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REPORT

ESTIMATING OPPORTUNITY COST FOR ENERGY LIMITED PLANTS

Practice, Modelling and Input Issues

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AEMC

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EXECUTIVE SUMMARY

The Australian Energy Market Commission (AEMC) has engaged Concept Economics to provide a commentary on the application of opportunity costs for generator compensation arrangements, including the methodology and inputs associated with the calculation of such costs.

The AEMC is in the process of considering a Rule change proposal relating to the compensation provisions during an administered price period ("APP") submitted by EnergyAustralia ("EA"). EA has argued that the current provisions that use generator offers as the basis for compensation expose retailers to a financial risk that cannot be hedged.[1] EA has instead proposed a compensation scheme based on direct operating costs alone. However, it has been argued by some market participants in the NEM that generators and other service providers should be compensated for opportunity costs in addition to any direct operating costs during an APP. This report:

1. Discusses some of the theoretical underpinnings of the opportunity cost concepts that arise in the context of the electricity industry;
2. Provides an account of approaches to compensation applied in other electricity markets; and
3. Describes the available mathematical modelling techniques and input issues.

THEORY AND PRACTICE OF OPPRTUNITY COSTS

The opportunity cost is the value of the next best choice that one gives up when making a decision. This fundamental economic concept has found numerous applications in the electricity industry where system and power station operators must frequently evaluate trade-offs between different courses of action.

Specifically where energy-limited plant are concerned, a requirement to generate at a particular point in time may eliminate future (more profitable) generation opportunities, and therefore imposes a (potentially substantial) opportunity cost on the generator in question. The opportunity cost of such foregone generation opportunities is an integral part of the short run marginal cost ("SRMC") of generation. Therefore, compensation measures based on opportunity costs over and above direct operating costs are theoretically sound.

It is well recognised that the application of a price cap in an energy only market leads to insufficient returns to all generators, and in particular to peaking generators who must recover their costs over a very limited number of (high-price) hours in each year. To the extent that compensation payments tend more frequently to be made to energy-limited (peaking) generators, compensation that is based only on the direct operating costs of a generator risks undermining the financial viability of such generators.

That said, the adoption of an opportunity cost standard raises a number of complex conceptual and computational issues that should not be underestimated. In particular, we

[1] EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

highlight the key risk that estimates of opportunity cost can be both very high and volatile. Thus the opportunity costs of foregone generation opportunities may substantially exceed SRMC estimates that are only based on direct operating costs.[2] This may expose participants responsible for paying the compensation to potentially significant risks that cannot be hedged.

Observed practices in both regulated utilities and electricity markets suggest that opportunity cost concepts have been applied in different contexts and for different forms of compensation. ICompensation based on some form of opportunity cost approach is paid for "reliability must run" services to alleviate transmission constraints and for the provision of ancillary services. Our short review of market practices in Ontario, Alberta, the US, New Zealand, and Western Australia suggest that:

- The approaches taken to translate opportunity costs into practical guidelines for compensation have tended to focus on objectives related to practicality and transparency, as opposed to conceptually "correct" compensation approaches. Arguably this leads, in a number of cases to opportunity cost estimates at the *low* end of what these costs are likely to be;
- The opportunity cost concepts that are applied tend to differ according to the type of generation technology used in the specific context, so it seems that only two markets with a significant hydro presence (Ontario and Alberta) have adopted an explicit opportunity cost approach for foregone future generation opportunities. Other opportunity cost components relate to a wide range of fixed and variable costs;[3] and
- A number of markets apply some mechanism to limit the exposure, such as a maximum per cent over and above direct costs.

We conclude from this review of market practices adopted internationally that:

- The guidelines need to have a detailed consideration of the scope of such calculation, including timeframe and facilities that are included or excluded. For instance, the compensation scheme in Ontario allows for a 3-month period for opportunity cost calculation and typically excludes run-of-the-river plants from claiming any opportunity cost;
- Flexibility is of essence to cater for a wide range of service providers. For instance, in the above example, if a run-of-the-river plants can establish the usage of water from an upstream storage, there is flexibility in the scheme for it to claim compensation; and
- Concerns about very high compensation outcomes and the corresponding effects on retailers could be addressed by carefully defining certain limits on compensation payments.

MATHEMATICAL MODELS TO CALCULATE OPPORTUNITY COSTS

Mathematical models and algorithms for calculation of opportunity costs have two major components, namely:

[2] Conversely, where the value of any foregone opportunities is low, opportunity costs can also be low or zero.

[3] As we note in Section 2, in some cases, fixed costs are incorrectly treated as opportunity costs.

- Some form of **optimisation** model, such as a linear programming ("LP") or dynamic programming ("DP") model, that evaluates alternative ways of using limited energy, namely, in alternative future periods beyond the APP. This optimisation may be performed in an iterative way to calculate the opportunity cost by trial and error using a conventional LP dispatch engine ("**LP-D**"), similar to the NEM Dispatch Engine ("NEMDE"). A superior alternative is to use an intertemporal optimisation across all time periods; and
- Some way of **capturing uncertainties** associated with demand, random outages of facilities, etc, which may be achieved using either a Monte Carlo technique around an LP model ("**LP-MC**") or stochastic optimisation integrated in an intertemporal LP/DP model, i.e, stochastic LP ("**SLP**") or stochastic DP ("**SDP**") models.

We offer the following comments on the relative merits and demerits of these four modelling choices (i.e., LP-D, LP-MC, SLP and SDP noted above):

- The choice of computational method depends on the nature of uncertainties that should be captured in estimating opportunity costs. If generation and transmission outages are part of these uncertainties, a Monte Carlo based technique as in a LP-MC is likely to be the preferred choice, because it:
  - Is a tried and tested method in the NEM;
  - Has the positive attributes of an LP based technique; and
  - Is less complex compared to the SDP/SLP techniques.
- The LP-D approach presents an option that relates directly to the market clearing process and also intuitively appealing. However, a manual iterative approach makes it inefficient, and an inter-temporal LP is superior to an LP-D approach.
- A pure SDP model with transmission constraints and multiple storage points is likely to be computationally too demanding. Similarly, the SLP approach is relatively unproven when it comes to dealing with large scale application involving random outages of system elements.
- However, we also recognise that each of these techniques has its merits that can be combined. Monte Carlo methods may be combined with SLP and similarly the ability of LP to solve large scale transmission-constrained problem may be combined with the SDP approach. Recent developments on algorithms and also commercial applications for the electricity system are certainly moving in this direction. As such, it is envisaged that models of opportunity cost will mix these ideas/techniques, rather than necessarily fall in one of these four categories.

INPUTS NEEDED FOR CALCULATING OPPORTUNITY COSTS

The calculation of opportunity costs is data-intensive. It may include, at minimum, participant-specific technical and cost related data for the relevant timeframe; at the limit it may require information for the entire NEM. We envisage that the opportunity cost of a generator would, in many instances, be linked with the bids/costs of other participants in the same or other regions – therefore the scope of the modelling would typically be wider than for a specific generating facility.

We also note that the data requirement may typically be more significant than required for a standard market simulation exercise such as the ANTS and SOO new entry studies conducted by NEMMCO.[4] This is because, in addition to standard market simulation inputs, there will be a greater need to model the constraints that have an impact on the opportunity costs of using the limited MWh that the relevant market participant may possess. While a high level representation of hydro, for instance, may be adequate for a typical market simulation, calculating the opportunity cost of energy-limited hydro will, in all likelihood, require a greater level of detail for each individual hydro scheme to fully demonstrate the value of an extra MWh of hydro energy extracted from the scheme. The modelling may need to encompass detailed constraints associated with upstream storage, flow constraints, efficiency curves and uncertainties associated with hydrological inflows, breakdown of gas pipelines etc, that all potentially determine opportunity cost.

Overall, the opportunity cost of limited energy will depend on:

1. The overall demand-supply balance, which will be determined by the availability of all generating units in the region as well as that of interconnectors. This, in short, covers all of the data that is needed for a dispatch model;

2. How tight the energy limit is which, among other things, will depend on the starting level of energy, e.g., the initial storage level;

3. Operational limits such as how fast the storage may be depleted, minimum storage limits, rate of inflows that replenishes storage, etc;

4. Operational limits of the generator that may prevent generation from being increased/decreased above/below certain limit – these may include ramping, time needed for start-up of the unit etc. Although these limits may typically not bind for hydro generators, these may in some cases be restrictive for other energy limited plants; and

5. Uncertain events that may affect the supply – for instance, the breakdown of a gas processing plant, or limited gas pipeline capacity, outage of pumping capacity (for a pump-storage hydro unit), etc for the limited energy resources. Uncertainties associated with demand, outages of other generators and transmission interconnections will also influence opportunity costs. For instance, if a region has several “lumpy” baseload units that are prone to outages, the opportunity cost of limited energy in such a region will typically be high because an outage of one big generating unit may have a major impact on the demand-supply balance so that the value of stored water/gas would typically be high. Coupled with factors (1)-(3) above, uncertainty may cause the opportunity cost to be both very high and volatile under extreme conditions.

4 NEMMCO, *Appendix A – Data and Assumptions for the 2008 ANTS Market Simulations*, February 2008.

1. INTRODUCTION

The purpose of this report is to provide a commentary on the key technical issues related to the specification of a model to estimate the opportunity cost of fuel/energy limited plants including:

- The application of opportunity costs in other markets;
- The specification of mathematical models used for the calculation of opportunity costs;
- The inputs needed for such calculations; and
- A commentary on related issues such as the time horizon over which opportunity costs are calculated.

The opportunity cost incurred by a limited energy plant relates to the potential value of such energy, for example stored water or a limited volume of gas, which the generator could derive from using it in another period (or more generally for any alternative usage). The concept is used more generally to include other expenses that a generator may incur – for instance, start-up costs, deferral of planned maintenance, sourcing fuel at a higher cost, etc. The broad context within which the concept of opportunity cost has been discussed relates to the compensation arrangement to the generators in the NEM during an administered price period (APP).

The generator compensation arrangements allow scheduled generators to seek compensation when their offer price for any cleared offer during an APP is higher than the administered price cap (APC). "Constrained-on" generators with offer prices higher than the APC are eligible for compensation if the resultant spot price payable to dispatched generating units in any trading interval is less than the price specified in their dispatch offer for that trading interval.[5] Services from these generators during an APP are essential to meet demand and also to ensure a reliable and secure operation of the system. Therefore, compensation in one form or another is needed to encourage participation during an APP which is typically a stressed system condition. Other market participants that can also claim compensation following an APC are Scheduled Network Service Providers, Market Participants, and ancillary service generating units and loads. Compensation is determined by the AEMC based on advice from an expert panel.

The AEMC is in the process of considering a Rule change proposal relating to these compensation provisions submitted by EnergyAustralia ("EA"). EA has argued that the current compensation provisions that use generator offers as the basis exposes retailers to a financial risk that cannot be hedged.[6] EA has therefore proposed a Rule change that would:

- Remove existing references to the difference between the capped spot price and a generator's offer price, and stipulate that the purpose of any compensation payable to a Schedule Generator is to recover *direct costs only*;

5 See National Electricity Rules, Clause 3.14.6.

6 EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

- Remove the reference to a generator's offer price in the compensation criteria; and
- Require the AEMC to publish the expert panel's report and the AEMC's proposed determination on compensation and consulting on these matters.

In short, EA expects the application of direct costs rather than offers/bids to reduce the likelihood of unreasonably high compensation arrangements during an APP. However, other market participants have noted that generators – especially limited energy plants – incur opportunity costs to provide energy during an APP.[7] Such opportunity costs can be significant if generation during an APP amounts to significant costs during/after an APP, or foregone profits in future. Therefore, compensation based on direct costs alone is unlikely to be a practicable form of compensation for limited energy plants.

That said, appropriate caution needs to be exercised to implement a compensation mechanism based on opportunity costs. An accompanying study conducted by Concept Economics has noted the following that summarises the key issues:[8]

- While compensation based on opportunity costs overcomes some of the theoretical limitations of the direct cost approach, there are formidable methodology, data and process issues that need to be addressed; and
- Compensation based on opportunity costs can also be high similar to offer-based payments. Particular attention needs to be paid to risks faced by purchasers of energy who may be subject to considerable high and volatile uncertain payments.

This report provides a more detailed commentary on these issues to assist AEMC in developing useful guidelines. For instance, a guideline on the timeframe for an opportunity cost assessment needs to be developed , since any stored water or limited gas could be used potentially in a number of alternative periods with very different price outcomes. Hence, opportunity costs could range from a very low value close to zero, in the event the stored water would simply go waste if not used at the time, to VoLL, if it could be used later on to avoid load shedding (or replace a high price bid), as well as anywhere in between these two extremes for a vast range of potential demand and system conditions. Similar issues arise in respect of other elements of an opportunity cost calculation, namely, start-up, fixed O&M and deferred maintenance.

To summarise, while there are many instances in which constrained-on generators incur opportunity costs that may be (significantly) in excess of direct costs, determining the magnitude of these costs in practice poses a number of conceptual and practical challenges.

The report is organised as follows:

- Section 2 reviews the key theoretical underpinnings discussed in the literature before discussing application of the general concept of opportunity costs in other markets; and
- Section 3 discusses alternative mathematical models that are used for the calculation of opportunity costs and also discusses input requirements for such calculations.

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7 Macquarie Generation, *Submission on Compensation Arrangement under Administered Pricing*, 20 February, 2008. also, Energy Retailers Association of Australia's submission dated 22 February, 2008, noted the need to extend EA's proposal to include opportunity costs for hydro generators.

8 Concept Economics, *Risk Assessment of Raising VoLL and the CPT*, Draft Report, July 2008.

2. APPLICATION OF OPPORTUNITY COSTS

The following section provides a brief outline of the opportunity cost concept and the types of opportunity costs that arise for different types of electricity generators. Opportunity cost formulations are used extensively in the electricity industry, both for planning purposes and in the context of energy-limited generation plant (such as hydro-electric generators). However, a brief survey of arrangements to compensate generators in various electricity wholesale markets shows that, with the exception of Western Australia, the formal application of opportunity cost concepts has tended to be limited to electricity industries in which hydro generation plays an important role.

2.1. GENERATOR OPPORTUNITY COST: KEY ISSUES

2.1.1. What is opportunity cost

The concept of opportunity cost is a fundamental one in economics and expresses the basic relationship between scarcity and choice. In a world where resources are scarce, choices must be made: the opportunity cost of a particular choice refers to the value of the next best alternative or opportunity.[9]

In the context of the electricity industry, the question what constitutes a particular generator's opportunity cost can generally only be answered with reference to the specific context in which the generator operates. For a thermal power station, the opportunity cost of beginning to generate power might include its start-up costs,[10] its direct fuel costs, and any additional maintenance or other costs that it might incur as a result of its generation decision. However, the question what constitutes the (opportunity) cost of fuel is often not straightforward. Thus the opportunity cost of a fuel such as gas may be higher than what the generator may have paid for it under a contract (i.e., the generator's "cost"), if the gas can be sold to a third party at a higher price (rather than burning it). On the other hand, the opportunity cost of a fuel such as coal may be lower than its contractual price, if a failure to take an agreed quantity leads to penalty charges or storage costs. The timeframe over which these costs are assessed is then clearly important – the longer the timeframe, the more alternatives would likely be available to a particular generator.

What constitutes opportunity costs is particularly complex in the context of an energy-limited plant. In these circumstances, opportunity costs typically arise because (in addition to direct production and other costs) there are intertemporal trade-offs between producing energy today versus at some point in the future. In other words, where the ability to store a fuel (such as water or gas) is limited, a generator must in effect undertake an intertemporal optimisation in order to determine the best generation and storage profile. The opportunity cost of generating electricity at a particular point in time then becomes the foregone revenue or profit that could be achieved if the fuel is instead stored for use at some future date.

While these calculations are complex, they are nonetheless well established:

9 Buchanan, James M., "opportunity cost", in The New Palgrave Dictionary of Economics, Eatwell, John, Murray Milgate, Peter Newman, Eds., Macmillan Press. 1987. Pp.718ff.

10 If the power station was already generating, start-up costs would not be included in the opportunity cost calculation.

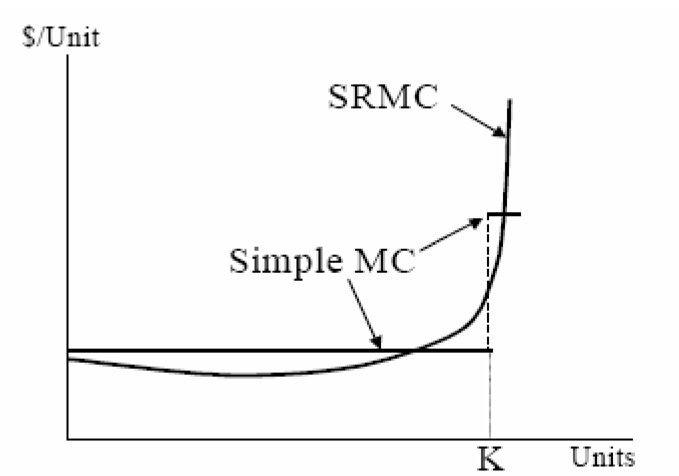
- In a regulated or centrally planned environment, estimates of opportunity costs for limited energy plants have been used for power system planning, reservoir scheduling and fuel scheduling; while
- In a market environment, opportunity cost concepts also continue to be used - hydro generators use water values for creating their bids, and pricing for reserve and other ancillary services (such as reactive power) explicitly recognise the opportunity costs incurred in providing these services.

2.1.2. Short run marginal cost should include opportunity cost

The short run marginal cost (SRMC) of generation, properly defined, includes all opportunity costs, including those that refer to foregone production opportunities. As Larry Ruff puts it: "*SRMC is the incremental cost of fuel and raw materials, maintenance and wear-and-tear on equipment, including any opportunity costs if producing more for this market now increases the costs of producing for some other or later market*."[11]

Ruff also emphasises that the distinction between direct operating costs which he refers to as "simple marginal cost or simple MC" as opposed to the "proper" SRMC that would include the opportunity cost component can be significant as the production approaches the (capacity/energy) limit. Figure 1, reproduced from Ruff (2002), shows that direct operating costs are typically invariant with respect to production levels, whereas SRMC (inclusive of opportunity costs) can be below such direct costs due to technological characteristics (e.g., a heat rate curve for thermal generators or hydro efficiency curve) and significantly above direct costs as the capacity limit (K) is approached.

Figure 1 SRMC versus Direct Operating Cost ("simple MC")



Source: Ruff (2002), p.5.

[11] Larry Ruff, *Market Power Mitigation: Principles and Practice*, Charles River Associates, 2002., p.4.

2.1.3. Implications of opportunity cost

The potential magnitude of the opportunity cost component is a significant issue, because it implies that the proper SRMC for generators with a binding energy limit can be well above direct operating costs. For example, the proper SRMC of a hydro MWh during peak periods may mirror the cost of units running on liquid fuel that may be in range of several hundred dollars per MWh. Hydro generators can effectively have opportunity costs in the order of several hundred dollars per MWh, if not thousands of dollars per MWh, reflecting:

- The value of power generation or demand side resources that it would replace at a future point in time; and
- The expected value of avoided load shed events.

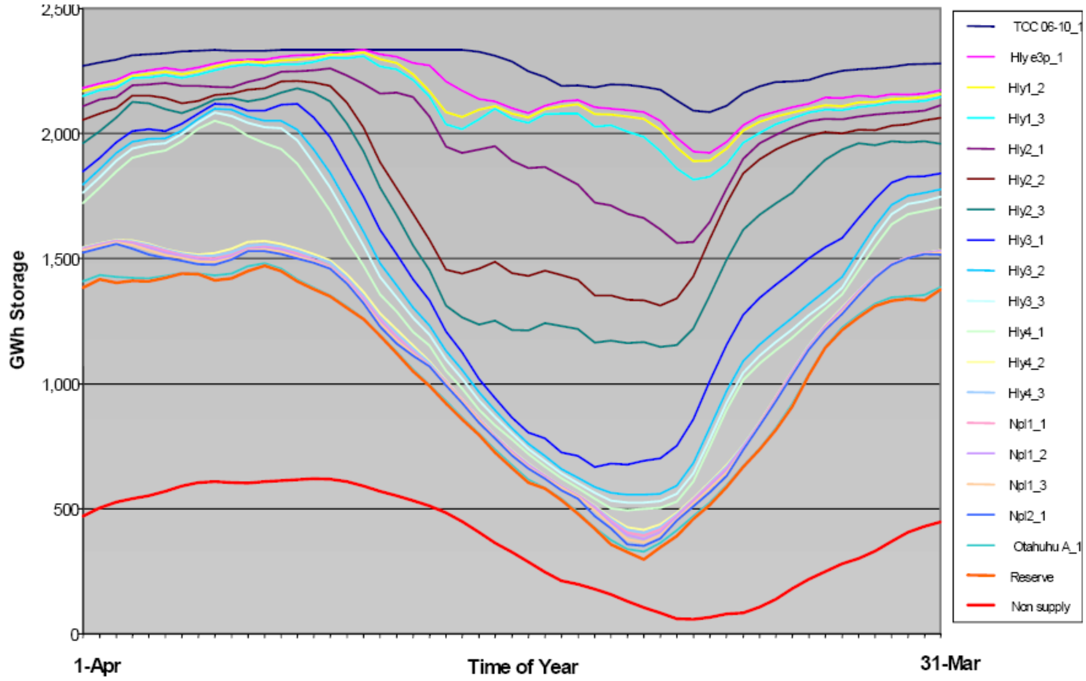
More generally, as we have noted in our previous report on risk assessment, the opportunity cost and hence SRMC of hydro can vary over the complete range from zero to VoLL. In particular, it may be equal to: [12]

- Zero or near zero in the event that the additional hydro energy would simply go to waste (spilled) if it is not used in the current time period;
- The marginal cost of coal/gas, say between $5/MWh to $40/MWh, if it is replacing a baseload coal or gas generated MWh;
- The marginal cost of a peaking plant running on gas around $55/MWh to $70/MWh;
- The marginal cost of a peaking plant running on oil around $270/MWh to $355/MWh;
- The marginal cost of any available demand side alternative in the range of a few hundred dollars per MWh up to $3000/MWh;
- The highest offer price of generation displaced by the dispatch of the hydro MWh; and
- The marginal cost of unserved energy or VoLL.

Figure 1 below shows an illustrative example of hydro opportunity costs for the New Zealand hydro system. These opportunity costs or “water values” are calculated in the context of the energy modelling undertaken on behalf of the Ministry of Economic Development. For a given level of storage and a given time of year the nearest contour(s) is an estimate of the opportunity cost of dispatching hydro. For instance, at relatively high storage level, the water value reflects the cost of a relatively inexpensive thermal resource such as TCC or Huntly (HLY) generators. As the storage level goes down, i.e., there is less hydro energy available for generation, the opportunity cost reflects progressively more expensive sources of generation such as New Plymouth (NP), Otahuhu and any standby generation (“reserve generator”). If the storage level is very low, using up energy creates a significant risk of unserved energy (or non-supply) in future and therefore the bottom redline is associated the cost of unserved energy.

[12] Concept Economics, *ibid.*

Figure 2: Waitaki Water value example

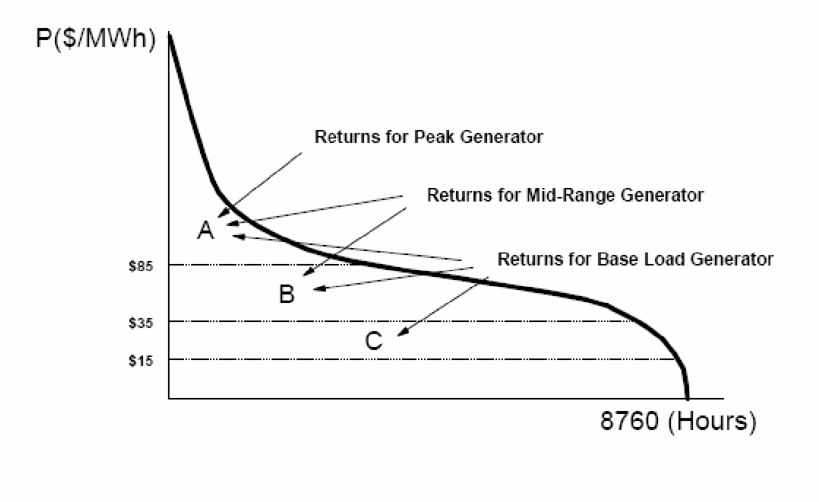


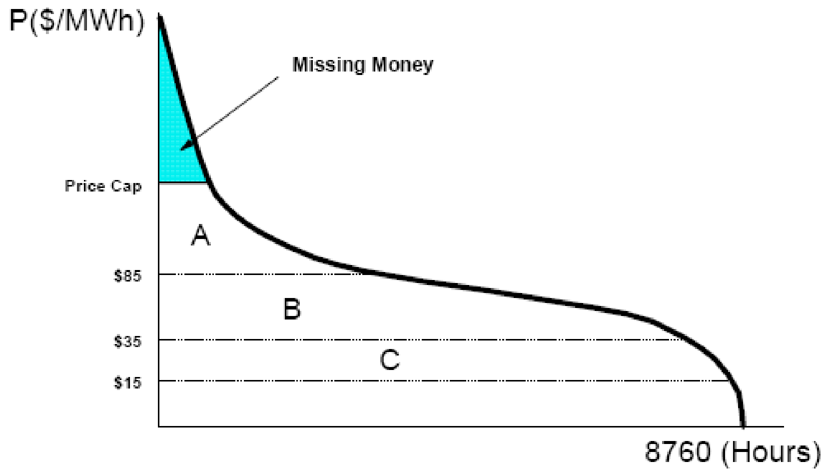
Source: Tim Denne, John Small (Covec), Adolf Stroombergen (Infometrics), “Presentation to Workshop: Future Directions for MED's Energy Modelling Efforts”, June 8 2005.

If hydro generation is being used during the APP, compensation using opportunity cost may therefore be anywhere in this range, although it is more likely to be at the higher end of costs for a dry year.

At the same time, the proper definition and measurement of SRMC goes to the heart of the price cap and related compensation issues. As William Hogan has discussed, the application of a price cap may restrict the ability of *all* generators to earn an adequate return. Figure 3 reproduced from Hogan (2005) illustrates the concepts. Hogan has termed this as the “missing money” and emphasised the need for appropriate compensation mechanisms in energy only markets for resource adequacy. Since opportunity cost can be significant, the missing money becomes a critical issue (although its importance depends on how frequently an APC event occurs).

Figure 3 Application of Price Cap and "Missing Money"





Source: W. Hogan, *On an Energy Only Market Design for Resource Adequacy*, Harvard University, September, 2005.

2.2. ELECTRICITY MARKET SPECIFIC APPLICATIONS

The following provides an overview of opportunity cost concepts as they are applied to constrained-on generators in various electricity wholesale markets internationally, and in the West Australian electricity market. We note that these applications of opportunity costs go beyond limited energy plants and application during administered price periods. They relate as much to other form of constraints such as transmission and reliability and for thermal generators. The general concepts and implementation issues are however common across these applications and together these applications provide a good understanding of the breadth of issues involved in application of opportunity costs.

However, we note that the scope of this discussion is limited to provide a broad exposure to the issues. We do not discuss the merits and demerits of various schemes. In general, all compensation schemes in real life inevitably require some degree of compromise for a range of reasons including limitations on data, computational requirements and a need to keep the scheme simple and transparent. As a consequence, compensation schemes in most markets have evolved over time as some of the limitations became apparent. Our discussion does not purport to provide a detailed commentary on these issues.

Compensation schemes are designed to deal with one or more of the following circumstances:

1. When market prices are replaced by some form of administered prices such as the situation in Ontario, the Australian NEM; and/or

2. When generators are forced to run above, or below, their desirable level of production such as a transmission/reliability constrained on/off payment in some markets such as Alberta and the US markets; and/or

3. When there is a significant fixed cost component such as start-up costs as is typical of most thermal systems including the Western Australia.

While electricity markets with a significant hydro generation component – Ontario and Alberta – apply a form of opportunity cost calculation to determine compensation to energy-limited generators, in the various United States power markets generators are compensated only for direct costs (including sometimes a payment for sunk costs), but not opportunity costs. In Western Australia, however, where generators are required to submit SRMC-based bids in the short term balancing market, the opportunity cost component of such bids has been formally recognised.

2.2.1. Ontario

The Ontario electricity market uses a compensation mechanism for periods of market suspension when generators have been issued dispatch instructions by the system operator (IESO) and administered prices apply. According to the IESO Guidelines, the market participant should be held whole for its operating costs, including:[13]

- Fuel costs or, if the generation facilities in question are energy limited, the expected future value or opportunity costs in lieu of fuel costs;

- Variable operating costs; and

- Maintenance costs.

Further, market rules allows additional compensation equal to 10 per cent of the above costs, except where, in the system operator’s opinion, the expected future value or opportunity cost adequately covers such an amount.

Specifically where energy limited generation facilities are concerned, how opportunity costs for constrained-on generators are determined depends on whether the additional energy is likely to have been used at some future date, or whether this is energy, which would have been used at a different time within the same day:

[13] Independent Electricity System Operator, *Guidelines for Additional Compensation During Administrative Pricing*, Version 3, Ontario, 2005. In addition to the constrained-on payments described above, the IESO also makes constrained-off payments, referred to as Congestion Management Settlement Credit (CMSC).

- If the opportunity cost of the energy used relates to its use at some future date, only the portion of generation that exceeds normal total daily generation levels is paid its opportunity cost, based on the value of generation at some point in the future. That value is related to the storage horizon for the energy limited fuel or water and expected, or actual, prices over that period.
- Alternatively, if it is the case that energy resources have been shifted from one hour to another within a 24 hour period, the opportunity cost is calculated as the difference between administrative pricing at the time of generation and the later hour when it might otherwise have been used.

More specifically, the guidelines establish the following methodology to establish compensation for hydroelectric facilities by:

1. Establishing the energy that would have been run on a daily basis through “normal” periods, referred to as “baseline” energy (with reference to actual inflows and representative days);
2. Using the actual MWh delivered to determine that portion of the energy output above the baseline that is eligible for opportunity cost payments; and
3. Finally, calculating payments for the energy supplied above the baseline assuming either the average energy price that day, or the average price paid that day for energy from the facility. In addition, if it is determined that water has been moved from a higher priced hour in order to generate in an hour where a lower administrative price has been applied, there may be compensation due for this difference.

Run-of-river hydro facilities are normally not compensated since they in most cases would have a zero opportunity cost. However, these generators may also be eligible for compensation if it can be established that energy was withdrawn from upstream storage reservoirs to supplement run-of-river stations.

2.2.2. Alberta

The Alberta Electric System Operator (AESO) makes out-of-market payments to generators who are required to provide “unforeseeable” transmission must run (TMR) service, that is, constrained-on generators. Thermal generators are paid a variable and a fixed cost component, while hydro generators can alternatively claim opportunity costs.[14]

For thermal generators, compensation payments have two components:

- Variable costs: the difference between the generator’s energy price and the pool price. The generator’s energy price is the heat rate multiplied with either the (published) natural gas spot market price or the generator’s coal cost. Variable costs additionally include all variable charges from the AESO Tariff and a variable O&M charge (fixed at $4/MWh) for the cost of providing incremental output.

[14] Alberta Electric System Operator, AESO 2006 Tariff, Effective February 13, 2008. “Foreseen” TMR services are contracted by the AESO.

- Fixed Costs: average monthly fixed cost (one-twelfth of the sum of annual costs), which include:[15]
  - Annual amortisation and depreciation amounts for the investment or acquisition;
  - The product of the unamortised or undepreciated capital investment multiplied by a deemed debt percentage of 70 per cent and multiplied by a debt interest rate equal to the current 10-year Government of Canada Bond interest rate plus 0.5 per cent;[16]
  - The undepreciated capital investment multiplied by a deemed 30 per cent common equity percentage of capital structure multiplied by a deemed 12 per cent rate of return on equity, including taxes;
  - Total annual direct fixed operation and maintenance costs;
  - Total annual direct fixed fuel costs; and
  - Any fixed charges from the applicable PPAs.

  Monthly fixed costs are multiplied with either the Must Run Ratio (MRR) – the proportion of hours in the month when unforeseeable TMR services were provided – or with the Minimum MRR. Minimum MRR is 12 per cent for the first or second unforeseeable TMR service event, 20 per cent for the third unforeseeable TMR service event, 30 per cent for the fourth, 40 per cent for the fifth, 50 per cent for the sixth or any additional unforeseeable TMR event.

Rather than receiving the variable and fixed costs described above, a hydro-electric generator is paid net opportunity costs if the generator can demonstrate foregone future energy sales due as a result of a TMR directive.[17] Unlike thermal units, hydro generator can save stored water for future generation opportunities. If the hydro unit is directed to provide TMR service, thereby using the hydro storage, the generator may be foregoing future generation opportunities. For instance, if a hydro unit was directed to provide TMR service when the pool price was $30/MWh and provision of the TMR service caused a verifiable lost opportunity to generate in another period when pool price was $50, the verifiable net opportunity cost would be $20/MWh.

2.2.3. Key United States power markets

Where power markets in the United States are concerned, the Federal Energy Regulatory Commission (FERC) has developed some general guidance on compensation for constrained-on generators, also referred to as “reliability must run” (RMR) generators. In

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[15] At least over a short timeframe, depreciation/amortization and financing costs would not generally be considered to be opportunity costs.

[16] If a generator provides verifiable actual values for debt and equity costs, those will be used instead of the deemed values.

[17] Alberta Electric System Operator, Article 11 Negotiated Settlement (1549401), AESO Responses to Information Requests, January 21, 2008.

practice, all power markets under FERC's jurisdictions have developed short-term payment formulae to compensate constrained-on (RMR) generators:[18]

- Pennsylvania – New Jersey – Maryland (PJM). PJM designates generators as "RMR resources" if they are needed to ensure system reliability. All such units are cost capped and must submit at least one cost-based schedule to PJM. Cost-based schedules are derived one of three ways:
  - Marginal cost plus 10 per cent;
  - Based on a historical value of locational marginal prices (LMPs) at the unit's location; or
  - Determined through negotiation with PJM's Market Monitoring Unit.
- New England Power Pool (NEPOOL). RMR generators can elect to be compensated either under a "Mitigation Agreement" or a "Cost-of-Service Agreement". If a generator elects to enter into a Cost-of-Service Agreement, it must file regulated charges for cost-based-rate recovery with FERC, and is compensated on that basis. RMR generators entering into a Mitigation Agreement are entitled to payment being the highest of:[19]
  - The LMP in that hour;
  - The generator's supply offer; or
  - The generator's stipulated (filed) bid cost.
- California ISO (CAISO). The CAISO also has two types of RMR agreements with constrained-on generators. Units operating under a Condition 1 Agreement may participate in market transactions, while units under a Condition 2 Agreement essentially recover their costs on regulated terms. Condition 1 units are paid (on a monthly basis):
  - A monthly option payment, linked to the generator's availability;
  - A variable cost payment;
  - A general start-up charge, and start-up adjustments for each start-up;
  - Dispatch payments;
  - Once a maximum has been reached, a payment for each subsequent billable MWh;
  - Once a maximum has been reached, a payment for each additional start-up; and
  - Charges for services delivered from substitute units.

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18 The literature we have reviewed suggests that no payments are made to constrained-off generators. Alberta Electric System Operator, Article 24 Amendment Application (1357161), January 28, 2005 Information Requests, Tuesday, November 22, 2005.

19 NEPOOL has additional compensation arrangements for RMR units with very low capacity factors, referred to as Peaking Unit Safe Harbor ("PUSH") Units. PUSH units can submit energy offers up to their marginal energy costs plus their levelised fixed costs, without the imposition of mitigation measures.

- New York ISO ("NYISO"). NYISO's Market Monitoring and Performance department has developed a data template to collect cost information from market participants to support the calculation of reference prices for each RMR unit. Required data includes fuel costs, variable production cost, variable operation and maintenance expenses, fixed costs, start-up costs, house service costs, other costs, risk premiums, emergency output costs, opportunity costs, environmental costs, regulatory and other ISO imposed costs, and additional in-day costs. Participants may also appeal for recovery of additional costs. A reference level for each component of a generator's bid is calculated on the basis of the following methods, in the order of preference:
  - Accepted bids;
  - The lower of the mean or the median of a unit's accepted bids or bid components in competitive periods over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices;
  - LMPs;
  - The mean of the LMP at the unit's location during the lowest-priced 25 per cent of the hours that the unit was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices;
  - Consultation with the generator; or
  - A level determined in consultation with the generator submitting the bid or bids at issue and intended to reflect a unit's marginal costs.
- Midwest ISO ("MISO"). RMR units are compensated for the cost of start-ups, operation, and any changes to planned maintenance schedules under a separate agreement with MISO. If MISO designates a generator as an RMR resource, the generator is expected to enter into good faith negotiations with MISO. If the Parties are unable to agree to the terms and conditions of such an agreement within sixty days, MISO may ask FERC to authorise an RMR agreement.

2.2.4. New Zealand

The New Zealand electricity market rules provide for constrained-on and –off payments to generators, but these payments essentially reflect current spot prices.[20] Specifically:[21]

- Constrained-off amounts are calculated as the product of the constrained-off quantity in MWh and the difference between the final price at the relevant grid injection point and the generator offer price; and
- Constrained-on amounts are calculated as the product of the constrained-on quantity and the difference between the final price at the relevant grid injection point and the generator offer price.

[20] Constrained on amounts are compensation payments made to a generator when that generator has metered energy above the level cleared in the final pricing process, for instance as a result of being ramp rate constrained. Constrained off amounts are payments made to frequency control providers when that generator has metered energy below the level cleared in final pricing.

[21] Slightly modified regulations apply in respect of generators required for frequency control services. Part G, Section V, 4.3, 5.3.

It is interesting to note the Ministry of Economic Development's Energy Modelling Team's discussion of the Ministry's energy models and energy modelling capabilities, which implicitly recognises the intertemporal optimisation that energy-limited generators perform. As part of this process, the Ministry adopted various recommendations regarding future directions for the Ministry's model development efforts, including for modelling the opportunity cost of hydro resources.[22] Specifically, it was found that modelling the dispatch of hydro-electric generators required an understanding of optimal hydro dispatch: that dispatch profile which results in the same value in each time period. In other words, where a hydro resource can obtain a higher price in some other time period, profit maximisation implies that the corresponding water should be stored for future periods to obtain that higher price. Conversely, if the price is expected to be lower in some future time period, the generator is better off by dispatching the hydro resource today.

2.2.5. Western Australia

The West Australian electricity wholesale market requires generators to submit bids that reflect their SRMC in the short term day ahead balancing market (Short Term Electricity Market or STEM). The STEM rules allowed the generators to bid their balancing capacity around their contractual capacity at a "reasonable expectation of the short run marginal cost". There has been considerable debate on what should or should not comprise such short run marginal cost.[23] Given that different (economic) concepts associated with SRMC are generally not well understood by market participants, the Economic Regulation Authority (ERA) has recently published a paper that highlights the importance of accurately reflecting opportunity costs in generator bids.[24]

In particular, the paper highlights that for thermal generators, the fuel costs that are relevant for calculating SRMC are not necessarily those costs that a generator may have incurred historically (or is incurring under contract). If the generator has the opportunity to sell the fuel at a higher price, then that higher price becomes part of the SRMC calculation (since it is that higher price that the generator is, in effect, giving up in order to generate electricity). Conversely, if the fuel cannot be sold, then the opportunity cost of that fuel may be zero. In either case, the current spot or market price for fuel contracts (adjusted, where relevant for storage costs and interest) is likely to provide the best basis for the opportunity cost of fuel.

More generally, although their calculation can be complex, opportunity costs can include various types of avoidable costs (expenditures to which the generator is not irrevocably committed), namely:

- Avoidable fixed costs, i.e. costs that can be avoided by producing zero output, such as start-up costs if the generator is not operating;

22 Tim Denne, John Small (Covec), Adolf Stroombergen (Infometrics), "Presentation to Workshop: Future Directions for MED's Energy Modelling Efforts", June 8 2005. http://www.med.govt.nz/templates/Page____10547.aspx#P284_10214.

23 See for example, Verve Energy, *Commentary on Proposed Rule Change*, November, 2006, Submitted to the Office of Energy, Western Australia.

24 Economic Regulation Authority, "Portfolio Short Run Marginal Cost of Electricity Supply in Half Hour Trading Intervals", Technical Paper, 11 January 2008.

- Shutdown costs, which a generator that is already operating would incur if its output fell below its minimum technical output (mingen), and which corresponds to the maximum amount a generator would be willing to pay to avoid the shutdown;[25] and
- Variable costs that vary with the level of output, such as fuel costs, operating costs, and costs associated with wear and tear on plant and equipment, and which may vary directly in proportion with output, increase (in some form) with output, or decrease with output.

[25] The opportunity costs of forcing such a plant below mingen will include not only the immediate costs associated with taking the plant offline but also the cost of starting the plant up again when it is required. If the time it takes to bring such a plant back online is long, there will be an additional opportunity cost associated with lost revenue in future trading intervals. In other words, while it may be cheaper – within a given trading interval to shut a plant down than to run it – this may not be the best decision over the trading day.

3. METHODOLOGY AND INPUT ISSUES

The preceding sections allude to some of the key complexities associated with determining opportunity costs. Unlike direct operating costs, opportunity costs will vary significantly with production levels and as such can be extremely volatile in an electricity market under stressed conditions. Administered price periods by definition are likely to be stressed conditions. But as practical applications of opportunity costs highlight, a properly articulated methodology can be devised to render reasonable and transparent outcomes. The key to developing an appropriate methodology is to develop a clear definition of the scope of the opportunity cost calculation and a calculation procedure that best fits this definition. This section discusses methodology as well as input related issues, namely, the methodology, process and data issues that are useful inputs to develop necessary guidelines in this regard.

3.1. SCOPE OF THE OPPORTUNITY COST CALCULATION

First and foremost, the attributes of opportunity cost that are most important need to be identified as part of the guidelines. In theory, opportunity costs may have many potential components some of which may even go beyond the NEM and/or may not be easily quantifiable. It is therefore important to define in clear terms the following factors.

3.1.1. Timeframe

This relates to the relevant time horizon over which the stored water/gas could be used. The timeframe may vary across plants depending on the nature of available storage, operational constraints and policies in place, and other factors. Stored energy may potentially be used over an extended period depending upon the storage capacity, flow constraints and contractual procedures in place. Due consideration should be given to these physical and commercial issues so that a market participant is able to recover all reasonable costs.

However, the timeframe also needs to be set keeping in mind practical aspects. For instance, the demand-supply balance over an extended period (say several months) would be subject to considerable uncertainty and may lead to a substantial overestimate in extreme cases. Opportunity cost estimates based on different demand-supply forecasts may therefore yield significantly different estimates. A narrow focus on the other hand – for instance restricting the usage of stored energy to the same day or next day – may underestimate the value of energy. In practice, the precise timeframe is likely to be case-specific and flexibility will need to be accommodated in the guidelines. The Ontario guidelines for instance allow for a three month period following the market suspension event that the generation will “self repair”, i.e., recover the additional water discharged during the event.

3.1.2. Type of costs included

Opportunity costs ultimately reflect some form of direct costs that are incurred, or benefits that are foregone, and may include fuel costs as well as non-fuel operation and maintenance costs. There may also be consequential costs associated with start-ups, or if additional fuel needs to be sourced at a higher cost to run a generator during an APP.

Costs may broadly be categorised in two ways, namely (a) fixed and variable costs; and (b) costs that are linked with direct operating costs (e.g., hydro MWh replacing a peaking oil-based MWh) and consequential expenses (e.g., deferral of maintenance, penalty for not honouring a gas contract, etc). For instance, the compensation arrangement in Ontario allows for the following components of costs:[26]

- Fuel Costs, being the actual delivered cost of fuel for:
  - Production;
  - Start-up (including cold start-up cost, if applicable); and
  - No-load costs.
- Maintenance Costs:
  - The incremental maintenance costs associated with the operation during this period for start-up or as a result of ongoing production.
- Operating Costs:
  - The incremental costs associated with the plant operation during this period for start-up or production;
  - Costs not otherwise covered by fuel or maintenance costs, e.g. labour costs and costs for other plant processes to support operation, such as: fuel handling, plant chemistry, flue gas desulphurization, waste disposal etc.
- Other Variable Costs:
  - Other variable costs not captured above. For example for a constrained-on dispatchable load, energy or other operating costs needed to support the additional consumption.

There are methodological and procedural difficulties associated with some of these cost components. Fixed costs raises difficult methodological issues that we discuss later, and establishing the causality of the consequential costs may not necessarily be straightforward. In the NEM compensation claims have to date been a moot subject and therefore the guidelines need to be clear on supporting documentation (such as receipts, past fuel bills, statements to support the causality, access to information, ability to audit accounts, etc).

3.1.3. Uncertainties

A significant part of the opportunity cost of limited energy arises from its value under stressed system conditions, which in turn arise from uncertain events. These events include fluctuation in level of demand, inflows, outages, etc, which are inherently unpredictable. To the extent that these drivers are common across a significant number of participants, the guidelines need to define the uncertainties that should be captured in estimating the opportunity costs.

[26] A number of the United States markets reviewed here also allow for similar cost components.

3.1.4. Scope beyond the NEM

Finally, a related issue is that the scope of opportunity cost calculation may potentially go beyond the NEM. This might be the case to the extent the opportunity cost of stored energy depends on upstream constraints (e.g., storage limit, gas pipeline capacity etc) or if such stored energy could be used for non-electricity purposes. The guidelines need to be clear on whether market participants are entitled to claim such costs.

3.2. ALGORITHMS FOR OPPORTUNITY COST CALCULATION

The calculation of opportunity costs involves, in one form or another, a simulation of the alternative usage of the limited energy to assess the value that could be extracted from these MWh by using them in an alternative period and/or location and/or form. The most commonly used opportunity cost is for storage hydro that involves calculating water value to associate different $/MWh for each stored MWh for different time period of the day/week/month/year under different scenarios (e.g., demand and inflow). The term “shadow price” is often used to describe the value of limited energy in a more general sense that measures the value (e.g., decrease in system cost or increase in participant’s profit) if an additional MWh of limited energy becomes available.

Typically, some form of optimisation is carried out that computes the shadow price for limited energy sources. Although the opportunity cost may apply for an individual station, the calculation process may encompass other stations, if not the entire market. This is because the value of such energy is intricately linked with alternative ways of meeting demand (say from using expensive peaking generation instead of stored water) and market prices that are determined by bids/offers from other generators among other things. As a result, the scope of the optimisation may be market-wide and algorithms suited for such large scale optimisation is needed.

3.2.1. Optimisation techniques

Broadly speaking, there are two classes of mathematical techniques that can deal with market optimisation:

- Linear programming (LP); and
- Dynamic programming (DP).

Both of these methods have been used for similar applications in the electricity industry, e.g., for calculation of water value or shadow price of stored gas, etc. The basic optimisation framework involves minimising system costs (or sum of market participant offers) subject to a range of constraints on the operation of the generation and transmission system, including the limited energy that is available from some of the generation sources. There are four alternative methodologies built around these two techniques that may be employed for the calculation of opportunity costs.

1. Static LP dispatch (**LP-Dispatch or LP-D**) models with a trial and error method to calculate the opportunity costs for a set of deterministic scenarios of future outcomes (demand profile, inflow sequences, outages, etc). The method involves:

a. Using an initial shadow price (in the form of a generator bid) to develop an initial dispatch;

b. Checking if the total dispatch across all time periods is above or below the energy limit;

c. Adjusting the shadow price (i.e., increasing the price if the energy limit has been exceeded or decreasing it if there is unused energy), and repeating step (b) above until the dispatch and shadow prices are consistent with the energy limit. It is possible that the shadow price or opportunity cost, is zero in which case there may be unused energy left in the system.

In principle, the pre-dispatch model used in the NEM (NEMDE-pre-dispatch) could be used for such application. While NEMDE does not use an intertemporal optimisation, bids for hydro units could be altered to keep the total dispatch within the limited energy. More generally, any dispatch simulation model could be used for such application.[27]

2. Inter-temporal LP models with a Monte Carlo simulation engine (**LP-Monte Carlo or LP-MC**) to create randomised sets of future outcomes and generate a probability distribution of opportunity costs. More specifically, the LP-MC approach involves:

a. Developing a randomised "sample" or future scenario that includes picking from a random distribution of demand, outages etc, one of the numerous possible random scenarios;

b. Performing an optimisation for *all* time periods taking into account, among other things, the limits on energy for limited energy stations. The solution will provide the optimal dispatch of resources for the scenario and also the shadow price of limited energy resources. In other words, the inter-temporal optimisation does not require a (manual) iterative procedure to compute the shadow price.[28]

c. Repeating steps (a) and (b) for a select set of samples (e.g., 500) and calculating the average outcome across the samples.[29] Apart from the average outcome, the distribution of outcomes (such as dispatch, shadow price, etc) also yields useful information on opportunity costs.

The Concept Electricity Model (CEM) used for the analysis of VoLL/CPT is an illustration of LP-MC approach. [30]

3. Stochastic LP (**SLP**) models to undertake an integrated optimisation of decisions under uncertainty. For example, the first stage of a two-stage stochastic LP decides on "here

[27] For instance, the PROPHET model of Intelligent Energy Systems (IES) has recently been used for drought studies by the NEMMCO that involves a similar iterative adjustment of hydro generator bids to observe limited hydro energy availability.

[28] The duality theory of LP ensures that the shadow price (also known as dual) of a constraint is economically consistent with the available resource.

[29] The number of samples depends on the level of accuracy and also the number of uncertain parameters – higher number of samples will enable coverage of low probability events. Typically, NEM simulation studies use between 100 and 1000 samples.

[30] Concept Economics, *Risk Assessment of Raising VoLL and the CPT*, Draft Report, July 2008. Figures 12-13 on p.71-72 include distribution of water values for major storage points in the NEM for average and low energy availability scenarios. LP-MC capability is also available in some of the commercially available software such as PLEXOS (Energy Exemplar, http://www.energyexemplar.com) and PROSYM (Ventryx, http://www1.ventryx.com).

and now" water release and dispatch for the current week, while the second stage makes "wait and see" decisions on future release under uncertain demand, inflow, etc. The process may be viewed as an integrated solution of all potential samples in an LP-MC approach as part of a single LP. That said, there is a subtle difference in how a SLP approaches the problem. Unlike an LP-MC that effectively assumes all actions to be recourse actions that are made after a random event has occurred (e.g., outages), the SLP approach makes a distinction between "here and now" decisions that must be made before the resolution of such uncertainty, followed by recourse decisions. The solution of an SLP is in principle no different from that of a dispatch LP – in fact, an SLP can be formulated as a single LP constituting all scenarios and solved as one large LP. However, for a problem involving many generators and time periods, the size of the LP may be prohibitively large. Specialised SLP procedures attempt to decompose the large LP into smaller more manageable sub-problems and solve them sequentially.[31] Although there has been considerable progress in such solution procedures, formulating and solving an SLP using a specialised techniques is a challenging problem. Given their computational complexity, large scale real-life application of SLP is relatively limited although this continues to be an active area of research and commercial applications may become available in the near future.[32]

4. Stochastic dynamic programming (**SDP**) models that also performs a similar integrated optimisation. There is a fundamental difference between a dynamic programming (DP) technique and the LP technique. The former breaks the problem into individual stages (e.g., time period) and works backward (from the last period) to develop a sequence of optimal operating policy that best meets the limited energy problem. While both techniques ensure optimality, there are some pros and cons of each. In short, LP is more amenable to a standard format and much more widely used. DP, on the other hand, may be particularly efficient for certain type of problems but in general suffers from the problem of dimensionality if the number of stages and decisions are high. DP is not well suited, for instance, for most transmission constrained problems because the number of stages can be very high for such problems.

   SDP and a variant of the methodology called Stochastic *Dual* Dynamic Programming (SDDP) have been used extensively in hydro system planning reservoir scheduling. They have also been combined with LP based methods to form comprehensive modelling suites used for hydro dominated systems. Dr Mario Pereira has led the development of a suite of models OPERA that has been used in most hydro systems around the world although there are other customised SPD/SDDP models that are used for some systems.[33]

3.2.2. Criteria for the choice of optimisation technique

The choice of methodology depends on the relative merit of a methodology to deal with the specific issues, for instance:

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31 G. Infanger, *Planning under Uncertainty: Solving Large-Scale Stochastic Linear Programs*, Boyd and Fraser.

32 Professor John Birge of Northwestern University among others have undertaken hydro planning and investment studies using SLP method. See for instance, C. Supatgiat, *Application of Stochastic Programming in the Energy Industry*, INFORMS Conference, 2001.

33 M. Pereira, *Studio Opera Software*, Available online: http://www.psr-inc.com.br/sopera.asp.

- Robustness, accuracy and reliability: These criteria are interrelated and together they form the most important criteria for selection:
  - LP based methodologies have generally proven attractive because the methodology with a few exceptions is robust – opportunity costs calculated using a set of inputs can be reproduced reliably and the methodology holds for a wide range of variation in inputs. An LP in most practical cases has a unique optimal solution that a good LP solver calculates accurately. Shadow prices calculated by an LP solver are economically consistent with the dispatch solution.
  - A pure dispatch LP model based on trial and error method may however be cumbersome and less reliable compared to the other alternatives. Although access to a dispatch LP model and the fact that the market clearing engine uses such a model are pluses, an iterative procedure may yield a sub-optimal value of opportunity cost and the outcomes may not be reliably reproduced. Both LP-MC and SLP approaches have an edge over the LP-D option in this regard.
  - The modelling requirements will drive the choice among these alternatives. If random outages of generators (and transmission lines) are to be incorporated, SLP and SDP options may also run into difficulty to deliver reliable and accurate outcomes given the vast number of outage combinations that the integrated optimisation needs to deal with. As we have noted before SLP has not been as widely used for large scale practical applications as LP and Monte Carlo techniques. SDP applications for hydro have typically been restricted to single node transmission representation and one or two storage points.[34]
  - On the other hand, the LP-MC option is theoretically less robust because the characterisation of uncertainty is less sophisticated, compared to SLP/SDP, but is flexible to deal with a wide range of uncertainties.
- Computational time:
  - Monte Carlo models are computationally very intensive. The LP-MC option therefore can take several hours solution time to analyse a single week's event. SLP, SDP (and SDDP) models are also computationally intensive but a direct comparison with Monte Carlo models is not available in the literature partly because pure SLP/SDP models are not suited for the type of uncertainties represented in Monte Carlo models.[35]
  - Also, if fixed costs are incorporated in the optimisation, these require a mixed integer programming algorithm that is substantially more complex and computationally intensive compared to an LP algorithm.
  - As noted before, SPD models are also susceptible to a “dimensionality” problem and if there are multiple storage points, regions etc, they may not be suited for the application;

34 See for example, A. L. Kerr, E. G. Read, and R. J. Kaye, Revenue maximising reservoir management with risk attitudes. Spring 1999 INFORMS Conference, Cincinnati, Ohio, May 1999.

35 Some of the recent stochastic programming models allow embedding Monte Carlo sampling as part of the SLP. But these models will also have similar computational performance as the LP-MC method.

- Scope of optimisation: Finally, all of these models with the exception of a pure dispatch model may in theory be extended to model upstream fuel or hydro system or for that matter have a simplified representation of alternative usage of stored energy. For instance,
  - A high level representation of the major hydro systems such as Snowy or Hydro Tasmania could be integrated in the inter-temporal optimisation or SLP/SDP models;
  - Alternative usage of hydro for irrigation or sale of gas for alternative use could be represented as alternative revenue streams for hydro/gas.

3.3. INPUT ISSUES

The calculation of opportunity costs is data-intensive. It may include at minimum participant-specific technical and cost related data for the relevant timeframe; at the limit it may require information for the entire NEM. As we have discussed earlier, the scope of modelling depends on the interlinkage between an individual participant's dispatch and that for other market participants. In most cases, we would expect the interlinkage to be significant.

The data requirement may typically be more significant than a standard market simulation exercise such as the ANTS and SOO new entry studies conducted by NEMMCO.[36] This is because, in addition, to standard market simulation inputs, there will be a greater need for a market participant to model the constraints that have impact on opportunity costs for the limited MWh that they possess. While a high level representation of hydro, for instance, may be adequate for a typical market simulation, calculation of opportunity cost of limited hydro will in all likelihood need greater level of details for each individual hydro scheme to fully demonstrate the value of an extra MWh of hydro energy extracted from the scheme. This may include not only a more detailed representation of the limited energy plant and upstream constraints, but also any additional constraints that may limit release of energy and also commercial considerations (such as take-or-pay constraint, maximum daily/hourly quantity of gas offtake, associated penalty for violating such obligations etc). Similarly, cost information needed for the analysis will likely require additional information on detailed fixed, variable and consequential cost information that is normally not needed for a market simulation. This is because all of these additional factors have an impact on opportunity costs. On the other hand, the extent to which the opportunity cost calculation can be isolated, or simplified, to a participant-specific issue, some of the NEM details may be omitted- for instance, only a sub-set of generic network constraints that are material to the limited energy station may be used.

The broad categories of input needed for an opportunity cost calculation for a market participant would include the following:

- Inputs on technical parameters of limited energy stations including:
  - Available capacity (MW) of the station;
  - Available energy (GWh);
  - Forced outage rate including partial outage rate;
  - Minimum MW limit;

[36] NEMMCO, *Appendix A – Data and Assumptions for the 2008 ANTS Market Simulations*, February 2008.

  - Ramping limits (up and down in MW/min);
  - Auxiliary consumption;
  - Market based ancillary service parameters;
  - Upstream constraints including:
    - Initial storage level;
    - Storage facility limit (e.g., hydro reservoir, or gas storage facility – if any);
    - Flow limit;
    - Cascaded river/reservoir chain;
    - Minimum storage limit;
    - Inflows into storage;
    - Maximum release;
    - Minimum and maximum spillage limit;
    - Efficiency curve.
- Cost information for all relevant market participants including:
  - Fixed cost for the limited energy plant;
  - Variable cost for the limited energy plant;
  - Offer/bid by all other plants in the NEM whose dispatch will be affected by the dispatch of the limited energy plant;
  - Where relevant, storage costs for the limited energy plant, e.g., underground storage of gas.
- System-wide information including:
  - Demand;
  - Transmission interconnection (if relevant market participants include generators from another region);
  - Generic constraints (inter- and intra-regional security constraints).

Overall, the opportunity cost of limited energy will depend on

1. The overall demand-supply balance which will be determined by the availability of all generating units in the region as well as that of interconnectors. This, in short, covers all of the data that is needed for a dispatch model;
2. How tight the energy limit is which among other things will depend on the starting level of energy, e.g., initial storage level;

3. Operational limit such as how fast the storage may be depleted, minimum storage limit, rate of inflows that replenishes storage, etc;

4. Operational limit of the generator that may prevent generation to be increased/decreased above/below certain limit – these may include ramping, time needed for start-up of the unit etc. Although these limits may typically not bind for hydro generators, these may in some cases be restrictive for other energy limited plants; and

5. Uncertain events that may affect the supply – for instance, breakdown of a gas processing plant, or limited gas pipeline capacity, outage of pumping capacity (for a pump-storage hydro unit), etc for the limited energy resources. Also uncertainties associated with demand, outage of other generators and transmission interconnection will also influence opportunity costs – for instance, if a region has several “lumpy” baseload units that are prone to outages, opportunity cost of limited energy in such a region will typically be high because outage of one of the big generating units may have a major impact on the demand-supply balance and hence the value of stored water/gas would typically be high. Coupled with the factors (1)-(3) above, uncertainty may cause the opportunity cost to be both very high and volatile under extreme conditions.