which would appear as 3 if it were to appear in the table. The numbers for coverage and density are fractions (e.g., 0.64 indicates 64 percent).

Table B.2
Results of Scenario-Discovery Analysis for Conditions Supporting Success in Meeting Cost-Criterion Threshold

	Condition Set											
Strategy	**1**			**2**			**3**			**4**		
WASP	Efficiency cost	>	0	CO_2 price	<	1	Efficiency cost	>	1			
	Natural-gas price	>	0	Efficiency cost	>	0	Natural-gas price	>	0			
	CO_2 price	<	2	Fossil-fuel technology cost	<	3	Demand	>	0			
	Coal price	<	2				Fossil-fuel technology cost	<	3			
	Coverage	0.66		Coverage	0.24		Coverage	0.11				
	Density	0.71		Density	0.76		Density	0.64				
Coal Rule	Efficiency cost	>	0	Efficiency cost	>	1	Demand	<	1			
	Natural gas	<	2	Natural-gas price	>	0	Efficiency cost	>	0			
	CO_2 price	<	2	CO_2 price	>	0	Alternative-energy technology cost	>	0			
	Coverage	0.72		Coverage	0.16		Coverage	0.08				
	Density	0.78		Density	0.85		Density	0.73				
Coal Rule_ Alt	CO_2 price	>	0	Demand	>	0	Demand	>	0	Alternative-energy plant capacity	<	2
	Natural-gas price	>	0	Alternative-energy plant capacity	<	2	CO_2 price	>	0	Alternative-energy technology cost	<	2
	Alternative-energy technology cost	<	2	GHG limit	<	2	Natural-gas price	<	2			
	Coverage	0.51		Coverage	0.25		Coverage	0.09		Coverage	0.08	
	Density	0.97		Density	0.76		Density	0.76		Density	0.58	

Table B.2—Continued

	Condition Set									
Strategy	**1**			**2**			**3**			**4**
Least Cost	Efficiency cost	>	0	Efficiency cost	>	1	Efficiency cost	>	0	
	Demand	<	2				Natural-gas price	<	1	
	CO_2 price	<	2							
	Coverage	0.66		Coverage	0.19		Coverage	0.09		
	Density	0.95		Density	0.96		Density	0.92		
Least Cost_Eff	Demand	>	0							
	Coverage	0.74								
	Density	1								
Gas Rule	Efficiency cost	>	0	Efficiency cost	=	2	Natural-gas price	<	1	
	Natural-gas price	<	2	CO_2 price	>	0	Efficiency cost	>	0	
	Demand	<	2							
	CO_2 price	<	2							
	Coverage	0.57		Coverage	0.24		Coverage	0.1		
	Density	0.86		Density	0.89		Density	0.82		

Table B.2—Continued

	Condition Set											
Strategy	**1**			**2**			**3**			**4**		
Gas Rule_ Alt	CO_2 price	>	0	CO_2 price	>	0	Demand	>	0	Alternative-energy technology cost	<	2
	Demand	>	0	Natural-gas price	>	0	Fossil-fuel technology cost	>	0	Alternative-energy plant capacity	<	2
	Alternative-energy technology cost	<	2	Alternative-energy plant capacity	<	2	Coal price	>	0			
							Natural-gas price	<	2			
	Coverage	0.52		Coverage	0.17		Coverage	0.1		Coverage	0.11	
	Density	0.98		Density	0.92		Density	0.79		Density	0.56	

NOTE: The number following a named variable refers to alternative assumptions for scenario elements as reported in Chapter Three and Appendix A. In each case, 1 corresponds to the middle alternative in the range of three, the one we have nominated as the base-case assumption in the earlier part of the analysis. The 0 case is the first one in the series of alternative assumptions for each case, generally less restrictive and more favorable than in the case of the 1 assumption. The 2 case represents the last in the list of three alternative assumptions under each such factor, generally the most stringent or least favorable one. Only the fossil-fuel technology factor has a fourth assumption, which would appear as 3 if it were to appear in the table. The numbers for coverage and density are fractions (e.g., 0.64 indicates 64 percent).

fewer emissions that are better suited to such possible futures. WASP tends to succeed, on the other hand, when efficiency gains are toward the costly end of their range, natural gas is an expensive fuel while coal tends toward the cheaper assumptions, and carbon charges are not set at the high end of their range of possible values.

The Coal Rule strategy similarly fails to meet the threshold when costs for achieving efficiency gains are in the lower range. Note that the coverage is highest when this is the only condition (condition set 2). Adding further conditions (condition set 1) reduces the coverage from 49 to 42 percent but provides sharper definition that reduces the number of false negatives, thus improving the density statistic to 83 percent. It succeeds under conditions similar to those for the WASP strategy.

Adding the alternative and efficiency policies to the Coal Rule strategy changes the conditions somewhat. Scenario conditions in which a carbon price exists, natural-gas prices are not set at their lowest, and the costs of alternatives are not at their highest will result in a scenario set that captures half the successful outcomes for this strategy with a set density of nearly 100 percent. It is interesting to note that there is a second set of conditions that uses completely different scenario factors to define a set that captures one-quarter of the successful-outcome cases for this strategy while yielding a density of 76 percent. In this case, success comes in those cases in which demand is relatively high, the full array of potential solar-thermal plant is not deployed, and the restrictive regulation on GHG emissions is not set at its highest.

The two strategies with the highest percentage of cases that meet the cost-condition threshold are Least Cost_Eff and Gas Rule_Alt (see Table 6.2 in Chapter Six). Since those two strategies each dominate their related strategies that do not also include the added efficiency component (and alternative-energy capacity, in the case of Gas Rule), it is profitable to examine their cost-condition results in detail.

It is not surprising that the Least Cost_Eff strategy succeeds nearly 100 percent of the time according to this criterion. For this reason, the conditions for success and failure are not particularly illuminating. If demand growth is either in line with the past pattern or somewhat higher, three-quarters of the success cases will be included in the resulting set. Interestingly, there are no cases in which demand follows either of these paths and in which Least Cost_Eff fails (i.e., density = 100 percent). Base demand growth would need to be at its lowest level for a failure scenario to appear.

Half of the cases in which Gas Rule_Alt succeeds are under scenario conditions in which there is a nonzero carbon price, base demand growth is not at the lowest level, and the cost of alternatives does not turn out to be at the high end of the range of assumptions. Almost no scenarios that include these conditions fail (i.e., density = 98 percent). Two-thirds of the cases of failure for this strategy occur when carbon prices are not set at their highest, alternative-energy plant capacity is in the middle or high range, demand is not at its highest level, and the costs for alternative-energy technologies are middling or high. However, nearly half of the time when these conditions are met, the Gas Rule_Alt strategy leads to successful outcomes (density = 53 percent).

APPENDIX C

Storage of Natural Gas

One of the main functions of natural-gas storage is to act as the supply-and-demand relief valve. Natural-gas storage enables backup inventory to meet seasonal demands, to provide reliable service to users, and to control price volatility. The cold months, the hot months, and unforeseen market conditions can create gas demands greater than production, imports, and long-haul pipeline throughput can supply. In such shortages, the stored gas can be withdrawn to satisfy the demand. In addition, transmission-pipeline companies use the gas in storage to maintain the pipeline system's gas flow and pressure to within design parameters, thereby preserving operational integrity. Furthermore, in market areas far from the supply source, establishing gas storage near the market helps to provide reliable service to users.

In addition to balancing natural-gas supply and demand, storage can also act as a marketing or price-hedging tool. For instance, storage supports deliveries to no-notice service customers. No-notice service is a contractual agreement for firm transportation or storage service. A specified portion of storage is reserved for the customer's support, and the customer is allowed to withdraw natural gas with little or no notice. Hence, natural-gas storage enables such business services. Natural-gas producers and marketers also use storage space as a price-hedging tool. They store gas when the price is expected to increase in the future and sell the gas once the target price has been reached (EIA, 2006).

In the following section, we define the parameters of natural-gas storage that are most relevant to the ensuing discussion. The physical characteristics of the three most common types of storage facilities—depleted reservoirs, aquifers, and salt caverns—are discussed. Next, the operations of each storage type are presented—followed by a discussion on the costs of storage development. We then discuss the deregulation of natural-gas storage and how that has changed the nature of ownership and, in turn, the operating practices for storage. Finally, the advantages and disadvantages of each type of storage are compared, followed by a short discussion on new technologies for developing new storage facilities and improving existing ones.

Storage Parameters Defined

The total gas storage capacity is the maximum volume of gas that can be stored in the facility. The total gas in storage is the actual volume of gas occupying that capacity at a particular time. Base gas is the volume of gas stored as semipermanent inventory that is not withdrawn and used. A certain amount of base gas is required to provide adequate drive pressure throughout the withdrawal season. The working gas capacity is the difference between the total storage capacity and the base gas volume. Working gas is the volume of gas stored that is not base gas. This portion of stored gas is intended to be withdrawn and used.

Deliverability is the rate at which stored gas can be withdrawn per day. The deliverability rate of a storage facility depends on multiple factors, one of which is the volume of gas present. The higher the volume of stored gas, the higher the deliverability rate. As the gas is withdrawn, the deliverability rate declines. Therefore, the deliverability rate is highest at the end of the injection season, when reservoir pressure is highest. In addition to volume of gas present, other factors affect deliverability rate: the design and configuration of surface facilities, such as the pipelines connected to the storage facility, and the compression capabilities available to the storage site. Injection rate is the amount of gas deposited per day. Injection rate depends on multiple factors, such as porosity of reservoir, available compression, and the volume of gas in storage. The injection rate is highest when storage is empty and decreases as storage capacity is reached. Injection rate is highest at the start of the injection period and lowest at the end of the injection period. Usually, both deliverability and injection rates are expressed as millions of cubic feet per day (MMcf/day). The period from the beginning of injection to the end of withdrawal of working gas represents one cycle. The duration of a cycle depends on the type of storage. Depleted reservoir and aquifers are typically cycled once per year, and salt caverns are cycled five to 12 times per year (EIA, 2006).

Stock Storage of Natural Gas

The three most common types of storage used for natural gas are depleted reservoirs, aquifers, and salt caverns. Depleted reservoirs are oil fields that have been depleted and now have been converted for natural-gas storage. Aquifers are reservoirs bounded by water-bearing rocks. Salt formations are salt caverns or salt beds leached from naturally occurring salt formations. Each type of storage differs in physical characteristics, such as porosity, permeability, and capability. This difference in physical characteristics leads to varying operating conditions and uses for each storage type. Because these storage types are developed from the natural physical environment, it is difficult to deterministically control the location, number, and type of storage to develop. The available geology is the main factor for determining the location, the number, and type of underground storage. In addition, the engineering conditions, the size requirement, and base gas requirements will determine whether and where to develop storage. The site's access to transportation-pipeline infrastructure, gas-production sources, and markets is another important element to determining the locations of storage development (FERC, 2004).

The storage space is just one component of a complete natural-gas storage facility. Other necessary components include injection and withdrawal wells, observation wells, water-disposal wells, gathering lines, dehydration facilities, gas-measuring facilities, and compressors. Access to major transportation pipelines to receive and deliver gas is also an essential component to ensuring that stored gas is efficiently distributed to meet demand.

Depleted Reservoirs

Once an oil field has been depleted of its oil, the underground space can be developed for natural-gas storage. The space is a permeable underground rock formation that is confined by impermeable rock or water barriers. The average thickness of the rock formation is 1,000 to 5,000 feet, and it is identified by a single natural formation pressure. Having contained petroleum for some duration, depleted reservoirs are storage space proven to hold natural gas. Furthermore, the geology and operating characteristics of a depleted field are already known. Another advantage of depleted field is that the existing wells, gathering systems, and pipelines used earlier for oil can be reused for natural-gas operations. The number and locations of depleted reservoirs to develop for natural-gas storage depend on the number and locations of already-existing depleted oil reservoirs. Generally, a depleted reservoir requires 50 percent of its total capacity to be filled with base gas, leaving 50 percent of the total capacity for working gas storage.

Aquifers

Aquifers are underground permeable rock formations that serve as natural water reservoirs. Aquifers can be converted to natural-gas storage by injecting gas into the water-filled space from the top and forcing the water down into the structure. Hence, natural gas essentially displaces the once-water-occupied space. The underground aquifer is appropriate for natural-gas storage if it is overlaid with an impermeable cap rock. However, even with the presence of impermeable cap rock, aquifers are unproven for natural-gas storage and therefore require further testing for leaks and monitoring of withdrawal and injection performance. Aquifers require a base gas volume of 80 percent of total capacity, leaving only 20 percent for working gas capacity.

Salt Formations

A hollow salt cavern can be leached from naturally occurring salt formations. In the United States, salt caverns are formed from salt domes that are fingerlike, cylindrical salt deposits of 1 to 2 miles in diameter. The top of the salt dome reaches 1,000 to 1,500 feet underground. The cavern is formed by drilling a hole, pumping freshwater or seawater through the hole to dissolve the salt, then pumping out the now–salt-saturated water. The process is repeated until the desired volume is carved out. The process usually requires one year. In the United States, salt caverns can hold up to 11 Bcf of natural gas. If a greater capacity is required in the future, the salt cavern can be further dissolved to meet new capacity requirements (Poten and Partners, 2004). The walls of salt caverns have the structural strength of steel and provide a high-pressure storage vessel. The salt caverns have proven to be resilient to reservoir degradation over the life of the storage facility. The base gas requirement for salt caverns, at 20 percent, is quite low relative to aquifers and depleted reservoirs. In addition, very little natural gas escapes from the formation unless deliberately extracted (FERC, 2004). Salt formations suitable for salt caverns are found throughout the United States, Canada, Mexico, the Mediterranean, and Southeast Asia.

Other Storage Possibilities

While the three aforementioned storage facilities are the most common ones employed, other types of storage facilities exist. Abandoned mines can also serve as a natural-gas storage vessel. One such facility is currently used in the United States (EIA, 2004). Rock caverns are another potential source of natural-gas storage. None is commercially operating at the present time, but rock caverns are undergoing investigation to surmise the feasibility for natural-gas storage (EIA, 2004). Work is being conducted to use steel-lined rock caverns, in which a steel tank has been installed in a cavern that has been blasted into the rock of a hill. Storing natural gas as cooled LNG in manufactured vessels on surface or subsurface is another option that has been employed. The United States has LNG-import terminals, mostly in the northeast region. Due to the potential dangers associated with highly pressurized LNG, LNG terminal development faces land-use and local siting barriers (FERC, 2004).

Operations of Storage

Not surprisingly, the differences in physical characteristics of the three types of storage lend themselves to varying operational characteristics. As mentioned earlier, depleted reservoirs and aquifers are composed of permeable rock formations, and salt caverns have walls the strength of steel, enabling high-pressure storage. This physical attribute affects how much gas can be carried over from year to year. When gas sits in storage for a long duration, gas will move from an area of high pressure to lower pressure. The gas spreads into a wider area and seeps into areas with tighter formations. As a result, the pressure of the storage decreases, the base gas level increases, and working gas is lost. Due to the permeable nature of depleted reservoirs and aquifers, depleted reservoirs and aquifers have higher base gas levels (50 percent and 80 percent, respectively) than salt caverns (20 percent). These base gas levels are rough estimates. Practically, how long gas can remain in the reservoirs prior to withdrawal and how soon the capacity can be refilled are answered through experience more than through theory. Experience of cycling storage facilities at various turnover and injection conditions provides insight into how long gas can sit in storage without resulting in great loss of natural gas.

Higher base gas levels mean that depleted reservoirs and aquifers will have lower injection rates than salt caverns. Lower injection rates lead to longer injection periods. For these two storage types, the injection period is 200 to 250 days during the months of April to October. On the other hand, for salt caverns, the injection period is 20–40 days. Because salt caverns can store natural gas at higher pressure, this type of storage has a higher deliverability rate than do reservoirs and aquifers. As a result, the withdrawal period of salt caverns is 10 to 20 days, whereas it is 100 to 150 days for depleted reservoirs and aquifers. Having shorter injection and withdrawal periods, salt caverns can be cycled 10 to 12 times per year, unlike depleted reservoirs and aquifers, which are cycled once per year (Simmons and Company International, 2000). For depleted reservoirs and aquifers, the gas is usually withdrawn in the winter season (November to March) to meet the cold-season demands and injected during the summer season. In addition to meeting seasonal demand, storage may be used to meet peak load requirements.

Of the three types, depleted reservoirs are the easiest and least costly to develop (FERC, 2004). Therefore, if available, depleted reservoirs are the favored storage choice. Aquifers are usually used in areas where depleted oil reservoirs are not readily available nearby. Aquifers are less desirable and more expensive to develop than depleted reservoirs: The geological characteristics of aquifer formation are not as thoroughly known as are those of depleted reservoirs. Hence, a significant amount of time and resources is dedicated to investigating the geological conditions of an aquifer and determining its suitability as a natural-gas storage facility (FERC, 2004). Salt caverns are more expensive to develop but, once formed, have many operational advantages. Their high deliverability and injection allow for greater flexibility in the operations. Due to relatively short injection and withdrawal periods, salt caverns are mainly used for short peak-day deliverability purposes (Simmons and Company International, 2000).

Cost of Storage

The costs of storage are site specific and depend on multiple factors, such as the quality and variability of the geologic structure of the proposed site, amount of compressive horsepower required, type of surface facilities needed, proximity to pipeline infrastructure, and permitting and environmental issues. Other costs include holding inventory and transporting natural gas from supply source to storage facility and from storage to market. Of all cost factors, the cost of base gas is one of the most expensive elements of a storage project.

Salt domes are more expensive to develop but offer more flexibility due to significantly shorter injection and withdrawal periods that allow the gas in salt caverns to be cycled as many as 12 times per year. Consequently, on a deliverability basis, salt caverns are less costly than depleted reservoirs. By one estimate, assuming one cycle per year, depleted reservoirs cost $0.48 per MMBTU, and salt domes cost $1.08 per MMBTU. But if the salt dome is cycled five times in one year, the cost is reduced to $0.28 per MMBTU (Simmons and Company International, 2000).

Tables C.1 and C.2 compare the cost of gas storage using depleted reservoirs versus salt caverns.

According to estimates in the United States, a typical six- to 12-cycle U.S. Gulf Coast salt cavern can cost upward of $10 million per Bcf of working gas capacity and as much as $25 million per Bcf. A typical two-cycle depleted-reservoir field costs $5 million to $6 million per Bcf.

Table C.1
Average Cost of Storing Natural Gas in Depleted Reservoirs

Cost Item	Cost ($/MMBTU)
Annual demand charge	0.40
Injection fee	0.02
Withdrawal fee	0.02
Fuel	0.04[a]
Total	0.48

[a] This is 1 percent of a $4.00/MMBTU natural-gas price.

NOTE: Storage costs vary from facility to facility and are often based on negotiated rates.

Table C.2
Average Cost of Storing Natural Gas in Salt Domes ($/MMBTU)

	Cycle				
Cost Item	**1**	**2**	**3**	**4**	**5**
Demand charge	1.00	0.50	0.33	0.25	0.20
Injection fee	0.02	0.02	0.02	0.02	0.02
Withdrawal fee	0.02	0.02	0.02	0.02	0.02
Fuel	0.04	0.04	0.04	0.04	0.04
Total	1.08	0.58	0.41	0.33	0.28

NOTE: Storage costs vary from facility to facility and are often based on negotiated rates.

One reason for the high cost of salt-cavern development is the large amount of water needed for the leaching process and environmental problems associated with disposing of brine.

Deregulation of Storage

Currently in the United States, the principal owners and operators of storage are interstate-pipeline companies, intrastate-pipeline companies, local distribution companies, and independent storage-service providers. Interstate-pipeline companies have used storage for load balancing and system-supply management on their long-haul transmission lines and for supplying gas to end users. Before 1994, the interstate-pipeline companies owned all the gas in their pipelines and storage and had exclusive control over the capacity and operations of their storage facilities. This situation changed in 1994, when FERC order 636 on open access was implemented. According to the new law, pipeline companies were required to provide third parties open access to their storage facilities. Minus the working gas capacity needed to maintain system balance, pipeline companies were required to make available for leasing to third parties a major portion of the remaining working gas capacity at each site.

Before open access, the traditional use of storage was as backup inventory or supplemental seasonal supply source. With the advent of open access, new uses and opportunities for the storage market have emerged. Marketers and other third parties can now lease storage capacity to move gas in and out as gas prices present arbitrage opportunities. Storage is now used as a tool to enable various financial instruments, such as futures and options contracts and swaps, in order to leverage market conditions and optimize profit.

The traditional use of storage has been to meet seasonal demand variations, hourly swings, and emergency situations. Since the unbundling of storage, the consequent market conditions have generated some new uses for storage. They include the following:

- Meet regulatory obligation to ensure supply reliability at the lowest cost to the ratepayer by maintaining specific levels of storage inventory.
- Avoid imbalance penalties and facilitate daily nomination changes, parking and lending services, and simultaneous injections and withdrawals.
- Ensure liquidity at market centers to help contain price volatility and maintain orderly gas markets.

- Offset the reduction in traditional supplies that were relied on to meet winter demand.
- Increase the acceptable inventory level of working gas or top gas—that is, the portion of gas that is recoverable from the reservoir.
- Offset, through the injection of more gas during the shoulder months, the growing summer peak impacts from electric generation. Support other electric-generation loads (FERC, 2004).

Ownership and Operation of Storage

As discussed, the owners of storage in the United States are not necessarily the owners of the gas inside. The stored gas may be under lease with shippers, local distribution companies, or end users. Who owns and operates that capacity portion determines how that storage is used. Since open access, local distribution companies have exploited opportunities to optimize revenue by leasing a portion of their storage capacity to third parties, which are often marketers. Marketers, in turn, use the storage to capitalize on arbitrage opportunities. Hence, who owns the storage capacity affects how that storage is operated.

Regulated gas utilities are price insensitive. Regardless of the current price, they inject gas during the summer and withdraw during the winter. Therefore, the stored gas level does not fluctuate much during the two seasons. Energy marketers, however, are price sensitive, as they try to capture any arbitrage between current and future gas prices. This price sensitivity is reflected in the highly fluctuating gas level in storage owned by energy marketers. A third group of storage owners is a hybrid of local distribution companies and energy marketers. In this case, local distribution companies have outsourced to marketers the management of storage. Marketers must meet the requirements for storage injections, withdrawals, and minimum storage levels. Beyond these requirements, marketers can use the storage at their discretion to capture any arbitrage available (Simmons and Company International, 2000).

In the United States, open access has had a significant impact on the portfolio of storage ownership. In 2002, interstate-pipeline companies operated 55 percent of gas storage capacity. Local distribution companies and intrastate-pipeline companies operated 35 percent of working gas capacity, and independent operators about 10 percent of working gas capacity. Although interstate-pipeline companies operated the majority of storage capacity, they had contractual rights to use only 8 percent of working gas capacity for their own purposes. The local distribution companies held contractual ownership of 73 percent of storage capacity, and marketers held 15 percent of storage under contract.

Recently, the demand for storage that provides operational flexibility and high deliverability and injection rates has increased due to two main factors: (1) There has been an increase in the number of gas-fired electricity-generating plants, and (2) energy marketers want to exploit arbitrage opportunities. In both cases, high deliverability rates and access to storage with flexible options that allow rapid and frequent injections and withdrawals of large volumes of natural gas are crucial. In response to this demand, independent storage providers that are often smaller and nimbler have developed salt caverns, which have high deliverability and injection rates. These storage providers have targeted marketers and electricity generators that would greatly benefit from the flexibility afforded by high-deliverability storage. Salt caverns provide rapid cycling—in other words, inventory turnover—and can respond to daily and hourly variations in customer needs.

Advantages and Disadvantages of Each Type of Storage

We summarize in this section the advantages and disadvantages of each of the three types of natural-gas storage. See Simmons and Company International (2000).

Depleted Reservoir

- Advantages
  - Depleted reservoirs are typically near existing regional pipeline infrastructure.
  - Fields already have usable wells and gathering facilities, a fact that reduces the cost of conversion to gas storage.
  - Their geology is well known; the fields have previously trapped hydrocarbons that minimize the risk of reservoir leaks.
- Disadvantages
  - Because of the nature of reservoir-producing mechanisms, working gas volumes are usually cycled only once per season (extremely high–storage reservoirs are the exception).
  - Often, these reservoirs are old and require a substantial amount of well maintenance and monitoring to ensure that working gas is not being lost via well bore leaks into other permeable reservoirs.

Aquifer

- Advantages
  - Typically, these are close to the end-user market.
  - They offer high deliverability from the combination of high-quality reservoirs and water drive during the withdrawal cycle.
  - High deliverability increases the ability to cycle working gas volumes more than once per season.
- Disadvantages
  - They have a high level of geological risk. These reservoirs have never trapped hydrocarbons, and there is uncertainty as to how well they will contain injected gas. A risk of substantial reservoir leaks exists.
  - Because these reservoirs are produced via water drive, water production is often experienced during the withdrawal cycle, increasing operating costs to dry the gas.
  - Due to the water-drive mechanism during the withdrawal cycle, the base gas requirements are high (80 percent). A large percentage of base gas is not recoverable after site abandonment. This high base gas requirement likely limits the number of new aquifer storage projects (increases initial capital cost).

Salt Caverns

- Advantages
  - The low base gas requirement is 25 percent and can approach 0 percent in emergencies.
  - They offer ultrahigh deliverability, much higher than depleted-reservoir and aquifer storage.

  - They offer operational flexibility, as these reservoirs can cycle working gas 12 times per year. Their location on the U.S. Gulf Coast allows daily production and nightly injection to help meet peaking natural-gas demand during the summer air-conditioning season.
  - Salt caverns provide excellent seals, their walls are essentially impermeable barriers, and the risk of reservoir leak is small.
- Disadvantages
  - They have a costly start-up.
  - Disposal of saturated saltwater generated during the solution mining process can be costly and environmentally problematic.

New Technologies for Underground Storage

Because the development of new storage facilities is limited by geological locations, cost, and environmental consequences, efforts have been made to reengineer existing storage to improve capacity and performance rather than add new storage. The current methods of improving storage-field efficiency include mechanically removing debris, washing, injecting acids, and creating new perforations in the well-pipe reservoir. These methods provide limited and temporary improvements. Another method to increase capacity and deliverability is to horizontally drill through a reservoir, thereby increasing the exposure surface of the well bore. This increases the rate and amount of natural gas that can be withdrawn from a well over a specific time period. Other methods to increase deliverability have included increasing the number of input and output wells and upgrading the compression units at existing depleted reservoirs (EIA, 2006). Other methods include drilling large-diameter wells, relocating wells within reservoirs, and incorporating coiled-tubing drilling.

To store a greater amount of natural gas in the limited storage space, salt-cavern operators have condensed the volume of natural gas by chilling it, thereby reducing the volume of brine that needs to be dissolved and disposed. Natural gas has also been frozen in the presence of water to create hydrates, allowing for large quantities to be stored in the same volume. The capacity of existing salt caverns has been expanded through addition of more caverns (EIA, 2006).

New technologies are now used to improve storage-field efficiency. Sound waves have been used to remove scale off the well pipe in order to unclog it and improve flow through the pipeline, thereby improving deliverability and injection rates. Fracturing technologies, such as injecting high-pressure liquid CO_2 instead of water or other liquids, are used to inhibit clay from sticking and sealing off parts of the reservoirs.

Another relatively new technology is the Bishop process developed by Conversion Gas Imports. In this process, LNG is unloaded offshore, warmed to 40°F, and stored as natural-gas vapor in underground salt caverns either offshore or onshore. The process obviates the need to build expensive surface cryogenic storage tanks. This technology is discussed in greater detail in “The Bishop Process” at the end of this appendix.

Liquefied Natural Gas and Flow Storage

When natural gas is cooled to temperatures below –260°F, it condenses to LNG.[1] In liquid form, natural gas occupies just 1/600 the volume of its gaseous form. With such a significant reduction in volume, large quantities of LNG can be transported in the volume of a single tanker ship. In fact, one tanker shipment of LNG can carry enough LNG to power the daily energy needs of more than 10 million homes. The liquefied form also allows for ship transportation to great distances, too costly to reach by building underground or undersea pipeline networks. Shipments of LNG have traveled as far as Japan from the United States and from Qatar to the United States (Parfomak, 2003). Liquefaction of natural gas provides an economical means to store and transport natural gas, thereby availing natural gas to areas of the world where natural gas is scarce.

When natural gas is needed, LNG is warmed, regasified, and pumped into the distribution pipelines to be used for the same purposes as conventional natural gas. A common use of LNG is for peak shaving. Peak shaving is the practice of storing gas for peak demands that cannot be met by their typical pipeline sources. During extremely cold months or hot months or other unforeseen events, the demand for electricity may peak. To meet this peak in demand, utilities need a reliable source of gas that can quickly supplement the existing supply and shave peaks in demand. LNG can be a reliable source that can be stored and quickly converted to usable gas. LNG can be diverted from the pipeline, liquefied, and stored for future use on site or trucked to satellite facilities (NETL, 2005).

The major stages of the LNG value chain are exploration and production, liquefaction, shipping, and storage. Most of the time, natural gas is explored and produced while searching for oil. Once discovered and extracted, natural gas is cooled and liquefied in order to transport LNG by ship. As of 2007, there were 224 tankers in service around the world (Foss, 2007). The final stage involves storing the LNG in special tanks, regasification to convert from liquid to gas, and infusion into the pipeline system for delivery to end users.

Costs

In the past 20 years, technology improvements, competition among manufacturers, and economies of scale have reduced the costs of development and operations in all phases of the LNG value chain. The costs of liquefaction plants have decreased from $600 per ton of capacity in the late 1980s to about $200 per ton in 2001. The construction of a new 8.2-million-ton-per-year liquefaction plant could cost between $1.5 billion and $2 billion (NETL, 2005). Construction costs of LNG ships have dropped from $280 million in 1995 for a 138,000-cubic-meter-capacity ship to $150 million to $160 million today. Chartering an LNG ship costs about $60,000 per day (NETL, 2005). The building and operating costs of onshore receiving terminals total upward of $400 million. Offshore-terminal construction cost is substantially

[1] LNG should not be confused with NGL, CNG, LPG, or GTL. The composition of LNG is distinct from these other natural-gas varieties. LNG is about 95 percent methane and 5 percent other gases. NGL is mostly composed of hydrocarbon gases heavier than methane, such as ethane, propane, and butane. LPG is 95 percent propane and butane. The composition of CNG is the same as the pipeline-quality natural gas. Unlike pipeline-quality natural gas, CNG is pressurized up to 3,600 psig and stored in welding bottle–like tanks. GTL is the process of converting natural gas to such products as methanol, DME, and other chemicals (Foss, 2007).

higher. These terminals function as unloading, storage, and regasification facilities (NETL, 2005).

Safety of LNG Storage

In the United States, FERC and DOT regulate land-based LNG facilities and onshore portions of marine terminals. Federal regulations require the LNG facilities to establish security patrols, protective enclosures, lighting, monitoring equipment, and alternative-energy sources. The regulation also requires an exclusion zone surrounding the facilities to protect adjacent sites in the event of flammable vapor-cloud release (NETL and NARUC, 2005).

Leakage from an LNG storage tank does not automatically lead to an explosion or fire. Natural gas has a limited flammability range of 5–15 percent composition in air. Above 15 percent, there is not a sufficient supply of oxygen for the natural gas to ignite. Below 5 percent, the concentration of natural gas is insufficient for a fire to start (NETL and NARUC, 2005).

The combustibility and ultralow temperature of LNG, however, do pose potential hazards. The likelihood and severity of hazardous incidents are debatable. However, experts tend to agree on what the greatest potential dangers are: pool fires, flammable vapor clouds, and flameless explosion. Pool fires occur when LNG spills near an ignition source and the evaporating gas burns over the pool of spilled LNG. The resulting fire spreads as the LNG pool expands and continues to evaporate. LNG pool fires burn more intensely and rapidly than oil or gasoline fires and cannot be extinguished. The LNG must be consumed completely for the fire to die. A pool fire, especially over water, is considered the most dangerous LNG accident. In cases in which LNG spills but does not ignite immediately, the evaporating natural gas will form a vapor cloud that drifts from the spill site. Once the cloud encounters an ignition source, the cloud could explode. The third potential LNG hazard results from an LNG spill over water. The LNG could heat up and regasify almost instantly in a flameless explosion. A flameless explosion is not likely to produce a hazard zone as large as a vapor cloud or pool-fire hazard zone (Parfomak, 2003).

The sea transportation and storage of LNG in the past 40 years have experienced relatively few accidents and injuries. LNG tankers have carried more than 40,000 LNG shipments more than 100 million miles without serious accidents at sea or in port. There have been 30 LNG-tanker safety incidents. Twelve of these involved small LNG spills, which caused freezing damage but did not ignite. Two incidents caused small vapor-vent fires that were quickly extinguished (Parfomak, 2003). One of the most lethal onshore accidents occurred in 1944, when an LNG spill from an improperly designed storage tank resulted in a fire that killed 128 people. From 1944 to 2003, there have been 10 serious accidents at LNG facilities. Two of these resulted in fatalities. In three incidents, the fatalities resulted from construction or maintenance failures and not from a direct interaction with LNG (Parfomak, 2003).

The potential hazard due to LNG spill, however, can be catastrophic. One study (Hightower et al., 2004) modeled accidental and intentional LNG spillage in order to determine the level of consequential hazard. The study estimated that the level of LNG–cargo tank breaches for intentional events, such as acts of terrorism, would be up to six times as large as for an accidental event. It was estimated that thermal hazards would occur mostly within 1,600 meters of an LNG-ship spill, with the highest hazard within 250 to 500 meters of the spill. The pool sizes for a credible spill were estimated to range from 150 meters for small spills to several hundred meters in diameter for large spills. Beyond about 750 meters for small spills and 1,600 meters for large spills, the impacts on public safety should be low (Hightower et al., 2004).

Traditional LNG Storage

As of 2007, 23 LNG-export (liquefaction) terminals, 58 import (regasification) terminals, and 240 LNG-storage facilities existed worldwide.

LNG is stored at atmospheric pressure in double-walled, insulated tanks. The inner walls of the tank are composed of special steel alloys with high nickel content, aluminum, and prestressed concrete. The storage tanks are built on top of concrete blocks that are reinforced with steel bars. The concrete base is composed of glassy volcanic aggregate perlite, cement, and special admixtures. The base blocks and perlite act to insulate the cryogenic tank from the ground and surrounding air. The wall can be as thick as 5.5 feet (NETL, 2005).

As a precaution against spills or leaks, the storage tanks are generally surrounded by containment structures, which limit the spread of an LNG spill and the potential vapor cloud. Some double-containment systems involve building an outer tank wall around the inner tank wall that can contain LNG. Another method builds an earthen dam or dike around a single-containment tank to serve as a secondary containment for any LNG spills (NETL and NARUC, 2005).

Although storage facilities can be located in remote locations, they are generally located near the population they serve and integrated with the local gas-pipeline network. Natural gas may be drawn from the pipeline grid, liquefied, and stored. If liquefaction facilities are not available, LNG may be received by truck or ship tankers and stored directly. LNG tankers unload their cargo at marine terminals, which store and regasify LNG. These terminals include docks, LNG-handling equipment, storage tanks, and interconnections to regional gas-transmission pipelines. Some terminals are established entirely offshore and connected to land only by underwater pipelines. These offshore-terminal designs conveniently avoid much of the community opposition and permitting challenges that can delay or prevent the construction of onshore LNG terminals. Offshore terminals, however, may create adverse environmental impacts. Because offshore terminals use the seawater to warm the LNG, the regasification process lowers the water temperature near the terminal, potentially affecting the local ecosystem (Parfomak, 2003).

At receiving terminals, LNG may be dispensed into tanker trucks for distribution to central refueling locations. LNG receiving terminals may be colocated with electric power–generation facilities, where the cryogenic properties of LNG are used to help cool the power plant or natural gas is converted to electric power. The LNG also can undergo regasification and be added into the natural-gas pipeline system to wide consumer distribution. Often, LNG is stored in its liquid state and saved for future demand peaks. Until demand calls for regasification of LNG, the liquid form allows for more natural gas to be stored in a lower-volume space. LNG is stored in a special cryogenic tank (Foss, 2007).

LNG Storage to Distribution

LNG-storage facilities can quickly regasify LNG and inject it into the transmission system. This ability is invaluable to meeting peak demands during cold and hot months on short notice.

Pumps transfer LNG from its storage tanks to warming systems, where the LNG is brought to its vapor state and delivered into the transmission and distribution network. The warming systems can be either ambient-temperature systems or above–ambient temperature systems. Ambient-temperature systems use heat from surrounding air or from seawater to vaporize the cryogenic liquid. Even during the cold months, the ambient temperature is higher than the LNG temperature. Above–ambient temperature systems vaporize LNG by adding heat to the system (NETL and NARUC, 2005).

Developing an LNG Terminal

In the United States, as many as 100 permits and approvals may be required from federal, state, and local government agencies to establish a new onshore LNG terminal. It may require three years to obtain all necessary permits and approvals and another four years before a new onshore terminal is operational. At the federal level, FERC, U.S. Coast Guard, DOT, the U.S. Department of Energy, and the U.S. Environmental Protection Agency play major roles in overseeing the LNG infrastructure. At the state and local levels, state departments of environmental protection, local governments, fire departments, and police are involved in the zoning, construction, operation, maintenance, and safety and security of the facilities and the surrounding areas (NETL and NARUC, 2005).

The Bishop Process

In a conventional terminal system, LNG is transferred as liquid into a cryogenic tank, maintained in liquid form, and vaporized when withdrawn from the storage tank for use. In the Bishop process, the LNG is vaporized at the point of ship discharge and stored as gas. For a 10,000-cubic-meter-per-hour unloading rate, the vaporization capacity reaches 5 Bcf/day, which is two to ten times greater than the conventional terminal rates. The greater pumping and vaporization rates, however, demand a significantly greater power input. About 65 MW of offshore power-generation capacity is needed adjacent to the offshore ship's unloading position (Poten and Partners, 2004).

The Bishop process entails transferring LNG directly from the offshore tanker at cryogenic temperature, pressurizing it to 2,000 psi and warming it to 40°F, then injecting into an underground salt cavern for storage or directly into the pipeline for distribution. This method obviates the need to build onshore LNG-receiving facilities, which local communities can heavily protest. Cryogenic LNG-storage tanks are the most expensive elements in a receiving facility. Underground salt caverns also offer greater storage capacity and expansion potential than aboveground LNG-storage tanks. The ship can also be unloaded miles from the storage caverns, providing more flexibility and security (Craddock, 2003).

The Bishop process encompasses three basic components: the LNG-ship mooring and transfer system, the process design and equipment, and the gas-storage salt caverns. Offshore mooring and transfer of crude oil is a well-established, 40-year-old practice. The technology and knowledge from this practice has been applied to the LNG-ship mooring and transfer system. The LNG is transferred from the ship to a nearby platform that contains the process equipment, power pumps, heat exchanger, and salt-cavern wellheads. The platform is designed to be suitable for the current LNG fleet's operational design. The onshore terminals receive LNG from ships at atmospheric pressures and discharge at pipeline pressures as high as 1,440 psi. To inject directly into salt caverns, the high-pressure pumps of the Bishop process achieve discharge pressures greater than 2,000 psi. The heat exchanger can warm the onboard LNG and ready it for injection into caverns and pipelines at a flow rate as high as 170 MMcf/day or 10,000 cubic meters per hour (McCall et al., 2005). The discharged LNG is pumped either directly into the pipeline at 1,000 psi or into salt caverns at 900 to 2,000 psi, depending on the fullness of the cavern.

The LNG is unloaded from the ship through its internal pumps at a relatively low pressure into a series of high-pressure pumps. The portion of LNG designated for direct injection into a pipeline is diverted to the low-pressure (1,000-psi) sendout pumps. The portion of LNG intended for salt-cavern storage is sent through the high-pressure (2,000-psi) sendout pumps. The low-pressure LNG is then sent to the low-pressure vaporizer, and high-pressure LNG is sent to the high-pressure vaporizer, where they are both warmed to 40°F by the seawater heat-exchanger system (Poten and Partners, 2004). After passing through this series of high-pressure pumps, the unloaded LNG rises to cavern injection pressures. The high-pressure, low-temperature LNG enters the heat-exchanger system, where its temperature and pressure are raised to cavern- and pipeline-compatible parameters. The gas can be directly injected into the salt cavern or into the pipeline network (McCall et al., 2005).

Traditional heat exchangers used to bring the LNG temperature up to 40°F employ natural gas to heat the LNG. This traditional process usually cannot keep up with the tanker offloading rates at marine terminals. The Bishop process uses a seawater heat exchanger that allows high-volume and high-pressure heat exchanging, thereby reducing the unloading time. Using the Bishop process, terminals with working gas storage of 16 Bcf and peak deliverability of 3 Bcf/day may be possible. These storage volumes and deliverability rates are at least twice those of most conventional LNG terminals. A DOE-funded project is exploring terminal designs with 30 Bcf of working gas storage and 5 Bcf of deliverability (Craddock, 2003). Tests of the heating and pumping system demonstrated that the Bishop process could convert LNG to flowing natural gas at full design rate exceeding 160 Mcf/day. At that rate, the tankers could finish unloading in one day (Korman, 2006).

It has been estimated that the developmental cost of a salt cavern–based LNG terminal is half that of a conventional LNG terminal (Craddock, 2003). Developmental cost for an offshore terminal with salt-cavern storage is the same as that for a conventional onshore LNG terminal but with three times the storage capacity. With permits secured, it is estimated that construction of a salt cavern–based terminal could be constructed in two years, which is one year less than tank-based designs (McCall et al., 2005).

Environment

Because the Bishop process uses large volumes of seawater as a heat-exchanging medium, the fish larvae passing through the area are likely to die. The National Oceanic and Atmospheric Administration estimates 100-percent mortality for all organisms passing through the system (Korman, 2006).

APPENDIX D

Technologies for Electricity Generation

Electric Power Plants

Currently, more than 50,000 power plants are operating worldwide (CARMA, undated; "Carbon Dioxide Emissions from Power Plants Rated Worldwide," 2007). Among the various types of electric power plants (fossil fuel, nuclear, geothermal, biomass, wind, and solar thermal), fossil-fueled power plants account for the largest share of electricity generation worldwide. The total world electricity generation by fuel type in 2002 was coal (39 percent), natural gas (19 percent), nuclear (17 percent), hydro (16 percent), and oil (7 percent). The remaining 2 percent consisted of contributions from solar, wind, combustible renewables, geothermal, and waste.

An electric power plant operates generating units and auxiliary equipment to convert various types of energy into electric energy. The most common types of generating units are steam turbine, CT, water turbine, and wind turbine. In a fossil-fueled power plant, the chemical energy stored in the fossil fuel (coal, fuel oil, natural gas) is successively converted to thermal energy, mechanical energy, and electrical energy (EIA, 2002).

The general construction of a turbine involves a series of blades mounted on a central shaft. Wire coils are wrapped around the shaft, and this assembly is placed between permanent magnets. Liquid or gas is forced onto these blades, thus rotating the shaft and the wire coils. The rotation of the wire coils between the magnets creates electricity. In the case of water and wind turbines, the force of the water and wind on the blades rotates the shaft (EIA, 2002).

Most power plants require a mix of generating units to meet load requirements that vary daily, weekly, and seasonally. Different generating units are chosen for different load requirements. Base-load generating units operate most of the time to meet the basic demand that is always present. Hence, base-load generating units operate at a constant output level all the time. Peak-load units are employed for short periods of time when the plant's load is near its maximum level. Intermediate-load generating units are operated less than base-load units but more than peak-load units (EIA, 2002).

The next section provides an overview of the leading fossil-fuel power-plant technologies.

Coal-Fired Steam-Turbine Plants

As stated before, fossil-fueled power plants are the most common power plants worldwide. Among the various types of generating units, steam turbines are mostly employed, followed by gas turbines. In the case of steam turbines, water in a boiler unit is heated to create high-temperature steam at very high pressure. The pressure of the steam on the blades turns the shaft connected to the generator. After the steam travels through the turbine, it is condensed back into water to start the cycle again. The source of heat to produce steam can be one of the various fossil fuels, such as coal, natural gas, or oil. Coal, however, is the preferred fuel for steam-generating units because of its low cost and its broad and secure availability worldwide (EIA, 2002). Modern large steam-turbine plants (over 500 MW) can achieve efficiencies ranging from 40 percent to 45 percent (Cogeneration Technologies, undated). The installation costs range between \$2,000 and \$4,000 per kW (FERC, 2008).

Its low cost and abundance in the world make coal an attractive fuel for supplying relatively inexpensive electricity. It has been estimated that there are more than 984 billion tonnes of proven coal reserves worldwide. Furthermore, the supply of coal is spread all over the world. Coal is located on every continent in more than 70 countries. The top five countries with the largest reserves of coal as of 2003 were the United States (250 billion tonnes), Russia (150 billion tonnes), China (120 billion tonnes), India (85 billion tonnes), and Australia (80 billion tonnes) (BP, 2004). The coal-reserve shares regionally, as of 2003, were Europe and Eurasia (36 percent), Asia Pacific (30 percent), North America (26 percent), Africa (6 percent), South and Central America (2 percent), and the Middle East (< 1 percent) (BP, 2004). The top five coal producers are China, the United States, India, Australia, and South Africa. With the abundance of coal and coal suppliers, it is no surprise that most of the world's power plants are fueled with coal. Coal provides about 25 percent of the world's primary energy and about 40 percent of the world's electricity, which is more than double the next-largest source (natural gas, 19 percent). In Poland and South Africa, more than 90 percent of the electricity is generated from coal. In the United States and Germany, more than 50 percent of the electricity is generated from coal (WCI, 2005).

The earliest coal-fueled steam plants used lump coal to heat the water boilers. Modern coal steam plants first pulverize the coal lumps into fine powder. The powder coal is blown into the combustion chamber, where it is burned at high temperature. The increased surface area of powdered coal allows it to burn more quickly. This pulverized-coal combustion (PCC) technology accounts for more than 90 percent of the coal-fired capacity worldwide.

As recently as 2004, the construction cost of conventional coal plants ranged from \$1,000 to \$1,500 per kW. In 2008, the construction cost of coal-fueled steam power plants ranged from \$2,000 to \$4,000 per kW (Table D.1). Construction costs of power plants, both fossil-fueled and renewable-energy plants, in general have risen sharply in the past few years. CC-plant cost has risen from \$700 per kW in 2004 to \$800 to \$1,500 per kW in 2008. Gas-turbine plants have risen from \$300–\$800 per kW to \$500–\$1,000 per kW over the same time period. The rise in construction costs is mainly due to increased prices of raw materials, such as steel and cement. The cost of raw materials has risen due to an increase in global demand for manufactured goods and higher production and transportation costs. Increased labor cost is a smaller factor to increased power plant–construction cost. This factor, however, can become more significant as large construction projects globally raise the demand for specialized and skilled labor (Chupka and Basheda, 2007).

The global average thermal efficiency of coal power plants is about 30 percent. Supercritical technology allows coal power plants to achieve 43- to 45-percent efficiency. Supercritical plants, to achieve higher efficiency, operate at higher steam temperature and pressures than conventional plants. Ultrasupercritical plants operate at even higher temperatures and pressures and can reach efficiency levels of 50 percent. More than 400 supercritical plants are operating worldwide (WCI, 2005).

Table D.1
Electric Power Plant Thermal Efficiencies and Construction Costs

Power Plant	Efficiency (%)	Cost ($/kW)
Hydro	95	
Tidal	90	
CC gas turbine	58	800–1,500
Pulverized coal boilers with ultracritical steam parameters	47	
Coal-fired IGCC	45	3,000–6,000
Steam turbine, gas fired	40	
Gas turbine	38	500–1,000
Steam turbine, coal fired	38	2,000–4,000
Steam turbine, fuel oil fired	38	
Wind turbine	35	1,200–2,500
Nuclear power	33	4,500–7,500
Biomass biogas	30	
Waste to electricity	22	
Geothermal	15	2,500–3,500
Solar-powered tower	15	3,000–5,000

SOURCE: Van Aart (2004).
NOTE: IGCC = integrated gasification combined cycle.

The negative environmental impacts, however, are sizable. New technologies are being developed to eliminate the sulfur, nitrogen, and mercury pollutants that are released with coal burning. Technologies to capture and isolate GHGs are also being researched. Furthermore, research is under way to increase the fuel efficiency of coal power plants. Currently, coal power plants convert only one-third of coal energy into electricity. New technologies to improve efficiency are highly sought (DOE, undated).

Emission of particulates, such as ash, affect local visibility and the nearby residents' respiratory systems. Technologies to reduce particulate emission are available. The process of coal cleaning lowers the sulfur and noncombustible content of coal, thereby reducing ash and sulfur oxides. The ash content can be reduced by as much as 50 percent through this process. Coal cleaning also increases thermal efficiency. Methods to remove particulates from coal-combustion flue gases are electrostatic precipitators and fabric filters. In electrostatic precipitators, flue gases containing particulates are passed between electrically charged collecting plates. As the particulates pass through, the particulates are charged and attracted to the collecting plate, where they can be accumulated and removed. Fabric filters are finely woven fabric that traps the particulates as the flue gas passes through. Both methods can remove more than 99.5 percent of particulate emission (WCI, 2005).

As mentioned earlier, cleaning coal before combustion reduces the sulfur content, thereby reducing the emission of sulfur oxides, which can lead to acid rain. Another method to reduce sulfur is flue-gas desulfurization using devices also known as *scrubbers*. This system can remove as much as 99 percent of SO_X emission. In the United States, sulfur emission from coal power plants decreased by 61 percent between 1980 and 2000, even though coal use increased by 74 percent. Selective catalytic reduction can reduce the emission of NO_X by 80 to 90 percent. Fluidized combustion is a technology that can reduce both NO_X and SO_X emissions by up to 90 percent. In this technology, coal is burned in a bed of heated particles suspended in flowing air. This allows the rapid mixing of particles, which leads to more-complete coal combustion at relatively low temperature (WCI, 2005).

CO_2 is a GHG emitted from coal power plants, as it is from all fossil-fuel power plants. Twenty-five percent (10 billion tons) of CO_2 emission is due to power generation. Coal cleaning reduces CO_2 emission up to 5 percent. Supercritical and ultrasupercritical plants have reduced CO_2 emission by up to 22 percent. The technology that has the potential to reduce nearly all CO_2 emission is carbon capture and sequestration. Significant international research is ongoing to realize this method. This method would involve removing from the power-plant exhaust stream nearly all the CO_2 and storing it permanently so that it does not enter the atmosphere. Potential storage spaces are underground, such as in depleted oil and gas reservoirs. Deep saline water–saturated reservoir rocks are another potential storage space for CO_2 (WCI, 2005).

Natural Gas–Fired Steam-Turbine Plants

In the United States, coal is the major fuel for electric power. However, natural gas is gaining popularity for electric power. More than 90 percent of the power plants to be built in the United States in the next 20 years will be natural-gas power plants. Natural-gas steam-generation units have efficiency of 35 to 40 percent (Table D.1). A natural-gas power plant requires half the time to construct that a coal-fired power plant requires (BP, undated).

Natural-gas reserves are found mostly in the Middle East and in Europe and Eurasia. The natural-gas reserve shares regionally, as of 2003, were Middle East (42 percent), Europe and Eurasia (34 percent), Asia Pacific (8 percent), Africa (8 percent), North America (5 percent), and South and Central America (4 percent). The natural-gas production shares were Middle East (12 percent), Europe and Eurasia (37 percent), Asia Pacific (8 percent), Africa (7 percent), North America (27 percent), and South and Central America (5 percent) (BP, 2008). Although the Middle East enjoys the largest share of natural-gas reserve, it does not hold the largest share of natural-gas production. North America, on the other hand, accounts for only 5 percent of the proven natural-gas reserve but holds 27 percent of the production share.

The burning of natural gas produces NO_X and CO_2 but less than the burning of coal or oil. In the United States, natural gas–fired power generation releases 1,135 pounds per MW of CO_2, 0.1 pounds per MW of SO_2, and 1.7 pounds per MW of NO_X. Compared to emissions from coal-fired generation, this is about 50 percent less CO_2, one-third less NO_X, and 1 percent less SO_X. Natural gas–fired plants can release CH_4, a GHG, when the gas is not burned completely or when there is a leak in the system (EPA, 2007).

Similar to coal-fired steam turbines, natural gas–fired steam plants also require large amounts of water for condensing steam. Removing water from lakes or rivers could have deleterious effects on aquatic life.

Gas (combustion) Turbine Plants

In a gas turbine, the natural gas or light fuel oil is burned in a high-pressure chamber. The resulting hot gases are directed through the turbine, spinning the generator to produce electricity. The size of gas-turbine generating units is typically less than 200 MW. At efficiency rates of 25 percent to 35 percent, gas turbines are less efficient than most steam turbines. But they have a faster start-up time than steam-turbine generating units and are suitable for a variety of sites. These qualities make gas-turbine generating units appropriate for peak-load operations. Similar to most peak-load generating units, the gas turbine is generally less efficient than the steam turbine used for base-load generating units (EIA, 2002). The operating cost per hour of gas turbines is higher than for steam turbines. The high operating cost, however, is compensated by the low construction cost of these generating units and by their usage for only peak-load demands. The installation cost of gas-turbine power plants ranges from $500 to $1,000 per kW.

Natural-Gas Combined-Cycle Plants

Although steam-turbine power plants dominate the world power-generation market, gas-turbine share of the world power-generation market has increased from 20 percent to 40 percent of capacity additions in the past 20 years. Most of this increase can be attributed to large CC power plants (> 500 MW) that required less capital cost (as low as $800 per kW) and higher thermal efficiency than steam-turbine power plants. Traditional steam-turbine and gas-turbine power plants operate at an efficiency rating of less than 50 percent (Table D.1). Coupling the gas turbine with a steam turbine in a CC operation increases the efficiency of gas turbines to more than 50 percent. In a CC gas-turbine power plant, one or more gas turbines is connected to a heat-recovery steam generator. The exhaust heat that results from gas-turbine operation is channeled to the water boiler of the heat-recovery steam generator. Steam produced from the heat-recovery steam generator powers a steam-turbine generator to produce additional electricity. As a result, the heat that is normally wasted in a gas-turbine generating unit is reused to generate more electricity without the use of more fuel (EIA, 2002).

The CC plant can be designed for various combinations of gas and steam turbines. A 3-1 CC plant is composed of three gas turbines connected to one steam turbine.[1] The configuration can range from 1-1 to 6-1, gas turbines to steam turbines. A 1-1 CC plant consists of one gas-turbine generator, a heat-recovery steam generator, and a steam-turbine generator. This configuration can produce about 270 MW of capacity, at International Organization for Standardization (ISO) conditions.[2] The 2-1 and 3-1 configurations are becoming more common. These configurations result in larger plants that benefit in economies of scale for construction and operation costs. A 2-1 configuration using FA-class gas turbines produces about 540 MW at ISO conditions (Northwest Power Planning Council, 2002).

A CC system can also provide peak-load capacity when various power-augmentation features are employed. For instance, duct firing, which is the direct combustion of natural gas in the heat-recovery steam generator, can provide an additional 20 to 50 MW of power from a 1-1 power plant. Though the thermal efficiency of duct firing is lower than that of the base CC plant, the incremental cost is low, and it provides a capability that may be used infrequently and for short periods of time yet is very valuable when peak-load supply is needed.

A thermal efficiency of 60 percent at a CC plant in Baglan Bay, Wales (5,690 Btu/kWh) has been demonstrated (GE, undated). This plant has operated this CC system since 2003 and has surpassed 26,500 operating hours. The same technology has also been installed at Tokyo

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1 The first number denotes the count of gas turbines, and the second number represents the number of steam turbines.

2 ISO reference ambient conditions: 14.7 pounds per square inch absolute (psia), 59°F, 60 percent relative humidity.

Electric Power Company's Futtsu Thermal Power Station. Three CC units were projected to enter commercial operation between 2008 and 2010, with a total output of 1,520 MW. This system is also scheduled to begin service in 2008 at the Inland Empire Energy Center in California. Operating on natural gas, the CC systems at Inland Empire will produce a total of 775 MW, or enough power to supply nearly 600,000 households. The CC gas turbine is capable of producing 87,000 fewer tonnes of GHGs per year than a typical gas-turbine CC plant generating an equivalent amount of electricity (GE, 2007a, 2007b).

A gas-turbine CC plant can be constructed in a relatively short amount of time. A 1,000-MW plant can be completed in about 18 months. The construction cost of a CC power plant ranges from $800 to $1,500 per kW. The gas turbines can operate on either gaseous or liquid fuels. The most common fuel used is pipeline natural gas because it has historically enjoyed relatively low and stable prices and because it produces less emission than liquid fuels. Hence, siting a new CC power plant near the natural-gas pipelines is an important factor. Other critical construction factors to consider are proximity to high-voltage transmission lines, proximity to water sources, ambient air quality, and elevation. Depending on the supply of water, water consumption for power-plant condenser cooling can be a critical factor. Significant reductions in water consumption are possible with closed-cycle (dry) cooling. This technology, however, adds cost and reduces performance. Despite these penalties, it appears that the industry is moving toward closed-cycle cooling.

Natural-gas CC power plants produce less CO_2 per unit energy output than other fossil-fuel technologies because of the relatively high thermal efficiency and the high hydrogen-carbon ratio of CH_4. Natural-gas CC technology, however, is not without some environmental concerns. The emission of NO_X and carbon monoxide (CO) are the main pollutant concerns for natural-gas CC power plants. Use of fuel oil in CC plants may produce SO_2. Dry low NO_X combustors and installation of a selective catalytic reduction system within the heat-recovery steam generator may be used to reduce NO_X emission. The selective catalytic reduction system does, however, produce a limited amount of ammonia. An oxidation catalyst within the heat-recovery steam generator is used to reduce the emission of CO. Another environmental concern with natural-gas CC plants is the high consumption of water for cooling steam condensers. This is of particular concern in arid environments.

Internal-Combustion (diesel, piston) Engine Power Plants

Internal-combustion engines have one or more cylinders where the diesel combustion takes place. The engine is connected to the generator shaft and mechanically rotates the shaft to generate electricity. These generating units vary in size from less than 1 MW to 10 MW. They are easy to transport and to install. The start-up time for these units is very short. They begin to produce electricity almost as soon as the engine is started. Therefore, internal-combustion engine generating units are suitable for peak-load demands (EIA, 2002).

Natural-Gas Pipelines

Gas Delivery System

The gas delivery system is a network of branching pipelines that delivers natural gas from the wellhead to homes and businesses (see AGA, 2005). Throughout the network, gas flows from an area of higher pressure to lower pressure. The gas travels from the wellhead into large pipelines that branch and multiply into smaller pipelines, until a pipeline reaches every user.

Gathering System. From various natural gas–producing well points, small-diameter pipelines gather all the crude natural gas and converge at a processing plant. In the processing plants, the crude natural gas is purified of water, CO_2, sulfur, helium, propane, and butane, impurities that may corrode the pipelines or reduce the combustion value of the natural gas. After treatment at the processing plant, the natural gas meets the quality standard for injection into transmission lines. Nonassociated natural gas—gas that was not in contact with significant quantities of crude oil—may be of pipeline quality after purification at the production area such that it does not have to undergo further purification at the processing plant. Therefore, this gas can bypass the processing plant and go directly into the transmission line. In addition to producing line-quality CH_4, processing plants may separate, purify, and collect other hydrocarbons from the crude gas mixture. Although crude natural gas is mostly CH_4, it also contains small portions of ethane, propane, butane, and other gases that are of commercial value.

Transmission System. From the gathering system, natural gas flows into the transmission system. Transmission lines connect a major supply source to a market area or to a local distribution center serving a market area. A transmission system usually takes on one of two designs, a grid system or a trunk-line system. A trunk-line system consists of wide-diameter pipelines that travel long distances. They tend to have few receipt points at the beginning of their route. They also have few delivery points and interconnections with other pipelines. The grid system is composed of a large number of lateral pipelines that form a network of integrated receipt, delivery, and pipeline interconnections. It is much like a local distribution company's network configuration but on a much larger scale.

The transmission-pipeline diameters range from 20 inches to 42 inches, the largest pipelines in the gas delivery network. The transmission pipelines carry large amounts of gas long distances to local distribution companies. The pressure of the transmission pipelines typically ranges from 200 to 1,500 psi, depending on the area through which the pipeline is passing. As a precautionary measure, the pipelines are designed to withstand much greater pressure than they are expected to. Often, two or more parallel transmission lines flowing in the same direction are laid down to provide extra capacity during peak demand times. During nonpeak times, the duplicate lines may serve as storage where natural gas can be line packed and quickly delivered to customers during peak hours.

Often, the transmission system is integrated with underground storage. The underground storage may be at the beginning, middle, or end of the transmission system.

Compressor Stations. Natural gas flows through the pipelines as quickly as 30 miles per hour. As gas travels the distance, it loses some pressure, as a result of friction between the gas and the walls of the pipeline. To pressurize the gas and maintain optimal gas flow, compressor stations are established about every 30 to 50 miles along the transmission pipeline between the supply source and the market area. The compressor stations can be automated so multiple pieces of equipment can be controlled from one central station. The compressors are driven by internal-combustion engines that run on a small amount of the gas from their own lines.

Gate Stations. When the transmission pipeline reaches the local gas utility, it goes through a gate station. The gate stations reduce the gas pressure from the transmission level of 200–1,500 psi to distribution levels of 0.25–200 psi. A sulfur odorant is also added to the gas so that users can detect gas leaks if one should occur. The gate station also measures how much gas the local utility receives.

Distribution Systems. After the gas passes the gate station, it enters the distribution system—pipelines that lead to the customers. The pipelines range from 2 to 24 inches in diameter, decreasing in size and pressure as the pipelines reach closer to the customers. The pipelines are designed to withstand pressure fives times higher than the normal operational pressure.

To ensure proper and consistent service, the gas utility's control center constantly monitors and adjusts the flow rates and pressures, ensuring that the gas arrives at the customers' end at the appropriate pressure for their appliances. Furthermore, the distribution pipelines are interconnected in a grid pattern with strategically placed shutoff valves, allowing for maintenance without disruption to customers.

The distribution pipelines finally enter the homes and businesses of the customers through service lines that are 1 inch or less in diameter. The pressure of the service lines ranges from 0.25 to 60 psi.

Pipeline Construction

Depending on the scale of the pipeline-construction project, it may require as much as 18 months to finish the project (see INGAA, undated). Before a construction project can begin, the right-of-way must be obtained from the landowners. Once the land for the pipelines has been secured, the construction project begins a long process, consisting of the following steps: clearing and grading, stringing, trenching, pipe bending and welding, coating, depositing the pipeline and backfilling, testing, and restoring. A large project is typically broken into manageable lengths, 30 to 100 miles long, called *spreads*, and each spread has a dedicated crew of workers specializing in one of the pipeline-construction tasks. As one crew completes its task on a spread, it begins its task on the next spread and the next crew begins on the spread just left. The crews move down the string of spreads like an assembly line. Hence, the front of the spread clears and grades the land while the last spread restores the land.

Clearing and Grading the Land. The right-of-way is carefully staked. The trees, boulders, and other obstructions are cleared, and the ground is leveled for the construction equipment that follows.

Stringing Pipeline Segments. Natural-gas pipelines are typically separated into segments 40 to 80 feet long. The stringing crew places the pipes on the right-of-way. Depending on the location and soil conditions, different types of pipe are distributed. For instance, concrete pipes may be used in streams and wetlands, while heavy-walled pipes may be used at road crossings.

Trenching. The trenching crew digs trenches to lay the pipes. In the United States, pipes are required to run 30 inches below the ground surface. At rivers and road crossings, the pipes must reside even deeper.

Pipe Bending and Welding. Bending machines are used to make slight curves in the pipe to custom fit it to the contours of the trench in which the pipe will rest. In the United States, strict standards apply to ensure that the integrity of the pipes is maintained during the bending process. The pipes are then welded together into one continuous length.

Coating. Before the pipes are delivered to the site, they are coated to prevent corrosion. Once on site and welded, the seams are treated with coating once more.

Depositing the Pipeline and Backfilling. The welded pipes are lowered carefully into the trenches, and the soil is backfilled.

Testing. Before the pipelines are used for delivering natural gas, they undergo hydrostatic testing to detect leaks. The pipeline is filled with water and pressurized above the maximum operational pressure. Once the pipeline passes the test, water is drained and the pipeline is dried.

Restoring. The final step is the restoration of the right-of-way as closely as possible back to its original state.

Capacity and Swing

The main requirement of the transmission system is to meet the peak demand of its shippers that have contracts for firm service (see EIA, undated [a, b]). To meet this requirement, the natural-gas delivery and storage system should be designed with the most efficient and economical mix of pipelines to deliver the gas and underground storage and LNG facilities to serve peak demands. The diameter of the pipeline and its operating pressure are important factors in determining how much a pipeline can carry. The availability of storage will affect how reliable the service is that is provided. Underground storage, LNG facilities, or line packing can be valuable components in providing an efficient and reliable transmission and distribution network. The size of the pipelines often depends on the availability of storage. Hence, to design a pipeline delivery network that provides the required capacity and handles the swings of supply and demand, both pipeline and storage must be integrated into the design. The right combination will allow flexibility in current operations as well as future operational expansions.

If underground storage is integrated with the transmission system, the portion of the system upstream from storage needs to be designed to accommodate the amount of natural gas that the shipper has committed to receive. The upstream pipeline also needs to meet base-load injection requirements. The portion of the transmission system downstream from the storage is designed to accommodate the maximum peak-period requirements of local distribution companies and consumers in the market area. In other words, it needs to meet the total peak-day withdrawal level of all storage facilities linked to the transmission system.

Operating the gas pipelines to full capacity is optimal for revenues. However, utilization rate (flow relative to design capacity) of pipelines is rarely 100 percent. A less-than-100-percent utilization rate results from a temporary decrease in market demand or from shutting off parts of the line for scheduled maintenance, weather-related operational limitations, or operational accidents.

Although pipelines may operate below a 100-percent utilization rate, it does not mean that extra capacity is available for use. It may operate below 100 percent during low-demand months, but, in the long term, it will have to be used at full capacity during the high-demand months. At times of high demand, sections of the pipeline may be used at more than 100 percent of certified capacity, which is the minimum capacity for maintaining service and not the maximum throughput capability of the pipeline. Pipelines are engineered to operate at much greater pressures than the pressures of certified capacity. Exceeding 100 percent can be accomplished through secondary compression or line packing to increase the pressure within safe limits to increase the throughput temporarily.

Integrating storage capacity into the natural-gas pipeline network can increase the average-day utilization rates and better meet the daily or seasonal swings in demands. Integration of storage capacity into delivery pipelines allows the movement not just of natural gas currently being produced but also of the gas that had been in storage. Hence, at times of high demand, pipeline gas can be supplemented with stored gas, and, at times of low demand, excess gas can be stored.

Trunk lines, which are closer to production fields, are likely to exhibit higher utilization rates during peak times. The grid systems, which are closer to the consumers, are likely to exhibit more swings in utilization rate, reflecting seasonal demand trends, and lower utilization rates than trunk lines.

APPENDIX E

The Natural-Gas Supply Model and Extended Results

We constructed a model of Israel's natural-gas infrastructure to assess four general strategies to meet future demand. The model assumes that new gas supplies could come from two sources. In this instance, they were modeled as the DDW resources and an LNG terminal, but the model is sufficiently general that other types of input may also be accommodated. The strategies vary in choosing how to build and operate this infrastructure. The four strategies are DDW Only, Joint DDW/LNG (LNG Priority), Joint DDW/LNG (DDW Priority), and DDW Then LNG. The model uses different assumptions about the future costs of natural gas from these sources and Israel's demand to estimate the cost of supplying natural gas. The model also calculates the amount of domestic reserve depletion under given assumptions of future demand and supply strategies. In the final part of the analysis, the model analyzes future scenarios in which the supply of natural gas imported through the foreign pipeline is disrupted for one year. The model is capable of analyzing how Israel meets its energy demand under different combinations of energy storage and spare natural-gas import capacity utilization.

This appendix first explains the natural-gas supply strategies and how infrastructure expansion differs between them. Then it describes the demand scenarios used in the analysis and the range of cost assumptions for each natural-gas source. This is followed by an explanation of the different options to meet energy demand under a surprise disruption in the supply of natural gas. The appendix concludes with documentation of the RAND natural-gas supply model used as the center of the RDM analysis of strategic options.

Natural-Gas Supply Strategies

The DDW Only strategy supplies all future gas demand from the DDW reserves. The Joint DDW/LNG strategies build initial increments of supply capacity at both the DDW reserve and an LNG terminal but differ in how they prioritize utilization of each source. In the Joint DDW/LNG (LNG Priority) strategy, natural gas is supplied first from the foreign import pipeline and LNG terminal up to their capacities, then any residual demand is supplied from the DDW reserve. In the Joint DDW/LNG (DDW Priority) strategy, the strategy first utilizes the foreign import and DDW sources before using any supplies from the LNG terminal. Finally, the DDW Then LNG strategy initially builds capacity at the DDW reserve up to a specified limit, then builds an LNG terminal only when triggered by future supply and demand conditions. This strategy also prioritizes supplies from the DDW reserves.

The decision to build capacity is triggered by next-period demand, plus any reserve margin, exceeding current supply capacity. In the model, we assume limited foresight so that planners could accurately predict demand in the next period. The *reserve margin* refers to the amount of capacity in excess of demand that could be used in an emergency.

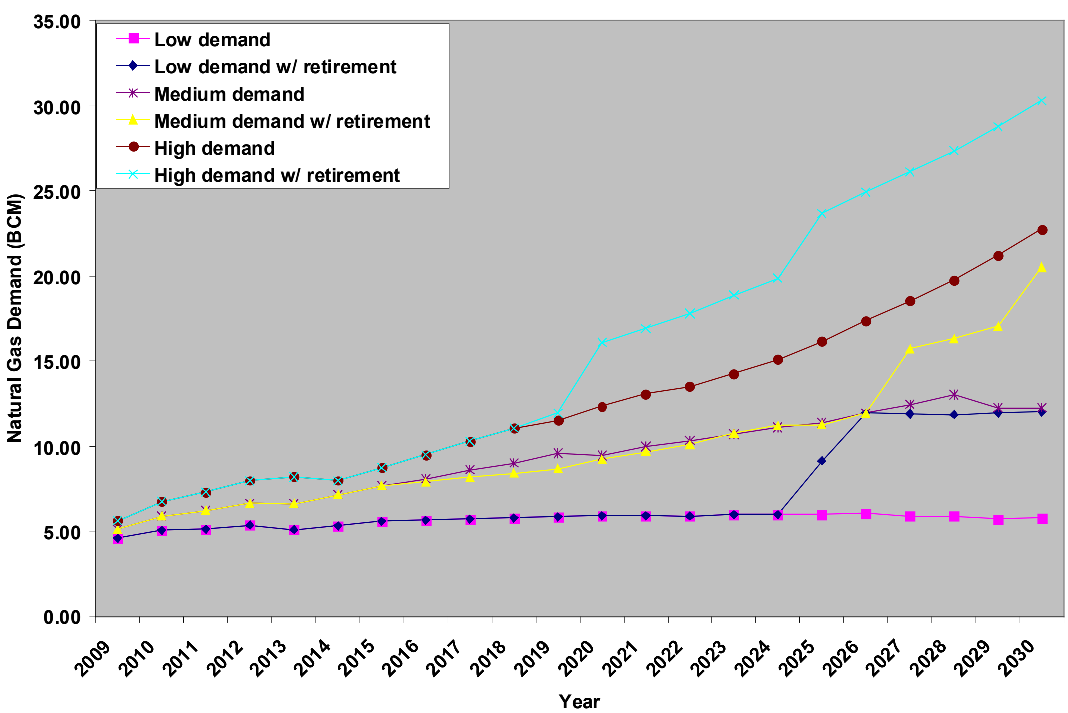
Natural-Gas Demand Scenarios

The natural-gas supply model was evaluated using several different levels of demand over the analysis period. These demand projections are taken from the database of LEAP model simulations that represent different future paths of Israel's electricity sector. The scenarios selected for the analysis are meant to demonstrate the types of infrastructure configurations needed to satisfy different levels of demand and are not representative of a "likely" scenario. Figure E.1 shows the natural-gas demand scenarios.

In the low-demand scenario, natural-gas demand slowly rises from 5 BCM per year to 6 BCM per year. In this scenario, the slow growth in natural-gas demand results from a combination of low electricity demand, successful energy-efficiency programs that moderate demand by 20 percent, and construction of a new coal plant. In the low-demand-with-retirement scenario, natural-gas demand follows a similar path until 2025, when demand increases by approximately 5 BCM per year after retiring Israel's existing coal power plants due to high CO_2 prices that are assumed in the scenario.

In the medium-demand scenario, natural-gas demand grows from 5 BCM per year in the earlier years to more than 10 BCM per year by 2025. This level of demand is driven primar-

Figure E.1
Natural-Gas Demand Scenarios Used in This Analysis



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ily by the demand for electricity and continued construction of new natural gas–fueled power plants to meet growing demand for electricity. The two medium-demand scenarios diverge in 2026, when, in this scenario, Israel begins retiring existing coal power plants and replaces them with combined-cycle plants (again, due to high CO_2 prices assumed in the scenario). The retirement of these plants increases annual demand to nearly 20 BCM per year by 2030.

In the high-demand scenario, natural-gas demand exceeds 20 BCM per year by 2030. In this scenario, the large demand for natural gas results from high growth in electricity demand combined with all new power-plant capacity fueled by natural gas. In the high-demand-with-retirement scenario, the same set of conditions occurs, plus Israel retires existing coal plants in 2026 and 2030. This scenario has the highest demand for natural gas in the sample. Again, all of these scenarios were selected to illustrate different plausible levels of natural-gas demand resulting from alternative future electricity-sector infrastructure configurations and demand. They are not meant to represent most-likely outcomes.

Given these natural-gas demand scenarios resulting from runs of the LEAP model and the "lumpy" nature of new increments of natural-gas infrastructure, Israel can bracket natural-gas supply infrastructure into several categories based on projected gas demand and limits to the supply infrastructure. The first level includes scenarios with demand less than 7 BCM. Israel's current contract with the foreign pipeline supply is to provide up to 7 BCM of natural gas per year, although the current pipeline constraint without any storage to moderate supply and demand imbalances is approximately 6.5 BCM. Given this initial source of natural gas, an important analysis is how Israel's new supplies can complement the gas delivered from the foreign pipeline supply or substitute for this source if Israel does not receive expected deliveries.

The next important level of natural gas is from 7 to 15 BCM per year. The government of Israel obtained a prefeasibility study that recommended an LNG terminal with an initial capacity of 5 BCM that Israel could expand up to 8 BCM per year. Given these figures, another important threshold is scenarios with natural-gas demand up to 15 BCM per year. In these scenarios, up to 8 BCM of natural gas could come from LNG in addition to the maximum of 7 BCM from the foreign pipeline supply. If this source delivered less than 7 BCM, gas from DDW would be needed to replace the supply from the foreign pipeline, possibly up to the full 7 BCM.

A third range of gas demand scenarios is 15–22 BCM. Assuming that, at least initially, the capacity for natural gas supplied from DDW could be expanded up to the full capacity of deliveries from the foreign pipeline source (7 BCM), the maximum supply from this source, an LNG terminal, and DDW is 22 BCM. Therefore, natural-gas demand above 15–22 BCM assumes some level of exports from the foreign pipeline source and gas supplied from all three sources.

A final range is gas demand greater than 22 BCM. Given the assumptions described earlier on the capacity of each gas supply, scenarios with demand greater than 22 BCM will require larger capacity facilities or a new fourth source of natural gas. This fourth source could be a second LNG terminal, new capacity at the DDW reserve, possibly new capacity in the foreign pipeline source, or a new source of natural gas. The qualitative difference with this scenario is that the currently proposed sources and capacities will be insufficient for the long-run demand.

Examples of Gas Strategies and Modeling Infrastructure Expansion

The previous sections described how we treat the natural-gas supply strategies, model expansion and utilization decisions, and basis for demand scenarios. We now show two examples to illustrate how the model uses assumptions about demand and supply strategy to simulate the capacity expansion and utilization decisions. These infrastructure expansion and utilization decisions are then used to estimate costs and domestic resource depletion. The first example shows the DDW Only strategy, which is the most basic of the strategies, and best illustrates how infrastructure expansion works in the model. Figure E.2 depicts one scenario in the model.

This scenario assumes the medium-demand scenario shown in Figure E.1 and that foreign pipeline imports will supply 7 BCM in the future. This figure shows that new supply is needed by 2014 and that the first increment of new DDW supply (3.5 BCM) comes online then. In this year, only a small amount is utilized, and most of the new expansion is spare capacity. From 2014 until 2022, Israel consistently uses more of the capacity from the DDW source, and, in 2023, the next increment of capacity is built. The model calculates the total supply used from the DDW source, which is approximately 60 BCM by 2030. Overall, the figure demonstrates that infrastructure expansion is driven by growing demand for natural gas and that the "lumpy" nature of capacity expansions results in some spare capacity that is available until the next increment of capacity is needed. The availability of spare capacity will become an important feature in a later section describing analysis on options Israel can use to insure against supply disruptions. The next example uses the Joint DDW/LNG (LNG Priority) strategy to demonstrate how the model treats capacity utilization decisions.

Figure E.2
Illustrative Scenario with Domestic Deepwater Only Strategy

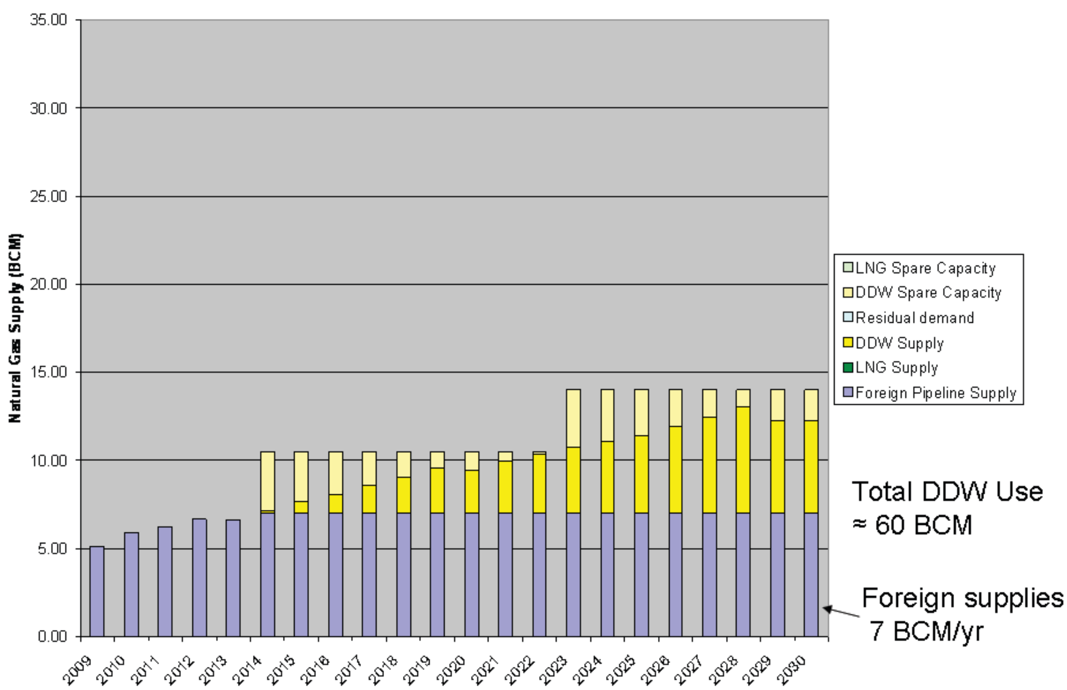

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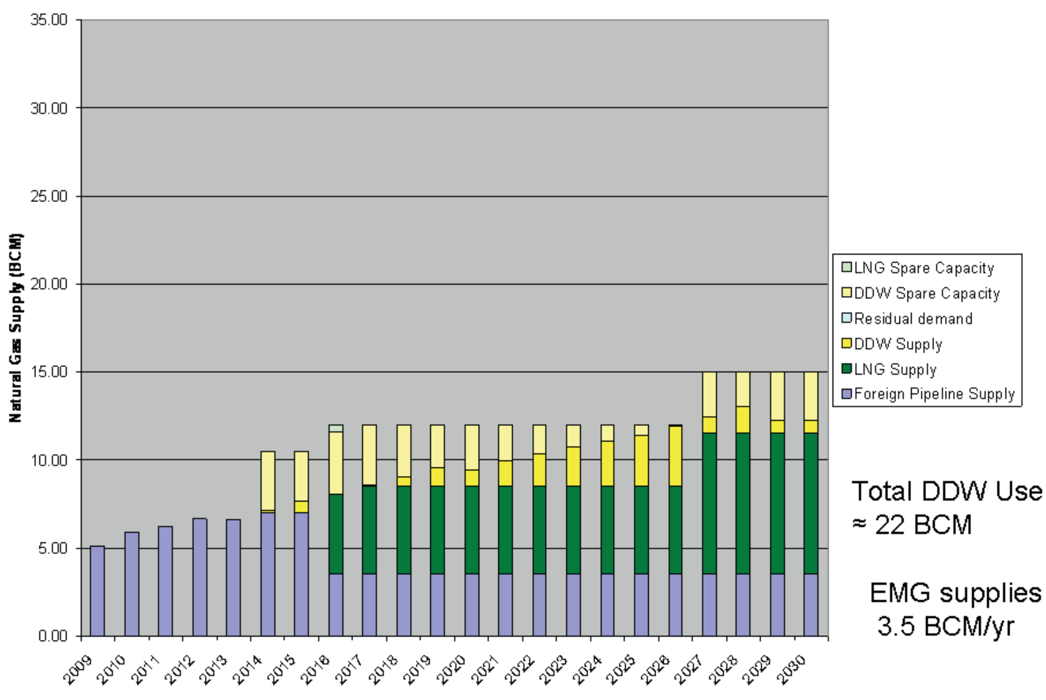
Figure E.3 also uses the medium-demand assumption but reduces the assumed level of foreign pipeline supply to 3.5 BCM per year starting in 2016. In this example, the initial capacity expansion occurs in 2014 with the DDW resource, but, in 2016, the first increment of capacity at the LNG terminal (5 BCM) comes online. This source then supplies most of the demand for natural gas in excess of the foreign pipeline supply. With this strategy, as soon as capacity for both DDW and LNG supplies exists, the LNG terminal will be used up to its capacity limit or demand is satisfied. When demand exceeds both the supply from foreign pipeline imports and LNG capacity, the remaining supply is met by the DDW resource. In the period from 2018 to 2026, increasing amounts of natural gas from DDW sources are required. In 2027, the second increment of LNG is built, and the total LNG capacity is 8 BCM. As the figure shows, total DDW depletion in this example—about 22 BCM—is considerably less than in the previous case. After estimating the capacity expansion and utilization path, the model calculates the costs of supplying natural gas from the alternative sources. The next section describes this process and the assumptions used in the model.

Natural-Gas Supply Costs

The natural-gas supply model estimates the costs of supplying natural gas for a given level of demand for each year of the analysis period. Because the two new sources of natural gas require different types of capital investments, we estimate the levelized cost of delivered natural gas for

Figure E.3
Illustrative Scenario with Joint Domestic Deepwater/Liquefied Natural Gas (LNG Priority) Strategy



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each source to account for these differences and provide a consistent cost basis for comparison across sources. The methodology is analogous to the levelized cost of electricity (LCOE) calculation used to compare electricity generated from different sources.

The basic difference between the two new sources considered in this analysis is that natural gas produced from LNG involves a considerable amount of capital investment "upstream" of Israel. Elements of the LNG supply chain upstream of Israel include natural-gas wells, liquefaction plant, and LNG container ship. Israel is not likely to directly make the capital investments in this portion of the supply chain, but the price of LNG delivered to Israel's LNG terminal would include the amortized capital and opportunity costs of these investments. As a contrast, the supply chain for DDW sources of natural gas, by definition, occurs entirely within Israel's boundaries, and, to make consistent comparisons across these, we estimate levelized costs of delivered natural gas for each source.

In the model, we split the levelized cost of each gas source into a capital cost and variable cost. The capital cost component covers the cost of capital investments made for supply infrastructure in Israel. These costs are annualized over an assumed 30-year time horizon, and the assumed interest rate is an uncertainty in the analysis. We then divide the annualized capital cost by the average annual capacity to estimate the levelized capital cost in terms of dollars per MMBTU of natural gas. The variable costs for each source include the variable costs associated with operating the infrastructure based in Israel plus any upstream costs associated with delivering natural gas (for the case of LNG). Both cost components are combined for an estimated levelized cost of natural gas delivered into Israel's existing distribution system and have common terms of dollars per MMBTU.

Each of the cost components for the two sources of natural gas involves considerable uncertainty, and we have used the best information available to develop plausible ranges for each cost component. For LNG, prefeasibility studies for Israel analyzed an onshore LNG terminal with an initial capacity of 5 BCM that Israel could expand up to 8 BCM per year. Capital csts of an 8-BCM onshore LNG facility have been estimated at $558 billion, which is approximately $70 million per BCM of capacity. As an example, assuming a 30-year lifetime and 10-percent interest rate, the amortized cost for this portion of the supply chain is approximately $0.35 per MMBTU. More-recent cost estimates for regasification have costs close to $0.75 per MMBTU, and we use a wider range of costs in the uncertainty analysis to account for possible cost increases since the Israel-specific estimate (Jensen Associates, 2007). These estimates pertain to an onshore terminal. Offshore terminals would have higher costs associated with the more challenging construction and costs of delivering gas onshore from the terminal and perhaps for security as well. Utilizing several studies, we found that the upstream costs per unit of LNG range from $1.75 to $2.75 per MMBTU, which is approximately $60 million to $100 million per BCM (Jensen Associates, 2007; EIA, 2003; Foss, 2007). By combining this range of sources, we develop a range of costs for LNG for the two increments of capacity and the variable costs. The range of costs is shown in Table E.1.

For natural gas supplied from DDW reserves, our team had only limited information on Israel-specific cost estimates and has relied on estimates for other offshore projects and publicly available information from Israel's existing offshore project. In a technical-feasibility study of developing offshore natural-gas reserves near Newfoundland (approximately 130 BCM of economic resource), the total capital costs of developing offshore fields were approximately $2 billion for 7 BCM/year capacity or about $290 million/BCM of capacity. Using the same assumptions for the LNG example given earlier, these costs translate into approximately $0.9

per MMBTU in levelized cost for the establishing infrastructure for the offshore wells. The estimated total operating expenditures for this project were approximately $2.3 billion for 130 BCM, which is about $20 million per BCM or $0.5–0.6 per MMBTU.

We also used publicly available data on Israel's existing offshore natural-gas supply project using the 2008 10-K Report for Noble Energy, which has the concession to this resource. In this filing, the average sales prices for natural gas from this project in 2006, 2007, and 2008 were $2.80, $2.87, and $3.19 per MMBTU, respectively. The reported production costs were $0.18, $0.20, and $0.28 per MMBTU, respectively, over the same period. Using these data, we developed ranges for capital and operating costs from this natural-gas source. The assumptions are shown in Table E.1.

Analysis of Disruptions in Natural-Gas Supply

The analysis of natural-gas supply security considers several alternative methods to insure against consequences stemming from a disruption in foreign pipeline imports of natural gas.

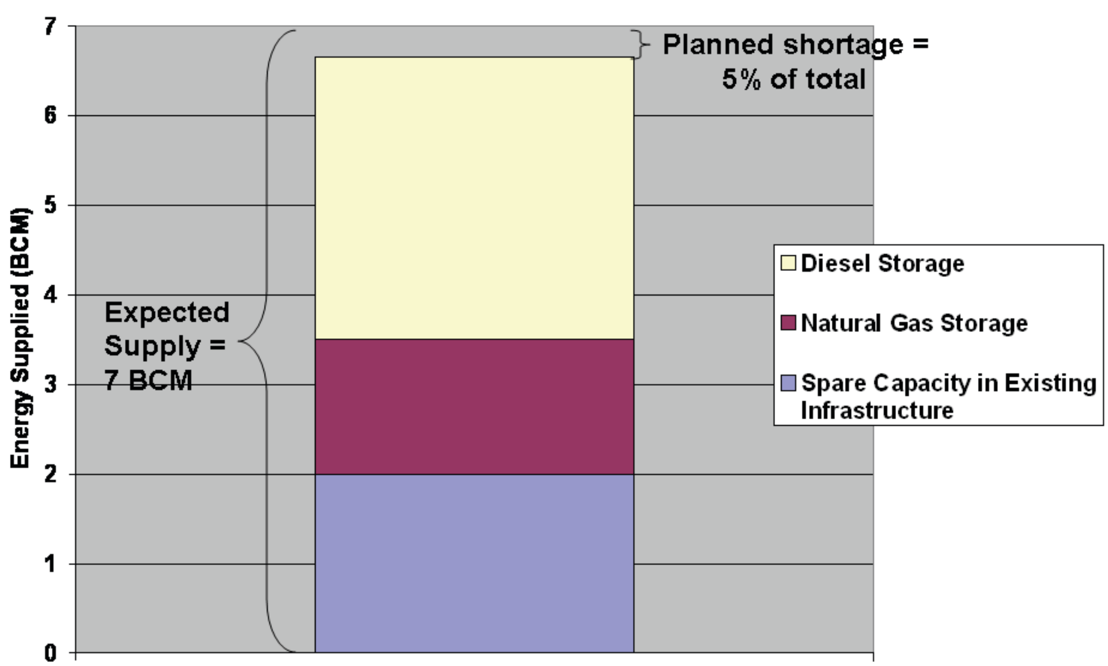
Table E.1
Range of Values for Variables Used in Natural-Gas Supply Model

Measure	Minimum	Maximum	Units
Demand path	Low	High with retirement	See scenarios.
Post-2015 foreign pipeline	0	7	BCM per year
Initial LNG increment	5	5	BCM per year
2nd LNG increment	3	3	BCM per year
Initial DDW increment	3.5	3.5	BCM per year
2nd DDW increment	3.5	3.5	BCM per year
Target reserve margin	0	1	Fraction spare capacity
Level of insurance	85	100	% of total demand
Depleted reservoir storage	0	3	BCM per year
Diesel storage	0	1	0 = no diesel, 1 = diesel use
DDW capital cost	200	1,000	millions $ per BCM
DDW variable cost	5	30	millions $ per BCM
Initial LNG capital cost	60	300	millions $ per BCM
2nd LNG increment capital cost	3	33	millions $ per BCM
LNG variable cost	50	150	millions $ per BCM
Diesel storage capital cost	7	25	millions $ per tank
Diesel storage price	20	150	$ per barrel
Natural-gas storage price	2	15	$ per MMBTU
Discount rate	3	10	%

The alternatives include both "hard" measures that involve infrastructure and "soft" measures to mitigate the effects of supply disruptions. The alternatives that utilize infrastructure construction include natural gas stored in depleted reservoirs, diesel storage in aboveground tanks, and using spare capacity in existing natural-gas infrastructure. Adding infrastructure provides a high level of assurance in securing energy supplies; however, it is costly. We also analyze "soft" options in the model to assess measures that could reduce the costs of insuring foreign pipeline imports. One option is to choose an import level below the capacity of the pipeline. For instance, the current maximum capacity of the foreign pipeline source is 7 BCM per year. Israel could choose a lower level of capacity from this source, which would reduce the cost of insuring this energy source. Of course, the reduction in imports from the foreign pipeline would require an increase in supply from another source. A second noninfrastructure option is to choose to insure some level less than the full 100 percent of the expected supply. This option would also reduce costs incurred to secure the energy supply but would require some type of energy-conservation measure in the case that the supply shortage actually occurs. Figure E.4 illustrates how we model these options in estimating the costs of securing energy supplies.

In this example, Israel plans to utilize full current capacity of the foreign pipeline source and import 7 BCM of natural gas but also allows for a 5-percent shortfall in supply in the case of an emergency. Meeting these targets requires 6.65 BCM in backup energy supply in the case of an emergency. In this example, Israel has 2 BCM of spare capacity in its existing sources that could be utilized in an emergency and an additional 1.5 BCM of natural gas stored in depleted reservoirs. In the model used in this analysis, both of these supplies are prioritized for first use in the case of an emergency. Diesel storage is the residual supply and is developed to

Figure E.4
Illustrative Example of Natural-Gas Supply Insurance Alternatives



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meet the difference between the sum of spare capacity and natural-gas storage and the targeted backup supply (6.65 BCM [target] – 2 BCM [spare capacity] – 1.5 BCM [stored natural gas] = 3.15 BCM [diesel requirement]).

If each portion of the natural-gas supply was known in advance with perfect knowledge, Israel would face no energy shortages above the amount planned in Figure E.4 (5 percent). However, in reality, exact capacity utilization can deviate from the planned level. In the model, we estimate a potential unmet energy demand that is the difference between the planned level of backup supply (6.65 BCM in this example) and the actual level of backup supply. As noted earlier, the primary reason for a difference is uncertainty in the actual capacity utilization for Israel's existing infrastructure. A second potential reason is a transition period as backup supplies are developed. In the model, we assume a transition period from 2016 to 2020 during which natural-gas storage is developed incrementally to the planned level. By contrast, we assume that diesel storage in aboveground tanks can be developed as needed.

Costs of Insuring Energy Supplies

The previous section described how the model adds new storage supplies to meet planned targets for backup supplies. The costs for the storage supplies consist of the capital investment in the storage method, operation and maintenance costs, and the cost of the fuel stored. In this analysis, we assume no additional capital costs for natural gas stored in depleted fields because storage will utilize the existing infrastructure. As the storage is developed, we assume that double the target amount of stored natural gas is required to maintain pressure in the reservoir. The cost of natural gas purchased for storage is assumed to vary between $2 and $15 per MMBTU. For the diesel storage, we assume that diesel is stored in 75,000-cubic-meter tanks, which is based on the average size of existing storage tanks at the petroleum-product import port in Eilat. We assume a range of costs for diesel tanks from $7 to $25 million per tank based on the estimated costs of fuel storage in the U.S. strategic oil reserve. For the cost of diesel, we assume a range of costs from $20 to $150 per barrel. As the backup supplies are added to the system, the costs are added to the natural-gas infrastructure costs in the net present value calculation.

Variables Used in Natural-Gas Supply Analysis

Table E.1 shows the range of values for the variables used in the model. The final section of this appendix describes each variable and how it is used in the model.

The first variable is the demand path, which was covered in an earlier section of this appendix. The model uses six different demand paths that are based on natural-gas demand results from the LEAP model. While these are not an exhaustive set, they bound the range of demand in the set of LEAP results and represent different levels of demand seen in the results. The next variable represents the expected supplies delivered from the foreign pipeline source after 2015. Israel's current contract extends to 2015 and will be renegotiated for the subsequent period. This variable covers the entire range of future supplies from no future supply to the full current capacity of the pipeline.

The next four variables represent the capacities for the two new sources of natural gas: LNG and DDW sources. The LNG terminal is modeled in two increments of supply. The first is a 5-BCM facility, and the second is 3 BCM. These values were taken from interviews citing the government of Israel's prefeasibility study, and we held them constant in our analysis, but they could be changed in the model. Similarly, we assumed that the DDW supply would be built in increments of 3.5 BCM and did not vary this assumption in the analysis. The model is capable of changing this in future work.

The next four variables concern the measures used to insure foreign pipeline imports of natural gas. The first variable in this group is the target reserve margin and takes values from 0 to 1. The reserve margin is a parameter used in infrastructure expansion that sets a target for available capacity. For instance, if natural-gas demand is 10 BCM and the reserve margin is 0.25 (25 percent), the target infrastructure capacity used for the capacity expansion decisions is 12.5 BCM. The level of insurance was described in the section on gas supply security. This variable establishes the amount of foreign import supply planned for backup energy supplies. Using the earlier example, if the post-2015 foreign supply is set at 7 BCM and the level of insurance is 95 percent, the planned level of backup supply is 6.65 BCM. The next variable establishes the planned level of natural gas stored in depleted reservoirs. The range of this variable is 0–3 BCM, and the storage is added incrementally from 2016 to 2020. The final variable affecting gas supply security is diesel storage. This option is treated as a yes/no option in the model. When diesel storage is used, it is added to meet any shortfall in backup supply between the target level and the combined supply from spare capacity and natural gas stored in depleted reservoirs.

The next five variables cover the costs of natural gas supplied through LNG or DDW sources. As described earlier, the costs are comprised of capital and variable cost components, which are variables in the analysis. In the case of LNG, the capital cost is broken into two components for each of the increments of supply. The range of costs covers the uncertainty in costs in developing these projects in Israel. For instance, Israel has not decided where to site the LNG terminal, so the capital costs cover a range to account for the possibility of an onshore or offshore terminal.

The final three variables account for the costs of diesel and natural-gas storage. Diesel storage includes the cost of a storage tank and purchase of fuel. Natural-gas storage includes only the cost of purchasing stored gas and excludes the capital investment of the existing infrastructure. The final variable in the analysis is the discount rate, which is used in the present-value calculations used both to compare costs of different infrastructure configurations and to annualize the costs of capital investments.

Model Documentation

This section describes the mathematical relationships between variables used in the natural-gas supply model. The first set of variables includes identities used to define equilibrium and the different components of energy supply, demand, and reserve capacity.

General Variables in All Strategies

- Total supply = total demand

- Total supply = foreign pipeline supply + DDW supply + LNG supply
- Reserve target = foreign pipeline supply capacity x reserve margin
- Foreign pipeline supply = min (total demand, total foreign pipeline capacity)
- Residual demand = total demand – foreign pipeline supply – DDW supply – LNG supply.

The first identity defines the equilibrium condition in the model that energy demand equals energy supply. Energy demand is taken as a given from the natural-gas demand scenarios used in the analysis. The model then determines which sources of natural gas fulfill demand, based on the different strategies used in the model. The second identity defines the three different sources of natural gas assumed in the model comprising the total gas supply. The next identity characterizes the reserve target as the portion of the expected supply from the foreign pipeline insured using spare capacity in the supply infrastructure. For instance, if the expected foreign pipeline supply is 6 BCM and a reserve margin of 25 percent is used, a reserve target of 1.5 BCM will be used in the capacity expansion decisions. The next identity defines the level of supply from the foreign pipeline as the minimum of the total demand or total supply capacity for this source. The final identity describes the residual demand for natural gas as the difference between total demand and the supply of natural gas from the foreign pipeline, DDW, and LNG sources.

Variables in the Utilization Decision

The next set of variables describes the supply utilization decisions for the different prioritization strategies (either DDW or LNG prioritized).

DDW Priority.

- DDW supply = min (total demand – foreign pipeline supply, total DDW capacity)
- LNG supply = min (total demand – foreign pipeline supply – DDW supply, total LNG capacity).

Under the strategies with DDW priority, the foreign pipeline source is still used initially, then the DDW source is used up to its capacity. Any final remaining demand is supplied by the LNG terminal. The formulas used in the model are a set of min functions. The DDW supply formula defines the supply provided by the DDW source as the minimum of two components. The first component is the difference between total demand and the foreign pipeline supply, and the second is the total DDW capacity. This formula establishes the DDW supply as the second source used to supply natural gas. A basic example illustrates this calculation. As an example, assume that total demand in the period is 12 BCM, the foreign pipeline supply delivers 7 BCM, the total DDW capacity is 3.5 BCM, and 5 BCM in capacity exists in an LNG terminal. The foreign pipeline supplies the first 7 BCM of natural gas, and the DDW source supplies the next 3.5 BCM. These two sources provide the first 10.5 BCM of supply, and LNG will provide the remaining demand, which is described next.

The LNG supply variable under this prioritization uses LNG to supply the remaining demand after the foreign pipeline and DDW supplies. This is captured in the first component of the min function. The second component establishes the LNG capacity as a limit. Following from the example, the remaining demand after utilizing the foreign pipeline and DDW source is 2.5 BCM, which is provided by the LNG terminal. This also means that, in this example, the LNG terminal has 2.5 BCM of spare capacity that can be utilized if necessary. The next section describes these calculations under the strategies with LNG prioritized as a source of supply.

LNG Priority.

- LNG supply = min (total demand – foreign pipeline supply, total LNG capacity)
- DDW supply = min (total demand – foreign pipeline supply – LNG supply, total DDW capacity).

Under the LNG priority, the LNG supply is utilized up to its capacity before drawing supply from the DDW supply. Using the earlier example, the first 7 BCM of supply comes from the foreign pipeline source, then LNG provides the next 5 BCM to meet to total 12 BCM of demand. In this example, under the LNG priority, the 3.5 BCM of capacity at the DDW source provides spare capacity that is available in an emergency.

Capacity Expansion Decision

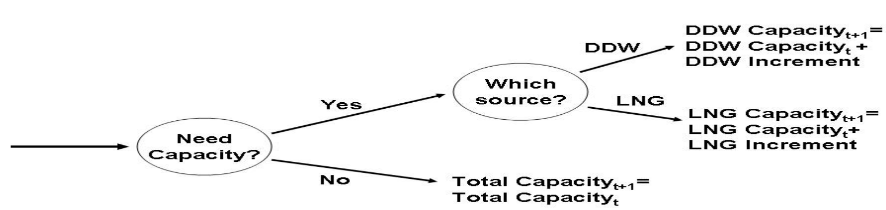
The schematic in Figure E.5 illustrates the decision logic inherent in the capacity expansion decisions in each strategy. Each strategy follows this sequence but differs in the rules and constraints applied to each decision node.

The diagram shows that the first decision node in each time period is whether new capacity is needed. In the model, when total demand in the next period plus the target reserve margin exceed total supply, the model triggers the need for new capacity. This condition is applied consistently across all of the strategies to the decision to build new capacity. Formally, the following expression describes when new capacity is needed:

$$\text{Condition when “Need Capacity?” = yes:}$$
$$\text{Total demand}_{t+1} + \text{reserve target} >$$
$$\text{total foreign pipeline supply} + \text{total DDW capacity}_t + \text{total LNG capacity}_t.$$

As noted earlier, the reserve target is a buffer in the amount of spare capacity available to offset any loss of supply from the foreign pipeline supply source—therefore, when expected demand in the next period plus the planned level of spare capacity (reserve target) exceeds cur-

Figure E.5
Conceptual Diagram of Decision Logic Used in Each Capacity Expansion Decision



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rent capacity. The model chooses to add capacity in the current period. Under the converse set of conditions, the model does not add new capacity. This is shown as

$$\text{Condition when "Need Capacity?" = no:}$$
$$\text{Total demand}_{t+1} + \text{reserve target} \leq$$
$$\text{total foreign pipeline supply} + \text{total DDW capacity}_t + \text{total LNG capacity}_t.$$

If the current total capacity is sufficient to meet total expected demand and the reserve target, no new capacity is added to the system. As described already, these conditions are applied consistently across all the strategies, and the only difference between them occurs in the decision about which source of natural gas to use to build new capacity when it is needed. The remaining sections describe the conditions applied to building each type of capacity.

DDW Only. Under the DDW Only strategy, if capacity is needed, it will always be added to the DDW source. Therefore, the following is true:

"Which Source?" = DDW when condition to build new capacity is met.

Joint Strategy. Under the joint strategies, new DDW capacity is built if no DDW capacity is currently available or LNG capacity reaches the maximum. The following conditions capture when new DDW capacity is built:

$$\text{Conditions when "Which Source?" = DDW:}$$
$$\text{Total DDW capacity}_t = 0\text{, or total LNG capacity}_t = \text{max LNG capacity.}$$

LNG capacity is added after the first increment of DDW capacity is built and LNG capacity is below the maximum. The following conditions represent when new LNG capacity is added:

$$\text{Conditions when "Which Source?" = LNG:}$$
$$\text{Total DDW capacity}_t > 0\text{, and Total LNG capacity}_t < \text{max LNG capacity.}$$

DDW Then LNG Strategy. Under the DDW Then LNG strategy, new capacity is added to the DDW sources until reaching a target level. After reaching this target, new LNG capacity is added. Finally, after the LNG terminal capacity achieves the maximum, new DDW capacity is added to meet any further demand. The following conditions capture this:

$$\text{Conditions when "Which Source?" = DDW:}$$
$$\text{Total DDW capacity}_t < \text{initial DDW limit, or Total LNG capacity}_t = \text{max LNG capacity.}$$

Again, LNG capacity is added after reaching the initial DDW limit. The following conditions represent this strategy's LNG capacity addition decisions:

$$\text{Conditions when "Which Source?" = LNG:}$$
$$\text{Total DDW capacity}_t = \text{initial DDW limit, and Total LNG capacity}_t < \text{max LNG capacity.}$$

APPENDIX F

Relevant International Experience with Natural Gas

Israel's energy situation has a number of distinctive features. However, there are other countries that are also, in effect, energy islands whose electricity systems are not connected to any larger cross-national grid and for which energy supply is a concern. Some of these countries have also turned to the use of natural gas. We give a short overview of two such countries' experience. The sole purpose is to provide a bit more context for the discussion of Israel's natural-gas strategic options and not to delve into the details of these two national energy markets.

South Korea

South Korea, with its limited domestic energy resources, is reliant on imports for nearly all of its energy needs. Approximately 12 percent of the country's energy is supplied via natural gas that is imported as LNG under long-term contracts.[1] These contracts cover sources of LNG from Qatar (28 percent), Indonesia (25 percent), Malaysia (21 percent), and Oman (19 percent).

South Korea's natural-gas industry is dominated by the Korea Gas Corporation (KOGAS), which is the sole importer and distributor of natural gas in South Korea. KOGAS is 27 percent owned by the government, 25 percent owned by the state-controlled Korea Electric Power Corporation, and the remaining ownership stake is controlled by local governments and institutional investors. KOGAS operates three LNG-import terminals as well as the nation's natural-gas pipeline system. A fourth LNG terminal is privately owned. In an effort to meet South Korea's growing demand for natural gas, KOGAS is planning to almost double its LNG-storage capacity from 2.75 BCM (2.0 million tonnes) in 2004 to 5.25 BCM (3.8 million tonnes) in 2017.

South Korea produces less than 2 percent of its own natural-gas consumption domestically in the Donghae-1 gas field. This reserve contains a little more than 7 BCM of natural gas and is producing at a rate of about 0.5 BCM per year. This field is anticipated to run out in 2018. The producer of gas from this field is the Korea National Oil Corporation, and the buyer is KOGAS.

Wholesale prices for natural gas are approved by the Ministry of Knowledge Economy.[2] The intention is that wholesale prices will cover KOGAS procurement and supply costs. Retail rates are approved by municipalities at the request of each of the 32 local natural-gas utilities.

1 In 2005, South Korea consumed 30.5 BCM of natural gas while producing only about 0.5 BCM domestically.

2 In 2008, the Ministry of Commerce, Industry and Energy merged with elements of the ministries of Information and Communications, Science and Technology, and Finance and Economy to form the Ministry of Knowledge Economy.

Approximately 59 percent of natural gas is consumed in the residential and industrial sectors, while 41 percent of gas is used to produce electricity. In the future, it is anticipated that most demand growth for natural gas in South Korea will be driven by the residential and industrial sectors; natural gas used for power generation may actually decline as electricity generated from coal and nuclear power plants ramp up.

Attempts to Privatize South Korea's Electricity and Natural-Gas Industries

In 1999, the government adopted the Basic Restructuring Plan for the Natural Gas Industry (Cho, Gulen, and Foss, 2007), which called for the breakup and privatization of KOGAS in 2002. Under the plan, KOGAS would be broken up into three LNG-import and wholesale companies and a facility-operation company. Any certified company was to be allowed to construct and operate natural-gas distribution facilities in areas where distribution services were not already provided. Downstream competition for retail services was to be achieved by breaking local natural-gas retailers up into operations and sales companies and allowing retail customers to choose between suppliers. A similar set of privatization steps in the electric-power sector were to occur ahead of these activities.

Critical legislation that would facilitate the transformation of the natural-gas industry did not pass in 2002, and, ultimately, restructuring of both the electricity and natural-gas industries was suspended in 2004. Plans to resume these activities remain in limbo.

Japan

Natural-gas production in Japan is limited, totaling about 3 BCM in 2004.[3] The country consumed 83.5 BCM of natural gas during that same year. To accommodate Japan's demand for natural gas, large amounts of LNG are imported. A number of Japanese companies, including INPEX Corporation and those created from the breakup of the former Japan National Oil Corporation are involved in overseas exploration and production efforts.

In 1969, Japan first began importing LNG from Alaska. Over time, Japan's demand for LNG has grown. Currently, it is the world's largest importer of LNG. In 2004, 97 percent of Japan's natural-gas consumption was satisfied with LNG imports that come from Indonesia (27 percent), Malaysia (23 percent), Australia (15 percent), Qatar (12 percent), Brunei (11 percent), and the United Arab Emirates (9 percent). Many of Japan's long-term LNG contracts were initiated many years ago. They are inflexible in that they stipulate quantities that must be purchased and link the price of those shipments to crude-oil prices.

Most of Japan's LNG infrastructure is owned and operated by local power-generating companies in cooperation with the major natural-gas retailers (Tokyo Gas, Osaka Gas, and Toho Gas). Japan has 23 LNG-import terminals with a total throughput capacity of 83 BCM per year. The majority of LNG terminals are located near the nation's population centers of Tokyo, Osaka, and Nagoya. Due to Japan's geography and previous regulatory restrictions on investment in the natural-gas industry, Japan has a limited natural-gas pipeline system.

The waters between Japan and China are believed to hold substantial natural-gas reserves. Production from these reserves has been limited due to disagreements between Japan and

[3] Most of Japan's natural gas reserves are colocated with the country's oil fields. Yufutsu, Japan's largest natural gas field, produces approximately 0.4 BCM per year (40 million cubic feet per day.)

China over the demarcation of their maritime boundary. Despite numerous rounds of negotiations between the two countries, no specific agreements have emerged.

To secure sources of natural gas, Japanese companies have pursued a number of overseas exploration and liquefaction projects. The government has allowed individual utilities and natural-gas distribution companies to sign LNG-supply contracts with foreign sources. For instance, the Japanese company INPEX initiated a $6-billion project in offshore western Australia. The project is expected to eventually produce LNG at a rate of more than 8 BCM per year, all of which will be exported to Japan.

Japan has also sought to procure LNG from Russia by taking a stake in the Sakhalin II project. The Sakhalin II project is being developed by Sakhalin Energy, with Shell as the operator and with Japanese companies Mitsui and Mitsubishi holding 25- and 20-percent stakes, respectively. The Sakhalin II project has been plagued with rising costs, and the Russian government froze a key environmental permit until the original investors sold a controlling stake to Gazprom, the Russian national gas company. Of the expected 13.25 BCM of LNG produced each year from the project, Japanese companies have signed contracts to buy 6.5 BCM per year. Japanese companies are also involved in projects in Indonesia, including Kalimantan Island, and on the island of New Guinea.

Japan's natural-gas sector has undergone two major reforms that have led to the partial deregulation of its natural-gas industry. In 1995, the retail natural-gas sector underwent its first deregulatory reform through amendments to the Electric Utility Industry Law. The amendments were an important step in opening up Japan's electric power industry to competition and established a means for independent power providers to operate. Under the 1995 amendments, large-scale supplies of gas (contracts for more than 2 million cubic meters) were deregulated and prices for natural gas were determined through competition. In 1999, a second set of reforms was initiated in which third-party–access regulations were established and price deregulation was extended to contracts for more than 1 million cubic meters. Between 1995 and 2003, 11 companies entered the natural-gas industry in Japan.

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