REPORT ON

GAS INTEGRATED RESOURCE PLANNING

Prepared for the

ONTARIO ENERGY BOARD

September 16, 1991

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I. INTRODUCTION

A. Background

In its April 9, 1990 Decision in E.B.R.O. 462 (the Union Gas Limited 1991 Test Year rate case), the Ontario Energy Board decided to call a generic hearing into Least Cost Planning. The Board stated that:

> managing demand in the context of utility expansion in Ontario is a matter of interest to the Board. The Board is also of the view that Least Cost Planning, in its widest sense, should include the environmental aspects raised by Energy Probe as well as minimizing gas leakage and the subject of NGV. (p. 101).

In the same Decision, the Board also stated its intention to consult with the Ontario gas utilities and other interested parties as to the form of the generic hearing.

Following this Decision, on behalf of the Board, Board Staff developed a Draft List of Issues in consultation with the three major Ontario gas utilities. During this consultation, it was determined that the subject of the generic hearing should be renamed "Integrated Resource Planning" or "IRP". The Board, by letter dated September 25, 1990, requested comments on this Draft List of Issues from a broad range of interested parties. Again in consultation with the major gas utilities, the Board determined that it would initiate the investigation into IRP by producing a Discussion Paper based on the Draft List of Issues.

The Board informed interested parties of its intention to produce a Discussion Paper by letter dated March 21, 1991 and that a draft version of the Discussion Paper would be available. The Draft discussion Paper was released on June 18, 1991 and at that time the Board invited brief written comments on the draft. The Board received comments from seven interested parties which are on public file at the Board.

B. The Final Discussion Paper

This report (the Final Discussion Paper) has been revised substantially from the original draft. This is as a result of the comments received as well as internal Board discussion. The purpose of this Discussion Paper is twofold:

1) to identify and discuss the major issues which arise when considering whether or not to implement IRP, and, if it is decided to implement IRP,

2) to identify and discuss the major issues which arise when determining how and to what extent to implement IRP.

By identifying the important issues, and presenting the range of options and opinions as to the resolution of these issues, it is hoped that this Discussion Paper will serve as a framework for the intervenors to focus the presentation of their positions on the various issues.

The Paper has been developed by Board Staff and MSB Energy Associates, Inc. The Paper is not intended to be a position paper which advocates the implementation of IRP; nor is it intended to be a position paper which advocates any particular perspective, model or process for the implementation of IRP. If there is any bias in the presentation of the issues, implied or explicit, it should not be taken as representative of the views of the Board. The Board intends to examine and consider all submissions before determining whether or not to proceed with the implementation of IRP for the Ontario natural gas utilities and if so, how?

C. Issues Addressed in the Discussion Paper

IRP evolved first with electric utilities in the United States. IRP was developed, at least in part, as a response to the dramatic price increases in electric power that resulted from the disruption of oil supplies in the mid- and late-1970s and unexpected cost overruns in the nuclear power sector. This combination of factors led utility regulators and planners to investigate whether cheaper alternatives were available to serve the public's need for electric power. A combined focus of electric IRP has evolved, highlighting increased energy efficiency as a means of providing service (primarily at the state level) and power production from smaller, independent sources (primarily at the federal level).

To date, U.S. IRP activity has focused on electric utilities, although there is a growing effort to transfer IRP concepts and practice to natural gas utilities. There are key differences between the electric and natural gas industries, however, and while general principles of electric IRP may be transferable to natural gas, careful attention must be paid to conditions unique to gas utilities. However, issues and differing perspectives which have arisen in the electric IRP process will probably arise in the gas IRP process, too.

If the determination is made to implement some form of IRP, the following issues must be addressed and resolved in the course of developing an IRP process:

Technical Aspects

- Forecasting techniques
- End-use data collection and analysis
- Resource identification for both demand- and supply-side options
- Resource characterization for both demand- and supply-side options in terms of technical potential and performance, existing market saturation and market penetration
- Cost-effectiveness analysis, including determination of marginal and avoided costs
- Resource integration
- Risk analysis

Procedural Aspects

- Type of IRP process to be adopted
- Planning cycle
- Dispute resolution procedures
- Data exchange and review procedures

Regulatory Aspects

- Legal authorities required for IRP
- Appropriate means of cost recovery for utility investment in energy-efficiency measures
- Need to provide utility recovery of revenues lost due to energy efficiency
- Need to provide utilities with incentives to invest in energy efficiency, and appropriate form of incentives
- Inter-fuel policies

Each of these issues is addressed below. An attempt has been made to present the variety of options available under each issue, illustrating the discussion, where possible, with examples from jurisdictions where particular methods are practiced.

Chapter II of this Report begins with a definition of IRP. This definition is adapted from the Draft List of Issues and is intended to be a general explanation of the components and goals of IRP. However, these components and goals are themselves likely to be subjects of discussion in intervenor submissions. It should be noted that this definition is provided for purposes of framing the discussion and in no way has it been adopted or approved by the Board.

Chapter II then provides a brief discussion of the "pros" and "cons" of implementing IRP. Again, it must be recognized that there are counter-arguments and debatable points for each of the pros and cons. It is anticipated that these pros and cons will be more vigorously challenged and/or advocated in the intervenor submissions.

The legal and procedural issues associated with IRP are the subject of Chapter III. Again, the report is designed to identify the issues which must be addressed when developing the procedural system for implementing IRP. The possibilities range from partial or gradual implementation to "full blown" IRP. The determination of the appropriate process will in large part determine what "model" of IRP implementation is selected.

One "model" for IRP is presented in Chapter IV. This model represents a comprehensive approach to preparing a utility IRP plan. The structure of this model allows for the development of a variety of plans which can then be assessed against a range of possible objectives, including minimizing utility revenue requirements, minimizing ratepayer impacts or minimizing societal costs. Each of these objectives represents a different perspective which in turn determines how "least cost" is defined. An alternative model for implementing IRP would see the objective or perspective established at the beginning of the process and result in the development of the plan which best meets that particular objective. Presenting all the possible alternative models would unduly lengthen this Report. For this reason, a comprehensive model has been adopted FOR DISCUSSION PURPOSES ONLY. It is anticipated that intervenors will make submissions as to the appropriate model for implementing IRP and the appropriate cost perspective to be taken.

The model has been described in as generic a fashion as possible in order to establish a framework by which the various sub-issues can be addressed. It is recognized that the specific characteristics of Ontario and its natural gas industry will have a profound influence on how IRP can be implemented. Further, it is recognized that the specific characteristics of each of the major utilities in Ontario will have a profound impact on how IRP can or should be implemented. A detailed discussion of these impacts is beyond the scope of this paper. It is anticipated that intervenors will pursue these issues and provide their specific expertise in these matters in their individual submissions.

Chapter V presents an overview of the various approaches which can be used to determine marginal and avoided costs. These benchmarks are one of the key components in all the cost-effectiveness test.

Supply-side considerations are the subject of Chapter V. Here an attempt has been made to discuss some of the reliability, flexibility, and security considerations associated with developing and assessing a natural gas supply plan.

Chapter VII presents a discussion of demand-side mechanisms and programs.

Chapter VIII presents the commonly used cost-effectiveness test. These tests can be used to assess individual resources for cost effectiveness, but they can also be used to evaluate entire plans.

Externalities are the subject of Chapter IX. These environmental and socio-economic factors may be included in an IRP process if one of the objectives is to minimize societal costs. Chapter X provides a discussion of inter-fuel programs. Finally, Chapter XI presents a discussion of demand-side program cost recovery mechanisms and utility incentives.

II. DETERMINING WHETHER IRP SHOULD BE PURSUED BY ONTARIO NATURAL GAS UTILITIES

The following definition of integrated resource planning is presented for purposes of framing the discussion, and is based upon a similar version developed by the Board in its Draft Issues List:

> Integrated resource planning (IRP) for natural gas utilities is an expanded method of planning whereby the expected demand for natural gas services is met from the least costly mix of supply additions, energy conservation, energy-efficiency improvements and load management techniques (i.e., the integration of supply-side resources and demand-side resources). Some of the specific objectives of the planning process are to continue to provide reliable service, equity among ratepayers, and a reasonable return on investment for the utility while addressing environmental issues and achieving the lowest cost to the utility and the consumer.
>
> The methodology for calculating the "cost" of each option and the analytical framework used for insuring consistent treatment of both supply-side and demand-side options must be developed and adopted prior to the development of actual plans.
>
> Fundamental to successful implementation of IRP is a refocussing of the gas utility's mission from being solely a purveyor of natural gas to a more comprehensive view of being a provider of natural gas services.
>
> Besides integrating demand- and supply-side options on a consistent basis, an integrated resource plan should be flexible and diversified; the utility should be able to respond to uncertainty and minimize risk. The planning exercise is preferably conducted on a cooperative basis which should allow for input from all parties interested in the development of the plan, and will include some form of regulatory review, thereby ensuring that the interests of all stakeholders are taken into account.

In this chapter, some of the potential benefits and potential risks of IRP are identified. This is followed by a discussion of the current institutional milieu of natural gas utilities and whether it is possible to achieve the goals of IRP without adopting an IRP process. The chapter ends with brief descriptions of gas IRP efforts in the U.S. and Canada.

A. Potential Benefits of IRP

There are a variety of potential benefits to consumers of natural gas in Ontario which arise from the adoption of IRP by gas utilities. These benefits may include cost reduction, environmental benefits, an open public planning process, and a reduction in financial and regulatory risk for the utility.

An integral part of the move towards IRP is an understanding and acceptance of the role of natural gas utilities as providers, not of *gas*, but rather of *natural gas services*. Customers are not interested in buying *gas*. They are interested in the *services* that the gas provides. With acceptance of this perspective, many new options for meeting customers' needs are opened. It makes no sense to burn expensive gas to meet customers' energy needs when less expensive demand-side options will meet the same needs. Why burn gas to replace heat lost through leaks in a home if those leaks can be closed at a lower cost?

Under IRP, the utility is responsible (with oversight from the regulatory agency and interested intervenors) for analyzing the energy uses of its customers, evaluating alternative energy-use options, and using its position as an energy supplier to try to put the most economically advantageous combination of alternatives into place. The result of the utility taking this perspective will be reduced long-term costs to utility customers. Reduced customer costs will be demonstrated by lower *bills*, though not necessarily, particularly in the short-term, lower *rates*. In the long term, the resource decisions that result from engaging in IRP may well lead to lower *rates* (as well as bills) than would have been the case had IRP not been implemented. This has proven to be true in some situations in the electric industry in the U.S.[1]

The IRP process can also yield environmental benefits. The extent of these environmental benefits depends somewhat on how the utilities' IRP mandate is defined. If the mandate is defined so as to include an overall societal perspective in the resource-planning process, the utility (with input and oversight from the regulators and interested intervenors) will have the responsibility to assess the societal impacts of alternative resource options and include those impacts in the resource selection process. Under this approach, an attempt is made to factor the full societal cost of energy resources into the resource planning process. The result will be a resource plan with reduced environmental impact from that which would result from a plan based on some other objective.

In addition, IRP can give the public the opportunity to have input into the utility long term planning process and not just into the rate-setting process or individual system expansion proposals. An integral part of the IRP process is public meetings and hearings wherein interested persons have the opportunity to present their views and ask questions of the other participants before a resource plan is implemented by the utility. Public input is important for the success of the IRP process for three reasons. First, the public often has legitimate concerns and interests which may be missed without the opportunity for public

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[1] Wisconsin Public Service Commission, Final Environmental Impact Statement on the Promotion of Electric Utility Sales, Docket 05-EL-15, April, 1984.

input. Second, if the public feels that its interests and concerns are being heard and that reasonable alternatives are being considered, it is much more likely to accept the plans that are developed via the IRP process. Third, public involvement in the gas-planning process will lead to greater public understanding of natural gas and its role as part of the energy resource mix in Ontario, including expectations of future availability and price, the role of gas vis-a-vis other energy sources such as electricity and oil, and alternatives to the use of gas.

Adoption of IRP may provide several benefits to the utilities themselves. The first is a potential reduction in business risk. A major source of business risk is uncertainty about the future. By including more options of both a supply-side and demand-side nature in its plans, a utility will be better positioned to deal with future uncertainty. Furthermore, demand-side options have certain characteristics which tend to directly mitigate business risk. Demand-side options are usually available in smaller blocks than are supply options, leading to a reduction in exposure to uncertain forecasts. This factor is less significant for gas utilities than for electric utilities, but is still applicable to some degree. Another characteristic is that demand-side options tend to provide more savings when load grows faster and less savings when load grows slower. Thus, demand-side options serve to mitigate uncertain load growth.

IRP may also reduce regulatory risk for a utility. Under a planning process in which the utility makes and implements its own decisions and then applies to the regulators to have the costs of those decisions included in rates, there is a risk that the regulator will disallow the costs. This is especially true if circumstances are such that a decision which might have appeared to be a good one when made turns out to be less than optimal when implemented. If, however, through the IRP process the regulatory agency has had a role in making the decisions, it is less likely to disallow the costs.

B. Potential Risks of IRP

There are also potential risks associated with implementing IRP. The decision whether or not to adopt an IRP process rests on a judgement as to whether the benefits are likely to outweigh the risks and costs.

It is clear that an IRP process is more complicated than the traditional utility planning process and raises a whole set of controversial issues. More options are considered. The analysis can be more difficult, especially if a societal perspective is adopted. This will require more data, more time, and more utility staff. It will also require more time and effort on the part of the regulators and probably more staff as well. The extent of this increased effort will be determined by how completely IRP is adopted.

Some of the data required may be difficult to obtain, at least initially. In order to conduct IRP it is necessary for utilities to forecast energy use by end-use. If the utilities have not been doing this already, they will need to collect a significant quantity of start-up data. Especially in the beginning of an IRP process, there is often difference of opinion about detailed energy end-use patterns.

One of the items that was discussed as a potential benefit for utilities must be included as a potential risk for regulators. This is the involvement of regulators in the planning process. Under the traditional regulatory framework, the regulatory agency has the opportunity to wait for the utilities to initiate plans or actions. The regulatory agency can then judge the utility's actions after the fact. Theoretically, this would appear to put much of the risk on the utilities and remove it from the regulators. Under an IRP process in which regulators have the responsibility to review and approve utility plans before they go into place, regulators will have more difficulty disallowing costs. While costs can clearly be disallowed if they are imprudently incurred, it is more difficult to disallow costs if the decisions turn out to have been less than optimal and the regulators have been included in the process of making those decisions.

Another element that is listed above as a benefit can also be viewed as a risk. Opening the utility planning process to the public may increase the diversity of opinion and make it more difficult to develop and implement a plan. The public will bring questions and concerns to the process at a stage where, under traditional planning, they would have had no input at all. That is, they will be involved in the determination and analysis of various ways of meeting future demand on a long term basis.

There is also the technical risk of non-performance of the demand-side management resource alternatives. While projecting the performance of future gas supply is also uncertain, utilities have, in general, learned to understand and adjust for this type of uncertainty. The uncertainties associated with the technical performance of demand-side resources may be greater at this time because of the relatively limited experience to date.

Also, demand side resources depend on the independent actions of a large number of individual actors rather than the concerted action of a small number of players and are thus more difficult to control.

A fully comprehensive IRP process would coordinate the planning of electric and gas utilities as well as other fuels. However, the Ontario Energy Board has only a review function with respect to Ontario Hydro, an indirect competitor of the gas utilities, and Ontario Hydro is currently engaged in its own IRP process before the Environmental Assessment Board. A somewhat less comprehensive adoption of IRP for gas utilities does not require complete coordination with other fuels or Ontario Hydro.

C. Current Institutional Milieu of Natural Gas Utilities

Natural gas utilities face a range of incentives which influence decision-making. Some are real incentives, while some are only perceived incentives. Perceived incentives can have as strong an impact on the actions of individuals and organizations as real incentives. In that sense, perceived incentives can be just as real as incentives that are more factually based.

Utilities have traditionally focused on adding new customers, increasing sales, buying more gas, selling more gas, and increasing system size. This approach has, in the past, served utilities and their customers well by reducing the cost of gas and making it available to more customers. This tradition serves as a strong incentive to continue a focus on expansion and sales. Utilities are much less familiar with the newer concept of reducing sales through demand-side management (DSM).

A utility's income comes from selling its product at a price determined by the regulatory agency. The regulatory-determined price is set so as to cover the utility's operating cost (treated essentially as a pass-through to customers), recovery of capital investments through depreciation, and a reasonable return on the shareholders' investment in capital equipment. As a regulated industry, the utility is expected to earn a reasonable but not excessive return for its investors.

Given this pricing structure, there are two ways for a gas utility to increase its revenues. It can sell more gas, which increases operating costs and causes more money to flow through the utility, or it can increase its investment in capital equipment, causing higher levels of depreciation and return on investment. Typically, these actions are interrelated so that increasing sales has a double impact on utility revenues.

Increased utility revenues are often viewed as being the same as increased profits. This view forms an incentive to growth. This particular incentive is more of a perceived incentive than a real one. Increased revenues go only partly towards increased profits. A portion (often a large portion) goes instead to pay for increased operating costs and has no impact on the level of profits. Even that portion that does go to increase the total amount of profits does not necessarily affect the rate of profits. Investors are interested in getting a return based on the level of their investment. If they double their investment and double the total return, the rate of return is unchanged. If they double their investment and the return goes up 90 percent, the investors' rate of return has gone down and they are worse off, even though the total absolute return has gone up.

A disincentive to DSM, both real and perceived, may arise from the use of the forward test year for ratemaking purposes. If sales are reduced below the forecast level due to DSM, the utility will actually lose revenues. The utility may *perceive* that it will lose revenue due to DSM and the use of a forward test year approach even when it theoretically should be able to anticipate sales reductions due to DSM and forecast the test year accordingly.

This is not to say that utilities have no incentives to engage in demand-side management activities. Businesses realize that, in order to be successful, it is necessary to be customer driven -- to actively seek out ways to meet customers' needs and desires. Many utilities (including each of the Ontario utilities) have found that offering assistance to improve efficiency is well received by customers. As a result, many utilities have gone into the demand-side management area as a customer service, without consideration of the integrated resource planning benefits to which DSM can lead. The disadvantage of viewing DSM purely as a customer service without considering it as a cost-effective resource option is that the services offered may be more limited than are justified economically. Adoption of IRP would lead to an expansion of activity in the DSM area, rather than a complete shifting of direction.

D. Can the goals of IRP be achieved Without Embracing IRP?

The goals of IRP, as identified in the definition (pp. 8-9), are

> "to continue to provide reliable service, equity among ratepayers, and a reasonable return on investment for the utility while addressing environmental issues and achieving the lowest cost to the utility and the consumer."

It is in the area of addressing environmental issues and minimizing costs to the utility and the consumer through the assessment of demand-side resources and supply-side resources on a consistent basis where IRP expands the scope of traditional utility planning. Whether or not these goals can be achieved without the implementation of IRP should be considered.

The traditional utility planning approach -- analyzing multiple resource-supply options and selecting those with the lowest long-range costs -- can be effective at minimizing the marginal cost of new supply. However, this approach will only lead to cost minimization from the utility perspective under circumstances where there are no demand-side options that are less costly than the lowest-cost supply option.

Even under those unlikely circumstances, the traditional supply planning approach cannot minimize the societal cost of energy services if that is the objective deemed most appropriate. The traditional approach does not address the full cost to society of producing energy. It focuses only on the direct cost to the utility and its customers and ignores externalities such as environmental costs.

Environmental issues and DSM may be incorporated into traditional planning on an ad hoc basis. However, the purpose of IRP is to ensure that demand-side and supply-side resources are compared on a consistent analytical basis.

E. Examples of Jurisdictions in Which IRP Has Been Implemented

A comprehensive survey of gas IRP in the U.S. can be found in the recent NARUC publication Survey of State Regulatory Activities on Least Cost Planning for Gas Utilities (April 1991). Here we will provide a summary of the results of the survey. Readers seeking more detailed information are advised to consult the NARUC Survey.

The NARUC Survey uses five categories to identify state activity in the area of gas IRP:

1) IRP in practice;
2) IRP under implementation;
3) IRP under development;
4) IRP under consideration;
5) IRP not actively considered or rejected.

29 states reported that gas IRP was either rejected or was not actively considered. Those were 4 major reasons given:

1) lack of jurisdiction over gas utilities;
2) the current focus on electric IRP;

3) no perceived gas supply or price concerns (generally gas producing states); and

4) current focus on gas supply issues; generally least-cost purchasing.

Seven states have gas IRP under consideration. Of these, four states are actively developing electric IRP first and gas IRP may be considered next. Six states have gas IRP under development through a variety of approaches ranging from establishing a formal regulatory framework to more ad hoc processes through individual rate cases.

Nine states have either implemented gas IRP or have gas IRP in practice. Seven of these have either developed IRP regulations jointly for gas and electric utilities or existing electric IRP regulations have been adapted to gas with only minor changes. IRP plans have been submitted by gas utilities in four states, though none had been approved as of February, 1991.

In comparison, there has been relatively less IRP activity in Canada. Canadian electric utilities, and to a lesser extent gas utilities, have implemented a broad range of demand-side management programs. However, only Ontario Hydro has developed an IRP plan which is currently being considered by the Environmental Assessment Board.

III. IRP PROCESS AND LEGAL AUTHORITY

The extent of the Ontario Energy Board's jurisdiction will need to be established before proceeding to implement any form of IRP. The process by which IRP will be conducted will also need to be determined. These issues will be addressed in this chapter. We first address the different sources of authority and the approaches (from litigation to collaboration) used to implement IRP in the U.S. We then discuss procedural and filing requirements for IRP.

A. Ontario Energy Board Jurisdiction

An opinion regarding the Ontario Energy Board's jurisdiction to implement IRP has been provided by a Board counsel and is included as Appendix D. In summary he finds that the Board does not have the jurisdiction to order the utilities to prepare integrated resource plans which it would then approve or modify through a hearing process. In order to undertake these activities, the Board's current legislation would need to be amended.

However, the Board's counsel goes on to conclude that the Board does have the jurisdiction to take IRP principles into account in establishing rate base, setting the rate of return and fixing just and reasonable rates. Likewise, in counsel's opinion, the Board has the jurisdiction to require evidence about the utility's use of these principles in establishing rates.

B. IRP Authority and Approaches in the U.S.

Jurisdictions that have implemented IRP in the United States have generally relied upon one or more of four sources of authority. Some (e.g., Nevada, Illinois, Wisconsin) have been able to initiate IRP based on an explicit *statutory* directive requiring utilities to file and regulatory agencies to review plans. Others (e.g., Massachusetts, Connecticut, Washington, D.C.) have used existing general statutory authority for reviewing and approving rate cases and facility construction applications to develop *administrative rules* to implement IRP. Others have used existing general statutory authority to initiate special investigations and issue *orders* that establish an IRP process and filing requirements. Vermont and Washington D.C., which has used both administrative rules and orders to establish IRP, are examples of jurisdictions that have used this source of authority. In some cases, (e.g., Delaware, New England collaborative) *ad hoc arrangements* among utility and parties and/or regulatory staff have resulted in utilities developing expanded resource plans without any explicit reliance on statute.

Each of the sources of authority to initiate IRP has advantages and disadvantages, which derive from the following factors:

- Time required to initiate IRP
- Ease of initiation of IRP process
- Ease of revision of process
- Constancy and continuity of process
- Opportunity for public input to IRP

- Legal recourse

The following table summarizes the advantages and disadvantages of each source of authority used to initiate the IRP process.

TABLE I

AUTHORITY TO INITIATE IRP

	Advantages	Disadvantages
Statutory	1. Establishes process with strong legal recourse 2. Assures right of public to participate 3. Fewer questions about Commission authority 4. Relatively permanent 5. Binding schedules 6. Opportunity to affect utility actions	1. Requires legislative action 2. May take years 3. Revisions to reflect evolving state of art can be difficult
Administrative (Rules)	1. Commission can initiate without legislative action 2. Assures right of public to participate 3. Relatively easy to revise/update 4. Binding schedules 5. Opportunity to affect utility actions	1. More questions of underlying Commission authority 2. More subject to short term pressures to change
Administrative (Orders)	1. Commission can initiate 2. Commission can control scope 3. Very flexible -- encourages experimentation	1. Questions of underlying Commission authority 2. Subject to short term pressures to change 3. May encourage "one shot" view of planning 4. Public involvement and recourse may be limited 5. Constancy of process is not assured
Ad Hoc	1. Can be initiated by any utility and willing participants 2. Negotiated -- less litigious 3. Good for utility image 4. Potential "win-win" situation	1. Subject to short term pressures to change 2. May encourage "one shot" view of planning 3. Public involvement limited to the participants -- what if all parties not participants 4. Legal recourse more limited 5. Constancy of process is not assured

If IRP is initiated, there is a variety of approaches that can be used to implement the process. The public hearing (litigation) approach and the collaborative approach are often viewed as the two extremes, with many hybrid combinations filling the continuum between them. Each approach has its advantages and disadvantages. Every jurisdiction in the U.S. that has implemented IRP has attempted to capitalize on the benefits of both by using hybrid combinations. For example, in the Northeastern U.S., the collaborative approach has been emphasized, while in Wisconsin, IRP has been undertaken with a greater degree of litigation.

The collaborative process provides opportunities to use an informal process to improve the exchange of information and to reach understanding and agreement. This can help to speed the process of developing, reviewing, approving and implementing IRPs. The collaborative process can be used as an adjunct to the litigated process. The collaborative portion of the process allows for issues to be clarified, misinterpretations to be corrected, and information shared, all of which make a more concise and usable hearing record.

The public hearing (a) provides an opportunity for those individuals not taking part in the collaborative to pursue issues, (b) provides an opportunity for participants in the collaborative to raise unresolved issues and to formally have them addressed, (c) takes the pressure off participants in the collaborative to compromise and reach consensus on all issues, (d) provides the regulatory agency with a range of options from which to choose, (e) provides the regulatory agency with a recommendation from each party as to how the many aspects which comprise the public interest should be weighed and, (f) provides a forum in which to report on or stipulate to agreements of the collaborative group.

The following table summarizes the advantages and disadvantages of the litigated, collaborative and hybrid approaches to the IRP process.

TABLE II

APPROACHES TO IRP

	Advantages	Disadvantages
Litigated	1. Clear legal rights and roles 2. Assures right of public to participate 3. Opportunity to affect utility actions	1. Adversarial 2. Lengthy and costly 3. Participation may be limited by expense
Collaborative	1. Promotes understanding among participants 2. Less adversarial 3. Opportunity to affect utility actions 4. Consensus approach may lead to more "ownership" of actions and faster implementation 5. Potential "win-win" situation	1. Commission may be faced with "all or none" choice 2. Consensus approach may lead to "middle of the road" planning 3. Scope of planning alternatives may be restricted by agreement 4. What recourse in case of non-consensus? 5. Need clout (e.g., capability to plan and threat of litigation) to negotiate 6. Non-participants in collaborative 7. Potential for co-option and capture
Hybrid	1. Less adversarial than fully litigated 2. Litigation is an option to resolve non-consensus 3. Matches approach to the issues	1. May be adversarial in part 2. Potential for co-option and capture

C. Procedural and Filing Requirements

This section focuses on the specific procedural and filing requirements that guide a natural gas IRP process. These requirements could be established through legislation, an order or set of guidelines. The following points should be considered:

- The regulatory agency's determinations on the integrated resource plan
- Milestones for integrated resource plan filings and approvals
- Criteria for evaluating and selecting resources
- Opportunities for public input
- Required utility data filings.

1. <u>The Regulatory Agency's Determinations on the Integrated Resource Plan</u>

A meaningful IRP process will provide the opportunity for regulators and the public to influence which resources are selected prior to the time a commitment is made to the resource by the utility. Stated another way, the IRP process is designed to publicly explore the proposed and alternative resources and to guide the utility as to which one(s) best serve the public interest. There are several models available to guide and direct the utilities' preparation of their IRPs. The options derive primarily from determinations as to whether the Board staff or other intervenors review plans or develop independent plans, and whether the Board comments on the plans or formally orders the plans to be implemented.

An approach common in the United States is for the regulatory agency to review and approve or reject the utility plan, but not develop independent alternative plans. The State of Nevada is an example of this approach. Other states, such as Wisconsin (for electric utilities), both review the utility plan and develop independent alternative plans, and formally approve, reject or modify the plan to serve the public interest. Generally, where the regulatory agency exercises formal approval authority, there is:

(a) Increased public input to utility planning;

(b) Increased likelihood of the public interest being explicitly identified and served;

(c) Increased sharing of risk and responsibility between the utility and the public (through the regulatory agency);

(d) Decreased flexibility for the regulatory agency in making prudence calls;

(e) Decreased utility financial risk;

(f) Increased tension regarding the regulatory agency usurping utility management prerogatives.

Formal approval can be the result of processes in which the integrated resource plan is; i) filed in a separate integrated resource planning proceeding; ii) filed as part of information required to process a rate case; iii) filed as part of information required to process facilities cases; or, iv) filed as part of information for a special investigation. In each of these situations, it is assumed that a process culminating in formal approval will entail public hearings and opportunity for public input. The form of the proceeding will affect the ability of the public to identify and evaluate alternative resources, e.g. if there is immediate need for action, there may not be time (except in a regularly filed IRP process) to identify a viable resource option and develop the analysis necessary to make it a practical alternative to the utility proposal.

Other states, such as Michigan, review and comment on utility plans, but do not issue formal orders. Arizona is unique because, although the Commission staff develops an independent alternative plan, the Commission only comments on, but does not approve or reject, the utility plan. The aspect common to the Michigan and Arizona approaches is that the regulatory agency comments on, but does not approve, the utility plan. Utility plans are influenced by the comments to the extent that the utilities are not willing to take the risk of being found imprudent. As a result, after-the-fact prudence determinations (characteristic of this IRP approach) serve to allocate the costs rather than providing an opportunity to avoid the costs.

A process not culminating in formal approval may take many forms, for example, a formal proceeding (e.g., rate or facilities case) which could provide formal opportunity for public input, or informational filings with the Board not requiring any specific proceeding which would not assure an opportunity for meaningful public input. Processes requiring formal approval are distinguished from processes requiring informal approval primarily in the degree to which opportunities for public input exists and the degree to which the utilities are obligated to heed the opinions of the public and the Board.

Generally, where the regulatory agency engages in an IRP which does not involve formal approval authority, it is likely to:

(a) Increase public input to utility planning relative to no process, but result in less input than if a formal approval were required. This is because the process may not assure the opportunity for input and may not result in the utility adequately considering public input when given. In turn, this could reduce the willingness of the public to participate because the potential impact of public comments is not apparent.

(b) Increase the likelihood of the public interest being identified and served relative to no process, but less than if the Board determined the public interest in a formal approval process.

(c) Maintain utility risk and responsibility for planning and commitment to resources at current levels.

(d) Maintain current flexibility for the Board in making prudence calls.

(e) On average, maintain utility financial risk at current levels. The nature of the review may change if the integrated resource planning process resulted in documented public and/or Board comments. For example, the Board's ultimate decision of the prudence of utility actions could be affected by documentation from the IRP process showing the utility rejected public comments suggesting what would have been a more prudent course of action.

(f) Not increase utility concerns regarding the Board usurping utility management prerogatives.

2. Milestones for Integrated Resource Plan Filings and Approvals

The following issues should be addressed in the procedures developed for implementing an IRP process:

(a) Frequency with which the IRP process is conducted and plans filed

(b) Planning horizon to be addressed in the long-range resource plan

(c) Need for, and time horizon of, a short-term action plan

(d) Schedule for Board action

(e) Consistency of applications for authority to implement resource options with the most recently approved long-range plan.

Generally, filing requirements should be established to provide the Board, the public and other agencies with both a long-range view and a detailed near-term view of the utility's plan. The plan should be filed regularly and frequently enough to be able to incorporate new information and developments. To meet these objectives, electric utilities in the United States file integrated resource plans as often as annually and as infrequently as every third year. Regular, frequent filings would provide an opportunity for public review and input into energy-resource plans and Ontario's energy policy. Annual filings, however, run the risk of diverting attention from the substantive aspects of planning to the procedural and administrative ones. A three-year filing cycle, on the other hand, risks plans getting stale and out-of-date. The approved plans, by the end of three years, could require significant modification based on new information regarding forecasts, additional public input, new technologies and resource options, and demand-side program monitoring and evaluation data acquired during the intervening three years. The planning horizon for natural gas IRPs can be shorter than that for electric utilities because the lead time for natural gas resource acquisition and transmission capacity expansion is typically shorter. In the United States, electric IRP planning horizons are typically in the range of 15 to 20 year. Ontario Hydro's Demand Supply Plan examines a 25 year period. A 10 year planning horizon for natural gas utilities may be adequate to assure that the long-term implications of near-term gas utility decisions are captured in the analysis and to ensure that major gas utility projects are evaluated within the planning horizon. Gas utility facilities will typically be evaluated and fine-tuned through several plan reviews before an application for construction of additional facilities needs to be reviewed.

The action plan is a subset of the long-range plan filing. The action plan is a magnification of the activities required to implement the first several years of the long-range plan prior to the expected approval of the subsequent long-range plan. Thus, an action plan is filed and decided upon at the same time as the long-range plan; however, the action plan contains more details, guidance and information pertaining to the immediate steps for implementation prior to approval of the next filing.

Approval of a plan, in whole or in part, usually gives the utility the authority to *plan* on the basis of implementing or installing resource options contained in the plan. This approval usually does not mean the utility has the authority to *build additional facilities or implement* those resource options. The integrity of the integrated resource plan can be enhanced by directly linking the approval of a resource application to the long-range plan approval. This can be done by requiring a finding in the resource application stage that the proposed resource is consistent with the most recently approved long-range plan. Some jurisdictions in the United States allow an emergency waiver of that requirement, contingent on a showing by the utility that the resource in question was not consistent with the long-range plan because of unforseen and unforeseeable circumstances.

Many of the same issues at the beginning of this section that apply to implementing a full separate IRP process also apply to IRP processes that are incorporated into rate or facilities cases, or into special investigations.

The frequency and regularity of review is an important aspect of the IRP process. A major drawback of incorporating IRP into rate or facilities cases is that they are not regularly filed. Thus the plans and IRP process cannot be updated on a regular basis. This tends to cause an urgency to have each plan be the "perfect" plan, addressing all issues, rather than to view the planning process as being dynamic and cumulative in nature. This also means that the interested public will tend to feel the need to take up every issue at each opportunity rather than to defer lower priority issues to the next case (not knowing with certainty when the next case will occur). These problems can be alleviated by regularizing the case filings, perhaps by establishing a schedule for annual rate case review (as is done in Wisconsin to regularize and schedule rate cases), or, perhaps by establishing a regular filing requirement (such as an annual report) for IRP information determined by the Board to be pertinent to rate and facilities decisions. The Board might, for example, in the context of the next rate case, determine that long range utility plans and objectives are relevant to setting policies and prices for energy service, extension of service rules, etc. The Board could then specify that IRP information be filed annually by the utility to apprise the Board of the utility's intentions, and that information could be used in rate and facilities cases as they arose.

The amount of lead time available to prepare and present alternatives is another important aspect of the IRP process. IRP filings occurring as part of existing cases may delay the normal processing of those cases, particularly if the utility is alleged to have not evaluated alternative actions adequately. The IRP information may come too late in the process to allow orderly evaluation of alternatives in the time frame proposed by the utility.

To the extent that the primary purpose of the case (e.g., need for new facilities or need for rate relief) cannot be delayed, the Board may not have complete information on alternative choices at the time it must decide. This problem can be alleviated by: i) filing IRP information on a regularized basis, so that utility plans are known before the application is filed; ii) filing the application earlier so that IRP information can be analyzed and appropriate adjustments made before the case needs to be decided; or iii) requiring that in facilities cases, all resource alternatives are equally viable at the time of the hearing on the proposal (tending to cause the utility to develop a comprehensive set of alternatives).

It is likely that the character of the short term action plans would be different if IRP filings did not occur on a regular basis. The time horizon covered by the short term action plan should be adjusted to assure that it reasonably addresses revenue requirement impacts from altered sales levels, altered utility commitments to energy resources, and altered staffing and materials requirements.

The schedule for Board actions and the consistency of the application with the integrated resource plan would be controlled by the schedules and requirements for processing existing cases, and would obviously be different from those entailed in a separate IRP proceeding. These would be determined on a case-specific basis.

3. Criteria for Evaluating and Selecting Resources

The IRP guidelines or order should also define the criteria and the method that the regulatory agency wishes the utility to use in developing its plan and selecting resources. Consistently and uniformly applied criteria and methods simplify the public's and the regulator's review of the IRP. Establishing the criteria and methods also helps to define the public interest and ensure that resources consistent with the public interest are being developed.

Two basic approaches to screening and selecting resources are noteworthy. One approach is to screen potential resources to achieve a specific objective, e.g., minimize customer bills. In this approach, resource options are eliminated early because they must meet the specified objective, and plans ultimately constructed from the remaining resource options are limited.

The second approach is to screen potential individual resources based on broad perspectives (societal or multi-test). More resource options survive the screening to become building blocks for alternative plans designed to serve alternative objectives, e.g., minimize customer bills, maximize societal benefits, and minimize rates. The alternate plans are compared and evaluated using consistent performance criteria, and the decision maker selects which plan(s) best serve the public interest. The second approach is summarized in Chapter IV, "A Working Model for IRP." The tests used to screen and select resources are discussed in Chapter VIII.

4. Opportunities for Public Input

Public participation, including that of government agencies, is important to the IRP process for a number of reasons. One is that public participation can increase awareness of a utility's operations, thereby minimizing misunderstandings and misconceptions and shortening public hearings. Public participation can also provide the utility with new ideas and perspectives which should ultimately result in a better plan for the utility. Public input can help to define public values and concerns which comprise the "public interest" upon which the regulatory agency will base its determinations.

In many jurisdictions in the United States, the public is involved both before and during the formal process of approval of the utility's plan. The public's involvement may be an informal one, through participation in working groups that can meet as necessary at any time before, during and after the formal process. This informal involvement can serve to educate the public, resolve issues, modify or expand a utility's plan, or even bring about a consensus regarding the plan.

Where the utility and members of the public have not informally resolved issues, the formal public hearing process can serve to provide a complete record on the issues and help bring about an informed decision by the regulatory agency.

The role of the public need not be limited to commenting on or providing a critique of a utility's plan. Public and government agencies may, if the situation warrants, develop alternative plans as well. Inadequate access to needed utility data is often a barrier to this role for public and government agencies, however, provisions can be made for the public to receive the utility information necessary to develop an alternative plan.

There are several other barriers to public participation which may also be addressed including: (a) the length and complexity of the process by which issues are addressed that are of interest to particular segments of the public; (b) the mechanisms available to fund active participation throughout the process, and (c) the lack of a sense of urgency by the general public to consider certain types of planning issues.

5. Required Utility Data Filings

The objective of specifying the utility data required to be filed as part of the integrated resource plan is to assure that there is sufficient information by which a technically competent person could understand and evaluate the utility plans, and identify and verify the assumptions, methods and inputs. The following information, which comprise essential data inputs to and products of the IRP model process, are generally applicable irrespective of which IRP process is selected:

(a) *Existing System:* Description of existing system, including major utility facilities for supplying natural gas (e.g., transmission and distribution pipelines, compressors, storage), programs to reduce natural gas demand or consumption, mix of sources of supply, and costs. Retirement dates for existing facilities scheduled to be retired during the planning horizon.

(b) *Load Forecasts:* Peak-day and annual gas sales volumes forecasted for each year of the planning horizon, and disaggregated by end-use and class of customer. Identify major new markets, if any. Natural gas sales volumes should be further classified as firm or interruptible, and whether the service was a sale or for transportation.

(c) *Natural Gas Price Forecast:* Forecast of the price of purchased gas for each year in the planning horizon.

(d) *Programs for Conservation and Load Management:* For each year in the planning horizon, develop conservation and load management programs. This includes identifying potential demand-side resource measures, screening measures for cost effectiveness, developing programs to deliver cost-effective measures, evaluating programs for overall cost-effectiveness and prioritizing implementation. Use objective criteria to screen and select. Design programs for all customer classes.

(e) *Plans for New Major Facilities:* For each year in the planning horizon, identify and determine the cost-effectiveness of alternative major facilities for the supply of gas. Describe the process of screening and selecting those which the utility plans to construct, acquire, operate or utilize, including fixed and operating costs, capacity and in-service dates.

(f) *Projected Gas Supply:* For each year in the planning horizon, provide the level and mix of sources of planned gas supply. Describe criteria for determining the appropriate mix and the criteria for selecting supply resources to meet that mix. Analyze the options to meet expected future requirements, including: (1) costs, benefits and feasibility of purchases from producers, other utilities, or other suppliers of gas; (2) transportation arrangements for obtaining supplies; (3) transmission and storage facilities; and (4) other options. The amount and cost of gas, by source, should be listed for each year in the planning horizon.

(g) *Integration and Analysis:* Describe the criteria by which various resource options are combined to develop alternative system plans. Conduct sensitivity analyses of system plans to determine their robustness and flexibility under changing conditions, including changing demand levels, economics of supply and demand-side resources, and security/reliability of resources.

IV. A WORKING MODEL OF IRP

There are many approaches available for conducting an IRP process for gas, the specifics of which would be defined by the legal requirements of the jurisdiction as well as its regulatory policy and approach. Although there is a variety of approaches available, a number of key steps begin to emerge as being critical to workable IRP approaches.

The purpose of this chapter is to discuss those key steps and to use them to define one approach to developing an IRP. In so doing, we hope to convey a working model for IRP (the issues to be addressed, the information needed, the analyses to be carried out, the decisions to be made) that will set the context for the issues discussed in the remainder of this report.

In Chapter III we identified two major approaches to integrated resource planning being used by utilities. The first defines the objective of the planning effort (e.g., minimizing bills, minimizing rates, minimizing environmental impact or maximizing societal benefit) at the outset and establishes screening criteria and methods to achieve that objective, possibly to the exclusion of other objectives. The emphasis, using this approach, is on the resource screening stages. Resource options meeting the screening criteria become part of the plan; options failing are rejected. Thus, only resource options meeting the specific, predefined objective are carried forward.

The second approach emphasizes the development and analysis of alternate plans at the utility-system level. No specific objective is established at the outset--rather, multiple objectives (e.g., minimizing bills, minimizing rates, minimizing environmental impact, and maximizing societal benefit) are considered. Resource options are screened to pass a broader criterion or any of several criteria. More resource options are carried forward to be incorporated into one or more alternative system plans. Each of these alternative plans can be designed to meet a different objective. Specific utility, societal, and customer data (e.g., utility revenue requirements, customer bills, societal benefits, rate impacts) are calculated for each alternative plan. The performance of the alternative plans can be compared, and the plan(s) best serving the public interest, however that is defined, can be selected.

The second approach is the more expansive and complicated of the two. It also provides more flexibility to the decision maker to define the elements comprising the public interest, and to determine how to weight those elements. The first approach is essentially one of the analyses contained in the second approach. Because the second approach subsumes the first approach, the working model we present here is based on the second approach.

This model includes the components necessary for the societal and utility perspectives to be included. The societal perspective is the most comprehensive perspective, and hence the model provides for it. The utility perspective, however, is also provided for in the model so that plans that provide for rate minimization can be evaluated alongside plans that emphasize the achievement of other objectives. By providing for these two perspectives, options that would be viable from other possible perspectives (e.g., ratepayer, participant) are automatically included.

If, of course, the Board chooses a more limited approach to IRP, such as the first approach described above, wherein the objective of the IRP is defined at the outset, the process described in the model would be modified, and would include changes in the use of the various cost-effectiveness tests and in the components included in avoided cost calculations.

The key elements of the second approach to IRP, emphasizing the development and comparison of alternative system-level plans, are:

I. Identify utility system conditions that may contribute to a loss or interruption of service.

II. Identify utility resource options, both demand- and supply-side.

III. Develop programs to deliver demand-side measures.

IV. Evaluate and compare resource options.

V. Develop long-range alternative plans.

VI. Evaluate alternative plans on a system basis.

VII. Receive regulatory agency approval for the plan(s).

VIII. Refine the plan(s).

IX. Evaluate strategic load-building based on the best plan(s) to provide energy services.

X. Implementation by the utility.

XI. Monitoring and evaluation.

XII. On-going planning and review.

This chapter presents a model that embodies and embellishes upon the key elements listed above. The purpose of this model is to demonstrate the information, methods, and analyses needed for a comprehensive and systematic evaluation of demand-and supply-resource options for reliable, low-cost and environmentally sound energy supplies for

Ontario's natural gas utilities. The issues behind the information, methods and analyses are discussed in the remaining chapters of this discussion paper. The model provides a series of steps that comprehensively identifies options, yet progressively narrows them down to a smaller set using objective criteria. Appendix A is an outline summary of this model. A description of each step of the model follows.

At the end of this chapter there is a brief discussion of the possible applicability of the Board's Report in E.B.O. 134 to IRP. In E.B.O. 134 the Board examined the economic feasibility analyses to be applied to system expansion proposals. The Board subsequently established guidelines for the cost-effectiveness tests to be used.

A. Steps in the IRP Model

Step I: Identify Utility System Conditions That May Contribute to a Loss or Interruption of Service

Examples of utility-system conditions which may threaten service could include a deficiency in pipeline transmission and distribution capacity or a constraint on natural gas supplies. Other utility-system conditions also may require attention. Examples of these conditions could include new markets resulting from changing economics, new technical innovations, or regulatory restrictions (e.g., environmental limitations on burning coal) on existing uses of competing fuels.

The intent is to define utility-system need in terms of reliably and flexibly providing energy services to customers. Other conditions triggering utility system need may arise and can be evaluated in subsequent steps, particularly when establishing alternative plans to meet objectives in Step V, "Develop Long-Range Alternative Plans."

Forecasts

In the integrated resource planning context, an adequate forecast must (a) address end-uses of energy for policy and planning purposes, and (b) assess forecast uncertainty and system robustness in responding to that uncertainty.

To be able to evaluate demand-side resources reasonably, the forecast method for energy and demand should be capable of specifically evaluating energy consumption by end use. Breaking down the total energy and demand forecasts by end-use requires the collection of data on energy intensity (how much energy is used for a given end-use application), saturation (the current fraction of customers using each end-use application), and penetration (the fraction of customers who will, over time, add the end-use application). These data enhance the ability of the utility to know and understand its customers and their preferences, an essential ingredient in successful integrated resource planning. In addition, the end-use approach allows for explicitly quantifying existing baseline consumption, demand-side resource potential, and the impact of improved efficiency, new demand-side programs, and other energy policies on utility-energy demand.

Forecasts are not developed with complete certainty. One of the major challenges to utility planners is to assure reasonable-cost, reliable service in an uncertain future. If insufficient energy resources are available, reliability will suffer. If excessive resources are available, the cost of service will increase unnecessarily. Resource planning seeks a balance to assure that service reliability is maintained at the lowest overall cost. One way of accomplishing this is to evaluate system flexibility and robustness under a variety of forecasted conditions, including alternative demand forecasts.

Marginal and Avoided Costs

Marginal and avoided costs are shorthand ways of representing the costs and operations of the utility system. These costs are used to screen resource options, DSM programs, and IRP plans. For use in the utility cost test, the direct avoided cost to the utility is calculated. For use in the social cost test, the avoided cost includes the direct costs plus the avoided externality costs which have been monetized associated with a utility supply source and other avoided costs and benefits which have not been monetized. Chapter V discusses these components in detail.

Step II: Identify Utility Resource Options

The purpose of this step is to identify comprehensively and systematically the resources available from demand-side options, supply-side options, and non-utility gas sources.

Demand-side options

An assessment of DSM technical potential involves the identification of a comprehensive set of demand-side technologies, and an assessment of which of those technologies are applicable to the utility system and to what degree they may replace existing end-use technologies. A good source of information identifying existing demand-side technologies can be had by reviewing commercially available databases and assessments of demand-side measures and potential savings developed by other utilities. Additional resources may be identified as a result of the end-use studies required to assess customer load and energy consumption. The load data that result from such a study are also necessary to establish baseline energy consumption and, from that, to develop estimates of total technical potential. Total technical potential is the amount of energy savings that would occur if existing and future end-uses served by standard-efficiency technologies were replaced by the highest-efficiency technologies for those end-uses. Technical potential is estimated without regard for economic criteria or barriers to customer acceptance of energy-efficient technologies.

The technical potential can be used to prioritize the various candidate DSM program areas by identifying which demand-side measures provide the greatest potential resources. In Step III the number of demand-side measures is narrowed from that indicated in the technical potential through cost-effectiveness tests, additional data refinement, and bundling into comprehensive demand-side programs to arrive at cost-effective conservation potential. Intuitive subjective screening methods risk rejecting reasonable resource options, and therefore should not be used. These issues are discussed in greater detail in Chapters VII and VIII.

Not all IRP approaches involve identifying the technical potential. Some methods identify the largest or most probable demand-side resources and focus their efforts there.

Supply-side options

Step II also requires the utility to comprehensively identify supply options to provide a complete resource picture for the utilities. Included in the definition of supply options are the mix of contracts used to secure natural gas supplies (tradeoffs between length of contract period, cost of gas, peak-day and annual takes), storage facilities (which enable the utility to purchase cheaper annual gas and store it for use on peak day), additional physical plant (such as transmission and distribution pipe, compressors), and purchasing arrangements with customers with multi-fuel capabilities (who may substitute alternative fuels for natural gas at time of utility system peak).

Non-utility gas sources

Non-utility gas sources are becoming an increasingly large option as customers add dual fuel capability and contract for their own natural gas supplies. These transportation gas customers could agree to switch to their alternative fuel and sell their gas to the utility when needed during peak-day conditions. Supply-side options are discussed further in Chapter VI.

<u>Step III: Develop Demand-Side Programs to Deliver Demand-side Measures</u>

Step III consists of two intermediate stages, one stage to narrow the list of demand-side measures contained in the technical potential assessment and the second to assemble the remaining demand-side measures into demand-side programs. The demand-side programs are ultimately the resource options that are used as inputs to the integrated resource planning process. The tests that are used for these purposes are the societal cost test and the utility cost test. At each of the two stages, both tests are used in order to assure that appropriate resource options are eligible for developing alternate resource plans servicing a variety of objectives, such as maximizing societal value or minimizing customer bills. The components of the costs and benefits included in these tests are identified in Chapter VIII.

Screen demand-side measures

The first stage is to screen the demand-side measures identified in the technical potential to eliminate the ones which are not cost-effective. The demand-side measures are evaluated using time-differentiated avoided costs and time-differentiated energy and capacity savings for each demand-side measure, assuming that each measure operates on a stand-alone basis. Assuming each measure is installed on a stand-alone basis does not reflect the interactions between energy saving demand-side measures (e.g., improving the efficiency of furnaces will have less impact if the home has been insulated and weatherized), and thus will overstate the amount of energy projected to be saved.

Bundle demand-side measures into demand-side programs

A demand-side program, comprised of multiple demand-side measures, is the counterpart of a supply-side resource -- a building block for a long-range plan. The second stage in the development of demand-side management programs is to group into programs those demand-side measures that have passed the avoided-cost analysis on a stand-alone basis. When bundled together into demand-side programs, the interactive effects between demand-side measures on energy-savings potential are accounted for. The bundling of demand-side measures into a demand-side program also permits the sharing and consolidation of program marketing and delivery costs among measures. In addition, demand-side programs are the method of delivery in the field. When a contact is made with the customer, it is to offer and discuss an entire demand-side program, not a single measure.

It is at the bundling stage that program administration costs should be first included. Including demand-side program administrative costs earlier, at the measure level, could mis-state the overall program administration costs, and could prematurely eliminate certain demand-side measures. Demand-side program administration costs can most reasonably be assessed once the basic program parameters, i.e., the customer segments being targeted and the demand-side measures being included, are known. In spite of this, some IRP approaches include an estimated value, usually a constant fraction of the measure cost, as an added cost of the measure. This method does not account for the fact that program administration costs of adding another measure to a program are incremental.

As a result of completing Step III, the demand-side measures are grouped into a demand-side program whose characteristics have been defined, including the customer group being targeted, the interactive impacts of the demand-side measures being delivered on the system load, and the cost of the delivered technologies (including a breakdown of participant cost vs. utility cost). With these characteristics defined, it is then possible to evaluate and compare resource options in Step IV.

Step IV: Evaluate and Compare Resource Options

Step IV is a comparative evaluation of each of the supply-side resources identified in Step II and each of the demand-side *programs* developed in Step III. The present-value life cycle benefits and the present-value life cycle costs for each resource alternative are calculated (each alternative demand-side program is an independent alternative resource). Resources with a positive present-value life cycle net benefit are selected for further analysis and incorporation into long-range system plans.

Step V: Develop Long-Range Alternative Plans

Alternative long-range plans are system plans built up from various combinations of demand and supply resources. The gas planning horizon may be about 10 years, arguably shorter than the 20 year horizon required for electric utility planning, yet long enough to directly assess the long-term implications of planning decisions. These gas utility resources would be planned to come into service in various years as necessary to ensure comparable levels of service among the plans. A broad range of alternative plans would be developed by varying the resource options installed and the timing of those installations.

Alternative plans would be developed to evaluate alternative major policy choices to highlight different objectives. The performance of alternative plans in response to different scenarios reflecting the uncertainties in customer demand, fuel cost, and other key assumptions can be compared, allowing an evaluation of the relative robustness of different long-range plans.

The scope of alternative plans could be increased through advisory groups using promising resources developed in Step IV. Each participant in the planning process would bring his/her own perspective on the objectives to be achieved and on the relative weights that should be applied to multiple objectives. Multiple plans would probably be developed because there is no single objective and no single set of values that define all aspects of the public interest. The goal is to develop a set of alternative plans that emphasizes different objectives, such as low monetary cost, reduced oil consumption, low environmental impact, minimizing rates, minimizing bills, maximizing net societal benefit, etc. Comparing the alternative plans allows various policy decisions to be tested under a variety of scenarios. Throughout the process, each participant would be encouraged to identify resource programs and options, and at this step, alternative plan(s). Extensive input from the parties is useful to identify a broad scope of objectives and develop corresponding alternative plans.

As discussed in the beginning of this chapter, not all IRP approaches focus on the development of alternative plans. Also not all IRP approaches utilize advisory groups as extensively or for the purposes described above.

Step VI: Evaluate Alternate Plans on a System Basis

The purpose here, as in Step V, is to find the system plan that best serves the public interest. In Step VI, the utility analyzes the alternative plans on an integrated system basis and generates comparable information on each so that each plan's performance can be measured against a set of criteria. Each party selects the plan it believes best serves the public interest. Each party is then free to recommend its preferred alternative plan to the regulatory agency. At this stage, all parties should be in agreement as to the validity and quality of the underlying technical data, with differing positions resulting mainly from the assumptions, objectives and values used to define the public interest. Each party is then free to recommend its preferred alternative plan to the regulatory agency and to prepare short term action plans for the preferred alternative.

The criteria upon which the parties should evaluate and select their preferred plan should allow the Board to make its own determination of which plan(s) are in the public interest. Societal, bill, ratepayer, and other impacts of each alternate plan should be identified to aid the Board's decision.

Societal criterion

One measure of the public interest is the societal perspective, which considers direct avoided costs plus all monetized and non-monetized externalities and non-price factors. Alternate plans can be compared from the societal perspective, based on the present value of the life-cycle societal net benefit, discounted at the societal discount rate.

Bill criterion

Another perspective can be examined by determining the economic value to the utility (and ultimately to the ratepayers) of alternative plans. This requires that the present value of the utility revenue requirement be calculated. Because each of the alternative plans is designed to meet the customers' needs for energy services, the net present value of the revenue requirement (NPVRR) is a measure of the average utility bill paid for energy services. The NPVRR is a good indicator of the ratepayers' economic public interest.

Rate impact criterion

Rate impacts are an important concern for the regulatory agency, the utilities, and other interested parties. Rate impacts are an indicator of the effect a plan will have customers which do not participate in demand side programs and represents yet another potential perspective. Alternate plans that produce large net societal benefits may increase rates and bills paid by non-participating customers. The rate impact measure does not decrease the amount of societal benefit resulting from the plan; it does, however, give some indication as to how it is allocated between participants and non-participants. The Board may, upon review of the rate impact information, determine that implementation of the resource plan should be revised to mitigate rate impacts (See Step VIII, refinement of the plan).

A short-term rate increase may be offset by a long-term rate decrease. Two measures of rate impact should be evaluated for each of the alternative plans. The first measure is that of average rates (total revenue requirement divided by sales volume) levelized over the planning horizon. The second measure is the maximum annual rate impact, again averaged over customer classes. By reviewing the levelized and maximum annual rate impacts, the regulatory agency will be able to determine the significance of impacts on non-participating customers and to make judgments concerning the equity of the allocation of societal benefits to the non-participating customer.

Non-participating customers, if the plan results in short-term rate increases, will receive rate and bill increases. Participating customers will also receive rate increases, but bills are likely to decline, due to decreased usage. However, both participant and non-participant customers will receive the societal benefits resulting from avoided externalities and avoided non-price factors that are not reflected directly in the rates paid by customers. Thus, a non-participating customer receives benefits of lessened pollution or improved reliability or reduced risk, if the plan under consideration produces those results external to the rates being charged. In the long-term, all customers may benefit from rates lower than those that would have been necessary if IRP had not been adopted.

Additional criteria

Additional criteria are useful in evaluating alternative plans, including participants' direct costs, environmental impact, and other benefits and costs. The participants' direct cost is a function of technology cost and demand-side program design. The installed-technology cost is split into a customer-direct component and a utility component. Program design results in some utility incentives being offered to reduce the participants' direct cost, so as to induce customers to implement the appropriate demand-side measures. The participants' direct cost can be made smaller through larger incentives, thereby allocating a larger portion of the societal benefit to the participating customer to insure deep penetration of the demand-side measures. The participants' direct cost can be increased through reducing the utility contribution, which, in turn, reduces the amount of rate impact seen by the non-participating customers. The participants' direct cost (as a fraction of total installed cost) for the demand-side measures is an indication of the degree to which benefits have been allocated to the participating customers. The participants' direct cost and the rate impact measures represent the two sides of the allocation issue.

A measure of the environmental impact and of other benefits and costs may also be considered in determining the public interest when selecting among alternative plans. Ultimately planning and good public policy are not the result of a calculation, a formula or a given number. The numerical analysis provides a tool for assessing alternative plans.

The various tests used in the evaluation described above are discussed further in Chapter VIII.

Step VII: Formal Approval by the Regulatory Agency

This step assumes that the regulatory agency formally reviews and approves the long-range plan(s) and associated short-term action plans it determines best serve the public interest. The IRP process also could be designed to reflect the regulatory agency only commenting on the utility IRP filing, or some other type of action. As stated at the outset of this chapter, the working model is being developed to address the most comprehensive approach, which subsumes other approaches. The public hearings and the associated review process are an important source of information to determine what constitutes the public interest. In addition, public input could have been received directly by the utility through an advisory group or collaborative mechanism. This also helps to define the options consistent with the public interest. The regulatory agency, which is responsible for ultimately determining what constitutes the public interest, would select the appropriate plan(s) to pursue. The result of Step VII is to select the best resource plan(s) and provide the utility guidance for implementing, refining or modifying the plan(s).

Step VIII: Refinement of the Plan

Among the possible refinements of the plan would be revisions to the resource implementation schedule or to the allocation of benefits between participants and non-participants in demand-side programs. This might occur if the Board determined in Step VII that the non-participant impact was too high, or that the level of participant incentive was too low. Program design would be revised until an appropriate balance of participant and non-participant perspectives was achieved.

The outcome of Step VIII is the "best" plan the regulatory agency could identify to deliver energy services. After adjustments and details have been incorporated, the revised avoided costs, based on the suggested plan, can be calculated and used as the basis for subsequent planning and resource payment analyses. This plan, and its related avoided costs, represent the utilities' best effort at developing a plan that the Board finds to be in the public interest.

Step IX: Evaluate Strategic Load-Building

Utilities often consider strategic load-building to be a demand-side management tool, and often analyze load-building activities in the same way as energy-efficiency and direct load-control options. This framework analyzes load-building activities in a separate step after a plan is selected to define which resources should be implemented. Another framework that could accomplish the same purpose would develop strategic load building as an alternative plan in Step V, evaluate it with other non-load building alternative plans in Step VI, and make it available for the Board's determination in Step VII. Step IX could be unnecessary if no load-building programs were being proposed.

Strategic load building represents a different kind of demand-side management program than the ones previously discussed. While the purpose of the other demand-side management programs is to increase the available energy service resources -- a resource addition -- strategic load building is a resource consumer. By building loads, more energy resources will be consumed, more fuel will be burned, and production costs will be increased. In addition, it is possible that load-building activities may also increase the need for new capacity. It is important that the load-building and resource-building functions be clearly distinguished and treated separately to avoid confusion and to assure that all potential resource additions are appropriately considered. Considering load-building strategies in Step V (as an alternative to evaluating them in Step IX) runs the risk that the distinction between resource building and resource consuming strategies will be blurred. The result could be an inadequate evaluation of demand-side resources.

One objective for load-building programs is to better utilize the existing supply-side system: that is, to reduce rates by spreading the fixed costs over an increased amount of sales. Thus, one aspect of the assessment of load-building strategies should be to determine how much load can be added, and during what time periods, to reduce average long-term rates. If any load-building strategies are deemed to be in the public interest, they should be included in the plan.

Another objective of load-building programs is to provide societal benefits derived from lower costs and/or environmental and social impacts relating to other fuels. Building gas load to achieve net societal benefits assumes that natural gas is a preferred fuel for the end use, and inherently assumes the societal test is being applied.

Step X: Utility Implementation

In most cases, the utility will be responsible for implementing the plan. Exceptions might be if the plan has identified government-sponsored processes to induce energy efficiency. Examples of such efforts would include the development or revision of provincial or local building codes, which establish minimum standards for energy efficiency. Another example would be the establishment of sliding-scale hook-up fees, based on the energy efficiency of the customer, in which case the nature of the hook-up fee would be defined through a regulatory agency hearing process. These examples are exceptions to the rule, and the utility will have primary responsibility for assuring that the plan is appropriately implemented. There are at least three mechanisms the utility can use: (a) conducting implementation by utility staff, (b) contracting work to private contractors and trade allies, or (c) issuing requests for proposals for competitive bids.

Step XI: Monitoring and Evaluation

A monitoring and evaluation plan, including a budget and a listing of the data to be collected and analyzed, should be part of the overall integrated resource plan filing. Evaluation and monitoring will provide information about the relationship between the projected and actual costs and performance for any given resource option. In addition, demand-side resource options can be modified if they are not performing to their expected levels. The program delivery mechanism or the rate of incentive can be refined and adjusted. Unlike a physical facility, which must be fully constructed and tested at full-scale before it can be evaluated, demand-side programs can be adjusted and refined while on a small scale. Thus, monitoring and evaluation has a particular benefit and importance for demand-side pilot programs. Monitoring and evaluation, and mechanisms for delivering DSM programs, are discussed in Chapter VII and Appendix C.

Step XII: Ongoing Planning and Review

Utility planning is a continuing effort. Utilities are well aware of changing conditions and the need to modify plans to reflect them, and would not normally wait until the next integrated resource plan filing to update its planning. Load forecasts could be updated at least annually to reflect new data on load growth. System-supply cost, dispatch and availability data could be reviewed at least annually, and updated when necessary. Demand-side resource programs could be updated and refined continuously, based on monitoring and evaluation data. As required by the IRP process, utilities could file new plans with the regulatory agency for public review, and return again to Step I.

B. E.B.O. 134 and IRP

The Ontario Energy Board's Report in E.B.O. 134 establishes the criteria to be used by utilities when assessing and justifying system expansion. It resulted from a formal review undertaken after examination of six applications by the Consumers' Gas Company Ltd. to provide service into marginally economic regions. The Board reviewed procedures proposed by the three major natural gas distributors in Ontario for evaluating the acceptability of system expansion.

1. Applicability of the EBO 134 Report to IRP

The Board concluded that a three-stage process should be used to determine whether a system expansion proposal is in the public interest. Stage one is a test based on a discounted cash flow analysis of the project. Stage two examines quantifiable public interest factors. Stage three takes into account all other relevant public interest factors. The Board concluded that a strict customer economic-feasibility test should not be the sole criteria used in making system expansion decisions.

The Board also concluded that the concept of the public interest is dynamic and that there can be no firm criteria established in advance. Rather, an application to the Board should include evidence on the public interest factors considered relevant to the participants. The Board stated that it would continue to be guided by the general principle that the public interest is served if "the welfare of the public is enhanced without imposing an undue burden on any individual, group or class" (p.25).

The principles set forth in E.B.O. 134 are similar to accepted IRP principles for evaluating selected resources on the basis of system-level impacts. The E.B.O. 134 process presents a framework for evaluating system expansion in the context of benefits and costs, including monetized and non-monetized public interest factors (externalities). However, the E.B.O. 134 process was not designed for IRP and as such stops short of incorporating two important and necessary aspects of IRP: resource option identification and selection, and supply-side and demand-side option assessment on a consistent basis.

The E.B.O. 134 process does not directly address the criteria by which supply-side options are selected by the utility; presumably supply-side options have been chosen as the lowest cost source of supply and/or as exhibiting net value on a societal basis. It can also be assumed that the options selected are of some benefit to the utility. There is no assurance that all potential measures have been considered. Furthermore, there is no guarantee that the options presented by the utility have considered the implication of lost opportunities for savings, including lower cost options.

Although the considerations of economic feasibility explored in the E.B.O. 134 Report were directed at a set of decisions different from those in the IRP process, the questions being considered were many of the same ones. These issues were essentially ones of how broad the economic tests should be, what costs and benefits should be included, and how much the potential for subsidies from one customer group to another should be a factor in the decisions.

The E.B.O. 134 process embodies issues to be considered with IRP, but it addresses only a small part of the overall IRP process. As such, it could be utilized as an established and accepted process which may be expanded into a more comprehensive treatment of the complete IRP framework.

2. <u>Options for Extending E.B.O. 134 process to IRP</u>

- The flexible but comprehensive treatment of public interest factors (societal factors) is consistent with comprehensive IRP approaches and could be retained for future use.
- The three-step process for evaluating options as outlined in the E.B.O. 134 Report is similar to the process presented in this Chapter and Appendix A as Step IV (Evaluate and Compare Resource Options) and Step VI (Evaluate Alternative Plans on a System Basis). Consequently, the E.B.O. 134 process may be substantially incorporated in the IRP process and could be extended to evaluating DSM programs and plans.
- Additions would be necessary to account for Steps I-III of the Steps identified in this chapter are necessary for a true IRP process, and procedures for Steps V-XII, as described in this chapter, must be established for both DSM and supply-side measures to assure consistent treatment and consideration.
- Resource selection, screening, and benefit/cost analysis must be comprehensively addressed and treat supply-side and demand-side measures on an equal footing.

V. MARGINAL AND AVOIDED COSTS

Integrated resource planning requires that costs and benefits of alternative resource options be compared on a consistent basis. The determination of marginal and avoided costs is a necessary aspect of this process. In this chapter, we discuss the general concepts of marginal and avoided costs, the elements of a utility's marginal and avoided supply costs, and some of the methods used to quantify them.

A. General Concepts

The role of marginal and avoided cost calculations in IRP is to allow comparison of costs and benefits of a base utility plan with alternative plans. The base plan is the utility plan developed using traditional planning practices--i.e., the resource options considered are traditional supply-side options with no consideration of DSM. The resource options of alternative plans typically incorporate a mix of DSM resources, committed supply resources, and traditional supply-side resources. The actual comparison of the DSM technology options, programs, or IRP plans is done through the use of various economic tests. The specific tests are discussed in Chapter VIII. The marginal or avoided costs appear as a benefit in the tests.

The difference between marginal and avoided costs is subtle and not always distinguished. Marginal costs refer to costs associated with meeting an increment of demand. These costs include both the incremental operating costs of the existing utility supply mix at the margin and the costs of incorporating new units of supply, if necessary. Costs may be time-differentiated by season, month, day, or even hour to allow for a greater degree of precision in identifying peak-period cost avoidance. These costs may be estimated for the planning horizon by using escalators for the fixed and variable portions of costs. They may also be calculated for each year of the planning horizon to account for changes in the option mixes utilized[2]. Marginal costs are typically expressed as cost per unit of energy or capacity.

Avoided costs, on the other hand, are used to estimate the difference in cost between the base resource plan and a resource plan that incorporates DSM. Approaches for determining avoided costs vary. One approach is to extrapolate the marginal costs for future supplies by using appropriate escalators for the fixed and variable components of the marginal costs. A second approach is to decrement the load by a fixed value or percentage, and determine the marginal costs at that level of demand. These values could be extrapolated into the future or, alternatively, determined for each year of the planning horizon. A third approach uses a system model to estimate the overall system cost differential between the base resource plan and the DSM resource plan.

Marginal costs and avoided costs as they have been defined here are employed at different steps in the IRP model described in Chapter IV. Marginal costs of the base resource plan are defined in Step I of the approach. Costs of DSM options are then weighed against the marginal costs of supply to screen technologies during the program design phase

[2] These changes may be a result of changes to overall utility load factor, significant changes in the ratio of fixed to variable costs of supply options, or the need to add capacity to meet increased loads.

(Step III). Avoided costs, on the other hand, are used for determining changes in overall utility costs for the purpose of evaluating programs (Step IV) and plans (Step VI).[3] The components of marginal and avoided costs used in the model vary depending upon the perspective being evaluated.

B. Components of Marginal and Avoided Costs

Marginal costs and avoided costs are based upon impacts to all aspects of the supply system and society. For natural gas utilities, a complete examination of marginal and avoided costs includes the following elements:

1. Direct costs including demand charges and capacity-related storage costs.
2. Direct local capacity costs for transmission and distribution facilities.
3. Adjustments to capacity cost for weather-sensitive loads.
4. Adjustments to capacity requirements for capacity-related compression and leakage losses on the local transmission and distribution system.
5. Gas cost for bundled services and direct purchases, transportation costs for direct purchases and storage costs related to seasonal gas storage.
6. Adjustments to energy costs for reductions in compressor fuel and leakage losses on the local transmission and distribution system.

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[3] It should be noted that the procedure discussed here is not universally utilized. It is rather comprehensive, however, and other methods exhibit aspects of it.

7. Monetized environmental externalities.

8. Adjustment for non-monetized environmental externalities.

9. Adjustment for non-price factors.

10. Time differentiation on a seasonal, daily, and hourly (if appropriate) basis.

11. Consideration of 1,2,7-10 above for avoidable capacity-related components of supply for upstream pipeline companies and producers.

The treatment of environmental externalities in avoided costs and other societal impacts will be addressed briefly at the end of this chapter and more thoroughly in Chapter IX. The discussion which follows will consider the approaches used to quantify the marginal and avoided costs of supply for LDCs.

C. Derivation of Marginal and Avoided Costs

Determining marginal and avoided costs requires three major steps: 1) identifying and calculating supply-side components which are likely to change between the base utility supply plan and the DSM plan(s); 2) adjusting these costs to account for differences in reliability, flexibility, and security between the base resource plan and the DSM resource plan(s); and 3) further tuning the adjusted costs to account for losses not incurred in the DSM resource plan (e.g., distribution and/or transmission losses and leakage). Each of these stages will be discussed in turn in the following three sections.

1. Identifying and Costing of Marginal and Avoidable Supply-side Options

Identifying and calculating marginal and avoided costs requires that some judgements be made. These include the method for identifying options used at the margin or that are potentially avoidable, the degree to which supply plans are adjusted in future planning to account for changes to supply mix, and the degree of time differentiation for peak and off-peak period costing.

The tools typically used to identify options operating at the margin are dispatch models. Historical supply procurement practices and purchasing heuristics may also be used to a limited degree. While dispatch models provide the more precise determination of marginal costs, they are expensive and may be time consuming to run. These factors may make regulatory oversight difficult, especially for detailed review. Historic purchasing analyses are somewhat more straightforward. They are less precise, however, and even though they may reflect past procurement decisions reasonably well, they may not provide a useful basis for future procurement practices.

Regardless of the method used to identify options, the costs associated with those options must be determined for the planning horizon. First-year costs may simply be escalated for future years (including time-differentiated costs). For greater precision, the supply plan may be adjusted on a year-to-year basis to account for changes to the supply mix which may result from load shape impacts of developing markets, DSM (for the DSM case), and different escalation rates between fixed and variable costs for some options. In instances where the supply portfolio as well as the relative costs of options within the supply portfolio are consistent throughout the planning horizon, escalating first-year costs may be appropriate. In instances where (a) significant load shifts occur during the planning horizon, or (b) the relative costs of the options change over time, the extrapolation of existing marginal costs may not yield reasonable estimates of future marginal costs, and the model should be run on a year-by-year basis. Thus, while an increase in precision in the marginal cost calculation may result from a year-by-year analysis, the benefits gained must be weighed against the loss of precision due to the introduction of uncertainties in the forecasts and supply costs upon which those marginal costs are based.

The difference between marginal costs associated with energy and capacity used during peak and off-peak periods may be determined for more precise costing. Multiple runs of a dispatch model may provide an estimate of the costs associated with different time periods by comparing the operating costs between a base-case load and a decremented load. Historic costs associated with different time periods may also be used.

The degree to which these parameters are incorporated in the different approaches used to calculate marginal and avoided costs varies. The following discussion of each method will address these points along with a general description of the approach.

a. Marginal Cost Methods

Marginal costs can be used as a basis for comparing costs associated with DSM options with the alternative supply options and with each other. In general, two methods have formed the basis for determining the costs associated with incremental additions to the system. These are the System Marginal Cost Approach and the Targeted Marginal Cost Approach.

(i.) System Marginal Cost Approach

The System Marginal Cost Approach uses a dispatch model to identify the most expensive unit of gas purchased and thus reflects the system incremental costs of supply. The degree of detail may be monthly, daily, or even hourly if appropriate.

The major difficulty with this method is the treatment of cost causation and allocation. A single system marginal cost is determined for each time period. The problem arises when the cost of options that exist primarily to serve weather-sensitive loads (seasonal storage and peaking facilities) are allocated to baseload measures. Under this method, costs which arise due to requirements for increased seasonal usage are shared by customers who do not contribute incrementally to seasonal loads. The result is that baseload marginal costs are over-valued, and weather-sensitive marginal costs are under-valued.

(ii.) Targeted Marginal Cost Approach

The Targeted Marginal Cost Approach was adopted in the State of New Jersey for determining marginal and avoided cost. This method is designed to address cost causation concerns. The approach attempts to match the load factor of an end-use technology with the mix of supply options best suited to serve that load factor. Marginal costs of the supply option mix are then used for valuing DSM load impacts for that end-use.

The supply option mix is determined by evaluating historic purchasing practices and peaking facility usage corresponding to baseload or weather-sensitive demands[4]. Costs associated with the marginal options used for serving these two different groups of customers are determined in the evaluation. These costs essentially become the marginal costs for those two categories of customers. End-uses are similarly categorized as weather-sensitive or baseload, and are weighed against the appropriate marginal costs.

b. Avoided Cost Methods

Avoided costs may be estimated by extending the marginal cost of supply into the future or by calculating the overall changes to system costs directly. The marginal costs provided by the System Marginal Cost Approach and the Targeted Marginal Cost Approach may be utilized as avoided costs for the purpose of evaluating programs and plans. Two additional methods, the Decremental Avoided Cost Approach and the Weighted Average Cost of Gas Approach, may be used similarly and will be discussed here. Finally, the System Optimization Approach may be used for the direct valuation of the difference between aggregate supply costs for the base resource plan and DSM resource plans.

(i.) System Marginal Cost Approach

Essentially all the advantages and disadvantages previously discussed of using this approach for a marginal cost calculation apply to the use of this approach for calculating avoided costs. Again, cost causation is not addressed directly.

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[4] Each of these two customer types may be further differentiated between firm and interruptible customers. Significant differences in supply procurement and peaking facility usage may exist between firm and interruptible customers.

(ii.) Targeted Marginal Cost Approach

Again, the previously discussed advantages and disadvantages of using this approach for a marginal cost calculation apply when this approach is used to calculate avoided costs. An additional advantage is that the avoided costs determined approximate the avoided costs provided by the System Optimization Model Approach, which is discussed below, without the great expense of modelling associated with the System Optimization Model Approach. The relative simplicity of the Targeted Marginal Cost Approach lends it well to regulatory oversight. Another advantage of this approach is that it is more scrutable than the system optimization methods. Using this approach, cost causation is clearly defined for the system.

(iii.) Decremental Avoided Cost Approach

The Decremental Avoided Cost Approach identifies differences in costs between a base-case load and a decremented load. The decrement is a fixed volume or percentage reduction to the utility load profile. This method has been used by electric utilities in Massachusetts. The marginal costs of supply are then determined using the System Marginal Cost Approach applied to these reduced load levels. This method helps reduce the exaggeration of avoided costs resulting from the use of the System Marginal Cost Approach alone, but does not directly address cost causation.

(iv.) Weighted Average Cost of Gas Approach

The Weighted Average Cost of Gas (WACOG) Approach uses a weighted average cost of gas to value gas savings. This method is currently used in the District of Columbia, but more sophisticated methods are now being explored there. The method's main attraction is its simplicity. Public understanding and regulatory oversight are easier when this method, as opposed to some of the more complicated methods, is used. Several problems arise with this method owing to the simplifications used. One of the problems is that average costs are not representative of avoided costs unless only a single supply option is utilized by the utility, and then only if seasonal or monthly cost differentiation is used. When using an annual WACOG, demand impacts of DSM are not considered properly; peak-demand savings are undervalued while off-peak period demand savings are overvalued. Use of seasonal or monthly WACOG improves the calculation. Another problem of this approach is that it must be recognized that long-term contracting practices are assumed to exist throughout the planning horizon. No recognition of contracting practice changes due to potential load shifts resulting from DSM is incorporated in the WACOG method. In situations where the utility has contractual restrictions that will not be influenced significantly by DSM, or when there is a large reliance on only a few major contracts, the method may provide a fair representation of avoided costs. Overall, this condition is unlikely to exist for an extended period of time owing to utilities' efforts to attain low-cost, reliable service, which require continual adjustments to the supply mix.

(v.) System Optimization Approach (also known as the Dispatch Model Method)

The System Optimization Approach uses a dispatch model to determine the optimal mix of supply options and the associated costs. The difference between gas and storage costs for two resource plans is calculated--one at forecasted loads with no DSM, and the other at reduced loads to reflect DSM. The present value of the difference in total supply costs provides the total avoided cost.

This is the most sophisticated and detailed of the avoided cost approaches. Given good and complete information, this method also provides the theoretically least-cost mix of the supply options under consideration. It follows that the avoided cost calculations will be theoretically correct. Supply options such as the addition of transmission and distribution capacity may also be modeled directly by using this approach. In addition, marginal costs, which may be used as part of the DSM technology screening analyses, are provided by models of this type.

Although optimization models provide mathematically correct options and the associated costs, the value of the results depends upon how well the data actually represent future conditions. Good and complete projections of supply-option costs and customer demand are required for this method. Uncertainties in projections of sales, natural gas prices, and contract type and availability yield results of questionable value.

In addition to requiring data for the planning horizon, this approach requires the incorporation of the impacts of resource additions that extend beyond the planning horizon. Quantification of these tail-end impacts is necessary for analyses in which the DSM option mix could significantly alter the load factor (and consequently the supply-side resource mix) during the planning horizon. In practice, these models were not originally designed to determine avoided costs for IRP; rather, they were designed to assist in formulating short-term least-cost supply procurement strategies. Consequently, they are typically set up for planning horizons of one to five years. Oftentimes they are used for determining monthly purchasing mixes.

Another disadvantage of this method is that the resource selection criteria are not transparent. Although ultimately the model relies upon cost minimization, it offers no clear explanation of how specific options interact, particularly regarding seasonal contract selection for storage injection and withdrawal. Consequently, the inputs must be reviewed carefully, as the impacts of erroneous or inexact assumptions may be lost in the outputs without any hint of error. The degree to which "soft" data and assumptions associated with uncertainty in the long-term projections of costs and sales affect the results are not clearly discernable. Moreover, the impacts of small increments of savings can be lost in the analysis. Ultimately, the resource option mixes selected in the optimization process should be evaluated from a common-sense perspective to ensure that the mixes chosen are practical real-world options.

Sensitivity analyses relating to projections of sales, natural gas prices, and contract availability are important. Time-differentiated avoided costs may be determined through multiple runs by decrementing the time periods under study.

Additional considerations are that the models are expensive and can be time-consuming to use, particularly if multiple sensitivity analyses are conducted. These reasons make it difficult for regulatory oversight or validation to occur.

2. <u>Adjusting Marginal and Avoided Costs for Differences in Reliability, Flexibility, and Security</u>

Marginal and avoided costs must take into account the differences between the reliability of DSM savings and the supply option(s) DSM replaces. The two major areas of concern are the potential for supply-system failure and peak-period reliability. Issues associated with the risk of supply system failure and reliability are discussed in Chapter VI. Briefly, system failures can occur due to failures in the transmission system, storage withdrawal, or production facilities. Supply options themselves are considered to have varying degrees of reliability. Some supply-side measures may be utilized to alleviate these problems, including type of contract; local, pipeline, or producer storage; and diversity of supplier and/or transporter. DSM, which exists at the end-user level, possesses none of these costs associated with reliability. It does, however, introduce new uncertainties to the planning process, as will be discussed later.

To some degree, DSM energy savings should include as a part of the supply costs they are avoiding the costs of all up-stream components of supply. For example, during periods of pipeline capacity constraints, DSM baseload measures may increase the viability of local storage as a cost-effective option while at the same time allowing for LDC peak-day savings. During peak periods, not only is transportation capacity freed up, but gas acquired during non-peak periods which has been diverted to storage is also available. The effective impact of baseload DSM on peak-day savings is much greater than the savings alone due to the synergistic effects of a baseload measure teamed with local storage. This, of course, precludes the possibility that additional local storage is available. Costs associated with seasonal storage would have to be subtracted from the costs the DSM measures are calculated to avoid.

Demands for weather-sensitive loads must be planned for by LDCs and direct purchasers. The demands of the customer must be determined, with some allowance made for increased requirements during extreme cold. To a limited degree, non-weather-sensitive loads may be affected due to the loss of backup systems and capacity during periods of extremely cold weather. "Best efforts" supply from any source is generally less available during these times. DSM reduces the costs of peak-day reliability to the degree that savings occur during peak usage, and the avoided costs that are calculated should reflect this fact.

A general discussion of the costs and risks associated with supply acquisition and flexibility is presented in Chapter VI. Included in that discussion are references to risks associated with entering into long-term contracts, contract and pipeline capacity deficiency due to forecasting error, and inadequate development of natural gas reserves to support growth. To the degree that DSM options avoid the costs necessary to insure adequate flexibility, the avoided costs should reflect those savings.

For example, direct costs associated with reserving pipeline space for expansion may be reduced as a result of DSM and these savings would be included in the avoided costs. Although DSM, due to its relative infancy as a resource, carries with it uncertainties related to technology performance, market penetration and persistence of savings, the presence of DSM may decrease the overall uncertainty associated with demand shifts that the utility faces, e.g., due to weather extremes.

Avoided costs also need to be adjusted to reflect the differences in flexibility associated with putting demand-and supply-side options into service.

The "lumpiness" of resource additions varies between DSM and supply-side options. DSM may be phased-in small increments. Supply additions may or may not have this advantage. Numerous small, short-term contracts may be relied upon until the level is reached where contracting for a substantial, longer-term resource is appropriate.

In addition, DSM resources may be brought into service during periods of unconstrained capacity. In these periods, the avoided capacity costs may be very small. Capacity brokering may be used to value excess capacity. Avoided energy costs alone may allow for selection of some measures.

As noted previously, considerable uncertainty exists for natural gas planning both for supply-planning assumptions and sales forecasting. These uncertainties affect the security of the gas resource. The lifetimes of supply-side options range from extremely short to quite long, depending on whether the option is a short-term contract, long-term contract, or pipeline/storage facility. The avoided costs should reflect the impact of DSM on supply acquisition; the longer the impacts of DSM, the greater the avoided supply-side costs and the greater the avoidance of the uncertainties associated with those costs.

While reducing planning uncertainties in some respects, DSM increases planning uncertainties in others. These include uncertainties associated with DSM resource acquisition and assumptions regarding the effect of DSM measures on the efficiencies of replacement equipment. Uncertainties associated with DSM resource acquisition include level of market penetration, actual effectiveness of installed measures, degradation of savings over the measure lifetime, and longevity of measures.

Experience gained from electric utility DSM is useful for reducing these uncertainties to a limited degree. Although market penetration models developed for electric IRP have been found to be suited for only rough estimations of market acceptance, the experience that has been gained regarding customer behaviour is applicable to natural gas customers. Engineering estimates have been found to both over- and understate realized savings, but actual savings achieved in electric utility DSM programs may be transferrable to natural gas DSM analyses for some end-uses (e.g., weatherization and shell measures). Similarly, estimates of degradation and longevity of measure life may be transferrable for some end-uses.

Overall, the degree to which these uncertainties affect avoided costs of DSM varies among end-uses, and should be reflected in a comprehensive determination of avoided costs.

3. Tuning Adjusted Marginal and Avoided Costs for Reductions in Losses

After adjusting marginal and avoided costs to reflect the costs of reliability, flexibility, and security, the costs must be further tuned to reflect the costs of losses associated with transmission and distribution of natural gas (e.g., compression energy used to overcome pipe friction and outright leakage). These losses are avoided by DSM. Typically, the costs associated with these losses will be restricted to the LDC system, since they are incorporated in the cost of gas supplies or directly as a part of transportation costs.

D. The Short-Cut Approach: Integration Via Direct Modeling

The Integrated Model Approach is not an avoided-cost model *per se*, but the method is similar to the System Optimization Approach in that an optimization procedure is used to select the mix of supply options. The difference lies in the treatment of DSM options; they are essentially treated as supply options in the optimization process. This method requires only that a single run be made; gas supply options and DSM options are weighed equally in the determination of the optimal resource mix. The uncertainties associated with sales and natural gas price projections are tempered by using a less-detailed data set. Actual avoided costs are not calculated in this approach; they are inherent in the resource-selection procedure.

An advantage, in addition to those detailed in the System Optimization Approach, lies in the theoretically optimal mix of DSM options. The uncertainties associated with designing the "best" combination of DSM options for a program or system plan are avoided.

Disadvantages to this method are similar to those described for the System Optimization Approach, with the added uncertainties associated with DSM program optimization. The degree to which the additional uncertainties associated with DSM savings (i.e., program implementation, participation, and persistence of savings) affect the resource selection is not obvious. As with the System Optimization Approach, multiple runs may be used to help identify the sensitivity of key variables.

Furthermore, it is difficult to incorporate the impacts of DSM on the flexibility, reliability and security concerns of the utility resource plan. Costs associated with the timing of resource additions as discussed in the previous section are also extremely difficult to address directly with this method.

E. Utility Marginal and Avoided Costs for Transportation Customers

The previous discussion focused on costs avoidable to the utility. For transportation customers, however, the utility does not avoid the major costs; rather, the customer does.

The distinction is clear when one considers that transportation customers procure their own supplies and rely upon the LDC only for transporting those supplies. Utility avoided costs for gas saved by these customers is restricted only to the costs of transporting that gas. Consequently, few if any DSM options for transportation customers will pass a marginal cost screen by the utility. DSM measures adopted by these customers, however, result in natural gas savings and societal savings just as do DSM measures adopted by utility customers.

F. Externalities

Avoided costs as addressed by the approaches previously described are those that fall completely into the utility's sphere -- cost of gas, pipeline costs, contract costs, etc. These do not, however, make up the complete set of avoided costs. There is a whole set of avoided costs that is traditionally considered to be external to the resource selection process. If the societal perspective is utilized in the IRP process it is important to consider these so-called "externalities." Those which can be monetized -- expressed in terms of dollars -- are reasonably straightforward to include in the analytical framework. They can be added directly to the avoided costs and used directly in the cost-effectiveness analysis. Those impacts that cannot be (or at least have not yet been) monetized are somewhat more difficult to include in the cost-effectiveness analysis. The values cannot be added directly to avoided costs. Various means have been developed to include non-monetized externalities in cost-effectiveness analysis. One of the most straightforward is to add an increment to the avoided costs to represent non-monetized externalities. Another related approach is to increase the monetized externality values by a multiplier to recognize the fact that monetized values alone cannot account for all externality impacts. While both of these methods are crude, they do have value. They establish the importance of considering externalities rather than dismissing the existence of those impacts entirely. Chapter IX describes the impacts that are usually considered externalities and discusses in more detail how they can be valued and factored into the planning process.

VI. INTEGRATED PLANNING CONSIDERATIONS FOR NATURAL GAS SUPPLY

The goal of IRP is to arrive at the least-cost resource mix while considering reliability, flexibility and security; equity among ratepayers; a reasonable return on investment for the utility; and environmental issues. Resources include both demand-side options and supply-side options. Demand-side options will be discussed in Chapter VII. This chapter addresses supply-side options and their role in IRP. The term "supply-side option" in the context of natural gas IRP refers to measures used by the utility to procure and deliver natural gas. Supply-side options for natural gas utilities include contracts for natural gas, pipelines for transmission and distribution of gas, and storage facilities. In all cases, the option is incorporated on the utility side of the meter and does not directly affect the usage of gas by any particular customer.

IRP goals are attained through a process of weighing supply-side options against demand-side options on a consistent basis. One way of doing this is to develop a base plan relying upon supply-side options which is then compared with plans that incorporate DSM. The actual comparison of costs is accomplished using marginal and avoided costs. Initially, the marginal costs of supply options are defined based upon the marginal options of the utility's base supply plan (in Step I of the approach described in Chapter IV and Appendix A). Costs of DSM options are then weighed against the marginal costs of supply to screen technologies during the program design phase (Step III). The second stage utilizes the avoided system costs to evaluate programs (Step IV) and plans (Step VI). Marginal and avoided costs are discussed in detail in Chapter V.

Below, we describe aspects of developing the utility's base supply plan, and address the inter-jurisdictional issues related to natural gas IRP.

A. Developing the Base Supply Plan

The comprehensive identification and evaluation of options is an important aspect of IRP to ensure that the most cost-effective options are included in the base utility supply plan. In particular, these options will address any or all of the following supply planning goals:

- increase the degree of reliability, flexibility, and security inherent in the supply portfolio; this reduces the need to incorporate additional options for enhancing these factors;
- increase the load factor for all segments of the supply system, thereby reducing costs for pure capacity; and
- reduce societal costs.

The degree to which the different supply-side options are useful in meeting these goals varies. A discussion of each of the three goals and how they are affected by supply-side options is next. These goals are the same types of goals utilities currently use to guide their gas supply planning. In an IRP process, however, a utility presents all of the supply options, their costs, and a base plan based on these options. This base plan becomes part of the total public IRP process.

1. Supply System Reliability, Flexibility, and Security

The primary objective of LDCs' supply planning efforts is to provide reliable, flexible, and secure service at reasonable cost. Reliability refers to the risk of supply interruption and reflects the interaction of all supply and demand components of the system at any one point in time. Flexibility refers to the utilities' ability to adjust supply procurement within contractual limitations to accommodate forecast growth as well as changes in demand which may occur due to large customer additions, large customer reductions or fuel-switching. Security of supply reflects concerns for adequate availability of natural gas reserves and transmission system to supply the LDC and to enable it to meet future demand.

Issues of these types are considered on an ongoing basis in Ontario and form an integral part of the utility's traditional supply planning. For example, buy/sell agreements are currently in use by Ontario LDCs. These agreements help to reduce concerns about flexibility and reliability which result from depending upon the LDC to provide natural gas for transportation customers, through supply-balancing or by other means.

Moreover, some of the issues relating to supply and availability of natural gas for existing and future demand were examined by the Board in E.B.R.L.G. 32, Gas Supply at the request of the Lieutenant Governor in Council. In particular, availability and security of supply, transportation capacity, market segmentation, and arbitration provisions were addressed. These issues include factors beyond local regulatory jurisdiction. Aspects of these issues continue to be discussed in the utility rate hearings *a. Reliability of Supply Mixes*

The key considerations for LDC reliability include diversity of suppliers, diversity of contract terms, interconnections with multiple pipelines and system looping, and backstopping. Diversity options discussed in the E.B.R.L.G. 32 Report include contracting with multiple producers, with producers with specific reserves dedicated to contracts, and with brokers with supply arrangements with multiple producers. The Board concurred with most of the participants that diversifying the supply portfolio is sound business practice.

Concerns over the type and extent of contractual arrangements extend to supply procurement and to transmission and storage arrangements. Considerations of reliability extend to particular contractual terms and conditions (terms, price, etc.) under which supplies are secured as well as the capability of suppliers to meet contractual obligations. Consequently, reliability considerations are manifest in all aspects of contractual supply, thus making it difficult to evaluate.

(i.) Transmission Contract Considerations

Discussions regarding contracts must necessarily address pipeline transmission arrangements. In E.B.R.L.G. 32 the Board recognized that interconnections with U.S. pipelines are valuable for providing additional diversity of supply and offering added levels of reliability. The Board also recognized that interconnections with multiple pipelines can be expected to reduce the impact of short-term transmission capacity constraints. Diversifying pipeline access continues to be of interest to many parties in Ontario.

In addition, looping of the transmission and distribution systems helps to ensure reliability of supply.

(ii.) Storage Considerations

The LDC may own or contract for a portion of peaking capacity in the form of storage. Depending upon the type of storage option (or mix of options) utilized, the LDC can provide for seasonal increases in demand, shorter-term increases in demand due to extremely cold weather (periods of several days to a few weeks), and for meeting the intensive hourly peak demands placed upon systems with significant gas-fired electric generation loads. Direct ownership of storage by an LDC offers a greater level of reliability, but introduces financial risk to the utility. Each of the Ontario utilities uses and/or operates storage facilities.

In addition to augmenting low-cost seasonal and peak-period supplies, storage enhances reliability by providing alternative supply during periods of producer and/or transmission system failure. The degree of reliability afforded depends upon the position of the storage facility along the pipeline system. Storage at the producer end and along the transmission system provides security against short-term production failure. Backstopping measures such as local storage provide the additional benefit of buffering temporary transmission failure.

b. Flexibility of Supply Plans

Part of the LDC's job is to balance the desired level of reliability from all possible supply options at the lowest cost with flexibility adequate to allow adjustments to the supply portfolio when necessary. Flexibility of supply is very important in a supply plan considering the uncertainties an LDC faces.

Major criteria to consider in developing flexible supply plans relate to an LDC's recognition of and response to upstream and downstream variables. Downstream variables include such things as sensitivity of load due to weather conditions, the degree to which transportation customers rely upon the utility to provide a supply-balancing service, customer interruptibility, and customer capability of and tendency toward fuel switching. Upstream variables include such things as supply and capacity availability.

Even though the supply plan itself could be designed to deliver extremely reliable performance to guard against pipeline and transmission failure, it could prove to be inadequate if reasonable reliability criteria were not used for defining and forecasting peak-period demand. Critical to this assessment is the criterion that establishes the design degree-day for assessing weather-sensitive load. Designing the system for excessive peak-day deliverability results in higher costs, potentially opening the door to disallowance of expenditures for imprudent practices. Insufficient allowance for peak-day demands poses potentially costly risks to customers.

Whereas LDCs have wrestled with these issues for decades, direct purchasers must plan for peak demand without the benefit of extended experience. Furthermore, rapid changes in the industry have left many end-users with responsibilities for management and procurement of gas supplies -- roles formerly performed by LDCs. This issue was addressed by the Board in its Report in E.B.R.L.G. 32, in which they emphasized the importance of appropriate contracting practices. Incorporating the effects of direct purchase may be an important consideration for utilities developing supply plans, although the Ontario utilities have no explicit obligation to supply direct purchasers who want to return to the system.

Even if a utility does not plan to supply gas to a direct purchaser, it will need to assess the capacity requirements of such customers.

A related issue is the reliance on the LDC by transportation customers to balance receipts and deliveries. The advantage is that a given level of reliability is attained at lower cost due to the sharing of the diverse supply contracts of the system, including the LDC contracts and other transportation customers. The balancing service does entail costs, but overall reliability and flexibility for the LDC and transportation customers can be increased significantly. Buy/sell arrangements in current use by Ontario utilities and direct purchase customers reduce the need for formal balancing service agreements.

An important factor of peak-day deliverability is the degree to which the utility can clip peaks through the use of interruptible tariffs. The actual level of peak clipping may not be fully realized due to ineffective rate design or implementation. Public conscience and concern for a good public image may prevent the utility from exercising full rights to interrupt certain types of customers who may have opted for interruptible rates (e.g., hospitals or schools). It may be appropriate to restrict interruptible service to certain customers. Moreover, it is important to assure that interruptible customers reliably curtail the use of natural gas throughout the interruption. There is not always assurance that this does indeed occur and system reliability must be adjusted accordingly.

Also important is an LDC's familiarity with and flexibility to cope with uncertain growth due to developing markets for electricity generation and cogeneration, natural gas vehicles, and natural gas cooling. These developing markets could have a major impact on Ontario LDC systems. The threat of fuel substitution or bypass requires the utility to know customer needs and provide for a supply plan flexible enough to accommodate changes. Reasonably accurate forecasts of sales and peak demand are important to flexibility as well as reliability in supply planning.

c. Security and Availability of Supplies

Security and availability of supplies are related to the adequacy of reserves to support future demand and the implications of increasing interconnection with the U.S. At the time of E.B.R.L.G. 32 the Board concluded that a possibility exists that uncontracted reserves of Canadian gas could become dedicated to U.S. markets, resulting in a temporary restriction of supply. The Board recommended conducting a periodic review of the security of Ontario's natural gas supply and related issues. Issues of security of supply continue to be of interest in Ontario. This is likely to continue, with the utilities and other interested parties acquiring and disseminating information on this topic.

2. Altering System Load Factor

Increasing the system load factor, a second possible goal of the base utility supply plan, generally tends to reduce investment per unit of natural gas sold. The farther downstream a measure can be instituted, the greater the impact. Supply options are generally not found at the end-user level, although theoretically on-site storage could be an option, albeit a costly one. DSM measures can target peak reduction at the end-user level and will be discussed in the next chapter. The next increment closer to the end-user is the LDC itself; the effective use of storage can increase upstream load factors, but downstream distribution capacity must be maintained. Travelling farther up the supply system, storage may be available for development along the transporting pipeline; again, such a measure would reduce upstream pipeline capacity requirements but would not affect downstream requirements for capacity.

Different types of storage fit different needs at varying costs. Seasonal storage requires the capability to store large volumes of gas, e.g, old oil fields or other porous geologic strata meeting design requirements. These storage fields may also be used to supply peaking capability, depending upon deliverability of the field. Deliverability, which refers to the ability to withdraw gas in large volumes for peak periods relative to the volume stored, varies with the geologic strata and the level of inventory at the time of withdrawal (higher levels of inventory provide greater withdrawal capability). The sum total impact of individual fields or contracted storage resources must be assessed (with consideration of downstream capacity constraints) to determine the degree to which peaking options other than storage are required.

One such alternative peaking option is liquified natural gas (LNG). LNG may be imported or produced during off-peak periods if liquefaction capabilities exist and if pipeline capacity is available. The deliverability of LNG systems is good, but it comes at a higher overall cost than that typically found for field storage. Siting of LNG facilities is also a problem owing to the potential hazards resulting from ground-level explosions which may result from mishandling or accidents. Consequently, LNG is used where storage is not adequate to meet LDC needs at reasonable cost, but its use is typically restricted to brief periods of greater demand.

In some areas, particularly areas with significant use of gas for electric generation, hourly load impacts may be significant. Hourly fluctuations may be handled to a limited degree by utilizing pipeline inventory or "line pack". Alternatively, small storage tanks may be used. These options are the highest cost, and exist to serve only a few customers.

3. Societal Costs

Finally, a goal for the base utility supply plan may be a comprehensive identification and evaluation of all options in order to identify options with lower social impacts. The following public interest factors represent some of the potential costs and benefits from the societal perspective: community benefits including industrial development, alternative fuel considerations, increased revenues to governments (taxes), local employment, and regional development; utility benefits; security of supply and safety; system flexibility; route/site selection and landowners' concerns; environmental impact; government policy. It is also important to note that a base utility plan may be developed to minimize the utility's costs, or to achieve some other goal, which may result in a more limited assessment of these societal factors.

B. Inter-Jurisdictional Issues

A comprehensive IRP effort for natural gas utilities entails consideration of issues that transcend the local jurisdictional boundaries. Although producers, pipeline companies, LDCs, and direct purchasers each contribute to the cost of natural gas service, in isolation they have limited influence over the planning variables that contribute to those costs. Furthermore, many cost variables extend beyond the jurisdictional influence of a single agency, making it more difficult to incorporate them into a comprehensive planning process. Further uncertainty is introduced to the IRP process when the potential impacts of fuel substitution are considered in sales projections. The alternative fuel industries competing with natural gas are largely unregulated, a factor that further complicates the IRP process. All of these issues will have to be considered and addressed by the utility when developing its base supply plan.

C. Conclusion

Important aspects of natural gas IRP include reliability, flexibility, and consideration of security and availability of supplies. Treatment of these issues by LDCs and, to a limited degree, by direct purchasers is within regulatory reach for IRP oversight. Plans developed in the IRP framework may be a valuable aid in coordinating upstream development of capacity and ensuring availability of supply -- factors which are outside of local jurisdictional control. To accomplish this, the IRP plans should consider the impacts of LDC and direct purchaser plans on upstream development and planning. Moreover, the IRP process may be useful to pipelines, producers, and marketers to guide future development.

The various types of supply-side options are suited for different roles. Storage, in its various configurations and locations along the pipeline, may be used for enhancing reliability, flexibility or security of the LDC supply system. Furthermore, it tends to increase the load factor of upstream components. Finally, storage may allow for increased supply during periods when customers may otherwise burn other fuels. Other supply options are less versatile. Reliability may be enhanced through looping of transmission and distribution networks. Reliability may be further augmented by diversifying suppliers and by increasing interconnections with other pipelines. Flexibility may also be enhanced in this way by potentially making available additional supplies to meet fluctuations in demand.

The complex process of balancing desirable levels of reliability and flexibility with costs is an important part of an LDC's job. A necessary step in natural gas IRP is to consider how the total costs and the level of reliability and flexibility may be affected through the implementation of DSM options in an IRP. The framework developed to address these issues consists of a determination of costs that may be avoided through DSM activities, and weighing the costs of DSM against the avoided supply costs in a consistent fashion.

VII. DEMAND SIDE OPTIONS FOR NATURAL GAS IRP

In this chapter, we identify many of the demand-side management (DSM) options available to gas utilities for consideration as part of their integrated resource plans. We also describe how DSM savings potential may be quantified, mechanisms that can be used to deliver DSM programs, the purposes of DSM pilot programs, how DSM programs should be monitored and evaluated, DSM research and development.

A. Demand-Side Options for Natural Gas Utilities

DSM refers to any measure taken by a utility to alter its load shape over a certain period, usually on a daily or seasonal basis. For natural gas utilities, the main load-shape objective that can be met through DSM is strategic conservation, which will result in a reduction in overall demand. Natural gas utilities may also wish to reduce peak demands. A natural gas utility may be able to reduce its costs for supply if it can flatten out its annual demand curve. A supply company may charge a lower rate to a distribution utility if that utility maintains a higher load factor over the year.

A natural gas utility's total load is comprised of two main loads: a non-weather-sensitive baseload and a weather-sensitive load. To accomplish any specific load-shape objective requires the utility to assess which of these load components is to be targeted and then to develop programs based on specific DSM alternatives for different customer sectors.

1. DSM Options for Natural Gas

DSM alternatives for achieving conservation within the residential and commercial sectors are similar and fall into three general categories, namely:

(a) Efficient equipment and appliances

(b) Control equipment

(c) Building envelope modifications

Utilities can reduce demand by developing programs that induce customers to replace existing natural gas appliances (furnaces, water heaters, clothes dryers, stoves, boilers, etc.) with higher-efficiency models. For example, a homeowner could replace a conventional natural-draft furnace (typically only 50-60 percent efficient) with a recuperative unit (typically 90-95 percent efficient) to reduce annual consumption. Utilities can similarly influence demand growth by ensuring that new installations utilize high-efficiency appliances.

In addition to simply replacing less-efficient appliances with more-efficient models, there are a number of opportunities to improve the efficiency of existing appliances and energy systems. Examples of retrofit measures that are commonly taken to improve appliance (or system) efficiency for residential and commercial customers are:

- furnace and boiler tune-ups
- installation of vent dampers on furnaces and/or boilers
- installation of electronic ignitions to replace pilot lights
- derating of furnace or boiler
- cleaning and adjusting of burners
- increased levels of insulation on storage tanks and pipes

- set-back thermostats
- energy management systems

Control equipment, such as set-back thermostats and energy management systems, can be used to decrease fuel use by operating a given appliance or system in the most efficient manner possible. For example, installation of a set-back thermostat can reduce night-time demand in a residential or commercial building without any noticeable loss of comfort. Energy management systems are used in commercial and institutional buildings to match occupant needs with operation of the heating, ventilating and air-conditioning (HVAC) system. The HVAC system can be controlled so that heating and cooling are provided only to occupied spaces.

Space heating is a major use of natural gas in both the residential and commercial sectors. The amount of useful energy needed for space heating is largely a function of climate and the thermal properties of the building envelope. Consequently, a utility can reduce energy demand by improving the overall insulative properties of building envelopes through such measures as increasing the amounts of ceiling and wall insulation and sealing cracks to reduce infiltration. Retrofitting existing buildings will reduce demand from current levels, while ensuring that new buildings are constructed according to high efficiency standards will reduce the rate of demand growth.

There is much less weather-sensitive load within the industrial sector than there is in the residential and commercial sectors. The focus for DSM within the industrial sector is generally on the process equipment and appliances that use natural gas, such as furnaces, boilers, dryers, etc. DSM alternatives for the industrial sector include:

- replacement of existing equipment with higher-efficiency models
- retrofit measures to improve the efficiency of existing equipment such as improved burners
- improvements in the efficiency of operation through improved controls
- utilization of waste heat through the use of heat exchangers
- increased levels of insulation of pipes and/or ductwork to reduce heat loss

Industrial DSM programs require greater customization than residential and commercial programs due to the greater diversity of industrial applications.

A starting point for the development of DSM programs for any customer sector is the gathering of information on energy use. Customers must understand their individual energy use in order to know what programs could potentially benefit them. Metering of end-use is important to establish a baseline by which to estimate potential savings of a given DSM measure. Large industrial or commercial customers may need sub-metering of natural gas use for certain applications.

2. Rate Design as a DSM Alternative

Rate design can be used to affect energy use as part of IRP. Rate structures and levels can be designed to provide customers with pricing signals that reflect the real economic costs of supplying energy at any given time. Customers may change their patterns of energy consumption to take advantage of different rates in order to lower their overall energy costs.

There are several alternative rate-related strategies that a natural gas utility could utilize. These are:

(a) Seasonal rates

(b) Inverted rates

(c) Interruptible rates

(d) Service connection policies/hook-up fees

Seasonal rates reflect the higher costs of meeting seasonal peak demands. Higher peak rates would be expected to induce consumers to take measures to reduce their fuel use during peak times.

Inverted rates refer to rate structures that charge consumers more for additional blocks of fuel use. They are designed to discourage consumption of large volumes of fuel by a given customer classification. Inverted rates for a natural gas utility would only be appropriate to reduce weather-sensitive demand in much the same manner as seasonal rates.

Interruptible rates can be used to give utilities the ability to directly control peak demands. They are appropriate only for large commercial and industrial customers with multi-fuel capabilities. Fuel switching raises a question of whether or not society benefits from a customer shifting its consumption of natural gas to another fuel, probably oil or electricity. Fuel switching is discussed in more detail in Chapter X.

Service connection policies and hook-up fees are other rate-related options that can be used by natural gas utilities to influence demand. New customers can be required to meet minimum energy efficiency standards to control demand growth. Sliding-scale hook-up fees can also be used by utilities to encourage conservation practices. For example, a utility may offer reduced hook-up fees to customers who meet certain standards. Alternatively, a utility may provide rate incentives (e.g. by-pass competitive, cogeneration, and high efficiency new technology rates) to certain classes of customers to manage its load growth or meet other strategic objectives.

The use of rates to influence customer demand is a DSM alternative that can be used by natural gas utilities, although there is limited experience with which to evaluate its effectiveness. Electric utilities have had more experience with the use of rates as a DSM alternative, and this experience has yielded mixed results. Generally, large industrial and commercial customers have the greatest opportunity to take advantage of different electric rate structures because of their capability to shift daily loads and limit peak demands. Use of rates as a DSM alternative for natural gas utilities may be limited by the different nature of natural gas end-use. Although the potential for using rate design as a DSM alternative may be limited, appropriate rate design is important when instituting demand-side measures to ensure that rate structures do not work at cross purposes with DSM programs by promoting increased energy use.

B. Quantifying DSM Savings Potential

As with supply-side resources, we need to assess the potential contribution of demand-side resources to meeting efficiently and reliably the energy service needs identified in the long-term utility plan. The energy-saving potential of demand-side resources is typically expressed in two ways: (a) the technical potential and (b) the achievable potential. The technical potential is the theoretical upper limit on energy efficiency improvements. The achievable potential is a practical estimate of energy efficiency improvements that could reasonably be expected to be delivered with some effort by the utility.

The technical potential is defined as:

> The amount of energy that could be saved if all gas end uses were served by the most efficient technology or design currently available in the market place to serve that end use without any significant change in output or life style. These estimates are derived without consideration of cost effectiveness, institutional barriers and manufacturing capability.

Recognizing that the technical potential is an unreasonable target, the next step is to develop an estimate of the achievable potential for DSM. The achievable potential provides a realistic baseline for utility DSM strategy development. It is defined as:

> The portion of the technical potential that can be achieved through education, economics, policies and programs. This includes utility programs and efforts, as well as those beyond the direct control of the utility, to encourage the adoption of energy efficient equipment and practices. The achievable potential is lower than the technical potential because it recognizes the various barriers that exist to achieving the technical potential.

In general, two broad approaches to quantifying technical potential are used, the "utility-specific" approach and the "representative-study" approach. The utility-specific approach involves developing the technical potential based upon the particular utility's end-use characteristics and market saturations for each DSM option. Not surprisingly, this can prove to be a daunting and expensive task. Alternatively, multiple utilities or regions may pool their efforts and expenses to provide a regional basis for estimating potential savings; this works particularly well for areas that have similar end-use characteristics. This is the representative-study approach. In areas where no pool of information exists, an even-larger scale study (e.g., based on national data bases or international data bases) may be performed.

While such an approach is likely to be less costly than a utility-specific study, the particular end-use information may not describe accurately a particular utility's service territory.

After the technical potential is estimated, the utility generally proceeds with the cost-effectiveness screening of technology options to determine the achievable potential savings. Measures that are found to be cost-effective are bundled into programs and the programs into a plan. These steps require the use of the economic tests described in Chapter VIII to: (a) establish the cost-effectiveness of individual measures (options), groups of related measures (programs) and system-wide aggregations of programs (plans); (b) assist in program design and (c) modify the plan. Although many jurisdictions implementing IRP utilize the above approach, in other cases a utility may fashion DSM programs from DSM measures it knows to be cost-effective rather than first assessing the technical and achievable potential.

C. DSM Program Delivery Mechanisms

Lack of information, performance reliability uncertainty, unavailability of efficient technologies, and higher cost with uncertain benefits have all been identified as barriers to investment in cost-effective levels of DSM measures by utility customers. Utilities attempt to overcome one or more of these problems with the mechanisms selected to deliver DSM programs. A wide array of mechanisms exists that vary in the level of involvement required of the utility, expense, and effectiveness.

1. Customer Financial Incentives

Customer financial incentives are used to overcome concerns regarding the cost of DSM measures, whether it be the up-front cost, capital needs, or potential reduction in returns. These costs relate to customers' economic, financial, and risk interests respectively. Customers' economic concerns deal with the up-front cost of the measure and how long it will take the measure to pay for itself in energy savings. Their financial concerns are over how to pay for the measure: will they have to borrow or will they be able to free up their own money? Customers will also consider the riskiness of the investment: what if the measure does not provide the projected savings, resulting in a slower or reduced return on the investment?

Incentive levels must be tested and analyzed before they are established to see if they achieve the desired market penetration without imposing undue costs on other ratepayers, the utility, or society as a whole. Customer incentives must also be reviewed in the monitoring and evaluation stage of the integrated resource plan in order that their effectiveness in stimulating DSM participation can be assessed and so that adjustments can be made to their levels.

The following three facts may be helpful in designing customer financial incentives. First, a major criterion in DSM investment decisions is the DSM measure's initial cost. Small customers make decisions based almost entirely on first cost. The larger the customer, the more complex the economic analysis undertaken. The most-used measure is payback--the time needed for the return on an investment to become positive. Estimates of threshold payback, the amount of time that customers are willing to go without positive returns, range from six months to seven years. Second, risk aversion plays a significant role in a consumer's decision to participate in a program. People fear the uncertainties involved with new technologies; if the utility can reduce this fear directly or indirectly, it can influence customer behaviour. Third, incentives aimed at easing the financing of DSM measures may have relatively low appeal to large commercial and industrial customers. Studies have shown that for these customers, loan financing is not a major criterion for DSM investment decisions because approximately 84 percent of these investments are funded internally[5].

There are basically four types of customer financial incentives -- loans/leasing, subsidies/rebates, direct installation, and shared/guaranteed savings. Loan incentives offer financing to customers at or below current market interest rates. These funds are provided by banks, third-party lenders or the utility itself. The goal is to ease the capital burden of the DSM measure either by lowering the cost of borrowing or making loans more accessible. Although these incentives target financial barriers, they also reduce a customer's perceived risk by reducing the potential downside investment impacts relative to other investments. Leasing programs reduce up-front capital requirements and may reduce the customer's maintenance responsibilities. Smaller customers, low-income customers and the government/institution sector are more likely to use these incentives because their access to capital is limited. For government/institution consumers, the funding may be available internally but difficult to obtain, while low-income customers may not have access to loans at all.

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[5] Electric Power Research Institute, DSM Commercial Customer Acceptance. Volume 1: Program Planning Insights, (EM - 5633), 1988.

Subsidies or rebates are cash payments made to customers based on criteria such as high-efficiency appliance replacement or an energy-reduction target. These incentives aim at increasing the profitability of the measure to the customer by reducing the payback period which in turn reduces the economic market barrier. Some examples of these incentives include cash refunds for the replacement of appliances with more efficient models, or payments for the maintenance of boilers, which improves the efficiency of already-installed equipment. Subsidies and rebates need to be set at a level high enough to reduce payback to below one to two years, easy to obtain, and flexible enough to meet individual customer requirements.

Direct-installation incentives are arrangements set up by the utility to have equipment installed for a reduced fee or free-of-charge. Utilities may install the equipment themselves or arrange for a contractor to do it. These incentives reduce customer risk by making the decision easier. The customer is not faced with an overwhelming amount of information and is guaranteed of product quality because the utility has a stake in the measure. The utility covers some or all of the cost of installation and either guarantees the payback or the system performance. Recent surveys show that risk-sharing between the utility and consumer increases the acceptability of the program. Reduction of uncertainty about reliability and performance of the measures is valued by all sectors. These incentives also reduce the up-front costs of the measures, which is an added benefit.

In a shared/guaranteed savings program, the utility arranges and pays for the installation of the measure and retains a portion of the resultant savings. The customer's monthly bills are adjusted to reflect a portion, but not all, of the total savings, thereby allowing the customer to reimburse the utility while also receiving bill reductions. A related program is performance contracting, whereby a third-party contractor installs the equipment and then receives part of the customer's energy savings. The contractor retains ownership of the equipment and may also provide maintenance, depending on the terms of the agreement. The utility plays a match-making role by linking contractors with customers. These incentives are gaining favour because they address the risk question directly and generate immediate benefits for all involved. Shared-saving programs offer not only risk reduction but also reductions in payback time and capital needs.

Renters, low-income customers, and the government/institution sector require special attention. Tenants who pay their own utility bills but do not own the equipment are hard to target because they are reluctant to invest in measures that will remain with the premises when their lease ends. Low-income customers face an array of problems, including difficulties in obtaining financing. The government/institution sector faces problems in that gaining internal capital can be extremely time consuming. The decision-making process in this sector slows investment choices to the point of being impossible in some cases. These groups deserve special attention because broad programs and incentives will not penetrate into these sectors. Programs and customer incentives must be expressly tailored to them to ensure their participation.

2. General Information Programs

General information programs are used to persuade customers, on their own initiative and at their own expense, to increase the efficiency with which they use energy. This approach is aimed at helping to overcome the institutional barrier of inadequate information as a hindrance to efficient energy use. General information programs typically reach a large number of people with a limited budget. Although coverage is broad, the information offered by these programs is usually general. The vehicles used for general information programs include brochures, direct mailings, bill inserts, clearinghouses, point-of-purchase advertising, mass-media advertising, audio-visual tapes, conservation vans, shopping centre displays, speaker bureaus, and workshops and seminars. Of all the DSM delivery mechanisms, general information programs require the least involvement and expertise on the part of the utility. They also tend to be among the less-expensive approaches. A major disadvantage of general information programs is that it is difficult to predict the outcome or to document the effectiveness of the program. The potential also exists to manipulate them into load-building programs or to use them for the purpose of enhancing corporate image. On the other hand, because of the large potential impact of lifestyle on energy savings, information programs can play a meaningful role in DSM, especially when combined with other delivery mechanisms.

3. Technical Assistance

More specific, personalized information is provided to the energy user via the technical assistance delivery mechanism than through the general information mechanism.

Typically, technical assistance consists of custom audits that result in a computer-generated list of preferred investments. Compared with the general information approach, this approach requires greater involvement and expertise by the utility (or the expense of contracting with vendors to supply these services). Reaching any of the three sectors is more expensive with a technical assistance than with the general information approach, but for the residential sector, baseline data are relatively easy to obtain. For the commercial sector, some transferrable data exist, but for the industrial sector, an audit is almost always site-specific and can be costly. The technical assistance approach, however, is more likely to result in the adoption of DSM measures than the general information approach used in isolation. This personalized, face-to-face approach is very effective, especially if financial incentives are offered to the customer at the same time. The barrier of inadequate information is targeted by direct customer contact, and the barriers of up-front costs and risks of DSM measures are the targets of the financial incentives. Energy savings are much easier to calculate for this than for the general informational approach, especially when financial incentives are included that require documentation of the installation of DSM measures.

4. Trade Ally Programs

Another delivery mechanism utilities can utilize to deliver DSM programs is joint programs with their trade allies: appliance dealers, HVAC contractors, architects and engineers. Joint education or advertising programs can be conducted, and/or the utility can train and certify the allies in energy-efficiency methods and technologies. Utilities and their trade allies typically have strong networks, and programs that allow trade allies to use financial incentives available from the utility as a marketing tool can be very powerful. Information programs not combined with financial incentives, on the other hand, may be of limited effectiveness. Although the effectiveness of trade ally programs is easier to document than that of a general information approach, it is difficult in this approach as well.

5. Competition

The injection of competition into the delivery of DSM programs is a relatively new concept. The general purpose of using delivery mechanisms based on competition is to deliver DSM services in the lowest-cost, most efficient manner possible. There are three basic ways of using competition as a delivery mechanism. The traditional approach is for the utility to minimize DSM program costs by comparing the costs of and services available from different vendors and its own staff. A second method is the use of competitive bidding. With this mechanism, a utility issues a request for bids to supply a given level of energy service. Energy service companies propose to meet the need through their choice of energy-efficiency measures. Another, innovative, mechanism is the conduct of a competition the utility and contractors. In a competition, the competitors and the utility are each assigned a budget. The winner in each sector is the competitor that achieves the greater level of efficiency more cost-effectively.

6. Rate Design

Utility rates can be designed to send pricing signals that encourage reduction in peak energy use and strategic energy conservation (reducing energy use over all time periods). This vehicle for delivering DSM was discussed earlier in this chapter.

7. Conservation Utility

The conservation utility, a rather new concept, is created for the sole purpose of saving energy. It typically utilizes a number of funding sources, which might include utilities. The conservation utility is free of the institutional barriers and current regulatory incentives that are believed to impede the widespread adoption of DSM programs by traditional utilities. The ease with which energy savings can be documented depends upon the DSM programs that are implemented.

8. DSM Panel

Finally, the DSM panel is a new DSM delivery mechanism. It is a policy body that determines how state and utility funds are to be spent to implement DSM programs. Although the panel does not itself conduct programs, its creation and activities inject new impetus for DSM into the community.

D. DSM Pilot Programs

For a utility that is entering into DSM programs for the first time, or one that wishes to attempt new delivery mechanisms, try new technologies, or reach new market sectors, pilot DSM programs are often appropriate.

From the utility's point of view, pilot programs provide an opportunity to develop the infrastructure it needs to plan, deliver, and evaluate DSM programs. They allow the utility to build its data-collection capability and collect data (including market research and end-use analysis). Vendors are evaluated and relationships with them are established. Various delivery mechanisms for different market segments can be evaluated to learn about customer preferences, administrative considerations, costs, energy savings, marketing techniques, and other factors. The technical feasibility of the DSM options can be assessed. Potential problems in any of these areas can be resolved before implementation of a full-scale program.

From the customer's point of view, pilot programs develop awareness of DSM measures and delivery methods.

The specifics of the pilot program--its design, budget, timetable, and other considerations--will be custom designed based upon the objectives and scope of the pilot program.

E. DSM Program Monitoring and Evaluation

Monitoring and evaluating DSM programs is an important aspect of DSM program planning and revision and of the IRP process. DSM programs need to be monitored to obtain information regarding how well a DSM program is being delivered and received (for a "process" evaluation) and/or how much energy or peak demand savings are attributable to the program (for an "impact" evaluation.) The evaluations that can be conducted based upon these data can serve multiple purposes.

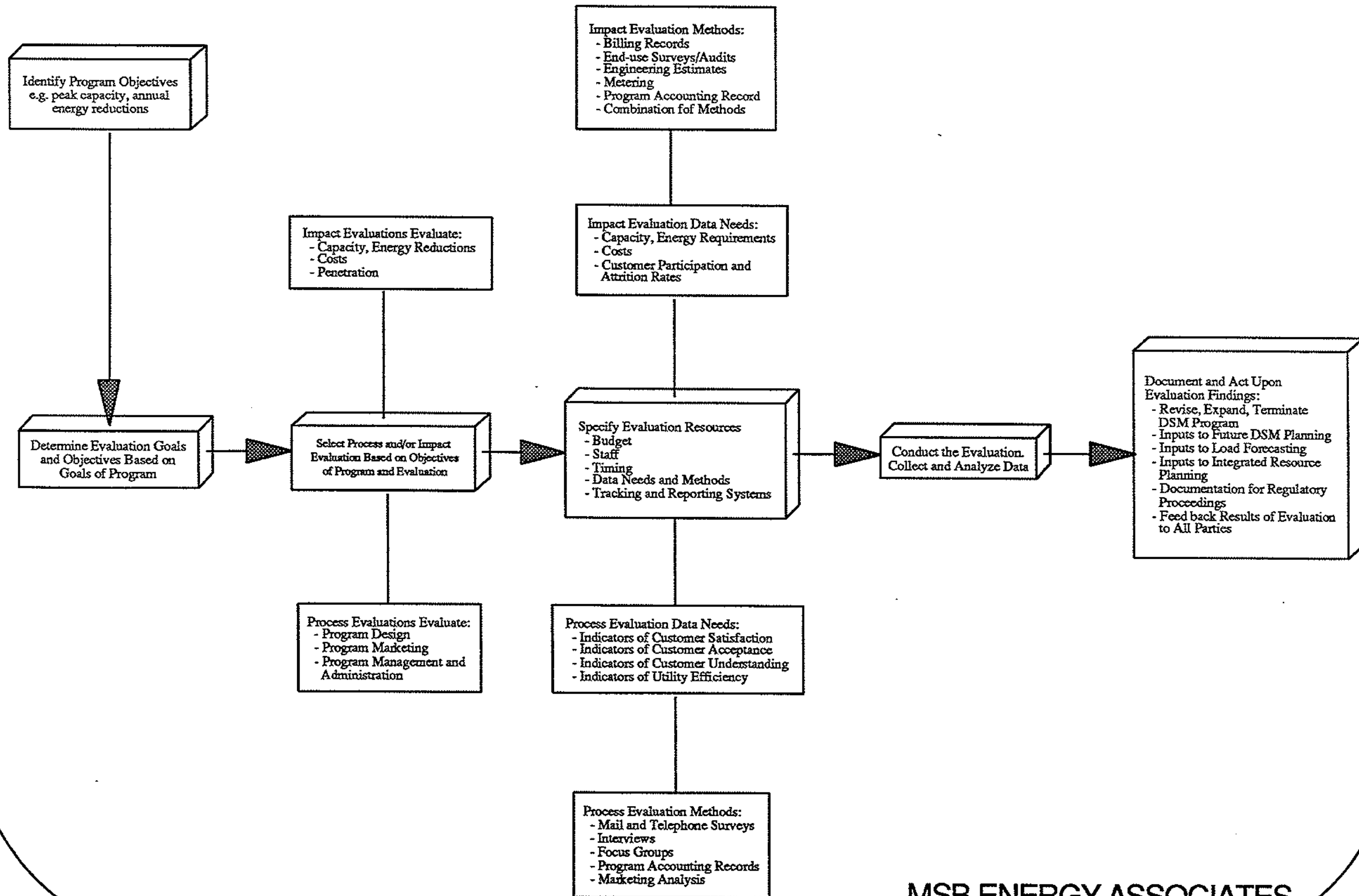
- Evaluations are *tools* that provide information about specific DSM programs. Depending upon the issues addressed, they can provide information as to how a program's delivery can be improved, participation increased, costs reduced, energy and capacity savings increased, and, ultimately, can provide a basis for program continuation, expansion or termination;
- They provide information about how best to design future DSM programs;
- Information collected in evaluations can be used in calculating the cost-effectiveness of the program being evaluated and future DSM programs;
- The data collected in some impact evaluations provide inputs into load forecasts;
- The data collected help identify the potential for DSM;
- Evaluation allows the assessment of freeriders and snapback effects;
- Evaluation is critical to IRP. Utilities routinely collect detailed information on the costs and operations of their supply-side alternatives; DSM evaluations

provide comparable information for conservation and load-management options. Evaluation reduces the uncertainties associated with the costs and benefits of DSM programs, enabling greater confidence in the comparison of supply- and demand-side alternatives and the choice of the least-cost alternatives;

- Evaluation is essential if financial incentives for aggressively implemented utility DSM programs are considered. Evaluation validates energy and capacity savings and the cost-effectiveness of DSM programs.

The figure on the following page portrays a guideline for systematically evaluating a DSM program. The process, which is based on evolving work in this relatively new area by utilities, regulators and researchers, includes five basic steps: (a) identify program objective, (b) select type of evaluation (process and/or impact), (c) specify evaluation resources, (d) conduct the evaluation, and (e) document and act upon evaluation findings. These steps are described in detail in Appendix C.

DEMAND-SIDE MANAGEMENT EVALUATION PROCESS



MSB ENERGY ASSOCIATES

F. DSM Research and Development

Research and development are essential to the development of new and improved technologies for demand-side management -- and for supply-side options as well. Utilities, with their substantial resources and infrastructures, can play an important role in research and development.

Several approaches are available for utility research and development. The first, wherein individual utilities conduct their own research and development, has the advantage of allowing the utility to tailor its efforts to its particular interest and needs, but does not allow for sharing information, expertise, and costs. Small utilities may have inadequate resource to conduct R&D on their own. Each of the Ontario utilities conducts some of its own R&D and/or funds specific external projects (e.g. research projects at universities).

A second approach, industry funding of a nationwide organization that conducts R&D, has taken the form in the United States of the Gas Research Institute (GRI). GRI, a private, non-for-profit membership organization founded in 1976, is comprised of some 300 member companies, including interstate pipelines, gas producers, gas utilities, and distribution and intrastate gas companies. Its budget, approximately $175 million in 1989, is partially provided through collection of uniform R&D funding unit on gas sales and transportation services (1.51 cents per thousand cubic feet for 1989) that is preapproved by the Federal Energy Regulatory Commission on the basis of an annual filing of the proposed R&D program plan and budget for the following year. State regulatory bodies participate in the review. Manufacturers, government agencies, utilities, producers, service companies, and energy users provide coordinated funding (about $85 million in 1989) for projects of special interest. According to GRI, since its inception it has developed 62 new gas products, processes and techniques, including the condensing furnace for residential applications In 1989, over half of GRI's R&D was allocated to improving end-use technologies, 27 percent to supply, and 14 percent to gas operations. The national, utility-funded approach has the advantage of offering participation to all utilities, having substantial resource and sharing information, expertise, and resources. In Canada, R&D is conducted by the Canadian Gas Association (CGA) and the Canadian Gas Research Institute (CGRI). Both of these organizations are funded by Canadian producers, transmitters, and distributors.

In some jurisdictions in the U.S. the direct value of GRI's work to gas utilities' ratepayers has been questioned, and in some cases the costs of participation in GRI have been disallowed. In an effort to provide R&D that is more directly tailored to a region's needs, several states have recently created organizations, funded in part by utilities, that conduct R&D on a statewide basis. The California Institute for Energy Efficiency, for example, plans and implements a statewide program of medium-to-long term applied research aimed at advancing the energy efficiency and productivity of all end-use sectors in California. The Institute is a joint effort among the California utilities, the Lawrence Berkeley Laboratory, the University of California, the California Public Utilities Commission, and the California Energy Commission. In addition to identifying, developing, and demonstrating efficient end-use technologies and processes, the Institute's goals include improving the data and analytical tools related to the end-use of energy. In Wisconsin, the Centre for Demand-Side Research is an affiliation of public, private and non-profit organizations the mission of which is to increase the efficiency in the use of energy and to modify the shape and level of energy demand. Coordinating, sponsoring and conducting research are among the Centre's activities.

VIII. COST-EFFECTIVENESS TESTS

The standard economic tests used in IRP were introduced in 1983 by the California Public Utilities Commission (CPUC) in the Manual of Standard Practice. These tests were revised and presented in 1987 under a similar title which has become the most widely used reference for economic tests used in IRP.[6] The tests, known by the names which reflect the perspective which they address, are the participant, rate impact, utility cost and societal cost tests. A less comprehensive form of the societal cost test, the total resource cost test, is commonly used in jurisdictions where monetized externalities are not considered.

Another IRP screening test not included among the tests in the California manual is the technical cost test. This test was developed in the Boston Edison collaborative to provide a method of option identification.

The interpretation and uses of each test described here correspond to the IRP approach presented in Chapter IV and Appendix A. It is important to remember that this approach uses the societal and utility tests to identify the broadest possible range of candidate options that are then fashioned into alternate plans. The plans are analyzed on the basis of the societal, utility, participant and rate impact tests and this information is provided to

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6 It should be noted that the Electric Power Research Institute defines tests of similar nature and intent as those presented by the CPUC. These may be found described in Volume 4 of the EPRI Technical Assessment Guide, 1986. Descriptions of the economic tests also may be found in the Least Cost Utility Planning Handbook, Volume 2, 1988, published by the National Association of Regulatory Utility Commissioners. These are essentially broad interpretations of the CPUC tests and do not provide original interpretation.

decision makers to facilitate their selection of the plan that they believe provides the balance of attributes that best serves the needs of the ratepayers, the shareholders and society at large. In the U.S. the roles of the different tests, the order of their usage in the IRP process, and the relative weighting of results varies between jurisdictions.[7]

The specific tests and their roles in the model IRP process described in Chapter IV are as follows:

> ***Technical Cost Test*** - This test is used to identify potentially cost-effective demand-side measures.
>
> ***Societal Cost Test*** - This test is a more comprehensive test than the technical cost test and is used to conduct a more refined cost-effectiveness evaluation. It is used to quantify the impact of measures, programs and plans upon society as a whole.
>
> ***Utility Cost Test*** - This test considers only those costs and benefits that are utility related. It measures changes to the utility's revenue requirements.
>
> ***Participants' Test*** - This test considers only the costs and benefits relevant to demand-side program participants. It is used for program design purposes and in evaluating alternative plans.
>
> ***Rate Impact Test*** - This test is used to compare the overall rate impacts of particular plans. It is used primarily in the plan evaluation stage.

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[7] For example, the Massachusetts Department of Public Utilities has selected the societal cost test as the primary test for screening and integration. The Wisconsin Public Service Commission has selected the utility cost test (NPVRR) as the primary integration test, but suggests that environmental externalities be considered heavily at the integration stage as well. The Illinois Department of Energy and Natural Resources (the agency in Illinois responsible for developing the statewide energy plan) has proposed that the societal cost test be used for resource screening, the utility cost test be used for plan integration, and the participants' test be used for program design.

A. Technical Cost Test

The technical cost test is used for identifying DSM options that may meet customer energy service needs in a cost effective manner. The test allows a simple technology-level screening to be performed to determine if an option is a likely candidate to be included in demand-side programs, a useful step considering the potentially large numbers of measures available. Measures that pass this test form the pool of options that will be evaluated later in the IRP process.

In the technical cost test, the benefits are the costs avoided by using the demand-side measure instead of supply-side resources. These benefits would include seasonally differentiated marginal supply costs (both demand and commodity- related) and avoided external environmental costs. In this test, the cost component is the cost of the measure itself, including engineering and installation costs. Customer incentives provided by the utility are not deducted from the total cost of the measure because they do not change the cost of the measure (they only change who pays for it).

It is important to note that neither the technical cost test nor the societal cost test considers non-monetized externalities. If these externalities are thought to be large, care will have to be taken to consider these non-monetized costs and benefits in resource selection. One way to incorporate these non-monetized costs and benefits is to use an "adder" which reflects an estimate of these impacts. This is described in Chapter IX.

B. Societal Cost Test

The societal cost test is designed to evaluate the cost-effectiveness of demand-side measures, programs and plans from a societal perspective. The benefit component of this test consists of avoided utility costs as well as avoided monetized externalities. The cost component is comprised of those costs considered in the technical cost tests, namely the total incremental costs of the equipment (including installation and O&M), as well as utility program administrative costs.[8] A variation of this test that does not include of monetized externality costs and benefits is the total resource cost test.[9]

C. Utility Cost Test

The goal of the utility cost test is to ascertain the degree to which revenue requirements are changed by a particular integrated plan. Revenue requirements are increased by program administration costs and utility incentive payments.[10] Revenue requirements are decreased by deferred or avoided commodity and capacity costs. The plan

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8 Program administrative costs do not include utility incentive payments (e.g., rebates). From the societal perspective incentives provided by the utility do not increase the cost of the measure, but simply change who pays for it.

9 Some analysts also use a different discount rate when moving from the societal cost test to the total resource cost test. They use a social discount rate for the societal test and a market discount rate for the total resource cost test.

10 Utility incentives (e.g., rebates) are relevant here because the focus is narrower. If the utility pays some of the cost through an incentive, the utility revenue requirement will change.

with the lowest net present value revenue requirements (NPVRR) is the optimal plan from the utility cost perspective. The plan that is represented by the minimum NPVRR would not consider the beneficial impacts of DSM programs on the environment, nor would it consider all customer costs and benefits (e.g., the cost of the technology to the consumer is excluded).

D. Participants' Test

The participants' test is designed to measure how customers' self-interest will be affected by participating in a demand-side program. The benefits are comprised of utility-sponsored incentives and the net savings on all utility bills paid by the customer. (Bill savings which may occur for other fuels are included in the benefit calculation.) The cost component is comprised of the equipment and installation costs as well as any operation and maintenance costs associated specifically with the technology.

The test should not be used for technology screening, as the cost-effectiveness of an option can be altered by simply changing the level of the incentive. Even a measure with very small savings could be shown to be cost-effective in this test by simply increasing the incentive provided by the utility.

The participant test is useful to the degree that it provides insight into the potential for customer adoption of the measure. If an applicable formulation relating customer payback and participation rates has been developed, the test may be useful in determining the level of rebate needed to meet the target penetration level of a program as established in an achievable potential analysis.

E. Rate Impact Test

The rate impact test is designed to measure the equity or fairness characteristics of the distribution of costs and benefits of a demand-side plan. The test is used to evaluate plans to determine the impact on rates. The benefit component of this test is the utility avoided costs as described for the societal cost test. Costs considered by the rate impact test include the revenue reduction to the utility from sales lost between rate cases, in addition to those costs considered in the utility test (program administration expenses and customer incentives). Under a plan that passes this test, rates will decline. Most demand-side options and integrated resource plans that are cost-effective on a societal basis will not pass this test. In general, it is not used to determine whether rates will increase, but rather, by how much will they increase.

IX. EXTERNALITIES

The recent interest in incorporating externalities into utility plans is a direct outgrowth of the IRP movement and its emphasis on ensuring fair competition among resource options by correctly reflecting their costs and benefits. Consideration of externalities, defined as costs and benefits that a party imposes upon others but for which it does not pay, may be incorporated in various ways into an IRP process. Externalities and methods for incorporating them into utility plans, which can include, as described in Chapter V, the inclusion of monetized externalities directly in avoided costs, are the subjects of this chapter.

In many respects, the externality movement is a microcosm reflective of the larger world of IRP. The movement has focused almost exclusively on environmental externalities associated with atmospheric emissions arising from fossil fuel combustion and is underscored by an assumption that DSM is inherently preferable from an environmental standpoint. Methods devised to incorporate externalities into IRP are all expected to result in adoption of more DSM, thereby decreasing impacts from combustion.

The combustion of natural gas has largely been viewed as environmentally preferable to combustion of coal or oil. In numerous U.S. jurisdictions, fuel-switching options (substituting natural gas for electric end-uses) and gas-fired power generation receive favoured treatments (along with DSM) when externalities are included in resource-allocation decisions.

The following policy and methodological questions, which are addressed in this chapter, should be considered if and when the IRP process evolves in Ontario:

- What are the goals of, and the justification for, incorporating externalities into the IRP process?
- What is the appropriate definition of an externality?
- How should externalities be factored into the IRP process?
- Where in a comprehensive IRP process should externalities be considered?
- How should non-monetized or non-quantified externalities be incorporated into the planning process?

Identification of some of the externalities related to natural gas and its supply-and demand-side alternatives, and a discussion of the methods available for quantifying and monetizing them, are included in Appendix B.

A. What are the Goals of and Justification for Incorporating Externalities into IRP?

Proper allocation of costs to those who create them is the main reason cited by regulators and utilities for incorporating externalities into utility plans. In economic terms, this should lead to a more efficient allocation of resources. The external costs imposed by energy-resource options are real costs, borne by real people. Incorporating externalities in IRP reduces total societal costs, which in turn maximizes welfare.

There is a second reason for considering externalities, however, and this one is not so frequently cited: business self-interest. To the extent that ignoring externalities poses risks and creates the possibility that businesses will not be profitable or ongoing, paying attention to them is simply good business.

B. What is the Appropriate Definition of an Externality?

Externalities represent a failure to include some costs in the transaction between consumers and producers. They arise for a variety of reasons: imperfect information, the existence of common-property resources, markets that are too thin (i.e., a small number of consumers or producers) or too costly to operate, and barriers to entry (e.g., high set-up costs). Externalities are also present where property rights are poorly defined. Some externalities are internalized through government regulation (health standards, environmental laws, etc.) but, in most cases, residual effects occur that continue to impose costs.

Theoretically, well-functioning markets should allocate resources efficiently. The presence of externalities prevents efficient allocation from occurring. In a strict economic sense, externalities are costs that are imposed on society or individuals by businesses but not included in the price charged by the business for its products. To the extent that these costs can be monetized, they can be included in the price charged for the good. Consumers will alter consumption, leading to a more efficient use of the resource.

In the utility-planning context, externalities are costs (or benefits) resulting from energy production, transmission, distribution and consumption, or reduction in energy use through efficiency improvements. In utility planning and regulation, the question of externalities must be addressed at two levels:

1) they must be addressed at the resource acquisition stage, where consideration of externalities may dictate a different set of resources than would be chosen relying on a narrower set of economic criteria, and;

2) they should be considered at the rate-setting stage, where incorporation of externalities may dictate a different (presumably higher) price for the energy commodity. A discussion of the implications of incorporating externalities into rates is beyond the scope of this paper.

The strict economic definition is very narrow as to what constitutes an externality and how it can be incorporated into the planning process. Many impacts exist that do not fall within the strict economic definition, but whose costs may be important to consider. This is not to say that utilities have historically been unaware of these factors or the potential risks posed by not taking them into account, but rather that they have dealt with them outside the formal planning process, often in a retrospective fashion.

Take, for example, the siting of a natural gas pipeline. When a landowner perceives that she is fairly compensated for the impacts caused by siting a pipeline on her property, the externality has been internalized in a strict economic sense. The compensation paid to the landowner becomes a part of the direct cost of building the pipeline and is ultimately reflected in the price consumers pay for the gas. The community at large, however, may continue to oppose the project. Their opposition, which could slow or halt the pipeline, should still be considered, although it is not an externality in the strict economic sense. When one broadens the definition of externality to include social, political, or other types of impacts not considered externalities in the economic sense, one must consider alternative methods of incorporating them into the planning process.

Current means of treating externalities function mainly as adjuncts to existing IRP processes. They operate primarily as additional variables in a complex benefit-cost calculus. These methods place great faith in:

(a) the benefit-cost calculus itself;

(b) the reliability and validity of the numbers that have been used to characterize direct benefits and costs of resource options;

(c) the reliability and validity of the numbers used to characterize external costs and benefits; and

(d) completeness.

Planning in general is fraught with uncertainties, so their presence should not necessarily prevent considering externalities. Nevertheless, there is good reason to have doubts concerning each point, which suggests that additional approaches for incorporating externalities beyond the traditional quantification and monetization methods may be in order. Possible approaches will be discussed in the next section.

Although the initial steps taken by regulatory agencies and utilities to deal with the externality questions are far from perfect, they have pushed planning forward. The Oregon Public Service Commission, in 1988, concluded,

> ...when the certainty of external costs is known, but the amount of the costs is not, zero is the least-desirable and least-accurate cost to apply...

This trend is an extension of the *societal perspective* for IRP. The move to a societal perspective has broadened the policy arena in which utilities and utility regulatory bodies operate. In most jurisdictions, a narrower utility revenue requirement perspective or rate-payer cost perspective has been the traditional standard for judgement. The move to a societal perspective, if considered appropriate, requires not only new analytical tools, as described above, but also new policy orientations.

C. How Should Externalities be Factored into the IRP Process?

Four methods have been used to date to incorporate externalities into utility plans: (1) simple description and characterization of impacts, (2) ranking and weighting methods, (3) adders, and (4) full costing. In the U.S., externalities have most often been factored into electricity planning. Natural gas IRP is still in its infancy and as such the vast majority of jurisdictions have not dealt with the externality question.

1. Description and Characterization of Impacts

Description and characterization of impacts is useful in situations where the impacts are difficult to quantify or monetize. This process identifies and describes the impacts without attaching any value to them. A key problem with this approach is that, in the decision-making process, dollar values have traditionally have more influence than non-monetized values. Many regulatory agencies require utilities to describe potential impacts, but do little or nothing with the information once it is produced.

2. Ranking and Weighting

Ranking and weighting is a semi-quantitative approach that combines subjective weights with selected quantitative information to produce a final score for a given resource option. A simple ranking-and-weighting scheme might give 50 percent weight to cost and 50 percent to environmental factors. In such a scheme, an option with very desirable environmental attributes could presumably cost more and still be implemented. Ranking and weighting methods have been criticized for shrouding subjective factors behind seemingly objective numbers. The assumptions that go into the process are not immediately apparent. The New York electric utilities have been ordered to use this method in their planning.

3. Adders

Adders apply a largely arbitrary credit or penalty to the cost of particular resource options, reflecting qualitative judgements of gross external costs and benefits. Basically, adders are used to adjust the costs of resources within the benefit-cost calculation to reflect the varying environmental externalities of different resource options. One key issue with the use of adders is the question of whether additional costs will be passed through to ratepayers or merely serve as placeholders in the planning process. Adders have traditionally been calculated as a percentage of the resource cost that is used either as a credit or penalty. The problem with using a percentage of the resource cost as an adder is that it ties the magnitude of the environmental damage estimate to the cost of the resource. The Northwest Power Planning Council, Wisconsin and Vermont all employ adders ranging from 10 to 15 percent of resource cost in electricity planning.

4. Full Costing

Full costing seeks to make the entire process as quantitative and objective as possible. This method requires that all damages be expressed in monetary terms; as the previous discussion suggests, the techniques for obtaining these data are themselves subjective and fraught with technical and analytic problems. The Massachusetts Department of Public Utilities ordered this method to be used for the first time in the U.S. in August 1990. The Boston Gas Company was the first U.S. gas utility ordered to incorporate these emission costs into its planning effort. Once the numbers have been derived, the implementation of the full costing method is straight forward; calculations of external costs and benefits can be used directly in calculating avoided costs, in cost-benefit calculations, and/or in resource screening.

It may be appropriate to combine these methods in order to capture a wide range of externalities in the planning process.

D. Where in a Comprehensive IRP Process Should Externalities be Considered?

IRP typically proceeds from option identification and screening to program design (for demand-side programs) to integration to plan selection. A component of sensitivity analyses is usually included, testing the robustness of the preferred plan under various alternative conditions.

Resource screening is a first-step test in which initial cost-benefit analyses of candidate options are performed to select options for further analysis. Some utilities and regulatory agencies screen on the basis of avoided costs, which, in turn, are calculated relying on a base resource strategy (i.e., no additional DSM or other alternative resources). Others use simpler methods, such as calculating the simple technical costs of resources ignoring, in the case of DSM, program costs, free-ridership concerns, and naturally occurring levels of DSM. The purpose of both approaches is to narrow the field of viable candidates. One serious problem is that potentially cost-effective resources are frequently eliminated prematurely. This is particularly problematic when so-called *intuitive screening* is performed. Consideration of externalities at this stage, even the application of a small credit for positive external benefits, may mean the difference for a marginal option. If externalities are not considered here, many options may be dropped and never reconsidered. If externalities are to be incorporated, it is important that some quantative device be adopted to eliminate the chances of premature elimination of an option. The methods available include proxy adders, abatement-cost proxies, and direct costing.

Externalities can also be considered at the plan-level analysis, through the use of sensitivity analyses. Once planning is complete, the utility usually possesses a wealth of data on the cost and performance of various resource options, cost-effective and non-cost-effective alike. Constraints can be imposed on plans that limit the use of resources having higher external costs, forcing the adoption of costlier alternate resources.

Externalities can be considered before the actual planning analysis commences. This thinking, along with any policy conclusions that can be drawn without the benefit of further analysis, should be carried through the planning process. For instance, some regulators and utilities have declared that DSM is preferable from an environmental point of view, and this affects the planning process.

E. How Should Externalities that are Non-Monetized and Non-Quantified be Incorporated into the Planning Process?

The entire process of incorporating externalities into the planning procedure is most effective when the impacts are quantified and monetized. This allows them to be directly incorporated into the benefit-cost calculus. Not all externalities can be quantified, yet incorporation is still possible. Evaluation of these impacts is done on an option-specific basis. One useful way to rate resource options is by using a worksheet format. Such worksheets allow commingling of both quantitative and qualitative data. In particular, these worksheets allow for a "fatal-flaw" analysis. Certain unquantifiable externalities--public opposition, for example--often represent fatal flaws, which should be factored into the planning analysis.

X. INTER-FUEL PROGRAMS

Inter-fuel programs are considered as part of the evaluation of strategic load building. Comprehensive and fully designed inter-fuel programs can realize overall greater savings through joint offerings of conservation or high-efficiency equipment for the fuel being switched to or, alternatively, by specifying minimal efficiency requirements for participation in the program. Moreover, comprehensive consideration of the conservation potential for the fuel being switched *from* may, in some instances, reveal significantly reduced benefits of an inter-fuel program. Finally, it must be recognized that significant load shape impacts arising from inter-fuel programs may alter the degree to which utility objectives can be met by DSM programs. Consequently, additional iterations of DSM program and plan design may be necessary to consider these impacts.

Inter-fuel programs are instituted in the guise of two different but related forms: fuel-conversion and alternative fuel programs[11]. Fuel conversion as used in this report refers to long-term changes in the fuel type used for a particular technology or end-use. The replacement of oil with natural gas for residential space heating or the replacement of electricity with natural gas for space cooling are examples of fuel conversions. Alternative fuel refers to short-term changes in the fuel that is used, such as the temporary substitution of natural gas with oil by customers with multi-fuel capabilities. The capability to utilize an

[11] It is important to recognize that the distinctions made here between inter-fuel program types are not typically recognized in the literature. More commonly, discussions on inter-fuel issues utilize the terms "fuel substitution" or "fuel switching" interchangeably. The distinctions are emphasized here to enable a discussion on the scope and longevity of inter-fuel program impacts.

alternative fuel is typically installed as a part of routine operations. Seasonal shifts in fuel use may be treated as alternative fuel or fuel conversion market behaviour. The distinction lies largely in whether longer-term patterns of seasonal energy-use shifts are of interest, or if short-term decision criteria are being studied.

Fuel conversion and alternative fuel programs target different issues and markets. They also recognize and tap the intrinsic physical differences in the ability of fuels to be stored and delivered, i.e., seasonal storage capabilities of natural gas systems relative to electric systems, and the storability and deliverability advantages of oil relative to natural gas for temporary usage (periods of one to several days). As a result, program focus, design, delivery mechanism, and implementation vary between them. Unique aspects of the two program types will be discussed in the following two sections. Fuel-price implications and developing market issues related to inter-fuel programs are next, followed by a discussion of how the impacts of inter-fuel programs can be treated in IRP.

A. Fuel Conversion Programs in IRP

Fuel conversion programs can enhance the security of fuel supply, address concerns regarding trade imbalances, reduce environmental impacts of energy use, and alter long-term societal costs arising from energy use. Fuel conversion programs may enhance the security of supply and reduce dependence on imported fuels (e.g. oil), thereby addressing concerns related to trade imbalances. The magnitude of environmental emissions, such as sulfurous and carbon emissions, may be reduced through utilizing natural gas in place of other, "dirtier" fossil fuels. Again, overall societal considerations are important in designing fuel conversion programs.

Electric-to-gas conversion programs exist largely as load-building programs instituted by LDCs. Demand additions may exist as valley-filling options, baseload additions, or even weather-sensitive (peak-season) additions. Clearly, valley-filling programs (off-peak load-building programs) increase the system load factor for LDCs. This is likely to reduce the costs per delivered volume of gas. Electric utilities, on the other hand, may experience reduced load factors as a result of a gas promotional program, thereby increasing the rates of electric customers. It is important to consider the long-term costs and benefits to all affected fuel-supplying industries to properly assess the value of fuel conversion programs.

Under conditions where upstream pipeline capacity is available year-round, or alternatively, where sufficient off-peak upstream capacity and local storage are available, baseload additions can be accommodated by an LDC and in fact, could increase the overall load factor and presumably lower customer rates.

Finally, weather-sensitive load additions may be the target of load-building programs. In isolation these programs will decrease the load factor of the utility but in situations where ample incremental storage exists, the overall utility load factor may potentially be maintained through the addition of storage. This presumes the availability of pipeline capacity upstream of the storage facility.

Electric-to-gas program impacts are typically of a long-term nature due to the long-lived nature of the technologies promoted (e.g., residential furnaces). Environmental advantages of natural gas use over electricity exist to the degree that displacement of coalfired production is accomplished. Displacement of natural gas-fired production may also result in environmental benefits owing to the overall greater efficiency of the fuel cycle for direct end-uses, although generation facilities may employ some emission controls. The major barrier experienced by customers is that initial costs are typically greater for natural gas technologies; successful program designs should recognize that barrier.

Whereas electric to gas conversions affect long-term societal costs and environmental impacts, oil-to-gas conversion programs also address security of supply and trade imbalance issues. In the early 1980s, the Department of Energy, Mines, and Resources developed programs that encouraged the use of natural gas over oil: the Distribution System Expansion Program (DSEP) and the Canada Oil Substitution Program (COSP).

These programs were designed to encourage distribution system expansion in areas of marginal cost-effectiveness and to encourage residential fuel conversion from oil to natural gas. These programs addressed three issues related to fuel conversion programs: the societal scope of the benefits, the long-term nature of program impacts, and issues associated with subsidization. A societal perspective is reflected in these programs by recognizing that the sponsoring agent is the national government and presumably the benefits are of national interest. The long-term nature of these programs is inherent in the target markets -- natural gas system expansion into marginally uneconomic areas (DSEP) and residential space heating equipment (COSP). Customer subsidization occurs to the degree that some end-users directly benefit from the program, while the costs are borne by others. Properly designed programs may address these issues in instances where subsidization is great.

Environmental issues were not major factors in the development of these programs, although no doubt reductions in sulfurous emissions were recognized. Greater consideration of environmental concerns today may form the basis for re-introducing fuel conversion programs and for expanding programs that currently exist. Programs that would have failed cost-effectiveness evaluations in earlier years possibly pass the evaluations if environmental factors are considered. Externality factors and inter-fuel program design will be further addressed later in this chapter.

It is also important to recognize the potential for transmission benefits from natural gas conversion programs. An example is a sales promotion program offered by Tenneco, a major gas distributor in the U.S. which services approximately 100 LDCs. In the program, Tenneco has provided end-user incentives for gas air conditioning and gas-fired cogeneration systems; the programs themselves are offered through the LDCs. This program evidences the potential direct impact of coordinated LDC activities on pipeline operations.

In designing fuel conversion programs, the overall emphasis must be on the societal impact of the program, and not just the utility supply cost impacts as represented by load factor changes and the associated change in supply option mix. The overall system efficiency must be considered. Generally speaking, when considering overall net energy losses due to inefficiencies of the fuel cycle (generation/production, transmission, distribution and end-use technology), the overall energy efficiency is greater for natural gas technologies than for electric technologies that perform the same function. Clearly, it is important to recognize that the determination and coordination of energy resource availability, transmission, and suitability to task as well as the delineation of environmental priorities are important and necessary considerations for successful fuel conversion program design and implementation.

B. Alternative Fuel Programs in IRP

Individual customers or groups of customers with alternative fuel capabilities may temporarily alter the mix of fuels they use. This market behaviour may result from price signals, supply limitations or constraints, or other factors. The behaviour may be customer-initiated or it may be induced (and to a limited degree, managed) by utilities through the use of interruptible rate structures.

The consideration of alternative fuel programs in IRP is important due to the potential societal costs incurred by LDCs when they serve customers with alternative fuel capabilities (e.g.,natural gas and oil). This stems from recognition that LDCs are obligated to provide reliable and flexible service to all customers, including those with multiple-fuel capabilities. In the absence of alternate fuel programs, designing the system for reliability requires that peak-day requirements for these multiple-fuel customers be included when supplies are acquired, even though the degree to which the utility experiences demands on the peak day from these customers is uncertain. This increases system supply costs, potentially to the point that system costs may exceed the cost savings realized by customers through short-term alternative fuel practices. Consequently, overall costs to provide energy (regardless of fuel type) may be increased due to alternating between fuels.

To a limited degree, the utility may be able to reduce the associated degree of risk at low cost by prescribing minimum-take requirements in service contracts for customers with alternative-fuel capabilities. On the other hand, the increased restrictions of these contracts could, in some cases, cause a customer to consider other options (fuel conversion or bypass of the LDC). Thus, the direct economic risk to the utility LDC may increase somewhat through the utilization of this option.

Utility-managed alternative fuel programs (e.g. through interruptible rates) may actually reduce system uncertainty and increase load factor, thereby reducing system costs. Properly designed, these benefits may be realized without incurring significantly greater incremental costs to interruptible customers during times of interruption.

C. Fuel Price and Developing Market Considerations for Inter-fuel Program Design

Historically, natural gas prices have tracked oil prices reasonably well. In part, this is due to the multiple-fuel capabilities of the technologies employed for many commercial and industrial end-uses. This trend has been reinforced by the competitiveness of alternative fuel prices and the associated technologies for end-uses for which fuels may not be substituted (e.g., residential space-heating technologies).

Increasing pressures to reduce emissions will tend to make natural gas more attractive relative to fossil alternatives in the future. The resulting increases in demand for natural gas may ultimately lead to higher prices for natural gas relative to oil and possibly higher prices relative to electricity. The valuation of certain emissions in the form of trading allowances to emit SO_2 will provide a limited degree of direct valuation in the United States and potentially in Canada through pipeline interconnections. Prices are expected to shift upward further with the eventual dissipation of the gas bubble. Further increases in demand which could also affect prices may occur due to developing markets for gas cooling and natural gas vehicles, and due to increased reliance on gas for cogeneration and electric generation. The price of gas relative to competing fuels will continue to be an important consideration for utilities and their customers.

D. Quantifying the Impacts of Inter-Fuel Programs

An economic test utilizing a societal perspective, implemented in tandem with consideration of non-monetized externalities and public interest factors, is the most overall comprehensive measure of the cost-effectiveness of inter-fuel programs. It should be recognized that the incremental costs and benefits of all aspects associated with fuel use need to be considered. This includes costs and benefits of alternative fuel and end-use technologies as well as pollution abatement equipment and emissions allowances (where applicable). For alternative fuel programs, the analysis should consider the impacts of alternative fuel use that occur during interruptions to gas service.

XI. FINANCIAL ASPECTS OF INTEGRATED RESOURCE PLANNING

There are three major financial issues associated with utility planning that arise when demand-side resources are being used. They are:

- Cost recovery - How will the costs associated with demand-side programs be recovered?
- Lost margins - How will the effects of demand-side programs on utility sales and revenues be considered in setting rates?
- Incentives - Do financial incentive mechanisms need to be implemented to encourage utility demand-side spending?

Each of these questions will be addressed in this chapter. We will provide some background discussion of these questions as well as a description of how they have been answered in other jurisdictions.

A. Collecting Demand-Side Program Costs

Unlike most utility costs, demand-side expenditures are somewhat discretionary. By this we mean that, at least in the short run, if the utility spends nothing on demand-side programs, the utility service will not be noticeably affected. (Of course, over the long run, failure to promote demand-side resources can lead to significantly higher utility bills and potentially to service reliability problems.) Failure to spend money in other areas is likely to be noticed more quickly. For example, if a utility did not pay its employees, service would be affected almost immediately. If it did not pay for the gas it consumed, the pipeline would presumably refuse to continue to provide additional supplies and shortages would occur.

Given the discretionary nature of demand-side expenditures, a utility might choose to spend little or nothing on demand-side programs, regardless of the level of spending assumed at the time rates were set. If demand-side costs were treated like other utility expenses in a forward test year, the money saved by the utility in not funding demand-side programs would simply flow to the bottom line and increase earnings. Thus, in some jurisdictions, utilities underspending on demand-side programs, and overearning as a result, is a major concern.

On the other hand, in some jurisdictions, utilities have been reluctant to spend money on demand-side programs because of the risk that the costs may not be recovered. For example, in jurisdictions with considerable time spans between rate cases, spending money on demand-side programs reduces earnings, and in some cases could cause the utility to earn less than a fair return on its invested capital. In these jurisdictions it is the risk of underearning that prevents utility spending on demand-side programs.

Because of these problems, special mechanisms have been established in many jurisdictions to recover demand-side program costs. The two mechanisms that have received the most attention are:

1. Demand-side cost recovery clauses; and
2. Demand-side cost balancing accounts.

1. Demand-Side Cost Recovery Clause

A demand-side cost recovery clause works in much the same way as a fuel adjustment clause. An original estimate of demand-side costs is made at the time rates are set. If the utility spends the pro rata share of those costs each month, no adjustment is necessary. If, on the other hand, the utility spends more or less than the forecasted amount, a surcharge or credit appears on the customers' bills to reflect the difference between actual and forecast demand-side spending. With this method the utility collects for its demand-side programs on a dollar-for-dollar basis. The Illinois Commerce Commission has allowed Commonwealth Edison to use this method to collect its demand-side program costs.

While this method removes any incentive for the utility to underspend on demand-side programs, it creates a new problem. Itemizing any cost on customers' bills will have a tendency to create negative publicity.

2. Demand-Side Cost Balancing Account

There is another way to provide dollar-for-dollar recovery of demand-side program costs without causing negative publicity--that is to use a demand-side cost balancing account. The balancing account or deferral account works in the following way. At the time rates are set, an estimate of total demand-side program costs is made. Assume that the estimate is $25,000,000 per year. If the utility actually spends only $15,000,000 on demand-side programs, in the next rate case the utility's revenue requirement will be reduced by $10,000,000 ($25,000,000 budgeted minus $15,000,000 actual) to reflect the underspending on demand-side programs. Conversely, if the utility actually spent $45,000,000 instead of the estimated $25,000,000, the $20,000,000 of overspending will be added to the utility's revenue requirement. This assumes, of course, that the overspending was due to aggressive demand-side promotion, not inefficient program administration. This is the method used by the Public Service Commission of Wisconsin for the gas and electric utilities that it regulates.

While the method does allow for dollar-for-dollar recovery of costs, it does not consider the time value of money. Recall that the demand-side cost recovery clause provides monthly cash flows for demand-side spending. The balancing account provides for cash flows above the forecasted level of spending only at the next rate case. This problem can be solved, however, by simply allowing the utility to earn a carrying charge on extra demand-side spending and to pay a finance charge when it underspends. The Vermont Public Service Board allows its utilities to collect a carrying charge on demand-side spending between rate cases.

B. Accounting for Demand-Side Program Costs

Regardless of how demand-side expenses are collected, there are two basic methods used to account for these costs: 1) expense treatment and 2) rate base treatment. An example will illustrate the difference between the two methods. Assume a utility spends $100 on demand-side measures. Under expense treatment, these costs would be included in full in the revenue requirement for the year incurred. Thus the revenue requirement would be $100. Under rate base treatment, the $100 cost would be amortized over the life of the measure (or some other appropriate length period). If the amortization period was four years, the revenue requirements by year would be calculated as follows:

Rate Base Treatment

Year	DSM Cost	Rate Base	ROE	Taxes	Depreciation	Revenue Requirement
1		100.00	10.00	5.00	25.00	40.00
2		75.00	7.50	3.75	25.00	36.25
3		50.00	5.00	2.50	25.00	32.50
4		25.00	2.50	1.25	25.00	28.75
TOTAL						137.50

Note: **This analysis assumes for simplicity's sake that the company is 100 percent equity financed, that the required return on equity is 10 percent and the income tax rate is 50 percent.**

From reviewing the table above we can see that nominal revenue requirements increase from $100.00 under expense treatment to $137.50 under rate base treatment. But since the revenue requirements occur over time under rate basing, we have to calculate the present value to compare them to the expense cost of $100. To do so requires a discount rate.

There are many discount rates that can be used to discount revenue requirements. In fact every ratepayer has his or her own discount rate which reflects the preference for consumption today versus consumption in the future. As it turns out, for customers with high discount rates, such as high risk small business, rate basing tend to be less expensive than expense treatment. The opposite if true for customers with low discount rates.

For example, if a customer had a discount rate of 20 percent, the present value of the nominal revenue requirement stream under rate basing is $91.18, which is lower than the $100 present value associated expensing. For this customer, rate basing is less expensive than expensing. If a customer had a discount rate of 5 percent, however, the answer would be the opposite. The present value of the nominal revenue requirements under rate basing is $122.70 which is higher than the $100 revenue requirement for expense treatment. So the answer to the question as to whether or not rate basing is more expensive than expense treatment depends on who the customer is. For some customers it is less expensive when rate basing is used; for other customers it is more expensive.

To analyze the question of whether rate basing is beneficial to utility shareholders, we need to convert the revenue requirement stream to cash flows, since that is what investors value, not revenue requirements. The revenue requirements from rate basing are made up of returns, taxes and depreciation. Returns and depreciation are cash flows; taxes are not. This means that the cash flows by year for the rate basing example presented above are, by year:

1	35.00
2	32.50
3	30.00
4	27.50

These cash flows must be converted to present values to compare them to the initial cash outlay ($100) spent on the demand-side measures. Contrary to the revenue requirements analysis, there is only one relevant discount rate to be used in calculating the present value of the cash flow, namely the utility's cost of capital. In this example, the discount rate is equal to the cost of equity (10 percent). It should be no surprise that the present value of the cash flows under rate base treatment equals $100 exactly. It should since the return on equity is set equal to the cost of capital in this example. So as long as the Board regulates in such a way that the return on equity is set equal to the cost of equity capital, there is no financial gain or loss from rate basing. On the other hand, if the Board sets the return on equity above the cost of equity capital, rate basing will be attractive. And, if the Board sets the return on equity below the cost of equity capital, rate basing will harm shareholders.

If under good regulation shareholders should be indifferent to rate basing, and some ratepayers will be helped by it and some harmed by it, what is the justification for the use of rate base treatment for demand-side expenditures? One answer is equity (i.e., as in fairness, not as in equity capital). Since demand-side expenditures produce benefits for the utility over more than just the current period, it is not fair to charge the entire cost of the programs to current ratepayers. By spreading the revenue requirements over the life of the measure a better matching of costs and benefits is achieved.

The other reason for rate basing demand-side expenditures is to avoid short-term rate shock. Since rate basing reduces the first revenue requirement associated with demand-side programs, it is sometimes used to soften the rate impact of major demand-side spending.

C. Impacts of Demand-Side Programs on Sales and Revenues

Demand-side programs, if successful, will reduce utility sales and revenues relative to what they would have been without the programs.[12] If the effects of the programs are not considered in setting rates, the lower sales and revenue levels can cause the utility to earn a less-than-fair return on its capital. The difference between the revenues that would have

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[12] In most cases, demand-side programs are likely to slow the growth in sales rather than cause sales growth to be negative.

been received without the demand-side programs and those that are received with them are referred to as "lost revenues."

It is important to note that the entire lost revenue amount does not equal the lost earnings. For example, if the utility charges $5.00 per mcf, and the variable costs associated with a sale are $4.00 per mcf, the utility loses only $1.00 per mcf lost. A lost sale causes revenues to go down by $5.00 per mcf, but costs also fall by $4.00 per mcf. Thus a better term to describe the effect of demand-side programs on sales and revenues is "lost margin", since that is the relevant variable.

It is interesting to note that in some jurisdictions the need to recover lost margins is not an issue. (The Wisconsin Public Service Commission is an example.) With annual rate cases, forecasts of the effect of the utilities' demand-side programs on test year sales can be made. This helps to eliminate concerns about lost revenues without using a decoupling mechanism. The reason is two fold: (a) the effects of demand-side programs are estimated at the time rates are set (thereby reducing the likelihood of large lost revenue amounts), and (b) errors in estimating program impacts can be corrected quickly at the annual rate case.

In other jurisdictions, however, many utilities have suggested that they "need" a lost margin adjustment before they can aggressively promote demand-side programs. In some cases their concern is justified. The cases in which a lost margin adjustment is likely to be needed are those that are the least like those faced by Wisconsin utilities--infrequent rate relief and no consideration of demand-side program impacts at the time rates are set. Whether a utility needs a lost margin adjustment depends largely on the regulatory environment in which it operates.

If a lost margin adjustment is necessary, there are two types that can be selected:

1. a demand-side only adjustment; or
2. a sales and earnings decoupler.

These mechanisms will be discussed next.

1. Demand-Side Only Adjustment

One way to adjust for lost margins is to estimate the lost margin from the reduction in sales from demand-side programs and allow the utility to recover those margins. This is the approach adopted by the New York Public Service Commission. An example of this approach follows. If the utility's demand-side programs reduce sales by 100 mcf, and the total lost margin on those sales is $100.00, the utility would be allowed to collect this amount either through a demand-side adjustment clause or a demand-side deferral account.

There are three ways to estimate the effect of demand-side programs on utility sales: engineering estimates; sub-metering of individual appliances; and conditional demand analysis.

Engineering estimates are calculations based on the typical savings for individual demand-side measures. For example, the savings from replacing a standard-efficiency water heater with a high-efficiency water heater might average 20 mcf per year. This estimate is based on either laboratory experiments, metering of appliances (discussed next), or both. For every efficient water heater installed by the utility program, the utility gets credit for 20 mcf of lost sales. If the lost margin on a single sale is $1.00 per mcf, the utility would receive a lost margin adjustment of $20.00 (20 mcf times $1.00 per mcf) per water heater.

The major advantage of this method is ease of administration; the disadvantage is that actual savings from the program may vary considerably from the estimates. This method is often used by utilities as they begin demand-side programs. They often move to more sophisticated methods as demand-side programs evolve.

One of the more sophisticated methods is sub-metering of a sample of individual appliances. The sub-meter is attached to the individual appliance to measure actual, as opposed to estimated, energy consumption. The major advantage of this method is obviously the increased accuracy of the sales-reduction estimates. The disadvantage is the significant increase in costs associated with the use of this approach. The use of a statistical sample helps to reduce these costs.

The other more sophisticated approach is conditional demand analysis. This is a statistical method that can be used to separate out the energy usage of individual appliances without sub-metering. The approach involves the use of regression analysis with indicator (dummy) variables used to identify the appliance mix of individual customers. The advantage of this method is that it uses whole-house (whole-building) meter estimates so the cost of collecting data is significantly lower than that associated with sub-metering. The disadvantage is that the estimates of individual appliance parameters may be imprecise due to statistical problems such as multicollinearity.

Regardless of how the problems associated with estimating lost margins are resolved, however, there is a major problem associated with the demand-side-only lost earnings adjustments. That is, they fail to consider the overall earnings of the utility. For example, with a demand-side-only adjustment clause a utility may receive a lost margin adjustment even if it is earning more than its authorized return.

2. Decoupling Sales and Earnings

Another approach to dealing with lost margins is to eliminate lost margins due to any cause. For example, if sales are less than forecasted for any reason (demand-side programs, weather, economic activity), under decoupling earnings are adjusted to the test-year level. This total decoupling eliminates the need to estimate the lost margins due to demand-side programs. One need simply compare the actual sales for the utility to the total sales. If sales are greater than forecasted, for whatever reason, extra margin will be generated. The decoupler method will adjust earnings downward. If, on the other hand, sales are less than forecasted, again for whatever reason, the utility will undercollect its necessary margin. The decoupler will increase the earnings in that case.

The California Public Utilities Commission has been the pioneer in the area of decoupling sales and earnings. It has implemented the Electric Revenue Adjustment Mechanism (ERAM) for electric utilities and the Sales Adjustment Mechanism (SAM) for gas utilities.

D. Utility Financial Incentives

Providing financial incentives to encourage gas utilities to actively pursue demand-side resources in their service territory is a topic that is being debated before many regulatory commissions. Some people strongly believe that such incentives are essential if we expect the utility to reduce its sales growth via demand-side management. After all, isn't reducing sales contrary to a utility manager's basic obligation to his or her shareholders?

The answer to this question is not as simple as it would seem. First of all, reducing sales growth is not necessarily harmful to utility investors; in fact, slowing growth could just as easily increase as decrease investor returns. For example, from 1972 through 1988, U.S. gas distribution utilities experienced a -3 percent annual sales growth rate. Over the same period, U.S. electric utilities grew at +3 percent per year. Even though their sales were shrinking, gas distribution utilities produced higher stockholder returns than did the growing electric utilities.[13] Asking a utility manager to slow the company's sales growth is not necessarily in conflict with the basic obligation to protect investor interests.

Does this mean that financial incentives are inappropriate for utilities promoting demand-side measures? Not necessarily. There are some cases in which such incentives make sense. For example, a particular utility may be able to show that, given its unique circumstances, aggressively promoting demand-side management would cause it to earn less-than-fair returns. This might be the case for a utility with a large amount of excess capacity on its system or a utility that has infrequent rate relief. It can also be argued that incentives will induce utilities to change the "corporate culture" and more aggressively pursue DSM. Similarly, incentives may provide the necessary impetus to utilities to provide DSM at the lowest possible cost.

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[13] The data in this example are Moody's Gas Distribution Utility Stocks and Moody's Electric Utility Stocks. For a listing of the companies in these indices, see Moody's Public Utility Manual, 1990 edition.

If it is determined that investor-based financial incentives are appropriate for a particular utility, there are two basic types from which to choose. They are: *return on equity adjustments;* and *shared savings*.

Return on equity adjustments are simpler to administer than *shared savings* systems. Under the *return-on-equity adjustment* approach, the Board would increase the utilities' allowed return on equity if it met certain energy- or demand- reduction targets. This approach can involve penalties as well as rewards. For example, if a utility were considerably short of the established targets, its allowed return on equity would be lowered. This is the approach recently ordered by the Michigan Public Service Commission in its Consumers Power Company rate order.[14] In that order, the Commission established the possibility of a <u>one</u> percentage point increase in return-on-equity if certain targets are achieved; a return on equity penalty of <u>two</u> percentage points will be applied if the Company falls considerably below its target. Note that the threat of a penalty can just as easily serve as an incentive as can the opportunity to earn a reward.

The other basic approach to utility financial incentive systems is the *shared savings* approach. Under this approach, the utility keeps a portion of the net benefits delivered by the demand-side measures. For example, if the utility implements demand-side programs that produce $1,000,000 of societal benefits, the utility may be able to keep 10 percent (or $100,000) of those benefits for its shareholders. This sum would be collected from ratepayers through an adjustment. In essence it becomes a return on equity adjustment, but

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[14] Michigan Public Service Commission, <u>Order in Docket U-9346, Consumers Power Company Rate Case</u>, May 7, 1991, p. 136.

the mechanism is based on net benefits rather than mcf or peak-day reductions. This is the approach adopted by the Rhode Island Commission for Narragansett Electric Company.

Another factor that needs to be considered in analyzing the necessity to provide incentives is whether they should be targeted at the utility investors or at the utility managers. It is perhaps through the utility managers that changes to the "corporate culture" can be made most effectively. The utilities' reluctance to promote demand-side programs may often be rooted more in the area of managerial disincentives than investor disincentives. In recognizing this fact, the Public Service Commission of Wisconsin has recently ordered Wisconsin Electric Power Company to establish a special employee bonus program to be used to reward employees who aggressively promote demand-side measures.[15]

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[15] See Public Service Commission of Wisconsin, Order in Docket 6630-UR-104, January 3, 1991.

APPENDIX A: FRAMEWORK FOR A PRAGMATIC APPROACH[1] TO DEVELOPING INTEGRATED RESOURCE PLANS

I. IDENTIFY UTILITY-SYSTEM CONDITIONS THAT MAY CONTRIBUTE TO LOSS OR INTERRUPTION OF SERVICE.

A. Develop annual energy and peak-day forecasts; include present and projected intensity of use and saturation and penetration by end-use, allowing for impacts from developing markets, customer bypass, fuel substitution, interruptible load.

B. Define the system deficiency; load level, load shape, capacity constraints.

C. Develop system marginal costs of supply needed to meet system loads. These costs should include:

1. Direct marginal costs including demand charges, and capacity -related storage costs.

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[1] The purpose of the model is to provide a working definition of the technical elements comprising an integrated resource planning process. The working definition is based on the most comprehensive and encompassing approach to IRP, one that subsumes other alternative approaches. This approach assumes that the societal perspective and the utility perspective are used to determine the cost-effectiveness of resource options. This approach assumes that the public, including governmental agencies, will participate throughout the development of the integrated resource plan. Finally this approach assumes that the Board will issue a formal order approving, rejecting or modifying the plan.

2. Direct marginal local capacity costs for transmission and distribution facilities.
3. Adjustments to capacity cost for weather-sensitive loads.
4. Adjustments to capacity requirements for capacity-related compression and leakage losses on the local transmission and distribution system.
5. Gas cost for bundled services and direct purchases, transportation costs for direct purchases, and storage costs related to seasonal gas storage.
6. Adjustments to energy costs for reductions in compressor fuel and leakage losses on the local transmission and distribution system.
7. Monetized environmental externalities.
8. Adjustment for non-monetized environmental externalities.
9. Adjustment for non-price factors.
10. Time differentiation on a seasonal, daily, and hourly (if appropriate) basis.
11. Societal perspective requires all of the above to be considered for upstream (pipeline, wellhead) suppliers.

II. IDENTIFY UTILITY RESOURCE OPTIONS.

A. Options do not have to individually meet the system deficiency described in Step I, rather in aggregate.

B. Prepare an assessment of technical potential of demand-side technologies in the utility service territory. Assess both the technologies available and their relative presence and potential on the utility system. Comprehensively identify applicable demand-side technologies, based on reviewing commercial data bases, assessments of demand-side management measures and potential savings developed by other utilities, and native system customer load data (to assess end-uses of energy).

C. Comprehensively identify options to be considered as part of long-term supply mix to meet the reliability and flexibility needs. These include: the addition of storage; transmission and distribution system looping options; contracts.

   1. Use estimates of technical cost and resource potential to quantitatively pre-screen supply-side resource options. Identify inapplicable technologies.

   2. Refine estimates of cost, efficiency, output through preliminary engineering analyses.

D. Identify the potential for incorporating alternate fuels to meet customer needs including: contracting with multi-fuel transportation customers for peak day gas supply (switching off natural gas to increase peak day gas supplies); increasing interruptible and curtailable customer loads.

III. DEVELOP PROGRAMS TO DELIVER DEMAND-SIDE MEASURES.

A. Develop a list of candidate cost-effective measures based on marginal costs developed in Step I.

1. Pre-screen by estimating savings based on system marginal costs as developed in Step I.C. Marginal costs for representative load shapes for options of various lives are necessary. Representative load shapes include separate shapes for weather-sensitive and non-weather-sensitive loads, each further differentiated for interruptible and firm customers.

2. Benefits and costs are measured on a societal and on a utility basis:

a. For the societal analysis, benefits equal direct and external (including monetized and non-monetized) marginal energy and capacity costs for each time period (from Step I) multiplied by the corresponding energy and capacity savings plus any additional measure-specific benefits not otherwise reflected. Costs equal total installed cost (participant plus utility, not including program administration costs) plus any monetized environmental, non-monetized environmental and non-price factors attributable to the measure.

b. For the utility analysis, benefits include direct marginal energy and capacity costs for each time period (from Step I) multiplied by the corresponding energy and capacity savings. Cost equals direct cost to the utility only.

B. Develop alternative demand-side programs to deliver the cost-effective candidate measures (Groups of demand-side technologies related by the mechanism used to deliver them and by the customer group targeted).

1. Emphasizes the utility programs to deliver demand-side technologies rather than the technologies themselves.
2. Bundle demand-side measures to avoid lost opportunities when visiting the customers' premises.
3. Estimate program administrative costs for each program.
4. Develop programs for retrofit and new construction, equipment and appliances.
5. For each program, characterize the:
    a. Customer group being addressed.
    b. Underlying demand-side technologies being delivered.

c. Cost of the delivered technologies, including administrative costs.

d. Estimate participants' direct costs as a fraction of total installed costs.

e. Interactive effects between technologies when delivered together.

f. Total system potential of each program to deliver capacity and energy savings.

IV. EVALUATE AND COMPARE RESOURCE OPTIONS.

A. Resources to be compared are: i) alternative demand-side programs, ii) supply-side alternatives developed to the point of preliminary engineering analyses, and iii) the incorporation of alternative fuels as per Step II.D.

B. Develop avoided costs considering the same components as discussed in Step IC, use to screen programs on both the societal and utility cost bases. Select for further analysis those resources whose total benefits are greater than or equal to their costs on a net present value life cycle basis. Costs and benefits are from the societal and utility perspectives.

C. Note that the impact on rates (non-participants' test) is not calculated for individual demand-side measures or programs, nor any other individual resource option. The aggregated revenues and rate levels for alternative plans are evaluated and compared in Step VI. Analysis at the integrated plan level accounts for the dynamic interactions among programs and other elements of the system, something which cannot be reliably captured at the individual option level.

V. DEVELOP LONG-RANGE ALTERNATIVE PLANS.

A. Meet the utility-system needs defined in Step I, as a minimum.

B. Design alternative plans for adequate and approximately-equivalent service reliability.

C. Take lost opportunities into account during plan development by:

   1. Using demand-side resource bundles to maximize the effectiveness of visits to the customers' premises.

   2. Immediately including options which improve efficiency of appliances with long-expected lifetimes.

D. Combine options to achieve the desired system effect.

E. Develop alternative plans to evaluate major policy choices by modifying the type, amount and timing of resource options. Different plans could be developed to highlight different objectives, including:

   1. Low monetary cost.

   2. Low emissions of environmental pollutants.

3. High end-use energy efficiency.

4. Reducing dependency on oil.

F. Each participant in the planning process can also propose an alternative plan highlighting his/her objectives for evaluation in Step VI.

G. Estimate the transmission and distribution system impacts, if any, of each plan.

VI. EVALUATE ALTERNATIVE PLANS ON A SYSTEM BASIS.

A. Long-term, based on planning window used in Step V.

B. Apply the same avoided cost methodology criteria as per IV.B.

C. Prepare and present consistent and comparable information for each alternative plan:

1. Present value of life cycle net benefit, discounted at societal discount rate, to determine overall value of each alternative to society.

2. Net present value of the revenue requirement, discounted at the utility's cost of capital, to measure economics of utility service.

3. Resultant levelized average rate levels.

4. Participants' direct cost.

5. Environmental impact.

6. Other benefits and costs, e.g., jobs creation, economic development.

D. Develop three-year action plans for preferred alternative plans. Various participants in the planning process may prefer different plans, and tentative action plans should be developed for each.

VII. BOARD FORMAL APPROVAL[2].

A. Make policy choices to determine which objectives are consistent with the public interest (See Step V.E).

B. Select plan(s) determining the appropriate type, amount and "in-service" date of resource options. Among other things, this will determine which demand-side programs to pursue. The plan(s) approved by the Board may include modifications of proposed plans.

VIII. REFINEMENT OF THE PLAN.

A. Estimate lead times and determine a schedule of work efforts needed to implement each component (supply- and demand-side) of the plan by its "in-service" date.

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[2] The formal approval by the Board in the integrated resource planning case may require additional follow-through, perhaps even in other formal cases to modify rates or to apply for authority to implement resources. Some portions of Steps VIII through XII will probably be conducted outside the formal integrated resource plan approval process.

B. Evaluate participant and non-participant perspectives to allocate benefits between participants and non-participants in demand-side programs. Refine and adjust demand-side programs as necessary.

C. Develop fine-detailed programs to implement demand-side measures.

D. Adjust plan as necessary to address supply- and demand-side concerns identified above.

E. Recalculate avoided costs based on adjusted plan.

IX. EVALUATE STRATEGIC LOAD-BUILDING[3].

A. Calculate the net present value of the average rates over the planning period for the selected resource plan.

B. Evaluate the long-term impact on rates of increasing natural gas load at various times of the day and year.

1. How much load can be added, and where on the load pattern, before average long-term rates increase? Include upstream capacity and development costs.

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[3] This is an optional step depending on whether strategic load-building is being proposed. If strategic load-building is being proposed, or is likely to be proposed prior to the approval of the next long-range plan, it should be evaluated at this step in the integrated resource planning process. Alternatively, a separate plan which includes load-building can be considered in Step V.

2. How much of the above load can be added to get the maximum rate reduction? Estimate the level of naturally occurring load impacts for developing markets and unsaturated markets.

3. How must load additions be targeted to achieve reduced long-term average rates?

C. Factor effect of the candidate load-building options into energy and demand forecasts and determine how resource needs are increased. Determine whether adding load, to the extent that additional resources are needed, is in the public interest--as distinct from adding load to more fully utilize existing resources.

X. UTILITY IMPLEMENTATION.

A. Utility implementation of the plan and programs in Steps VIII and IX.

1. Implemented by utility staff.

2. Contracted out to private contractors.

3. Competitive bids -- issue requests for proposals from energy service companies to compete against avoided cost as calculated following Steps VIII.

XI. MONITORING AND EVALUATION.

A. What was the actual cost and effect of implementing each resource option?

B. How did it compare to the projected cost and effect?

C. How should programs be modified to improve their cost and effectiveness?

D. Refine programs.

XII. ON-GOING PLANNING AND REVIEW.

A. Utility update load forecasts annually.

B. Utility update system-supply data annually.

C. Utility update planning/program parameters continuously based on monitoring in Step XI.

D. In accordance with IRP process, utilities revise forecasts and plans and file with Board to conduct integrated resource planning process.

E. Return to Step I to conduct public review process.

APPENDIX B: EXTERNALITIES AND THEIR QUANTIFICATION AND MONETIZATION

In this appendix, we identify the environmental externalities associated with natural gas and its alternative supply-and demand-side options. We then discuss how these effects can be quantified and monetized.

A. Externalities of Natural Gas and its Supply-and Demand-Side Alternatives

The following table sets forth a list of possible environmental externalities associated with natural gas and competing supply and demand options. For each externality, its effects, temporal scope, the causal agents and geographic scope of the problem are laid out. Temporal scope indicates whether an effect is short-term, long-term or irreversible. Long-term externalities may affect future generations; the intergenerational equity issues that arise from these externalities are important, albeit thorny, issues that must be addressed. Intergenerational equity plays an important role in planning with resources that are finite such as natural gas. Geographic scope indicates the size and dispersal of affected constituencies. Both temporal and geographic scopes are important, because irreversible or long-lasting effects of broad geographic impact call for different incorporation treatment than short-lived local effects.

All resource options create "front-end" and "back-end" impacts. Atmospheric emissions created in the course of manufacturing demand-side technologies are an example of a "front-end" impact. The disposal of the technology at the end of its useful life is an example of "back-end" impact. Although such impacts may in some cases be significant, many methodological questions relating to the assessment of those externalities have resulted in their being little-studied to date. Except where specifically stated, the impacts listed in these tables occur in the construction and operational phases of the resource option.

The geographic scope of an externality helps determine how it is most appropriately treated, and it is for this reason that the geographic context is important. The economic literature suggests that externalities affecting numerous, dispersed constituencies (global) are most troublesome from both an analytical and a policy perspective. Localized, site-specific impacts can usually be dealt with on a case-by-case basis through the permitting process or litigation. Incorporating the externalities associated with energy production via the integrated resource planning process promises to provide, for the first time, a means of addressing geographically wide-ranging impacts in a systematic way.

Because geographic scope has implications for their treatment, we divide environmental externalities into three geographic categories, ranging from global externalities such as ozone depletion, to regional externalities such as habitat disruption, to site-specific externalities such as soil erosion.

In the case of finite natural resources (such as natural gas) it may be appropriate to consider the use of a depletion surcharge to reflect costs imposed on future generations by decreased availability of the finite fuel or, ultimately, unavailability.

The table below lists environmental externalities related to both supply and demand-side resources. The externalities associated with transportation are beyond the scope of this report; the complexities involved warrant a separate study. The agents listed in the table are associated with natural gas, oil and coal combustion, electricity generation from fossil-fired or hydroelectric facilities, and DSM resources. In the table, the impacts of natural gas combustion are distinguished from the impacts of the combustion of other fossil fuels (either directly or for the purpose of electricity generation) as well as from the impacts of demand-side management in order to allow a comparison of the externalities of natural gas versus DSM and natural gas versus other fuels. For example, in a case in which natural gas is compared with DSM options, the externalities from natural gas combustion (e.g., methane releases contributing the greenhouse effect) will diminish, while other impacts (e.g., ozone depletion from CFCs in insulation) will be introduced. Inter-fuel programs reduce the externalities associated with the fuel being switched from, but increase the impacts associated with the fuel being switched to. For example, a program that encourages the substitution of natural gas for electricity generated by hydro-electric power, the externalities associated with hydro-electric power (e.g., disruption of ecosystems due to reservoir construction) would be reduced, while externalities associated with natural gas (e.g., acid rain from Nox) would increase.

TABLE I: ENVIRONMENTAL EXTERNALITIES OF NATURAL GAS* AND ITS SUPPLY- AND DEMAND-SIDE ALTERNATIVES**

GEOGRAPHIC SCOPE	IMPACT	AGENT/SOURCES	TEMPORAL SCOPE
Global			
	Greenhouse	CH_4, CO_2, CFCs, NO_x	Long-term, possibly irreversible
	Acid Rain	NO_x, SO_2	Long-term
	Ozone Depletion	CFCs	Irreversible
	Species Extinction	Disruption/Destruction of Ecosystem	Irreversible
Regional			
	Visibility	O_3, NO_x, SO_2, Particulates	Short-term
	Habitat Alterations	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D	Long-term, possibly irreversible
	Disruption of Ecosystem	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D, NO_x, SO_2	Long-term
	Changes in Recreational Uses	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D	Long-term, possibly irreversible
	Solid Waste	Early Retirement of Appliances, Transformers, Converters, and Industrial Equipment	Short or Long-term
	Groundwater Contamination	Toxics	Long-term possibly irreversible
	Aesthetic Impacts	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D	Long-term, some irreversible
	Human Health Impacts	O_3, NO_x, SO_2, Particulates, CFCs, Toxics	Short or Long-term
Site-Specific			
	Erosion	Site Preparation	Short-term
	Loss of Riparian Acreage	Dams, Reservoirs	Long-term, possibly irreversible
	Habitat Alterations (e.g., changes in nesting sites)	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D, Cooling Water	Long-term, possibly irreversible
	Changes in Recreational Uses	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D	Long-term, possibly irreversible
	Aesthetic Impacts	Dams, Reservoirs, Site Preparation, Pipeline Construction, T&D, Plant	Short, Long-term, some irreversible
	Human Health Impacts	O_3, NO_x, SO_2, Particulates, CFCs, Toxics, EMF, Radioisotopes, Indoor Air Pollutants	Short or Long-term

* SO2 production from natural gas combustion is negligible, but it is a by-product of coal and oil combustion. Combustion of any fossil fuel produces CH4, CO2, Nox, 0C precursors, and particulates. Natural gas, however, produces less of the pollutants compared with coal and oil.

** Environmental impacts associated with demand-side measures include CFCs, Early Retirement of Appliances, Toxics, Radioisotopes and Indoor Air Pollutants.

B. Quantification and Monetization of Externalities

Quantification of impacts (e.g., raw methane release from pipelines) is expressed in rates such as cubic feet per minute. Monetization attaches a dollar value to that rate. Economists have developed a number of techniques to estimate the value of non-market goods. Three basic approaches are employed: (1) direct costing, (2) revealed preferences, and (3) expressed preferences. Each has inherent strengths and weaknesses. Each provides a quantitative estimate of external costs and benefits.

1. Direct Costing of External Effects

Direct costing relies heavily on marketed goods to determine damage costs. For example, studies of declining agricultural and timber production in areas affected by acid rain are combined with known market prices for these products to derive a damage estimate. The lost economic production becomes a measure of the environmental harm, which in turn acts to represent the value of the affected resources. Direct costing requires causation to be determined in detail. Where commodities are not marketed directly, direct costing is not possible. More importantly, many resources have value beyond what they would fetch in the market if harvested; this approach does not address these benefits.

2. Revealed Preference Approaches

Revealed preference approaches attempt to derive values through consumer choices. They derive implicit market prices for the externalities. Two methods that fall under this category include *shadow prices* and *travel cost models*. *Shadow prices* assume that a market price exists that can be used to reflect the cost of the externality. Abatement costs are the most commonly used shadow prices for environmental externalities in the utility industry. The critical underlying assumption here is that abatement costs related to the regulatory mandate are equivalent to the social cost of the pollution. Most studies assume that there is a socially defined level of acceptable damage, which can be determined. Lacking the thresholds provided by precisely defined regulatory mandate, no socially acceptable level of environmental harm is defined. In such cases, the shadow-price approach is limited to that calculated on the basis of completely avoiding the impact, which may not accurately reflect the level of concern that society feels for the externality.

Travel cost models rely on survey data to determine the amount spent by consumers to utilize a particular resource. Total expenditures serve as a proxy for the total value of the resource. This method cannot be used to allocate the costs of environmental effects among different producers. Travel cost models are useful when the causal link is strong between producers and damages, but such circumstances are comparatively rare.

There are a number of critical survey-related problems with revealed-preference estimates, including strategic bias (respondents are unlikely to reveal their true feelings but answer in hopes of obtaining their preferred choice), informational biases (survey design) and hypothetical bias (stemming from the fact that the valuation concerns non-market goods). These surveys are very site-specific, making it difficult to extrapolate to generic resources.

3. Expressed-Preference Methods

Expressed-preference methods rely on contingent valuation surveys. In such surveys, respondents are asked what a change in environmental or health quality is worth to them. People are often asked to state what they would be willing to pay to avoid degradation, or whether they would be willing to be compensated for accepting degradation. In practice, willingness to pay is usually less than the willingness to be compensated, although in theory they should be equal. Which measure should be used is determined by property rights. Willingness to pay should be used when those bearing the cost have no property rights to the resource in question; willingness to be compensated should be used when those bearing the cost do hold the property rights.

These techniques have been employed to estimate the value of a wide range of resources. The results of such studies tend to be very site-specific; generalization is often not possible. In many studies, firm causal links cannot be established, making it impossible to allocate costs among a collection of cost-causers. Finally, most of these studies consider only single effects, in isolation; synergies, should they exist, are not accounted for.

4. Environmental Target Approach

The environment target approach is not strictly an economic method for valuing environmental externalities. This method uses public policy in conjunction with economics. It is a variation of the shadow price method in that it estimates the value of the environmental harm by estimating the compliance cot of competing abatement strategies for different levels of environmental protection. Under this approach, a set of environmental goals are established (e.g., a 20% reduction in carbon dioxide emissions, relative to 1988 levels, by 2000). The incremental cost of each constraint equals the cost of the relevant externality. For example, if the incremental cost of reducing carbon dioxide emissions, assuming a 20% reduction target, is \$50 per ton, then the external environmental cost of a ton of carbon dioxide emissions is \$50. The cost of achieving different levels of environmental protection can be determined in this manner. The policy process can be used can be used to determine what the citizenry is willing to risk in meeting energy needs, or, alternatively, how much it is willing to pay for reducing the risk of environmental impacts. Thus, this method can be used when determining the level of environmental protection via the regulatory process or after the mandate, to determine the cost of different reduction strategies. In either case, a monetized estimate of the environmental externality can be generated. The weakness of this approach is the same as the shadow price method -- namely, it assumes that once a regulatory mandate is decided upon, the attendant abatement costs are equivalent to the social cost of pollution. This process is being used formally for the first time in the collaborative process in New England.

APPENDIX C: THE FIVE STEPS OF DSM PROGRAM MONITORING AND EVALUATION

DSM program monitoring and evaluation is comprised of five steps: (a) identify program objectives, (b) select type of evaluation, (c) specify evaluation resources, (d) conduct the evaluation and (e) document and act upon evaluation findings. Each of these steps is discussed below.

A. Identify Program Objectives

The obvious objectives of a DSM program are energy and/or capacity savings, but ancillary goals necessarily exist, e.g., achievement of specific penetration rates, targeting of low-income or other populations, equipment testing, customer satisfaction, etc.

B. Select Type of Evaluation

The type of evaluation selected depends upon the objectives of the DSM program and the objectives of the evaluation. The objectives of the evaluation depend upon the stage of implementation of the program (i.e. whether it is a pilot or full-scale program), future DSM program plans, the scope of the DSM program, and other factors. Unfortunately, a "model" evaluation design that can be perfectly applied to all DSM programs does not exist. All evaluations, however, should be designed to produce information that is relevant to future management decisions, in a time frame that allows the information to be best utilized.

There are two basic types of evaluations: process evaluations and impact evaluations. Process evaluations, which are largely qualitative, address how well a program is being implemented and suggest ways to improve delivery. They address issues such as effectiveness of promotional methods, ease of participation for customers, reasons for participation levels, quality of contractor services, vendor concerns, timeliness of delivery and the like. They address the who, how, when, where and why of DSM programs. Impact evaluations, which are largely quantitative, address issues related to program performance. They measure energy and capacity savings, program costs, and changes in load shapes resulting from the program. An example of a situation in which a process evaluation might be deemed to be most appropriate might be when expansion of a pilot program is being considered, whereas an impact evaluation would be selected if greater accuracy in inputs into integrated resource planning are sought or financial incentives are being considered. Frequently, it is appropriate to evaluate a program using both types of evaluation.

C. Specify Evaluation resources

Budget, staffing, timing, data needs and methods and reporting systems are identified.

1. Budget

The budget level for the evaluation should be based upon the value of the program as a resource, the importance of the information to management decisions about the program and future programs, and the type of evaluation to be conducted. Credible U.S. sources suggest an evaluation budget of approximately 10 percent, with a recommended range between 5 and 15 percent of the program budget; however, this can vary widely depending on the evaluation's objectives and methods. For example, costs differ greatly among a simple process evaluation, a thorough process and impact evaluation with no end-use data collection, and an impact evaluation with an extensive end-use data collection effort.

2. Staffing

An interdisciplinary team of people, with backgrounds in areas such as market research, economics, psychology, sociology, statistics, engineering and business, is well-suited to evaluating DSM programs.

In order to avoid a possible conflict of interest and enhance objectivity in performing evaluations, it is advisable for the evaluation team to report directly to senior management. The appropriate officer might be the person responsible for planning, load forecasting, load research or integrated resource planning. This arrangement offers less potential for conflict than does having the evaluation staff report directly to the person responsible for DSM program design or implementation.

3. Timing

It is advisable that the program evaluation be designed concurrently with the DSM program itself, in order to incorporate data collection into program administration at the outset, and to obtain the necessary monitoring equipment in a timely manner.

It is also important to include a mechanism that will allow the information collected to be fed back in a timely fashion to program modification, expansion, or termination; new DSM program design; load forecasting; integrated resource planning; etc.

4. Data Needs

The data needed to conduct the evaluation depend upon the type of evaluation (i.e., process or impact) selected and its objectives.

As identified in Table I below, the general objectives for process evaluations include evaluating the program's design, marketing, and management and administration. The types of data required for process evaluations include indicators of customer satisfaction, customer acceptance, customer understanding, and utility efficiency in delivering the DSM program. A variety of methods are available to collect these data. They include mail and telephone surveys, both prior to and after implementation of the program, interviews with both those who deliver the DSM services and customers who participate (and those who choose not to participate) in the programs, focus groups comprised of participants in the program, program-accounting records, and marketing analysis.

The questions that are appropriate to ask in surveys, interviews, and focus groups vary widely, depending upon the DSM program and the purpose for which the evaluation is being conducted. They include, for example, questions directed toward utility personnel operating the program regarding roles and responsibilities, promotional and marketing activities, and program structure, administration, organization, and quality control. Questions would also be directed toward any contractors involved in program delivery regarding their satisfaction with program administration and design, availability of supplies, satisfaction with subcontractors, methods of quality control, and suggestions for program improvements. For program participants and nonparticipants, questions might include why some potential participants chose not to participate, which elements have wide appeal, their opinion of the technical abilities of the utility and contractor representatives, any perceived roadblocks to participation, and many others. Combined with a review of program records and marketing analysis, the process evaluation should provide many insights into the strengths and weaknesses of the program being evaluated, whether it is reaching the market segments originally intended and why or why not, how market penetration can be improved, how the program can be made more cost-effective, and other information useful for both revising the program being evaluated and designing future programs.

TABLE I

PROCESS EVALUATIONS

General Objectives of Program	Reduce MCF/reduce peak
General Objectives of Evaluation	1. Evaluate program design 2. Evaluate program marketing 3. Evaluate program management and administration
Data Needs	1. Indicators of customer satisfaction 2. Indicators of customer acceptance 3. Indicators of customer understanding 4. Indicators of utility efficiency in delivering program
Methods	1. Mail and phone surveys - benchmark and post-implementation 2. Interviews 3. Focus groups 4. Program-accounting records 5. Marketing analysis

Table II identifies the objectives, data needs, and methods used to conduct impact evaluations. The general objective of impact evaluations is to determine the energy savings or peak reductions actually achieved, the costs of achieving those savings, the market penetration achieved, and the cost-effectiveness of the program. In order that the evaluation be as widely useful as possible, another worthy goal for the evaluation is designing the evaluation such that the data that is collected can be extrapolated. To meet these evaluation objectives, an evaluator must collect data that measure the change in energy use or peak resulting from the program, the costs of the program, and participation and attrition rates.

Several methods are available for deriving the information and/or collecting the data required for impact evaluations, ranging from less precise methods that do not rely on metered consumption data to more exact--and expensive--ones that do. A commonly used method that does not require metered consumption data is engineering estimates, which calculate savings on the basis of commonly accepted engineering principles. Program-accounting records are used in combination with engineering estimates to calculate savings from the program. Engineering estimates are the least expensive method of collecting data for impact evaluations, but are also the least exact. Customer end-use surveys or audits (especially for large end users or when used in combination with quality control inspection) provide more precision; premises are inspected to certify the installation of DSM measures, and engineering calculations are conducted on the basis of this information. Billing analysis--in which the gas bills of participants are compared prior to and after the installation of the DSM measures--also provides greater precision than engineering estimates based on commonly accepted engineering principles. For more precision in billing analysis, control groups are evaluated in addition to program participants. Another method is the use of building simulation models (e.g. DOE-II) which calculate savings based on architectural and engineering assumptions. Finally, the most exact--and most expensive--method of collecting data for impact analyses is metering, either of entire buildings or, for the greatest precision, by end use. The use of electronics in metering and improvements in flow-measurement technologies have greatly improved gas-metering technologies, including allowing ready access to data through real-time metering, and have reduced their price. Selective metering, in combination with one or more of the other methods described, offers a means of keeping costs down while obtaining information valuable for calibrating engineering estimates. One or a combination of these approaches, along with other information from program records, provides the data necessary to calculate the program's savings, costs, penetration, and ultimately, cost-effectiveness.

TABLE II
IMPACT EVALUATIONS

General Objectives of Program	Reduce MCF/reduce peak
General Objectives of Evaluation	1. Determine MCF reduction/peak shift 2. Determine market penetration 3. Determine costs 4. Determine cost-effectiveness 5. Ability to extrapolate data
Data Needs	1. Change MCF/customer 2. Determine costs 3. Determine customer participation/attrition rates
Methods	1. Engineering estimates 2. Program accounting records 3. Customer end-use surveys/audits 4. Billing analysis 5. Simulation models 6. Selective metering

5. Tracking and reporting systems

Ideally, the tracking and monitoring system is designed such that it is in place from the very beginning of a DSM program. The appropriate reporting media (whether mainframe, personal computer or manual records) depend upon the type and quantity of data that are being collected for the evaluation.

D. Conduct the Evaluation

After selecting a process and/or impact evaluation and specifying the budget, staff, data needs, data collection methods, and tracking and reporting systems, the evaluation is conducted. Depending upon the data needed for the evaluation (e.g., energy or peak savings, program costs, indicators of customer satisfaction and acceptance), and the methods chosen to collect those data (e.g., interviews, metering, billing analysis), the population to be sampled is defined. If appropriate, a control group is established. The sampling technique and data collection and analysis methods employed should be statistically valid and the questions used in interviews tested. The techniques employed should allow for extrapolation of the data, to achieve its widest-possible usefulness. Data can then be collected and analyzed.

Planning and conducting the evaluation in an open manner, involving all interested parties, can help ensure that the results of the evaluation will be widely accepted as valid.

E. Document and Act Upon Evaluation Findings

When the evaluation is completed, its findings are documented, reviewed, and reported to all interested parties including utility staff, regulators and members of the public. Throughout the conduct of the evaluation, as well as at its conclusion, the information obtained in the process can be used by the utility. The program that was evaluated can be revised, expanded, or terminated. Future DSM programs can be designed with the aid of the information. Load forecasters can use the impact data that were collected. The data can also be used to improve the accuracy of comparison of supply-and demand-side resources in the integrated resource planning process.

Cassels, Brock & Blackwell

DATE: June 11, 1991

TO: Ontario Energy Board

MEMORANDUM

FROM: IAN BLUE, Q.C.

RE: **Integrated Resource Planning ("IRP")**

I was asked to carry out the following assignment:

a) To conduct a review of the current legislation governing the Ontario Energy Board (the "Board") in order to determine its jurisdiction regarding the implementation of integrated resource planning by the natural gas distribution utilities in Ontario.

b) To identify what changes, if any, are required to the Board's current legislation in order to implement integrated resource planning by the natural gas distribution utilities in Ontario.

In making these determinations, Counsel should consider each of the following scenarios as a possible form of IRP implementation:

i) The Board orders the Ontario LDCs to develop integrated resource plans using criteria established by the Board. These plans are then filed and become the subject of a hearing. The Board's decision in the hearing would involve the approval of the integrated plan and the implementation of the plan.

ii) The Board pursues option (1) but further orders the utilities to develop the plans using a collaborative process whereby input into the development of the plan is acquired from various interested parties through working groups. The goal is to achieve the maximum level of agreement possible in advance of the public hearing on the specific plan.

iii) The Board orders the Ontario LDCs to provide evidence in their rate cases that they are planning their systems according to IRP principles and criteria (as established by the Board). The Board's decision in the rate case would use the IRP principles for purposes of establishing rate base, setting the rate of return and fixing just and reasonable rates.

iv) The Board issues recommendations on IRP and the appropriate principles and informs the utilities that these principles will be taken into account in the utility rate cases.

v) The Board orders the utilities to develop and pursue demand-side management or conservation and load management programs.

For purposes of this opinion, I adopt the definition of integrated resource planning ("IRP") adopted in the MSB Energy Associates, Inc. Report on Gas Integrated Resource Planning prepared for the Board, which states:

> Integrated resource planning (IRP) for natural gas utilities is an expanded method of planning whereby the expected demand for natural gas service is met from the least costly mix of supply additions, energy conservation, energy-efficiency improvements and load management techniques (i.e. the integration of demand-side resources and supply-side resources). Some of the specific objectives of the planning process are to continue to provide reliable service, equity among ratepayers, and a reasonable return on investment for the utility while addressing environmental issues and achieving the lowest cost to the utility and the consumer.
>
> The methodology for calculating the "cost" of each option and the analytical framework used for insuring consistent treatment of both supply- and demand-side options must be developed and adopted prior to the development of actual plans.

> Fundamental to successful implementation of IRP is a refocussing of the utility's mission from being solely a purveyor of natural gas to a more comprehensive view of being a provider of energy services.
>
> Besides integrating demand- and supply-side options on a consistent basis, an integrated resource plan should be flexible and diversified; the utility should be able to respond to uncertainty and minimize risk. The planning exercise is preferably conducted on a cooperative basis which should allow for input from all parties interested in the development of the plan and will include some form of regulatory review, thereby ensuring that the interests of all stakeholders are taken into account.

The organization of this opinion follows the format in the Terms of Reference. First, there is a review of the Board's jurisdiction over IRP. I analyze each of the five scenarios presented to me in the terms of reference in order. My main legal analysis is in scenario 1. Second, I identify, in general terms, changes required in the Board's current legislation in order to implement IRP as an independent requirement in situations where I conclude that the Board lacks jurisdiction.

PART I - REVIEW OF THE BOARD'S JURISDICTION OVER IRP

Scenario 1

Description of Scenario

> The Board orders the Ontario LDCs to develop integrated resource plans using criteria established by the Board. These plans are then filed and become the subject of a hearing. The Board's decision in the hearing would

involve the approval of the integrated plan and the implementation of the plan.

Summary of Opinion

The Board lacks jurisdiction to implement this scenario.

Reasons for Legal Opinion

As stated above, it is my opinion that the Board lacks jurisdiction to implement this scenario. The Parts and sections of the Ontario Energy Board Act, R.S.O. 1980, c.332 ("the Act") and their subject matter can be seen from the following analysis:

Part and Section	Subject Matter
Part I - General	
s.1	definitions
ss.2-17	general powers; composition of the Board;
ss.18-19	rates, rate base, rate orders;
ss.20-22	storage of natural gas in geological formations and agreements re. same;
s.24	allocation of market demand and joining interests in spacing units and pools;
s.25	discontinuation of gas supply;

s.26	changes in ownership and control of gas systems;
s.27	
ss.28-34	legal provisions re. Board decisions;
s.35	regulations;
s.36	references;
s.37	Ontario Hydro Rules
Part II - Gas Priorities and Allocations	
ss.40-45	allocation plans, process and regulations;
Part III - Pipelines	
ss.46-48	leave to construct and hearing process;
ss.49-50	expropriation powers;
ss.51-55	crossings, right of utilities, compensation, inspectors;
Part IV - Energy Returns Officer	
ss.56-63	Powers of the Energy Returns Office; status of documents and information in officer's possession; use of documents and evidence in hearings;
Part V - Miscellaneous	
s.64	in conflicts with other Acts, this Act prevails

There is nothing in the Act authorizing a process akin to the IRP process described above. The Supreme Court of Canada has held in TransCanada PipeLines v. National Energy Board [1981] 2 S.C.R. 688 that there is no equity in a statute. A statutory body, like the Board, has only the jurisdiction conferred on it by the statute creating it. The Divisional Court of Ontario, in determining the nature and extent of the cost powers granted to a Joint Board under the Consolidated Hearings Act, 1981 Stats. Ont. 1981, c.20, has stated:

> "This Board, being a creature of statute, can only exercise the powers conferred upon it by its enabling legislation." Re Hamilton-Wentworth and Save the Valley Committee et al. (1985), 51 O.R. (2d) 23 at p.30.

The same Court that decided the Hamilton-Wentworth case also decided the case stated by the Board about its jurisdiction to order interim payment of costs: Re Ontario Energy Board (1985), 51 O.R. (2d) 333. Although the Divisional Court acknowledged the broad jurisdiction of the Board, it held that, for the reasons given in the Hamilton-Wentworth case, however laudable, or desirable it might be for the Board to grant funding in advance of a hearing, the Board did not possess authority to do so. The courts will not read in grants of authority that are not found in the wording of the statutes being considered. This is the principal rule of statutory interpretation applicable to deciding whether the Board can implement the IRP process, described in the first scenario.

Let me deal with some possible bases for suggesting that the Board has jurisdiction.

Subsection 13(1)

> The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and of fact.

Subsection 13(1) gives the Board a broad grant of discretionary power. It does not, however, go beyond what is "within its jurisdiction". In other words, it is not a source of plenary independent authority but only goes as far as the jurisdiction which the Legislature has granted to the Board goes. As already stated above, in my opinion, the present Act does not grant to the Board the jurisdiction to require LDCs to implement an IRP process as set out in scenario 1, above, as a separate and distinct area of authority.

The Divisional Court of Ontario has held that the Legislature intended to vest in the Board the widest powers to control the supply and distribution of natural gas to the people of Ontario "in the public interest". Hence, the Act was classified as special legislation which overrides the general powers granted to municipalities to enact land use by laws under the Planning Act: Union Gas Ltd. v. Township of Dawn (1977), 15 O.R. (2d) 722 at p.734. In the Dawn case, the Township of Dawn had passed zoning by-laws which dealt with locations in which gas pipelines could be constructed within the municipality. The by-laws came before and were approved by the Ontario Municipal Board. Two gas companies appealed the Municipal Board's approval of the by-laws to the Divisional Court which held that because the municipality was without jurisdiction to pass the by-laws, the Municipal Board was, therefore, without jurisdiction to approve them. Keith, J. said at p.731:

> In my view this statute makes it crystal clear that all matters relating to or incidental to the production, distribution, transmission or storage of natural gas, including the setting of rates, location of lines and appurtenances, expropriation of necessary lands and easements, are under the exclusive jurisdiction of the Ontario Energy Board and are not subject to

> legislative authority by municipal councils under the *Planning Act.*
>
> These are all matters that are to be considered in the light of the general public interest and not local or parochial interests. The words "in the public interest" which appear, for example, in s.40(8), s.41(3) and s.43(3), which I have quoted, would seem to leave no room for doubt that it is the broad public interest that must be served. In this connection it will be recalled that s.40(1) speaks of the requirement for filing a general location of proposed lines or stations showing "the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed line is to pass."
>
> Persons affected must be given notice of any application for an order of the Energy Board and full provision is made for objections to be considered and public hearings held.
>
> In the final analysis, however, it is the Energy Board that is charged with the responsibility of making a decision and issuing an order "in the public interest". [emphasis added]

That portion of the quote which I have underlined when read out of context might suggest that there is no end to the jurisdiction of the Board so long as one is dealing with matters which relate to or are incidental to "the production, distribution, transmission or storage of natural gas". In my opinion, however, such an interpretation is unwarranted. The use of "all", in "all matters relating to ....", is clearly wrong, for as we know there are matters relating to or incidental to the production and transmission or storage of natural gas which are dealt with by others than the Board: Ministry of Natural Resources; National Energy Board; Ministry of Consumer and Commercial Relations; and Ministry of Labour, under other legislation. Further, the Divisional Court did not refer to this passage nor even to this case in its more recent decision concerning the cost powers of the Board mentioned above. If the Board possesses the broadest jurisdiction unfettered by considerations of other sections of the Act, as may be suggested by a reading solely of the underlined portion of Keith J.'s reasons, then the Divisional Court should have found that the Board possessed the authority to grant funding in advance of a hearing by ordering interim payment of costs in the Ontario Energy Board case, supra. But it did not.

It is my opinion that it is not appropriate to rely upon the underlined portions of the quote above as being the correct interpretation of the jurisdiction granted the Board by the Act. Rather, it is my opinion that because the Act does deal with location of gas pipelines in Part III of the Act, this issue is within the exclusive jurisdiction of the Board and not subject to legislative authority by municipal councils under the Planning Act. In other words, it is my opinion that because the Act specifically deals with subjects listed by Keith J., i.e. "the setting of rates, location of lines and appurtenances, expropriation of necessary lands and easements", that the Board in granting leave to construct pipelines is not bound by municipal by-laws.

Further, it is my opinion that the Divisional Court would reject an attempt by the Board to find jurisdiction to require LDCs to implement an IRP process on the basis of the underlined portion of the above quote, because of the absence of a specific statutory reference.

Subsection 13(5)

> The Board of its own motion may, and upon the request of the Lieutenant Governor in Council shall, inquire into, hear and determine any matter that under this Act or the

> regulations it may upon an application inquire into, hear and determine, and in so doing the Board has and may exercise the same powers as upon an application.

Subsection 13(5), in my opinion, does not grant the Board jurisdiction over new areas of activity. In my opinion, the authority of the Board under this subsection is restricted to enquiring into those matters that are specifically mentioned under other sections of the Act or the regulations as being areas it may, upon an application, inquire into. Thus, for example, the Board would have jurisdiction under subsection 13(5) to consider IRP during a generic hearing called to consider IRP in relation to such matters as rates, rate base, methods for determining rate base or factors to consider in approving the expansion of a natural gas system, because these are specific matters which have been made subject to the jurisdiction of the Board under other sections of the Act, i.e. section 19 and section 46. As there is, however, no specific grant of solely IRP jurisdiction to the Board or no mention of the concept of IRP process in the Act or the regulations, it is my opinion that the Board, absent such other hearing, cannot find the necessary jurisdiction in subsection 13(5) to proceed as contemplated under this scenario.

While it might be tempting to suggest that the Board should have the authority to inquire into any energy matter that is in the public interest, nevertheless, it is my opinion that the Board currently lacks such jurisdiction under the Act. In coming to this opinion, I note the broad grant of power given to the Lieutenant Governor in Council under section 36 of the Act to "require the Board to examine and report on any question respecting energy that, in the opinion of the Lieutenant Governor in Council, requires a public hearing". It is my opinion that the Board itself has jurisdiction to inquire into only those matters that under the

Act or the regulations are specifically provided for, and only at the request of the Cabinet may the Board by reference inquire into other energy matters among which I include IRP.

Subsection 13(6)

> The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act.

Subsection 13(6) of the Act gives the Board exclusive jurisdiction "in respect of all matters in which jurisdiction is conferred on it by" the Act or any other Act. Like the power in subsection 13(1), this, in my opinion, does not grant the Board any authority over matters beyond what is otherwise stated by other sections of the Act to be "within the Board's jurisdiction". Thus, it is not a source of plenary independent authority. For the reasons noted above, it is my opinion that there is nothing in the current legislation which would authorize the IRP process as described in this scenario.

Subsection 15(1)

> The Board may at any time on its own motion and without a hearing approve the form of a document or give directions or require the preparation of evidence incidental to the exercise of the powers conferred upon the Board by this or any other Act.

Subsection 15(1) gives the Board a broad grant of discretionary power to require the preparation of such evidence as is incidental "to the exercise of the powers conferred upon the Board" by the Act or any other Act. As with the powers conferred by subsections 13(1) and 13(5), this, in my opinion, is not a source of plenary independent authority. It is my opinion that the phrase "incidental to the exercise of the powers conferred upon the Board by this or any other act" means that the Board may exercise a power under subsection 15(1) to require the preparation of evidence only in those situations where the Board has under another section of the Act been granted an explicit power to hold a hearing where the use of such evidence may be required. Thus, the Board in a rate hearing conducted under sections 19 and 20 of the Act, has the power to require the preparation of IRP process documents if the preparation of such evidence would be incidental to the exercise of the Board's rate-approval powers. What is proposed in this scenario, however, is that the Board hold a hearing devoted solely to approval of utility-specific IRPs. Because it is my opinion that there is nothing in the legislation which authorizes an IRP approval hearing being conducted by the Board, there is no authority for the Board to order the LDCs to prepare such evidence under subsection 15(1) and no power in the Board to hold such hearings.

Scenario 2

Description of Scenario

> The Board pursues option (1) but further orders the utilities to develop the plans using a collaborative process whereby input into the development of the plan is acquired from various interested parties through working groups. The goal is to achieve the maximum level of agreement possible in advance of the public hearing on the specific plan.

Legal Opinion

This scenario is the same as scenario 1 dealt with above to which has been added the additional requirement that the LDCs would, in the development of their IRP, use a collaborative process and seek input from interested parties. As stated above, it is my opinion that the Board lacks jurisdiction to implement scenario 1. It follows, therefore, that the Board also lacks jurisdiction to implement this extended scenario 1 proposal.

Scenario 3

> The Board orders the Ontario LDCs to provide evidence in their rate cases that they are planning their systems according to IRP principles and criteria (as established by the Board). The Board's decision in the rate case would use the IRP principles for purposes of establishing rate base, setting the rate of return and fixing just and reasonable rates.

Summary of Opinion

The Board has jurisdiction to implement the first sentence of this scenario. As long as the Board does not act in a way that fetters its discretion about what IRP principles it will ultimately decide to adopt in the rate case discussion, the Board has jurisdiction to take IRP principles into account in establishing rate base, setting the rate of return and fixing just and reasonable rates. It, therefore, has jurisdiction to require evidence about the LDC's use of these principles in establishing rates.

Reasons for Legal Opinion

I have set out above under the heading "Subsection 15(1)" my opinion that the Board in a rate hearing conducted under the provisions of section 19 of the Act has the power to require the preparation of IRP process documents because the preparation of this evidence is incidental to the Board's powers to set rates.

I am, however, worried by the overall impression that could be given by reading both sentences of this scenario together. This worry will be eliminated if the Board declares that it will keep an open mind about whether IRP principles are appropriate. While courts have long recognized the right of a tribunal to formulate general principles by which it will be guided, the courts also have held that the tribunal must not fetter its hands and fail, because some principle has been declared, to give full hearing and consideration to any matter before it. The courts have noted that to lay down principles by which a tribunal would be guided may be both reasonable and wise but to say that a party must comply with such principles before the tribunal will allow the application is clearly wrong and the Board lacks the authority to so fetter its jurisdiction. See, for example, the decision of the Court of Appeal in Re Hopedale Developments Ltd. and Town of Oakville, [1965] O.R. 259 at pp.263-265.

More recently Mr. Justice Estey in giving the judgment of the Supreme Court of Canada in Innisfil Township v. Vespra Township, [1981] 2 S.C.R. 145 at p.136, states, with respect to the Municipal Board:

> "The Board must not, it is clear, adopt any procedure or follow any course that will in any way prevent or limit its inquiry into the "merits" of the application or "any objections" that "any person" may seek to place before the Board."

Scenario 4

Description of Scenario

> The Board issues recommendations on IRP and the appropriate principles and informs the utilities that these principles will be taken into account in the utility rate cases.

Legal Opinion

For the reasons noted above under scenario 3, it is my opinion that the Board has the jurisdiction to implement this scenario, subject only to the comments I have made above about the Board not "fettering its discretion".

Scenario 5

Description of Scenario

> The Board orders the utilities to develop and pursue demand-side management or conservation and load management programs.

Summary of Opinion

The Board lacks jurisdiction to implement this scenario as a separate and plenary matter of its energy regulation of LDCs.

Reasons for Legal Opinion

As stated above, it is my opinion that the Board lacks jurisdiction to implement this scenario as the sole subject to a hearing. A review of the Parts and sections of the Act above makes it clear that there is nothing in the Act which authorizes the Board to order LDCs to develop and pursue demand-side management or conservation and load management programs. In coming to the conclusion that the Board lacks jurisdiction to implement this scenario, I rely upon the reasons for legal opinion set out under the heading "Scenario 1" above.

As noted above under the heading "Subsection 13(5)" with respect to the IRP process, it is my opinion that the Board would have jurisdiction under subsection 13(5) to consider demand-side management or conservation and load management programs during a generic hearing dealing with such matters as rates, rate base, or factors for determining rate base or expansion of natural gas system, where demand-side management or conservation and load management can be shown to be incidental to the Board's exercise of its jurisdiction during any such hearing. In such situations, it is also my opinion, as noted above, that the Board has the power to require LDCs to develop evidence of such programs under subsection 15(1) of the

Act because the preparation of this evidence would then be incidental to the exercise of the Board's jurisdiction.

PART II - CHANGES REQUIRED TO CURRENT LEGISLATION IN ORDER FOR THE BOARD TO IMPLEMENT IRP

I will now identify, in general terms, those changes which are required, in my opinion, in the Board's current legislation to implement IRP as an independent requirement in those scenarios where I have concluded that the Board presently lacks jurisdiction.

Scenario 1

To enable the Board to proceed with this scenario, the following changes should be made to the Act:

1. A definition of IRP should be provided in subsection 1(1) of the Act which, under this scenario, should make specific reference to criteria as established by the Board;

2. A new section, perhaps 18a, should be provided:

   (a) to require all persons subject to the Board's jurisdiction to develop IRP using criteria established by the Board;

(b) within a time frame to be established by the Board, to provide copies thereof to the Board;

(c) to require the Board to hold hearings to approve IRPs for each person subject to the Board's jurisdiction;

(d) to require each person to implement the IRP as approved by the Board with specific powers to the Board to issue binding orders to force compliance;

(e) to require any approved IRP to be modified or changed in accordance with such directions as may be given by the Board following a hearing called to consider same; and

(f) to provide the Board with the discretion to take the approved IRP into consideration in the exercise of its other jurisdiction whether conferred on it by the Act, or any other Act.

<u>Scenario 2</u>

To enable the Board to proceed with this scenario, the changes to the Act noted above should, in my opinion, be made together with:

1. An additional reference in the definition section to the collaborative process; and

2. As each person will undoubtedly have his or its own interpretation of what level of collaboration is required, the new section 18a should probably set out those with whom each person must consult in the development of his or its IRP.

Scenario 5

To enable the Board to proceed with this scenario, those changes to the Act of the type noted above with respect to "Scenario 1" should be made but, instead of referring to IRP, there should be a reference to demand-side management or conservation and load management programs.

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