An Optimal Hydrothermal Planning Model for the New Zealand Power system

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Abstract

The Stochastic Dual Dynamic Programming software is a mathematical programming model for medium and long term planning of generation and transmission systems. SDDP applies stochastic dynamic programming to a high dimensional problem which can not be solved by standard techniques. A recent study by Transpower NZ Ltd has successfully tested this model on the New Zealand power system. The requirements for a stochastic hydro-thermal optimization are described, the principles of the model are outlined, some results from a trial study are presented and possible applications are discussed.

1. INTRODUCTION

Over the last few years the New Zealand electricity generation system has been extensively restructured with changes in ownership structure and the introduction of a wholesale market. This represented a radical change from the previous centralized control and government ownership. Restructuring involved very large cultural changes, and consequentially were a major focus for management. Modeling carried out over the last few years has reflected this preoccupation with restructuring and market development. Consequently, models have focused on providing insights into market behaviour, rather than the good representation of the physical system. Supply problems experienced in two of the last three years have shown the need for models which focus on the capabilities of the power system.

Transpower New Zealand Limited is the owner and operator of the New Zealand transmission grid. In addition, it performs the market clearing and dispatch functions for the New Zealand Electricity Market. Transpower have recently carried out a study to demonstrate the feasibility of using an existing hydro-thermal optimal dispatch model for detailed studies of the power system. The SDDP model developed by Power systems Research Inc of Rio de Janeiro, Brazil, was selected. This paper outlines the requirements for such a model, discusses some alternative algorithms, briefly describes the algorithm of the SDDP model and finally presents some typical results.

2. MODEL REQUIREMENTS

2.1 The Optimal Dispatch Problem

The objective of the model is to minimize the sum of fuel and variable operation and maintenance costs, subject to constraints. For a given power system configuration, these are the only variable costs. The most important stochastic variable is inflows. Electricity demand is taken as given, although it may reduce in response to high prices. While demand has a random component which is usually highly correlated with temperature, this variability is ignored.

Hydro reservoirs are required to be modelled individually. In some models, reservoirs are aggregated, but this ignores the effects of the different inflow patterns of each reservoir, and also requires the aggregation of the power stations that they feed. Aggregation effectively allows the inflows into one reservoir to be utilized by capacity installed in a different location. This is especially significant in New Zealand where inflows to the Upper Waitaki lakes have a low correlation with those into Lake Manapouri, for example.

Thermal stations often have alternative fuel sources, and there may be constraints on the total quantity of each fuel type available. For example, Maui gas supplies are limited, but the fuel can be shared amongst a number of stations.

The HVDC link between the two islands is an essential part of any model, both due to the constraints on transfer and the losses involved.

For some studies, the AC transmission system is also an important constraint. In particular for studies involving new generation in locations which are away from major load centres grid capacity may be a constraint. Steady state thermal ratings of lines are not usually the binding constraint - the N-1 contingency is often the issue. This requires that the tripping of any one line should not cause the loading on any other line to exceed some value.

An essential feature in any system with significant hydro capacity is the correct treatment of the uncertainty of inflows. If mean inflows only are used incorrect conclusions are likely to be drawn. There will be no need for dry year reserve plant, and the HVDC link will very rarely transfer power from north to south. Carrying out a number of deterministic studies would give a range of outcomes, and might seem to be adequate. However, each of these studies would assume perfect foresight, which will greatly improve the system's ability to meet load during low inflow periods. Reserve plant requirements and shortfalls will be under estimated. Using the average of a number of deterministic solutions does not give a good result - the stochastic optimum is not necessarily a convex combination of a number of deterministic solutions.

2.2 Possible Algorithms

The use of a deterministic model has been dismissed in the previous section. However, it is often found to be an attractive option as such models are easy to build and solve. Modern modelling languages and linear solvers enable large models to be set up and solved very effectively. Such models should be a last resort - perhaps can some insights can be gained, provided all concerned appreciate the limitations.

Stochastic Linear Programming is frequently described in the literature, often dealing with the two stage problem with recourse. The two stage formulation implies that the uncertain quantities become known at the end of the first stage. From that point forward, the problem is deterministic. This approach has been implemented in some hydro scheduling models. However in reality the uncertainty continues to evolve over the whole time horizon. Therefore multiple stages of recourse are required, giving the problem a tree structure, with branching occurring at each stage. One method for solving this is by building the complete tree as a single large problem to be solved by linear programming. For even a modest number of stages, this can create a very large problem, unless only a limited amount of branching is permitted.

Stochastic Dynamic Programming requires the discretisation of the state space which usually consists of reservoir storage levels. If each storage dimension is discretised into 20 levels, then an n reservoir problem requires the investigation of 20^n points in the state space at each time step. For n greater than 3, the problem becomes impractical.

Stochastic linear programming is limited in the extent of the uncertainty that can be represented for multi stage problems, and stochastic dynamic programming is feasible only for a two or three dimensional state space, but is capable of giving a good representation of uncertainty. Most models for the medium term hydro-thermal problem make severe compromises to allow one of these techniques to be used, often by aggregating the system to one or two reservoirs, or by treating inflows as deterministic.

The special feature of SDDP is its use of a sampling strategy to make stochastic dynamic programming feasible for a high dimensional problem. This enables SDDP to meet all the requirements described in 2.1 above.

3. SDDP ALGORITHM

3.1 Methodology

SDDP incorporates a strategy for sampling the state space which allows it to solve only in the regions of interest, i.e. the regions that are likely to be visited in reality. More details can be found in [1]. The algorithm proceeds as follows:

a) Discretise time into weekly or monthly steps. Define the state space for each time step as the storage level in each reservoir and each inflow in the previous week.

b) Perform a backward optimization pass for k discrete points within the state space, using the normal DP method, where at each point each reservoir's level is a fraction k/(k-1) of full. At each stage, build a piecewise linear cost-to-go function.

c) Simulate system operation going forward in time for k inflow sequences, recording the points in the state space that the simulation passes through.

d) Perform a backward optimization pass for k discrete points within the state space, where these points are those that were visited on the previous forward simulation. At each point, the results of the new cost-to-go calculation are

added to that previously calculated, i.e. the cost-to-go function becomes more detailed.
e) Repeat the simulation of step c
e) Compare the cost-to-go at the beginning of the first time step with the average cost of the k simulations. If the difference is less than some tolerance, stop, otherwise continue from step d).

The means of representing the cost-to-go function is important. A separate function is created for each discrete time. Cost is given as a function of reservoir storage and the previous week's inflow. At each time step, the cost-to-go will be calculated for k states. At each of these points, a hyperplane is added to the cost-to-go function, where the hyperplane is defined by the magnitude of the cost-to-go at that point, and the partial derivatives of the hyperplane correspond to the simplex multipliers on the water balance constraint for the appropriate reservoir. These hyperplanes form a convex hull for the cost-to-go function. The iterative process continues until the linear approximation becomes good enough.

At each point in the state space, a number of one stage optimal dispatch problems are solved which trade off current period costs with future costs, the latter being defined by the cost-to-go function. Any linear feature of the power system can be incorporated in these dispatch problems, provided it does not create non-convex regions in the cost-to-go function. Several problems must be solved at each state space point to investigate a number of possible realizations of inflows. The cut added to the cost-to-go function is an average from these problems.

3.2 Other Applications of SDDP

SDDP is probably the world's most widely used hydro thermal planning model - forty eight organisations have licenced the software in the last six years.

It was originally developed by Power Systems Research Inc for a World Bank project to investigate the benefits of coordinated operation of the six Central American countries. This study involved optimizing the operations of each country separately, and comparing the outcome with an optimisation of them all as a single coordinated system. Since that time, SDDP has become widely used throughout Central and South America for routine system operations planning and for system development studies. The Colombian power system, for example, has a similar mix of generation to New Zealand and SDDP is used in that country by several government agencies for planning purposes. It has recently been used for a major Canadian Government sponsored project to analyse the power systems of nine countries in the Balkans area. As with the original Central American study, independent and coordinated operations were compared. Other systems studied with SDDP include part of China, some ex-Soviet republics in Central Asia and the entire Scandinavian system. One generation company in Austria uses SDDP.

4. SOLVING THE NEW ZEALAND SYSTEM

4.1 NZ System Features

For the New Zealand Electricity Market in 2002 [2] generation was 63% hydro, 29% coal/gas, 7% geothermal and 1% was from cogeneration. The South Island has hydro plant only, and has significant seasonal variation of inflows requiring spring snow melt to be stored to meet the higher demand in winter

The hydro system has ten large lakes, with significant differences in flow patterns between lakes. Storage volumes vary widely, but none are large by world standards. This results is a system where shortfalls in supply can occur after relatively short periods of time.

Not all hydro plants are in a simple cascade - some are located between large lakes, and spill flows can result in a number of stations being bypassed.

Huntly thermal station has a coal stockpile, which is important in the management of the system. Maui gas is a limited resource, which can be burned by a number of stations, ranging from efficient combined cycle plants to older steam plants.

The major transmission constraint is the HVDC link between the two islands.

4.2 Solution Process

For the optimization phase of the algorithm, trials have been made analysing fifty points in the state space at each time step, with fifteen possible inflow realizations optimised at each point. A two year time horizon was used, with an additional two years solved to remove end effects. Between twenty and thirty iterations are needed for convergence. Each iteration requires approximately 20 minutes processing on a 1.8 GHz computer with 386 Mb of RAM.

Convergence of the New Zealand system is much slower than that for other countries such as Colombia, Panama or Guatemala, for example. Two factors contribute to this.

Weekly time steps have been used for the New Zealand model, whereas monthly steps are generally used for the Colombian system, which is comparable in size to New Zealand. Weekly time steps were selected for New Zealand due to the relatively small reservoirs, in which storage can change by a large percentage over a single month. Convergence occurs when information from future time periods has flowed back to the earlier stages where operating policy is required to be influenced. For example, high winter prices require water to be retained in storage from spring snow melt. Use of monthly time steps requires the information to be passed back through fewer time steps - hence faster convergence.

Minimum flow requirements exist at a number of points in the hydro system. To meet these constraints, water must be held in storage for up to twenty weeks. These constraints are enforced by means of a penalty. As they are rarely violated, their contribution to the cost-to-go function quickly diminishes from a given stage to the previous stage during the backward optimization phase. As a result, a heavy penalty weight is required, and more iterations to obtain convergence than would be the case without these minimum flows.

4.3 Sample Results

Results from the model are provided as comma separated variable (csv) files, where data is reported by inflow sequence, week, and load block. Some outputs from the trial study follow.

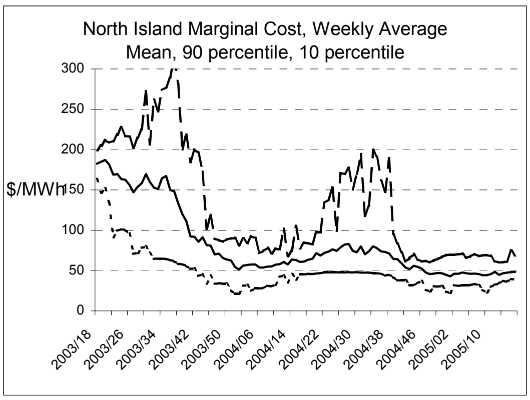

Figure i

Figure i shows weekly average system marginal costs, beginning at 1 May 2003. Supply shortfall is costed at $200/MWh for the first 10% of demand, and $500/MWh for the remainder. Clearly some significant shortfalls were likely for the conditions existing on 1st May - hence the savings campaign we have experienced.

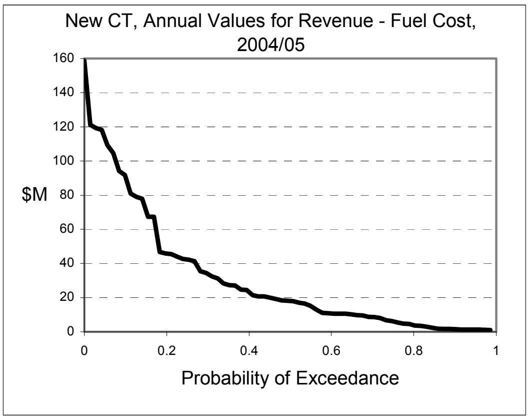

Figure ii

The variability of the revenue earned by a possible dry year reserve plant is shown in figure ii. Section 4.4, below, discusses the relevance of this variability in revenue to the investment decision.

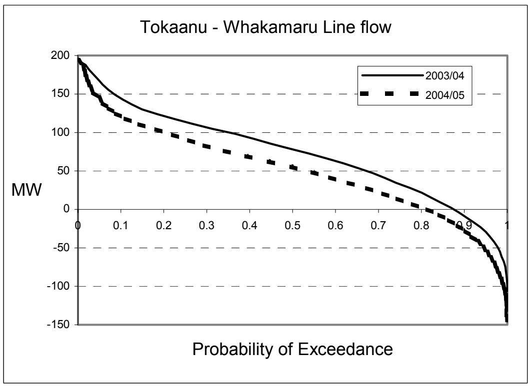

Figure iii

The distribution of flows on one of the two Tokaanu - Whakamaru lines in shown in figure iii. This is one of the 220 kV lines which carries power from South Island generators to load centres in the northern half of the North Island when water is plentiful in the south. The figure shows how northward transfers decrease in 2004/05, as compared with 2003/04, probably due to additional fuel supplies at Huntly and increased generation on the Waikato in 2004/05.

The number of simulated sequences that experience shortfall in supply is shown in figure iv. This is the type of information that could be useful to the proposed Electricity Commission when determining whether the system meets some desired security criteria.

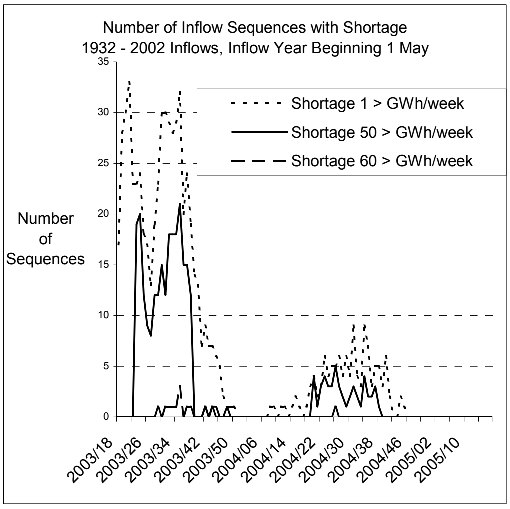

Figure iv

4.4 Application to Investment Analysis

Despite not representing market mechanisms explicitly, an optimal dispatch model can provide useful information about system dispatch within a market. A market system can at best reach the global optimum result, but will in general be less efficient due to information deficiencies, the exercise of market power, etc. Market prices can be expected to be above short run marginal cost due to market power and generator market strategies. SDDP determines prices which are therefore a floor on short run marginal prices, except under unusual circumstances. This feature of optimal dispatch models is useful when analysing new generation projects - if the optimal dispatch shows the project is viable, it will almost certainly be profitable in practice. Therefore such modelling is often required by banks, rather than some method that attempts to represent the higher market prices achieved through marketing strategies.

A deterministic approach to determining projected revenues from an investment opportunity has serious drawbacks. The value of a hydro plant will be over-estimated by modelling that uses only mean inflows as market prices are lower when the plant has higher output. The value of a thermal plant will be under-estimated by such a model. Some important information that can only be given by a stochastic model such as SDDP is the volatility of revenues earned by a plant. When analysing a stand alone power plant project, if is important to determine whether there are situations when the plant can not earn sufficient revenue to cover its fixed costs. If such situations exist, then a credit line must be secured. This represents an extra cost, and is likely to result in the project being viewed by potential financiers as being more risky. This volatility of earnings is a significant issue in New Zealand where the government has had to take action to promote the development of dry year reserve plant.

No major transmission system construction has been undertaken in New Zealand for some time, but the current changes in the regulatory environment may result in some reinforcement of the grid. Transmission system loading varies with hydro system inflows, so a model representing these effects has the potential to provide significant new insights into grid expansion options.

4.5 Management of System Security

To manage plant held in reserve for dry years, the New Zealand Government is setting up an Electricity Commission. One of the tasks of this commission will be to determine the probability of shortfalls in supply. This probability can not be determined from analysis of hydrological data alone as the state of hydro system storage, coal stockpile levels, and fuel availability for thermal stations all influence security of supply. Shortfalls in supply predicted by SDDP are likely to be a lower bound on those actually experienced due to the loss of co-ordination through the electricity market.

It has been suggested that the Commission would hold back reserve generation until a very dry year occurred. However when such an event has become recognisable, a very large amount of reserve generation is likely to be needed to avoid supply shortfall. The most effective means of management might be to operate the plant according to the schedules produced by SDDP. This would result in reserve plant being operated whenever the risk of a shortfall justified the high operating cost of the reserve plant. A difficulty with this approach would occur when the commission estimated risks were sufficient to justify the operation of its plant, but other market participants did not. This could result in the commission's high cost plant being dispatched when some other generation company's lower cost plant was not dispatched.

A wide range of policy issues such as the above could be analysed using the SDDP model.

6. CONCLUSIONS

The trial study carried out demonstrates that the SDDP model is able to satisfactorily solve a detailed representation of the New Zealand system. All relevant physical features of the power system required for a medium to long term model can be represented.

SDDP is especially suited to transmission system planning as it shows the variability of line flows with inflows. Monitoring and implementation of the New Zealand government's 1 in 60 standard for electricity supply could be carried out with the help of SDDP. To do this, the model could be used to calculate the Electricity Commission's required portfolio of dry year reserve plant, and when to run this plant. Any studies requiring an assessment of the national benefit of a project would be candidates for analysis with this model.

7. REFERENCES

[1] Pereira, M.V.F. , and Pinto, L.M.V.G., "Multi-stage stochastic optimization applied to energy planning", Mathematical Programming, Vol 52 (1991), pp 359-375.

[2] New Zealand Electricity Market, January - December 2002 Market Report.