JAPAN INTERNATIONAL COOPERATION AGENCY

CEYLON ELECTRICITY BOARD(CEB)
DEMOCRATIC SOCIALIST REPUBLIC OF SRI LANKA

STUDY
OF
HYDROPOWER OPTIMIZATION
IN
SRI LANKA

FINAL REPORT

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APPENDIX-I

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I-A HYDROLOGICAL ANALYSIS

HYDROLOGICAL ANALYSIS

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1 Objectives of Hydrological Analysis

The objectives of the hydrological analysis are follows:

- Review and supplement hydrological data;
- Estimating the daily runoff in all major reservoirs for river system analysis;
- Review the low flow runoff analysis of the Broadlands hydropower project;
- Review the flood analysis of the Broadlands hydropower project; and
- Review the sediment analysis of the Broadlands hydropower project.

2. Data Collection and Hydrological Analysis

2.1 Major Types of Hydrological Data and Their Use

The major types of hydrological data and their use are mentioned below:

(1) Rainfall Records

There are three types of rainfall records, namely, monthly rainfall record, daily rainfall record and hourly rainfall record. These records were utilized for different purposes.

1) Monthly Rainfall Records

Monthly rainfall records were utilized for establishing the seasonal rainfall characteristics, analysis of runoff data, and the conversion method, by catchment area ratio and monthly rainfall ratio, which is the low runoff analysis, for the Broadlands hydropower project.

2) Daily Rainfall Records

The daily rainfall records were utilized for low flow runoff analysis for Broadlands hydropower project, and for flood runoff analysis for the project. Basically, the flood runoff analysis was carried out by using hourly rainfall records. However, there are no rainfall gauging stations that have hourly rainfall records in the river system for the hydropower project. Hence, the hydrologist estimated some flood hydrographs for the project based on some daily rainfall records for the project basin and hourly rainfall records from the Ratnapura rainfall gauging station which is located close to the river system.

3) Hourly Rainfall Records

As mentioned above, hourly rainfall records were utilized for estimation of a flood hydrograph for the Broadlands hydropower project.

(2) Runoff Records

There are three types of runoff records, namely, monthly average runoff records, daily average runoff records, and daily peak runoff records. These records were utilized for the following purposes.

1) Monthly Average Runoff Records

Monthly average runoff records were utilized for establishing the seasonal rainfall characteristics for the target area. If a daily average runoff recording is not available, the river analysis or estimation of power generation will be carried out using the monthly average runoff data provisionally. Basically, low flow runoff analysis should be carried out using daily average records.

2) Daily Average Runoff Records

Daily average runoff records were utilized for river system analysis and to provide low flow runoff data for power generation for the Broadlands hydropower project.

3) Daily Peak Runoff Records

Daily peak runoff records were utilized for frequency analysis of the flood peak.

(3) Monthly Average Temperatures

Monthly average of daily maximum temperatures and daily minimum temperatures will be utilized for the construction plan of the Broadlands hydropower project in the feature.

2.2 Hydrological Data Collection

Rainfall data and runoff data in Sri Lanka were collected and described in the report of the "Master Plan for the Electricity Supply of Sri Lanka". In the present hydrological study, the rainfall data and runoff data around the target area, the Mahaweli river system, the Kelani river system and the Walawe river system, were obtained from the report and supplemental data from October 1985 to September 2001 were collected and classified. A location map of gauging stations is shown in Figure 1, and a list of rainfall data and runoff data is shown in Table 1.

2.3 Rainfall Data Analysis

The results of the rainfall data analysis were utilized to give an understanding of the characteristics of the target river systems, to verify runoff data, to supplement missing data, and to undertake low flow and flood analysis. The rainfall data analysis consisted of:

- verifying rainfall data,
- supplementing missing data, and
- estimating average rainfall in each river system.

The above data analyses were applied to daily rainfall records and monthly rainfall records.

(1) Verifying Rainfall Data

1) Double Mass Curve Analysis

The verification of runoff analysis was carried out by double-mass-curve analysis and correlation analysis.

Double mass-curves consist of monthly or yearly cumulative rainfall at one gauging station on the X axis plotted against the cumulative rainfall for corresponding periods at another gauging station on the Y axis. If there are no aberrations in either set of data, the plot will be linear. If the line shows an inflection or gap in the double-mass-curve, there is abnormality in the data of one or both. The aberrant data of a group of gauging stations are identified by making double-mass curves one by one.

2) Correlation Analysis

The gauging station data verified by double mass-curve analysis would be analyzed by correlation analysis one by one. The coefficient of correlation is calculated by equation (1). The test of significance is checked by equation (2). If the test of significance of two series of data is failed by equation (2), even if the coefficient of correlation is high, there is deemed to be no correlation between them.

$$r = \frac{\sum x_i \cdot y_i - \sum x_i \cdot \sum y_i / N}{\sqrt{\left[\sum x_i^2 - \left(\sum x_i\right)^2 / N\right] \cdot \left[\sum y_i^2 - \left(\sum y_i\right)^2 / N\right]}} \qquad (1)$$

$$|r| \geq \frac{1}{\sqrt{\dfrac{N-2}{t^2(N-2,\alpha)} + 1}} \qquad (2)$$

Where,

r	: coefficient of correlation
xi, yi	: x-data, y-data
N	: the number of data
α	: significance level (normally 0.05)
t(N-2,α)	: t-value of t distribution under the conditions of N-2 degrees-of-freedom and significance level of α

Double mass curve analysis and correlation analysis were carried out for all rainfall records and the gauging stations that have accurate rainfall records were selected for this hydrological study. The selected gauging stations are listed in Table 2.

(2) Supplementing Missing Data

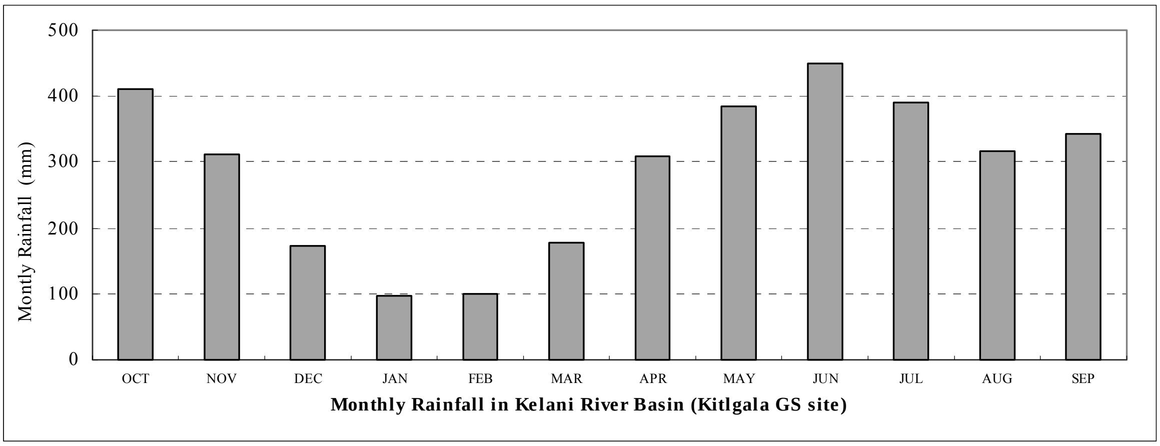
In case a gauging station whose data was verified by double mass-curve analysis and correlation analysis has missing data, the missing data can be estimated using the regression relationship between this station and another station with which the station is highly and significantly correlated.

(3) Estimating Average Rainfall for a River System

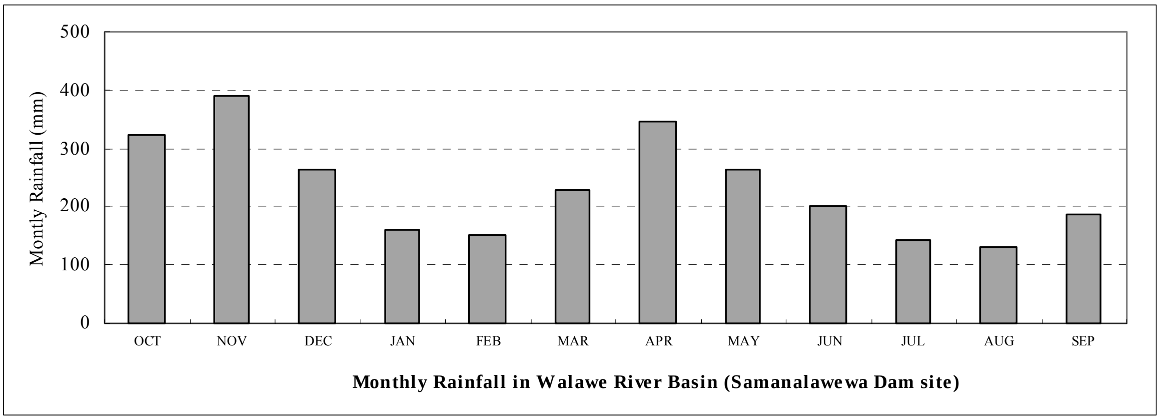
The average rainfall of each river system was estimated by the Thiessen method based on verified records by the above mentioned data analysis. The Thiessen polygons of each river system are shown in Figures 2 to 3.

These results are shown as follows.

1) Average rainfall in the Kelani River System (Kitulgala GS site)

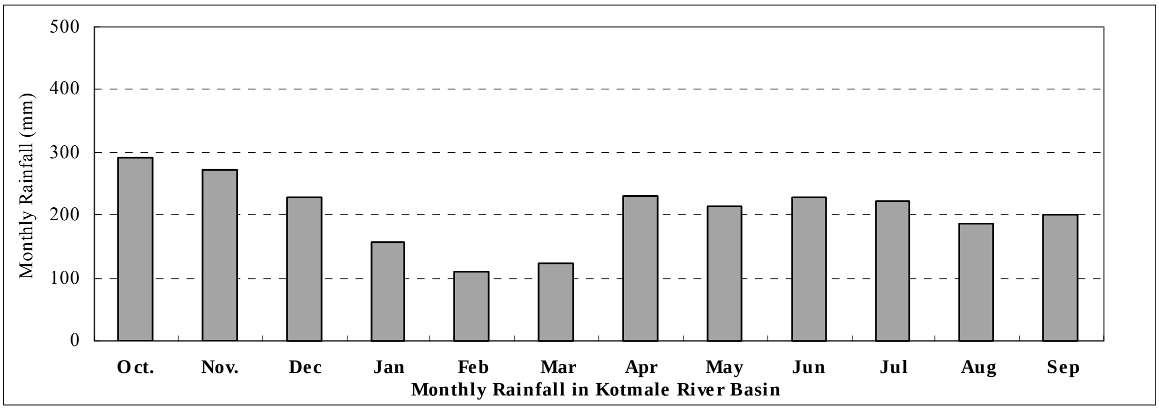


2) Average rainfall in the Walawe River System (Samanalawewa Dam Site)

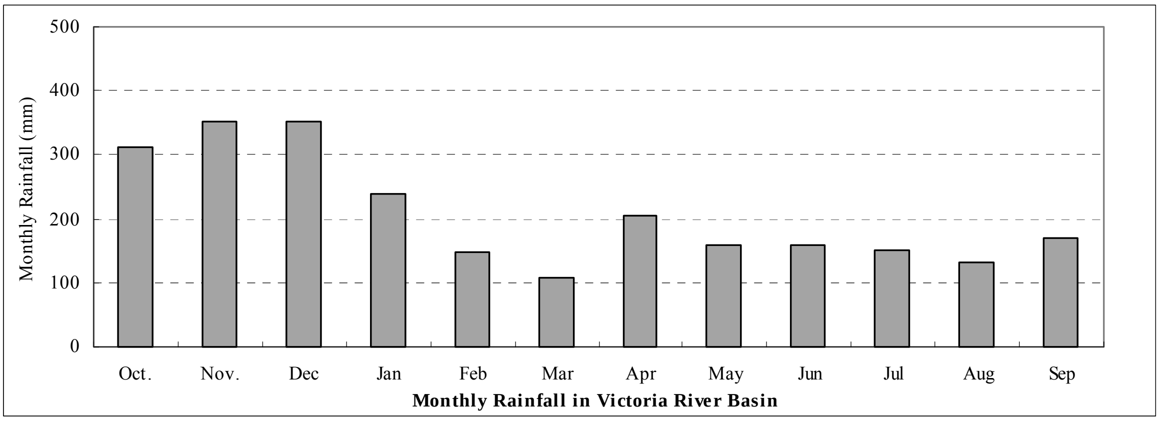


3) Average rainfall in the Mahaweli River System

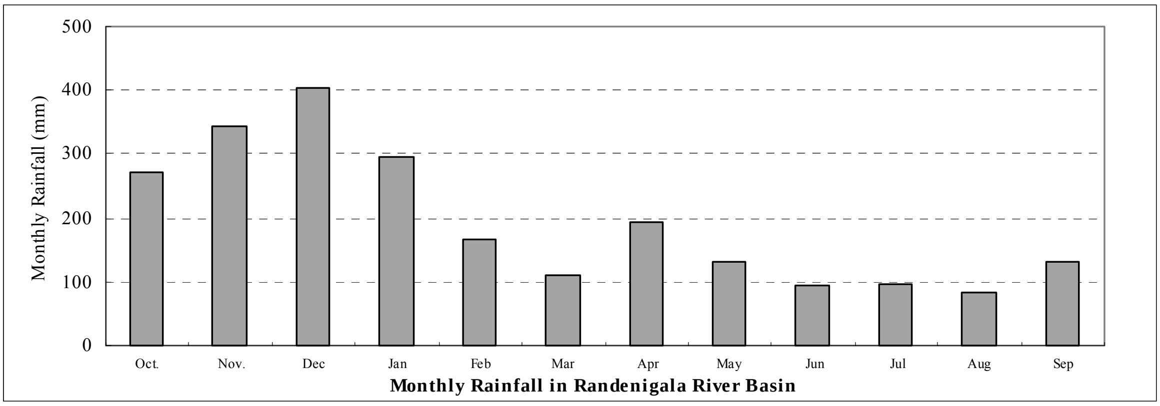
- Kotmale Dam Site



- Victoria Dam Site (excluding Polgolla Diversion catchment area)



- Randenigala Dam Site（excluding Victoria dam catchment area）



2.4 Runoff Data Analysis for Economic Operation of Existing Hydropower Stations

Data analysis was carried out to validate runoff for an economic operation study of existing hydropower stations

(1) Target Data

The runoff data analysis was carried out to calculate inflow data for the following major dam or weir sites.

1) Mahaweli River System

- Kotmale dam site
- Between Kotmale damsite and Polgolla diversion weir site
- Between Polgolla diversion weir site and Victoria dam site
- Between Victoria dam site and Randenigala damsite

2) Kelani River System

- Mousakelle damsite
- Castlereigh damsite

3) Walawe River System

- Samanalawewa damsite

(2) Components of Runoff Data Analysis

The runoff data were used for double mass curve analysis and correlation analysis to compare the runoff data of the target site with the average rainfall at the target site. The components of this analysis were:

- Double-mass curve analysis
- Correlation analysis
- Duration curve analysis

(3) Results of Runoff Data Analysis

The results of runoff data analysis in the Mahaweli river system are shown in Figures 4 to 7, and the results of the analysis in the Kelani and Walawe river basins are shown in Figures 8 to 11.

There were no abnormal data among the selected gauging stations and all of the data can be used for the economic operation study.

2.5 Runoff Data Analysis for the Broadlands Hydropower Project Site

(1) Target Data

The low flow data required to estimate the energy output of the Broadlands hydropower project was estimated from daily runoff data at Kitulgala gauging station, which is the nearest station to the project site. The runoff data analysis was applied not only to Kitulgala gauging station but also to Mousakelle gauging station and Deraniyagala gauging station to verify data and supplement missing data at Kitulgala gauging station and to check the possibility of converting runoff data from Kitulgala gauging station to unknown data in another river system.

Selected Runoff Data in Kelani River Basin

Station Code	Station Name	Latitude	Longitude	Elevation	Catchment Area
0105	Deraniyagala	06-55-30N	80-20-15E	82m	152km^2
0106	Kitulgala	06-59-30N	80-24-45E	56m	388km^2
0107	Mousakelle	06-50-15N	80-33-00E	1,158m	122km^2

(2) Components of Runoff Data Analysis

The runoff data was used for double-mass-curve analysis and correlation analysis to compare the runoff data of the target site with the average rainfall at the target site. The components of the analysis were:

- Double-mass-curve analysis
- Correlation analysis
- Duration curve analysis

(3) Results of Runoff Data Analysis

The results of the runoff data analysis are shown in Figures 12 to 13.

Based on double-mass-curve analysis, the data from July 1976 at Mousakelle gauging station and the data from January 1985 at Deraniyagala gauging station displayed some anomalies, so the data for those periods was rejected.

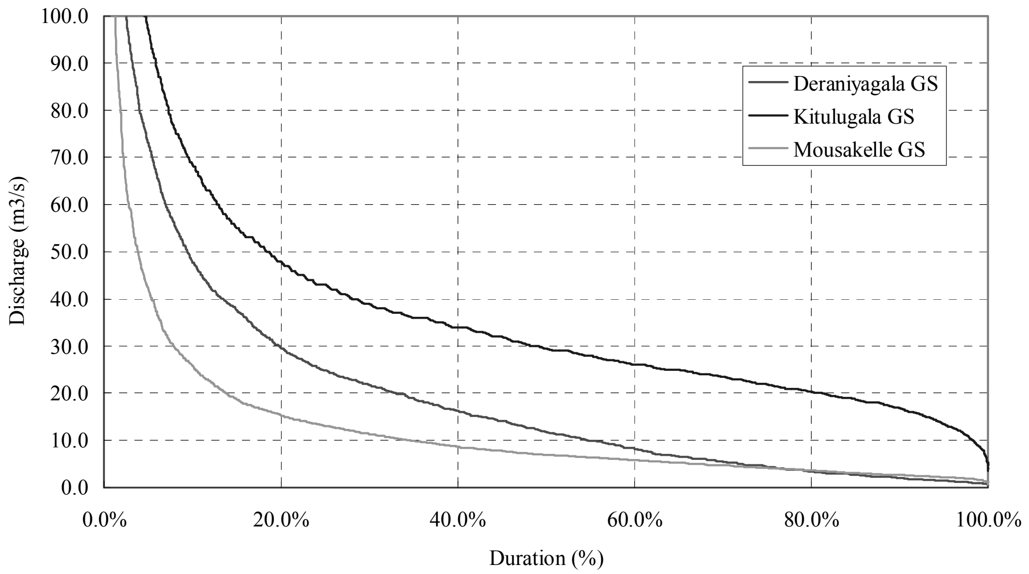
The runoff data at Kitulgala gauging station became relatively stable after the impounding of Mousakelle reservoir in 1969. It was observed from the double-mass-curve that the effect of regulation from the reservoir did not significantly change the daily discharge range.

The correlations between runoff at each gauging station and average rainfall for the same river system were high. Hence, it is judged that the accuracy of this data is high.

Based on the above results, the inflow at the intake site of the Broadlands hydropower project could be estimated from daily runoff data at Kitulgala gauging station.

The discharge-duration curve for each gauging site is as follows:

Duration Curve of Runoff Records in the Kelani River System



Duration curve of runoff data

3. Low Flow Runoff Analysis

3.1 Estimation of Runoff Data for the Economic Operation Study for Existing Hydropower Stations

(1) Methodology

The runoff data in the Kelani river system, Mahaweli river system and Walawe river system are estimated by water level at reservoirs and ponds in each river systems. The data type of these runoff data is monthly. On the other hand, the operation study for existing hydropower stations should be applied to, not only yearly operation with monthly deviation of runoff data, but also daily operation with daily deviation of runoff data.

In order to estimate daily runoff into all major reservoirs, low flow runoff analysis was carried out based on daily rainfall records around each reservoir and monthly average inflow records at each reservoir. The estimated runoff data into each reservoir are treated as natural inflow, this neglects the influence of reservoir operation, into each reservoir.

(2) Low Flow Runoff Analysis Model

The tank model method was selected for low flow runoff analysis. This model is the most popular method in Japan and this model is applied in many foreign countries.

The tank model consists of several tanks in order to adjust the runoff characteristic of each river system. A four (4) layer and four (4) row tank model was applied in this study. This model is recommended by Mr. Sugawara, who developed the tank model method, for a basin that clearly has a dry season and a wet season. The outline of the tank model is shown in Figure 14 and the equation of the 1-step-tank is shown below.

$$X_n = I_n - E_n$$

$$y_n = 0 \qquad (X_n \leqq h_1)$$

$$y_n = \alpha_1 \cdot (X_n - h_1) \qquad (h_1 < X_n \leqq h_2)$$

$$y_n = \alpha_2 \cdot (X_n - h_2) + \alpha_1 \cdot (X_n - h_1) \qquad (h_2 < X_n)$$

$$z_n = \beta \cdot X_n$$

$$X_n' = X_n - y_n - z_n$$

where、

X_n	:	water depth of tank 'n' at present step (mm)
X_n'	:	water depth of tank 'n' at next step (mm)
I_n	:	Input water into tank 'n' from upper tank (mm), (rainfall depth for the first layer tank , $I_n = z_{n-1}$ for second to forth layer tank)
E_n	:	evaporation depth at tank 'n' to upper tank (mm)
y_n	:	outflow depth from side hole of tank 'n' (mm)
z_n	:	outflow depth from bottom hole of tank 'n' (mm)
α_1, α_2	:	outflow coefficient of side hole 1 and 2.
β	:	outflow coefficient of bottom hole

(3) Results of Low Flow Runoff Analysis

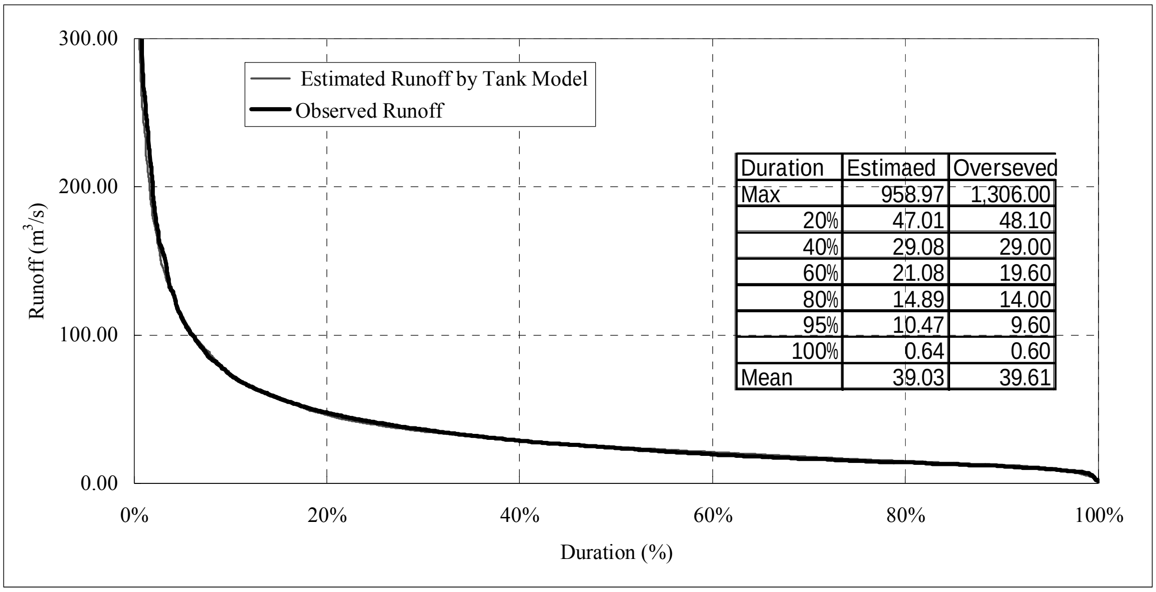
Low flow runoff analyses were carried out based on daily basin average rainfall. Parameters were identified by using daily runoff records before constructed the Mousakelle reservoir in the Kelani river system, and were identified by using monthly runoff records into each reservoir in the Mahaweli and Walawe river systems.

The check items for adjustment of the parameters for the low flow runoff analysis are the average discharge, the shape of the hydrograph except at flood peak and the shape of the duration curve except at flood peak.

The summaries of the analyses are shown below.

1) Kelani River System

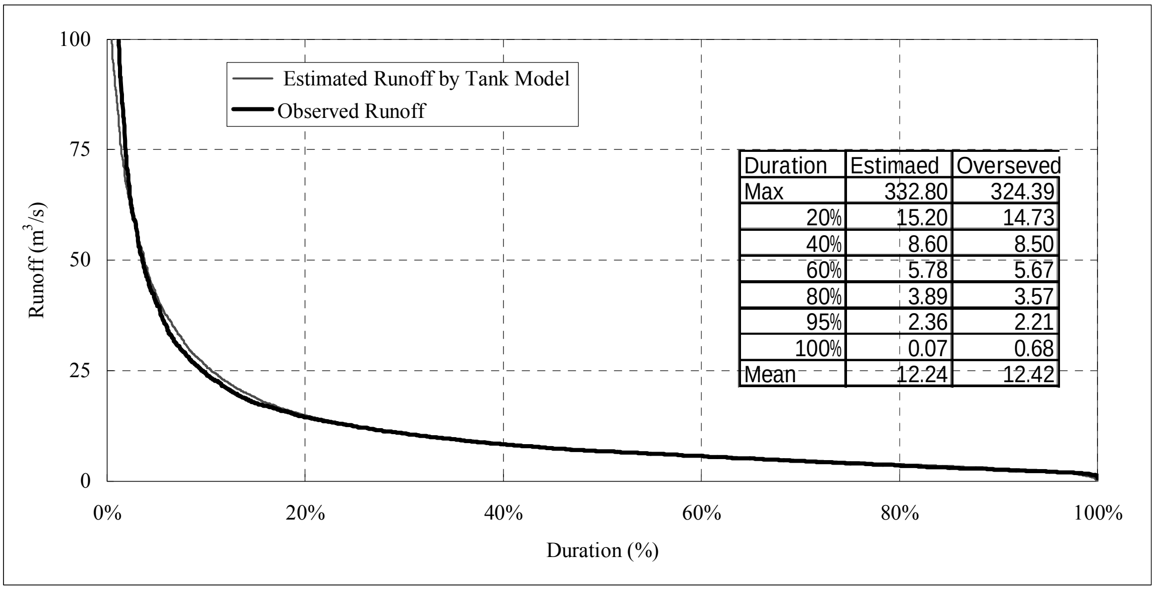
a) Kitulgala Gauging Station Site



Duration	Estimaed	Overseved
Max	958.97	1,306.00
20%	47.01	48.10
40%	29.08	29.00
60%	21.08	19.60
80%	14.89	14.00
95%	10.47	9.60
100%	0.64	0.60
Mean	39.03	39.61

Duration Curve of Estimated and Observed Runoff at Kitulgala Gauging Station Site

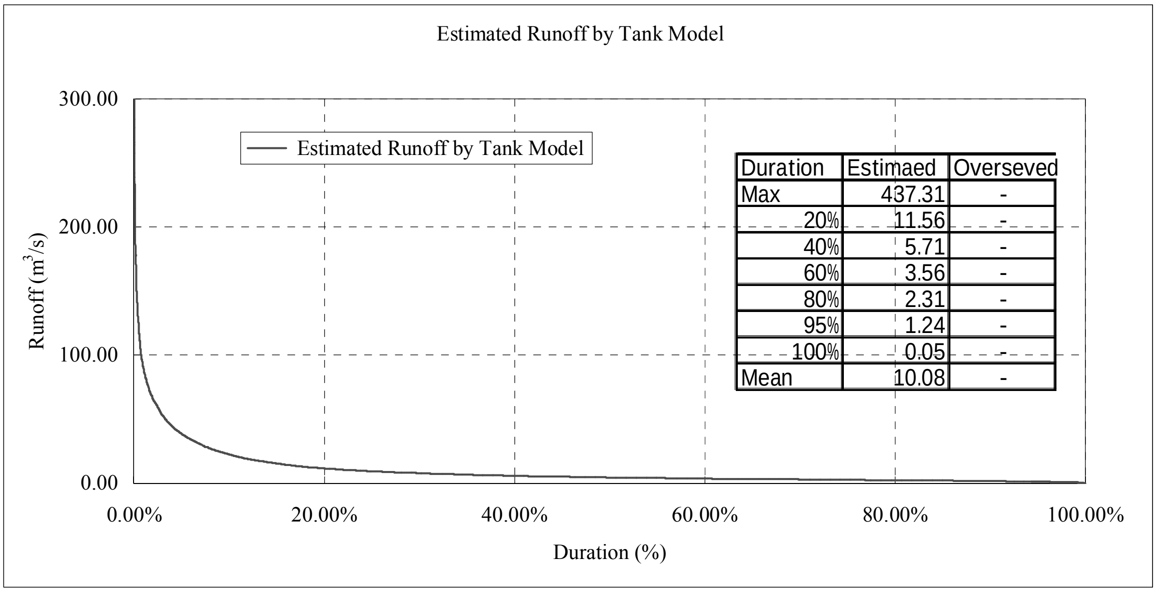
b) Mousakelle Gauging Station Site



Duration	Estimaed	Overseved
Max	332.80	324.39
20%	15.20	14.73
40%	8.60	8.50
60%	5.78	5.67
80%	3.89	3.57
95%	2.36	2.21
100%	0.07	0.68
Mean	12.24	12.42

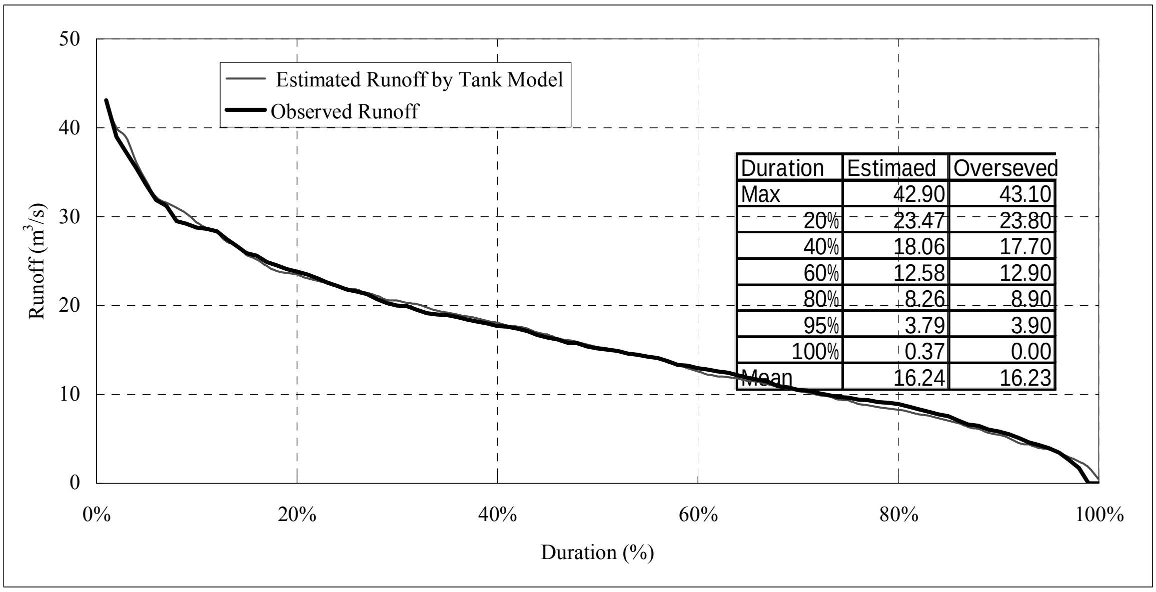
Duration Curve of Estimated and Observed Runoff at Mousakelle Gauging Station Site

c) Castlereigh Dam Site



Duration Curve of Estimated Runoff at Castlereigh Dam Site

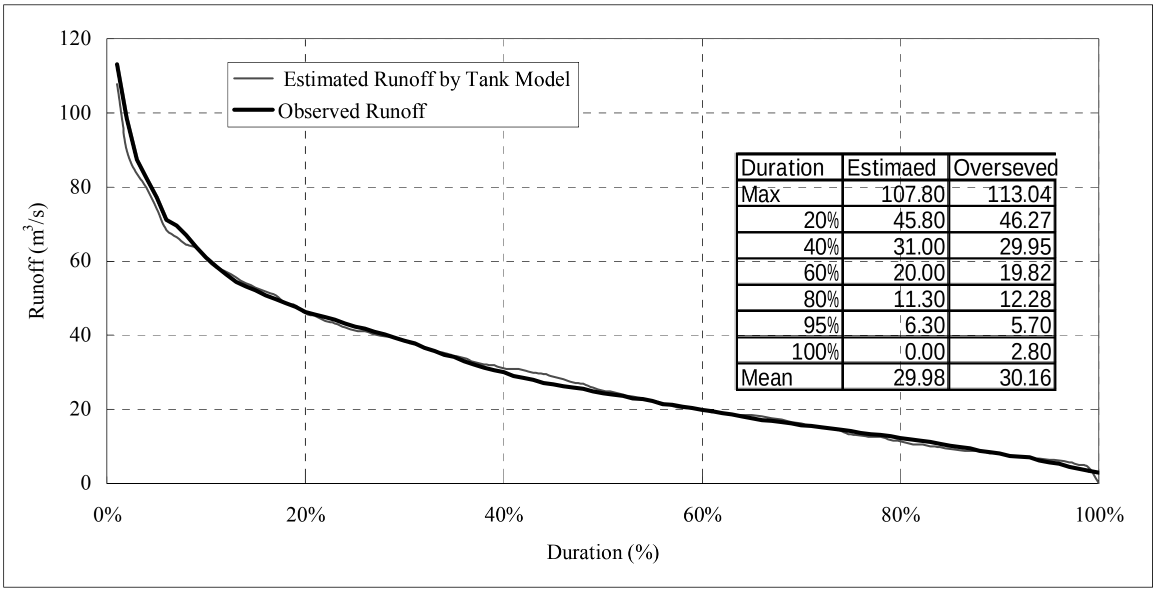
2) Walawe River System (Samanalawewa)



Duration Curve of Estimated and Observed Runoff at Samanalawewa Dam Site

3) Mahaweli River System

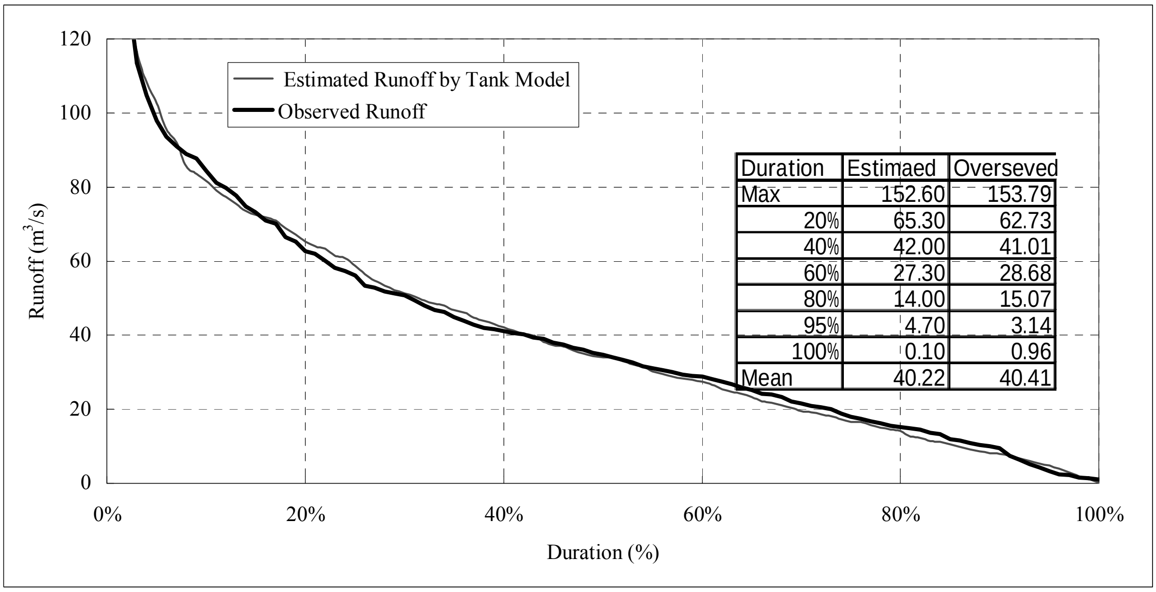
a) Kotmale Dam Site



Duration	Estimaed	Overseved
Max	107.80	113.04
20%	45.80	46.27
40%	31.00	29.95
60%	20.00	19.82
80%	11.30	12.28
95%	6.30	5.70
100%	0.00	2.80
Mean	29.98	30.16

Duration Curve of Estimated and Observed Runoff at Kotmale Dam Site

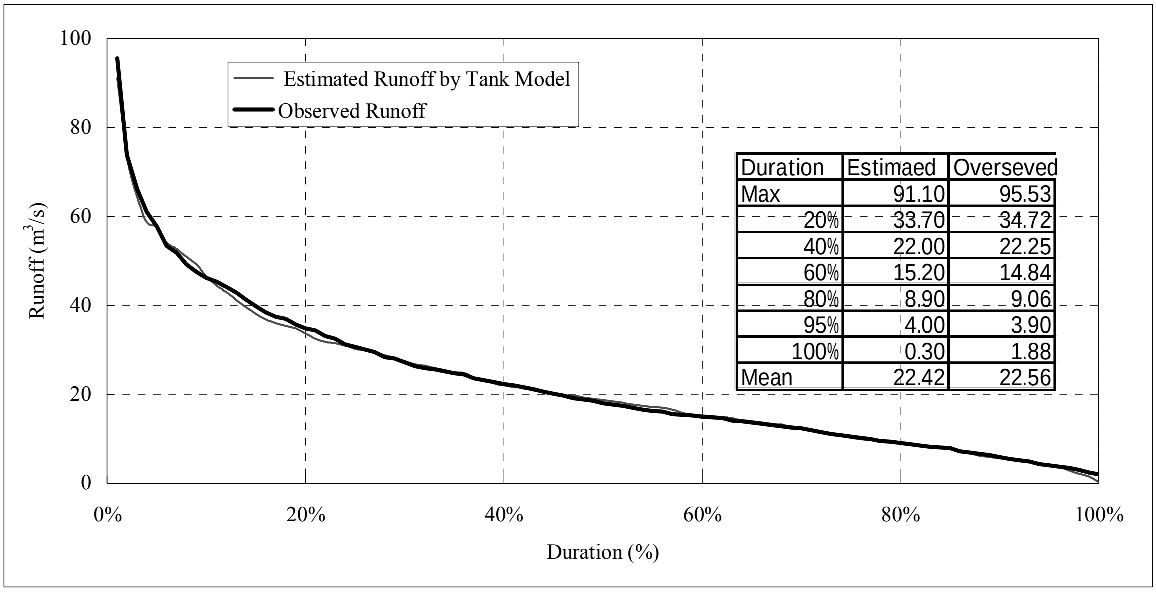
b) Polgolla Diversion Weir Site (Excluding Catchment Area of Kotmale Dam Site)



Duration	Estimaed	Overseved
Max	152.60	153.79
20%	65.30	62.73
40%	42.00	41.01
60%	27.30	28.68
80%	14.00	15.07
95%	4.70	3.14
100%	0.10	0.96
Mean	40.22	40.41

Duration Curve of Estimated and Observed Runoff at Polgolla Weir Site

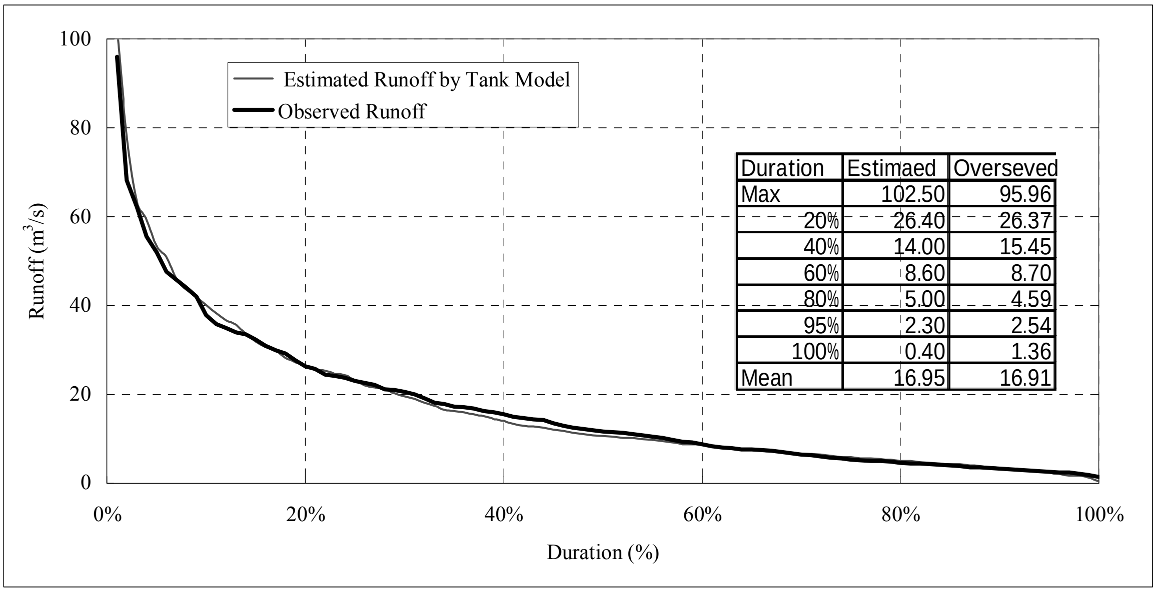
c) Victoria Dam Site (Excluding Catchment Area of Polgolla Weir Site)



Duration	Estimaed	Overseved
Max	91.10	95.53
20%	33.70	34.72
40%	22.00	22.25
60%	15.20	14.84
80%	8.90	9.06
95%	4.00	3.90
100%	0.30	1.88
Mean	22.42	22.56

Duration Curve of Estimated and Observed Runoff at Victoria Dam Site

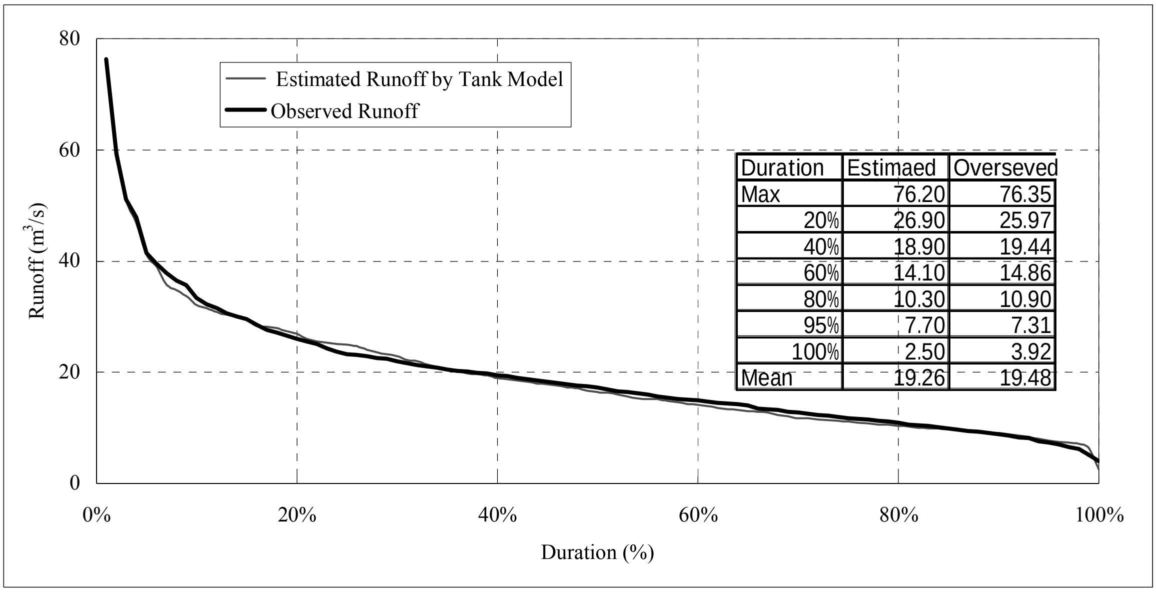
d) Randenigala Dam Site (Excluding Catchment Area of Victoria Dam Site)



Duration	Estimaed	Overseved
Max	102.50	95.96
20%	26.40	26.37
40%	14.00	15.45
60%	8.60	8.70
80%	5.00	4.59
95%	2.30	2.54
100%	0.40	1.36
Mean	16.95	16.91

Duration Curve of Estimated and Observed Runoff at Randenigala Dam Site

e) Rantambe Dam Site (Excluding Catchment Area of Randenigala Dam Site)



Duration Curve of Estimated and Observed Runoff at Rantambe Dam Site

3.2 Low Flow Runoff Analysis for Broadlands Hydropower Project

(1) General

The runoff records in Kitulgala gauging station have been influenced by artificial discharge released from Mousakelle reservoir and Castlereigh reservoir, which have been located upstream of the gauging station since Mousakelle dam was constructed in 1968. The runoff released from Castlereigh reservoir is diverted form Norton pond on the Kehelgamu Oya to Maskeliya Oya via Old Laxapana hydropower station. The maximum diverted discharge is 14.42 m^3/s, which is the plant discharge of the Old Laxapana hydropower station. There is an absence of daily discharge records at these reservoirs and all power stations in the Kelani river system. Hence, under the existing conditions, it is impossible to establish natural runoff records for site E on Maskeliya Oya and weir site on Kehelgamu Oya, which are candidates for the dam site of the Broadlands hydropower project. In order to estimate these runoffs, 1) the natural runoff at the sub basin of Kehelgamu Oya should be estimated by low flow runoff analysis 2) released discharge from Castlereigh reservoir should be estimated by reservoir operation, and 3) the flow of each dam site, site E and weir site, should be estimated by water balance model.

(2) Calculation Method of Inflow at the Candidate Dam Site for the Broadlands Hydropower Project

The calculation method of inflow discharge at the candidate dam site for the Broadlands hydropower project is mentioned below, the sub basin model of Kelani river system and schematic diagram of the water balance model of the Kelani river system are shown Figures

2 and 15 respectively.

Note: The schematic diagram of water balance model of Kelani river system was generated describing the water balance of the Kehelgamu Oya and Maskeliya Oya. Among the existing hydropower stations, only Old Laxapana hydropower station gives influence of the water balance model because the power station diverts the water from the Kehelgamu Oya to Maskeliya Oya. Another hydropower stations have no influence of the balance model. Therefore, only Old Laxapana hydropower station was mentioned in the schematic diagram.

1) Estimation of Natural Runoff

The natural runoff at :1)Castlereigh dam (RB1 in Figure 15), 2) between Castlereigh dam and Norton dam (RB2), 3) between Norton dam and the confluence point of Kehelgamu Oya and Maskeliya Oya (RB3), and 4) between the confluence point to Kitulgala gauging station (RB8) are estimated by the tank model method of low flow runoff analysis. The target areas are hatched in Figures 2 and 15.

QBi = F(Rfi)

Where F() : tank model. (mentioned above)

QBi: natural runoff at sub basin "i" (m^3/s)

Rfi: basin average rainfall at sub basin "i" (mm/day)

The target sub basins are hatched area of i = 1,2,3,8 in Figures 2 and 15.

i=1 : Castlereigh reservoir sub basin.

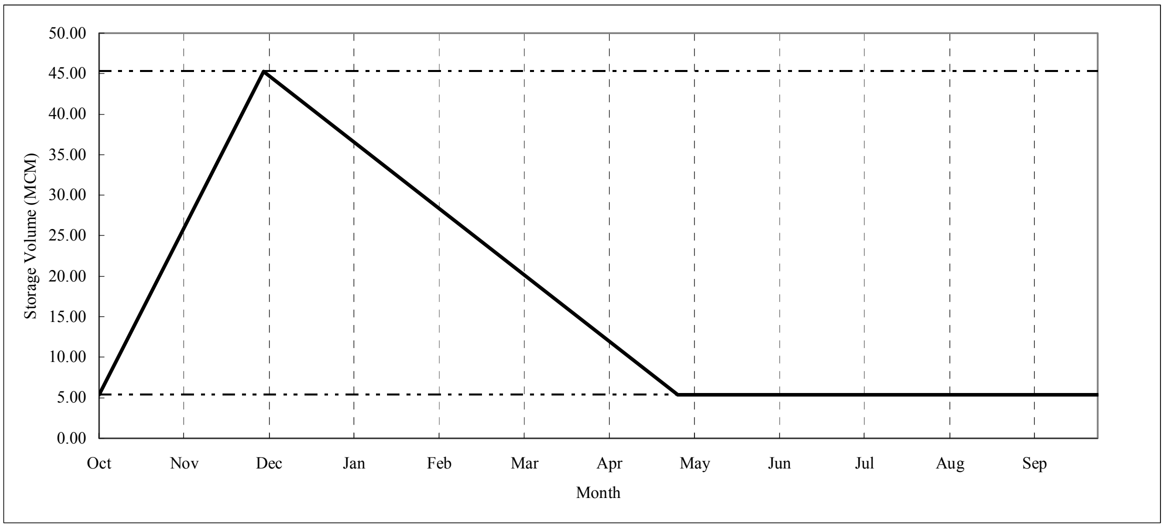
i=2 : sub basin between Castlereigh dam and Norton dam.

i=3 : sub basin between Norton dam and confluence point of Kehelgamu Oya and Maskeliya Oya

i=8 : sub basin between the confluence point and Kitulgala gauging station.

2) Estimation of Released Discharge from Castlereigh Reservoir

The released discharge from Castlereigh reservoir was estimated by simulation of reservoir operation based on existing rule curve of the reservoir using natural runoff at the reservoir that was estimated by 1).



Rule Curve of Castlereigh Reservoir

- Ve ≥ Rule

$$Q_{Cas.} = (Ve - Rule) / (24 * 3600) \quad \leq Qmax$$

- Ve < Rule

$$Qout = Qmin$$

where, *Qcas.* : released discharge from Castlereigh reservoir(m^3/s)

Ve : effective storage volume for one day (m^3)

Rule : storage volume for one based on rule curve(m^3)

Qmax : maximum discharge from the reservoir ($29.5m^3/s$)

Qmin : minimum discharge from the reservoir ($4.75m^3/s$)

3) Estimation of Inflow at Dam Site by Water Balance Calculation

Inflows at site E on Maskeliya Oya and at the weir site on Kehelgamu Oya were estimated by water balance calculation taking into account the water transfer of 14.42 m^3/s, which is the maximum value, from Norton pond to Maskeliya Oya based on results of 1) and 2).

$$Q_{Weir} = Q_{Cas.} + Q_{B2} - Q_{OLx} + Q_{B3}$$

$$Q_{siteA,\,D} = Q_{Kltu.}$$

$$Q_{SiteE} = Q_{Kitu} - Q_{Weir} - Q_{B8}$$

where, $Q_{weir.}$: inflow at weir site (m^3/s)

$Q_{siteA,D}$: inflow at dam site A and D.(m^3/s)

$Q_{siteA,D}$: inflow at dam site E. (m^3/s)

$Q_{cas.}$: released discharge from Castlereigh reservoir (m^3/s)

Q_{Bi} : natural runoff at sub basin "i:"(m^3/s)

$Q_{OL\,x}$: diverted discharge from Norton pond to Maskeliya Oya

(maximum14.42m^3/s)

$Q_{Kitu.}$: Observed runoff records at Kitulgala GS(m^3/s)

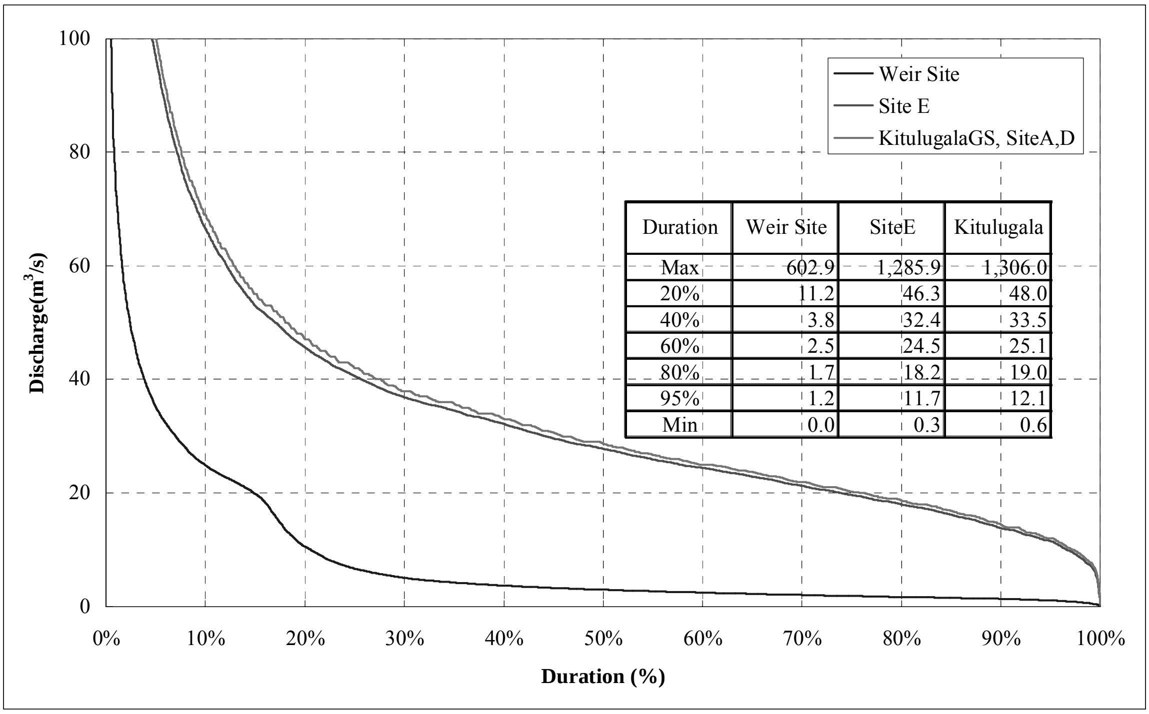
(2) Calculation Results

The summary of calculation results of low flow analysis at the candidate dam site of the Broadlands hydropower project is as follows;

Monthly Inflow at Candidate Dam Site of Broadlands Project

Site	CA (km^2)	type	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Kitulgala GS Site	388	Rain (mm)	380	311	184	102	108	184	306	355	396	330	275	301
		Runoff (m^3/s)	56.4	44.4	27.8	21.9	19.6	20.1	22.9	41.7	63.4	55.4	50.2	50.8
Dam Site A, D	388	Rain (mm)	380	311	184	102	108	184	306	355	396	330	275	301
		Runoff (m^3/s)	56.4	44.4	27.8	21.9	19.6	20.1	22.9	41.7	63.4	55.4	50.2	50.8
Dam Site E	201	Rain (mm)	429	331	186	103	112	193	327	418	494	410	348	367
		Runoff (m^3/s)	42.7	36.2	22.7	18.3	16.2	15.2	13.9	31.8	50.3	41.2	37.4	45.1
Weir Site	176	Rain (mm)	397	348	215	119	122	207	335	354	401	339	281	299
		Runoff (m^3/s)	12.7	7.3	4.8	3.2	3.2	5.1	9.1	9.2	11.9	13.8	12.3	13.1

Note: These results were estimated based on observed runoff from October 1950 to September 1998 at Kitulgala gauging Station.



Duration	Weir Site	SiteE	Kitulugala
Max	602.9	1,285.9	1,306.0
20%	11.2	46.3	48.0
40%	3.8	32.4	33.5
60%	2.5	24.5	25.1
80%	1.7	18.2	19.0
95%	1.2	11.7	12.1
Min	0.0	0.3	0.6

Inflow Duration Curve at Candidate Dam Site of Broadlands Project

4. Flood Analysis for Broadlands Hydropower Project

4.1 General

The design flood peaks at the intake dam site were determined by adopting the largest values estimated from the following alternative methods. The design flood peaks at the intake weir site were determined by adopting the largest values estimated from 1) flood runoff analysis and 2) frequiesncy analysis of flood peak. The value estimated by Creager's method was utilized for checking the design flood peak of the weir site.

- flood runoff analysis,
- frequency analysis of flood peak,
- Creager's method.

The scale of the flood peak adopted was a 1 in 10,000-year flood for the intake dam site and 1 in 1,000-year flood for the intake weir site in accordance with the experience of recent hydropower projects in Sri Lanka, as illustrated in the following table.

Design Floods at Intake Sites for Hydropower Projects in Sri Lanka

Projects	Intake dam	Intake weir	Note
Bowatenna HPP	1 in 1,000 year	-	Operating
Kukule HPP	1 in 10,000 year	-	Under construction
Upper Kotmale HPP	1 in 10,000 year	1 in 1,000 year	Planning
Broadlands HPP(F/S: 1986)	1 in 10,000 year	1 in 1,000 year	Planning

4.2 Flood Runoff Analysis

Flood runoff analysis was carried out using HEC-HMS software developed by the US Army Corps of Engineering. There are two methods of flood runoff analysis in HEC-HMS, the unit hydrograph method and the kinematic wave method. The kinematic wave method requires many parameters and it is difficult to determine these parameters correctly with only a few flood records. On the other hand, the unit hydrograph method requires only two parameters. Hence, the unit hydrograph method was adopted for flood runoff analysis.

(1) Rainfall Analysis

1) Daily Rainfall Records

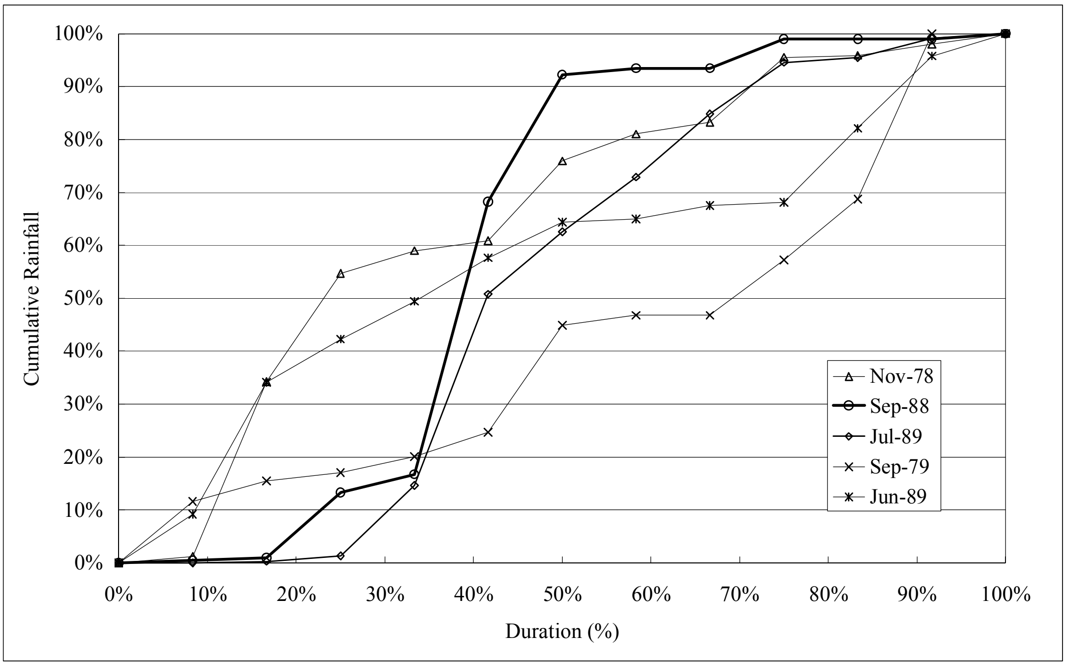
Daily rainfall was available from 11 gauging stations covering the intake river basin. The observation period for the data was 51 years, from October 1950 to September 2002. The average rainfall for the intake river basin was estimated based on these daily rainfall records.

2) Hourly Rainfall Records

Hourly rainfall records were observed at Ratnapura gauging station, which is close to the Kelani river system. The design hydrograph was determined based on the hourly rainfall record of the gauging station.

3) Design Hydrograph

The hourly rainfall data for 48-hour duration rainfall from Ratnapura gauging station was used to prepare the design hydrograph. The cumulative hourly rainfall patterns for five major 48-hour events recorded at Ratnapura gauging station are shown in the following figure.



Accumulated Hourly Rainfall Pattern (48-hr Rainfall) in Ratnapura GS

As seen in the above figure, the accumulated hourly rainfall pattern for July 1989 and June 1989 are fairly typical of normal events. On the other hand, the shape for the September 1988 event shows a concentrated accumulation rainfall pattern and it can be inferred that the flood peak value from this event would be high.

In this study, the hyetograph of September 1988 was adopted with a view to determining the peak flood value.

4) Probable Rainfall

Since the duration time of the hyetograph is 48-hours, a frequency analysis was carried out for two days total rainfall. The analysis applied three methods, the Hazen, Log-Pearson III and Gumbel type distributions. The results are shown in Tables 3 and 4 and Figures

16 to 18

As seen from these figures, the Log-Pearson III distribution was found to fit the data best and so the Log-Pearson III distribution was adopted.

(2) Parameters of the Unit Hydrograph

Calculation of the unit hydrograph adopted Snyder's unit hydrograph model, which is the simplest model available. Since there are few flood records, the parameters had to be estimated from recommended values.

Parameters of Snyder's unit hydrograph

C_p : Peak coefficient (0.4～0.8)

t_p : Related basin lag (hr)

$$t_p = 0.76 \cdot C_t \cdot (L \cdot L_c)^{0.3}$$

C_t : Basin coefficient (1.8～2.2)

L : Length of major river of the basin (m)

L_c : length from outlet to the centroid of the basin along the major river (m)

A value of 0.7 to 0.8 was adopted for parameter Cp in order to produce a high flood peak. The value of parameter Ct was set at 2.0, which is a middle value for the recommended range of 1.8 to 2.2.

The following table shows the results of calculations for tp.

River Basin	CA (km^2)	L (m)	Lc (m)	Ct	tp (hr)
Kitulgala GS	388	37	6	2.0	12
Maskeliya Oya	201	33	19	2.0	11
Kehelgamu Oya	176	40	17	2.0	11

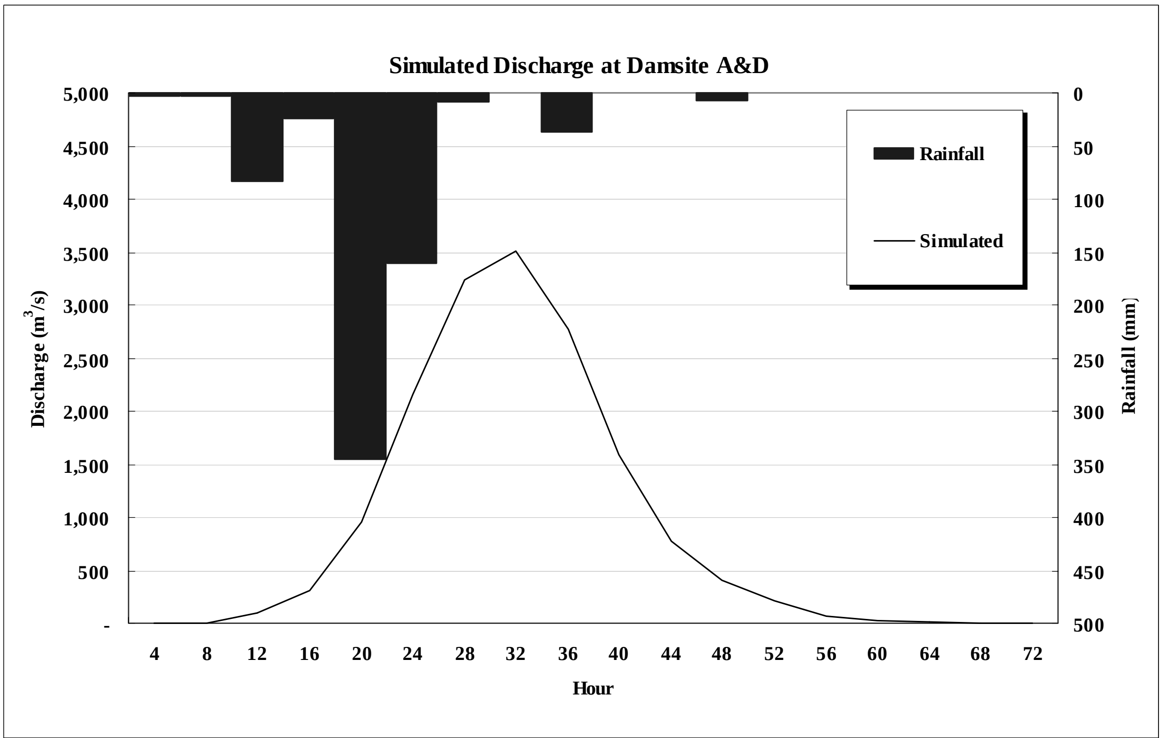
(3) Calculated Flood Peaks

The following table shows the unit hydrograph flood peaks at each site for a range of return periods.

The following figure shows an example flood hydrograph at damsite A and D.

Results of Flood Runoff Analysis by Unit Hydrograph（unit : m^3/sec)

Return Period	Damsite A, D	Damsite E	Weir Site
50year	1,738	1,007	824
100year	1,960	1,095	929
200year	2,182	1,187	1,187
1,000year	2,682	1,397	1,297
10,000year	3,514	1,667	



Results of 1:10,000 year flood runoff analysis by unit hydrograph (Dam Sites A and D)

(4) Frequency Analysis of Peak Flows at Kitulgala Gauging Stations

The results of frequency analysis of the peak flows from 1948 to 1985 at Kitulgala gauging station are shown in Table 5 and Figure 19.

The analysis applied three methods, the Hazen, Log-Pearson III and Gumbel type distributions. As seen from these figures, the Log-Pearson III distribution was found to fit the data best and so the Log-Pearson III distribution was adopted.

The flood peak at the Broadlands hydropower project was estimated from the catchment area ratio and average rainfall ratio based on the above results for Kitulgala gauging station.

$$Q_{pi} = Q_{pk} \times \frac{CA_i \times Rf_i}{CA_k \times Rf_k}$$

where Q_{pi} : flood peak at target site (m^3/s)

Q_{pk} : flood peak at Kitulgala GS (m^3/s)

CA_i : catchment area at target site (km^2)

CA_k : catchment area at Kitulgala GS (km^2)

Rf_i : annual rainfall at river basin of target site (mm)

Rf_k : annual rainfall at river basin of Kitulgala GS (mm)

Flood Peak by Frequency Analysis at Kitulgala GS and Candidate Damsite

(unit : m^3/sec)

Return Period	Kitulgala GS	Damsites A and D	Damsite E	Weir Site
Catchment Area (km^2)	388	388	201	176
Annual Rainfall (mm)	3,232.4	3,232.4	3717.4	3127.6
50year	1,810	1,810	964	774
100year	2,054	2,054	1,064	884
200year	2,307	2,307	1,167	998
1,000year	2,931	2,931	1,431	1,304
10,000year	3,927	3,927	1,761	

(5) Creager's Flood Peak

Creager's flood peak is calculated from

$$Q_p = (46 \times 0.02832) \times C \times (0.3861 \times A)^{(a-1)}$$

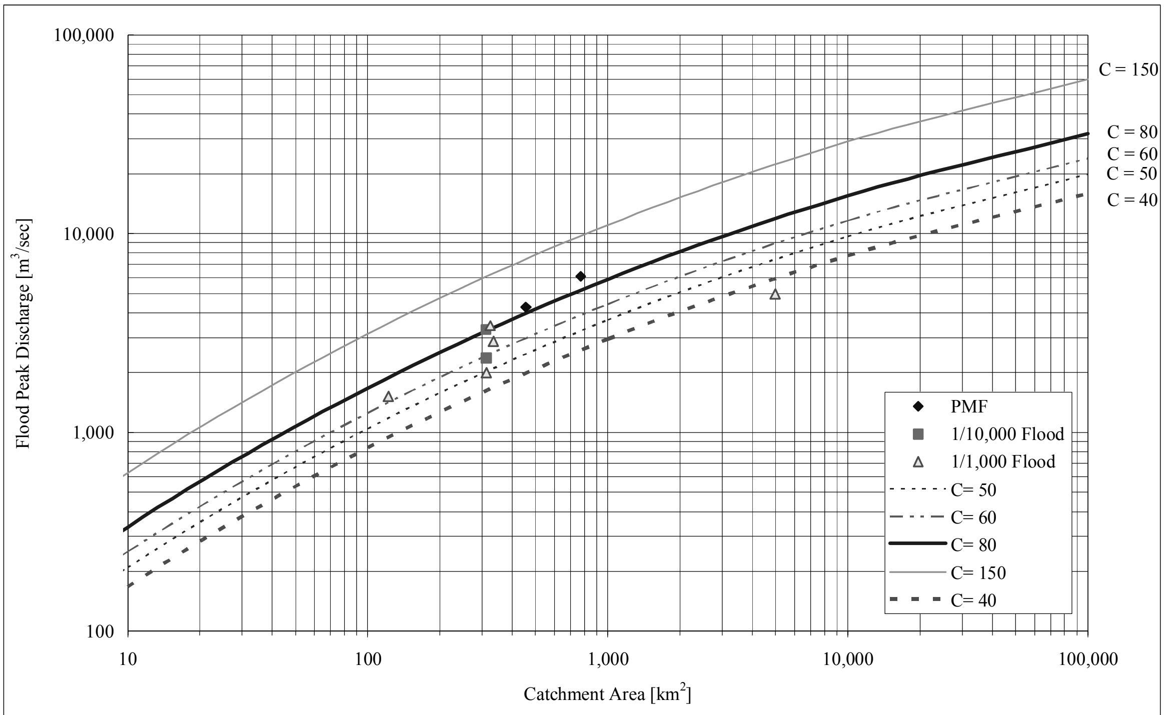
$$a = 0.894 \times (0.3861 \times A)^{-0.048}$$

where, Qp : Peak discharge [m^3/sec]

C : Creager's coefficient

A : Catchment area [km^2]

Generally, Creager's coefficient is adopted within the range 30 to 100. In Sri Lanka, for a catchment area of around 400 km^2, a value of 80 would be used, and for a catchment area of 200 km^2, a value of around 40 would be used. The results using Creager's equation are shown in the following table.



Design Flood for Dam in Sri Lanka

Flood Peak by Creager's Equation

Item	Damsite A, D	Damsite E	Weir Site
Catchment Area (km^2)	388	201	176
Creager's Coefficient C	80	60	60
Flood Peak (m^3/sec)	3,650	1,902	1,761

(6) Design Flood Peak.

The flood peaks obtained by the various methods for each site are shown in the tables below. The design flood peak adopted are 3,930 m^3/s, estimated by the frequency analysis, for the damsite A and D, 1,910 m^3/s, estimated by the Creager's equation, for the damsite E and 1,310 m^3/s, estimated by the frequency analysis, for the diversion weir site.

Flood Peak at Kitulgala GS site (Site A and D, CA = 388km^2)

Return Period	50	100	200	1,000	10,000
by Unit Hydrograph	1,738	1,960	2,182	2,682	3,514
by Frequency analysis of Peak flow	1,810	2,054	2,307	2,931	3,927
by Creager's Equation	3,650				
Adopted	1,810	2,060	2,310	2,940	**3,930**

Flood Peak at Maskeliya Oya (Site E, CA = 201km^2)

Return Period	50	100	200	1,000	10,000
by Unit Hydrograph	1,007	1,095	1,187	1,397	1,667
by Frequency analysis of Peak flow	964	1,064	1,167	1,431	1,761
by Creager's Equation			1,902		
Design Flood	1,010	1,100	1,190	1,440	**1,910**

Flood Peak at Kehelgamu Oya (Site E, CA = 176km^2)

Return Period	50	100	200	1,000
by Unit Hydrograph	824	929	1,187	1,297
by Frequency analysis of Peak flow	774	884	998	1,304
Design Flood	830	930	1,190	**1,310**

(7) Comparison of Design Flood Peaks

The results of the Feasibility Study conducted in 1986 and this JICA Study are compared in the following table.

Comparison of Design Flood Peak

	Damsite A and D	Damsite E	Weir Site
JICA Study	3,930	1,910	1,310
1986 FS	3,580	1,809	1,270

4.3 Design Flood for Construction Period

Design flood for construction of the Broadlands hydropower project is generally estimated by frequency analysis of the flood peaks. The result of frequency analysis at Kitulgala gauging station is shown in Table 5. The probable design flood for the candidate dam sites were estimated from catchment area ratio and average rainfall ratio based on the results of frequency analysis at Kitulgala gauging station. The calculation method is as same as 4.2 (2).

Design Flood for Construction at Candidate Dam Sites

Item		Kitulgala GS Site	Dam Site A & D	Dam Site E	Weir Site
Catchment Area (km^2)		388	388	201	176
Annual Rainfall (mm)		3,232.4	3,232.4	3717.4	3127.6
Return Period	2	700	700	420	310
	5	1,030	1,030	620	460
	10	1,270	1,270	760	560
	20	1,500	1,500	900	660
	30	1,640	1,640	980	720
	50	1,810	1,810	1,080	800

5. Sediment Yield of Broadlands Hydropower Project

5.1 Design and Measurements Value of Sediment Yield

The design value and measurement values of sediment yield in Sri Lanka are listed below.

According to below table, the design of Upper Kotmale hydropower project and Kukule hydropower project adopted sediment yield value of 180 and 320 $m^3/km^2/year$ respectively. These hydropower projects have a regulating pond same as the Broadlands hydropower project.

The measurement values of sediment yield were 182 to 320 $m^3/km^2/year$.

Design and Measurements Value of Sediment Yield

Location / Project Name	River Basin	Catchment Area (km^2)	Sediment Yield $m^3/km^2/year$	Note
Peradeiya	Mahaweli	1167	320	measured
Kirindi Oya		-	182	experimental value
Upper Kotmale	Mahaweli	310.6	180	design
Canyon	Kelani	20	218	design
Mousakelle	Kelani	130	1028	design
Kukule	Karu	312	320	design
Samanalawewa	Walawe	431.7	1750	design

5.2 Estimation using Measurement Value

The "Master Plan for the Electricity Supply of Sri Lanka 1988" described the formula of estimation of sediment yield of a target site based on measurement results of Peradeniya gauging station which is located in the Mahaweli river system. The formula is as follows;

$$S = \left(\frac{Pm^2}{P} \right)^b \cdot (H50 \cdot G)^c \ {}^1\!/_a \leq 500m^3/km^2/Year$$

where, S : sediment yield at target site ($m^3/km^2/year$)

Pm : average rainfall in wettest month (mm)

P : average rainfall at target site (mm)

H50 : average ground height of target river basin (m)

G : slope index

a = 317, b= 2.65, c= 0.46

Sediment Yield Estimated by Measurement Value

Item	Mark	Site A, D	Site E	Weir Site
Catchment area (km2)	CA	388	212	176
Mean rainfall in wettest month (mm)	Pm	396	494	401
Mean annual rainfall (mm)	P	3,232	3,717	3,417
Mean elevation of catchment area (m)	H50	1310	1350	1370
Slope index	G	0.035	0.035	0.035
Sediment yield (m^3/km^2)	S’	500	500	500

5.3 Estimation using Standard Formula

Since there are no survey results of sediment yield in Kelani river system, it is recommended to adopt the formula that consists of simple parameters. The following Ishigai’s formula is adopted for small river basins in Japan. The formula’s parameters consist of topographic condition, average rainfall and geological condition of a target river basin. Major geological features in Kelani river system is consists of gneiss of the Precambrian era and it is classified as Category B in Ishigai’s Formula.

$$\log S = 1.6\log(Rf \cdot P) - 9.52 \pm 1.16\sqrt{0.05 + (\log(Rf \cdot P) - 5.47)^2}$$

.... Ishigai ‘s Formula Category B

where, S : sediment yield (m^3/km^2/year)

Rf : average undulations of a target river basin (m)

P : annual total rainfall above 100mm (mm)

The estimated value of P=590mm, Rf = 590m at the candidate dam site of the Broadlands project were adopted to the above formula. The results are as follows;

S = 176, 598 (m^3/km^2/year)

5.4 Design Sediment Yield

The summary of the above results are follows.

The sediment yield of Broadlands project in Kelani river system is assumed to be form 200 to 600m^3/km^2/year. The design values of Upper Kotmale and Kukule hydropower project, which were 180 and 320 m^3/km^2/year respectively, were adopted.

Generally, a sediment yield is adopted based on design value of the other projects and the standard value is utilized to check the range of the sediment yield. Hence, the sediment yield adopted for the Broadlands project was 350 m^3/km^2/year. The value consists of design value of the Kukule hydropower project and allowance.

Design Sediment Yield

Items	Sediment Yield ($m^3/km^2/year$)	Note
Design value of the other projects	182 , 320	Upper Kotmale, Kukule project
Estimation using measurement value	500	maximum 500($m^3/km^2/year$)
Estimation using standard formula	176 to 598	
Adopted	350	

Table 1   List of Rainfall and Runoff Data in Gauging Stations (1 / 3)

Sta. No.	Station No.	Latitude			Longitude			Elevation	River Basin	40/41	41/42	42/43	43/44	44/45	45/46	46/47	47/48	48/49	49/50	50/51	51/52	52/53	53/54	54/55	55/56	56/57	57/58	58/59	59/60	60/61	61/62	62/63	63/64	65/66	66/67	67/68
M001	ABERGELDIE	06	55	06	80	33	49	1,097.0	Mahaweli									12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	9	11	12	12
M008	ALUPOTA	06	41	53	80	35	00	543.0	Kalu										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M015	AMBAWELA	06	53	29	80	47	47	1,828.0	Mahaweli													12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M021	ANGAMEDILLA	07	51	33	80	54	15	70.0	Mahaweli			9	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M023	ANNRFIELD	06	52	27	80	37	59	1,311.0	Kelani											12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M031	ARDLENEA	06	57	25	80	29	21	457.0	Kelani										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M038	BADULLA	06	59	27	81	03	15	677.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M040	BAKAMUNA	07	46	54	80	48	27	137.0	Mahaweli				12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	11	11	12	12	12	11	12	12	12
M041	BALANGODA	06	39	08	80	41	46	549.0	Walawe										12	12	12	12	12	12	12	12	12	12	12	12	12	11	11	12	9	10
M059	BLACKWATER	07	00	13	80	29	42	671.0	Mahaweli				12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	11	12	12	11	12	12	12
M060	BLACKWOOD ESTATE	06	45	41	80	55	33	1,158.0	Walawe				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12
M068	CALEDONIA	06	54	04	80	42	25	1,301.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M069	CAMPION	06	46	48	80	41	47	1,524.0	Kelani											12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M096	DELWITA ESTATE	07	31	37	80	31	12	149.0	Deduru				12	11	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12
M100	DETANAGALA	06	44	29	80	41	04	1,024.0	Walawe									12	11	11	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12
M103	DIGALLE ESTATE	06	57	31	80	17	46	122.0	Kelani										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M107	DIYATALAWA	06	49	07	80	57	29	1,256.0	Mahaweli				12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12
M115	DUNEDIN	07	02	32	80	16	07	122.0	Kelani										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M117	DYRAABE ESTATE	06	53	36	80	56	22	1,219.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M120	EHELIYAGODA	06	51	12	80	16	35	225.0	Kalu										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M126	ELKADUWA	07	25	14	80	41	09	853.0	Mahaweli				12	12	12	12	12	12	12	12	11	12	12	11	12	12	12	12	12	12	12	12	11	12	12	12
M146	GALPHELA	07	21	13	80	42	14	701.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M174	HAPUGASTENNA	06	43	36	80	30	22	594.0	Kalu										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11
M180	HELBODA NORTH	07	05	49	80	40	48	1,494.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12
M186	HINGURAKODA AGR.	08	03	13	80	56	57	70.0	Mahaweli				10	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M190	HOLMWOOD ESTATE	06	51	15	80	42	37	1,585.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M191	HOPE ESTATE	07	06	31	80	44	20	1,356.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M205	ILLUKKUMBURA	07	31	41	80	45	00	1,219.0	Mahaweli				12	12	12	12	12	11	10	12	10	12	12	11	12	12	11	12	12	12	12	10	9	12	12	12
M209	INGOYA ESTATE	07	00	35	80	25	51	305.0	Kelani										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M219	KADUGANNAWA	07	15	26	80	20	58	518.0	Maha				12	12	12	12	12	12	12	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M223	KAL BAR	08	16	04	81	16	04	12.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	10	12	6	12	11
M238	KANDAKETIYA	07	10	20	81	00	25	122.0	Mahaweli								12	11	11	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	11	12
M263	KEENAKELLE	07	03	10	81	00	52	1,177.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M270	KRNILWORTH	06	59	37	80	28	30	762.0	Mahaweli									12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M280	KIRIKLEES ESTATE	06	59	13	80	56	03	1,433.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M283	KOBANELLA	07	21	15	80	50	21	1,372.0	Mahaweli				12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	7	11	12	12	12	12	12	12
M309	LEGERWATTA ESTATE	07	01	49	80	00	38	1,219.0	Mahaweli				12	12	12	12	12			12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M313	LIDDESDLE ESTATE	07	01	47	80	51	12	509.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M314	LIMYAGALA ESTATE	06	55	57	80	21	41	259.0	Kelani										12	12	12	12	12	12	12	12	12	12	12	12	0	0	0	0	0	0
M317	LOWER SPRING VALLEY	06	55	21	81	05	51	1,113.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M328	MAHADOWA ESTATE	07	03	37	80	38	34	1,390.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	9	12
M337	MAHAWELATENNA	06	35	31	80	44	44	549.0	Walawe			12	12	12	12	12	12	11	12	12	12	12	12	12										12	12	12
M377	MILLAWANA	07	39	44	80	33	08	183.0	Deduru				12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12
M382	MINNERIYA TANK	08	02	33	80	53	36	95.0	Mahaweli				11	9	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12
M410	NANU OYA	06	56	35	80	44	25	1,628.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	10	2	10	12
M419	NAWALAPITIYA	07	03	48	80	31	31	1,158.0	Mahaweli				12	12	12	12	12	12	11	12	12	12	12	12	12	12	10	9	12	12	12	12	12	12	12	12
M423	NEW FOREST	07	08	53	80	40	34	1,067.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12
M430	NORTON BRIDGE	06	54	56	80	31	06	893.0	Kelani																											
M431	NORWOOD	06	50	38	80	35	59	1,122.0	Kelani				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M433	NUWARA ERIYA MET STATION	06	58	31	80	46	10	1,895.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M435	OHIYA FOREST	06	49	12	80	50	22	1,774.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	11	12
M440	OONAGALLA ESTATE	07	02	15	80	35	49	1,219.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	11	11	12
M470	PATHIGAMA ESTATE	07	10	04	80	41	52	1,067.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12
M475	PERADENIYA GARDENS	07	16	15	80	35	28	469.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	11	8	12	12	12
M610	WRIYAPOLA	07	27	47	80	37	37	365.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M612	WATAGOGD	06	58	01	80	38	57	1,910.0	Mahaweli											12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	11
M614	WATAWALA	06	57	43	80	31	22	960.0	Mahaweli				12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M620	WELIMADA GROUP	06	54	26	80	53	48	1,155.0	Mahaweli				12	12	11	12	11	12	12	12	12	12	12	12	12	11	12	12	11	12	12	11	12	11	12	12
M626	WEWLITALAWA	07	03	14	80	22	57		Kelani										12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M627	WEWESSE ESTATE	06	58	08	81	06	18	914.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	11	11
M628	WIHARAGAMA ESTATE	07	29	48	80	38	31	1,067.0	Mahaweli											11	12	12	12	12	12	11	12	12	12	11	12	12	11	12	9	12
M631	WOODSIDE ESTATE	07	15	52	80	49	39	1,067.0	Mahaweli				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	7
0105	DERANIYAGALA	06	55	30	80	20	15	82.0	Kelani									11	12	12	12	12	12	12	12	12	12	12	12	12	12	7	12	12	11	12
0106	KITULUGALA	06	59	30	80	24	45	56.0	Kelani									12	8	12	12	10	12	12	11	11	11	12	12	12	12	12	12	12	12	12
0107	MOUSAKELLE	06	50	15	80	33	00	1,158.0	Kelani									12	11	12	12	12	12	12	12	12	12	12	9	12	12	12	12	12	11	12

[Note]   12: Conplete months of records   1 to 11: Nunber (1 to 11) of completed monthes ofrecords

Table 1   List of Rainfall and Runoff Data in Gauging Stations (2 / 3)

Sta. No.	Station No.	Latitude			Longitude			Elevation	River Basin	68/69	69/70	70/71	71/72	72/73	73/74	74/75	75/76	76/77	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94	94/95
M001	ABERGELDIE	06	55	06	80	33	49	1,097.0	Mahaweli	12	12	12	11	6	0	0	9	12	12	12	12	12	12	12	12	12	11	12	10	12	12	11	12	12	11	11
M008	ALUPOTA	06	41	53	80	35	00	543.0	Kalu	12	11	12	12	12	12	12	12	12	12	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M015	AMBAWELA	06	53	29	80	47	47	1,828.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	9	0	10
M021	ANGAMEDILLA	07	51	33	80	54	15	70.0	Mahaweli	11	12	12	12	12	12	12	12	9	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12
M023	ANNRFIELD	06	52	27	80	37	59	1,311.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M031	ARDLENEA	06	57	25	80	29	21	457.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12										
M038	BADULLA	06	59	27	81	03	15	677.0	Mahaweli	12	12	11	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	11	11	12	12	12	12	12	12
M040	BAKAMUNA	07	46	54	80	48	27	137.0	Mahaweli	6	12	11	12	11	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	11	0
M041	BALANGODA	06	39	08	80	41	46	549.0	Walawe	3	1	11	7	12	12	12	11	7	10	12	12	9	5	12	12	12	12	12	12	12	12	12	12	12	12	10
M059	BLACKWATER	07	00	13	80	29	42	671.0	Mahaweli	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12					
M060	BLACKWOOD ESTATE	06	45	41	80	55	33	1,158.0	Walawe	12	12	11	11	12	12	12	12																			
M068	CALEDONIA	06	54	04	80	42	25	1,301.0	Mahaweli	12	2																									
M069	CAMPION	06	46	48	80	41	47	1,524.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	12	11	12	12	12
M096	DELWITA ESTATE	07	31	37	80	31	12	149.0	Deduru	12	12	9	12	12	12	12	12	12	12	12	12	11	12	12	12	12	10	9	9	11	12	12	11	12	12	12
M100	DETANAGALA	06	44	29	80	41	04	1,024.0	Walawe	12	12	12	12	12	12	12	12	12	11	12	12	12	8	12	12	12	12	12	12	12	12	12	12	10	12	12
M103	DIGALLE ESTATE	06	57	31	80	17	46	122.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	4	12	12	12	11	12	11	12	12	12	12
M107	DIYATALAWA	06	49	07	80	57	29	1,256.0	Mahaweli	9	12	12	12	12	11	11	12	12	12	10	12	12	12	12	12	12	12	12	12	9	10	8	8	12	12	10
M115	DUNEDIN	07	02	32	80	16	07	122.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12
M117	DYRAABE ESTATE	06	53	36	80	56	22	1,219.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	11	12	12	12	12	12	12	12	12
M120	EHELIYAGODA	06	51	12	80	16	35	225.0	Kalu	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12
M126	ELKADUWA	07	25	14	80	41	09	853.0	Mahaweli	12	12	11	12	12	12	12	12	11	12	9	12	12	11	10	5	12	12	12	12	12	12	12	12	12	12	11
M146	GALPHELA	07	21	13	80	42	14	701.0	Mahaweli	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12
M174	HAPUGASTENNA	06	43	36	80	30	22	594.0	Kalu	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M180	HELBODA NORTH	07	05	49	80	40	48	1,494.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	11	12	12
M186	HINGURAKODA AGR.	08	03	13	80	56	57	70.0	Mahaweli	12	12	12	12	12	12	12	12	12	11	12	12	12	12	11	11	12	10	11	12	11	12	12	12	12	11	12
M190	HOLMWOOD ESTATE	06	51	15	80	42	37	1,585.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	11	12	12	12	12	12	12	12	12	12
M191	HOPE ESTATE	07	06	31	80	44	20	1,356.0	Mahaweli	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M205	ILLUKKUMBURA	07	31	41	80	45	00	1,219.0	Mahaweli	12	12	12	12	12	12	12	12											12	12	12	12	12	12	11	8	12
M209	INGOYA ESTATE	07	00	35	80	25	51	305.0	Kelani	12	12	12	12	12	12	12	12	11	11	12	12	11	12	12	12	12	12	12	12	3	9					
M219	KADUGANNAWA	07	15	26	80	20	58	518.0	Maha	12	4	10	12	12	12	2																				
M223	KAL BAR	08	16	04	81	16	04	12.0	Mahaweli	10	12	12	12	12	12	12	4	4	11	12				12	12	12	12	12	12	12	12	12	12	12	12	12
M238	KANDAKETIYA	07	10	20	81	00	25	122.0	Mahaweli	12	9	4	11	12	9	8	3			6	5	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M263	KEENAKELLE	07	03	10	81	00	52	1,177.0	Mahaweli	12	8	9	12	12	12	12	12	12	12	12	11	12	12	12	12	12	11	12	12	12	11	10	12	12	12	12
M270	KRNILWORTH	06	59	37	80	28	30	762.0	Mahaweli	12	12	12	11	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M280	KIRIKLEES ESTATE	06	59	13	80	56	03	1,433.0	Mahaweli	12	12	12	11	12	11	12	12	11	11	12	12	12	12	12	12	12	12	12	12	11	11	12	12	12	12	12
M283	KOBANELLA	07	21	15	80	50	21	1,372.0	Mahaweli	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	12
M309	LEGERWATTA ESTATE	07	01	49	80	00	38	1,219.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12
M313	LIDDESDLE ESTATE	07	01	47	80	51	12	509.0	Mahaweli	12	12	12	12	12	12	12	11	10	11	12	12	12	12	12	11	12	12	12	12	12	12	11	12	12	12	12
M314	LIMYAGALA ESTATE	06	55	57	80	21	41	259.0	Kelani	0	9	12	12	12	11	12	12	11	12	12	12	9	12	12	12	12	12	12	11	11	11	12	12	5	8	7
M317	LOWER SPRING VALLEY	06	55	21	81	05	51	1,113.0	Mahaweli	12	12	12	12	12	12	12	12	11	12	12	12	11			12	12	12	12	12	12	12	12	12	12	12	12
M328	MAHADOWA ESTATE	07	03	37	80	38	34	1,390.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	12	11	12	12	12	11	12	12	12	12	12
M337	MAHAWELATENNA	06	35	31	80	44	44	549.0	Walawe	12	12	12	12	12	12	12	12	12	12	12	12	12	10	6	12											
M377	MILLAWANA	07	39	44	80	33	08	183.0	Deduru	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	10	12	12	12	12	12	12
M382	MINNERIYA TANK	08	02	33	80	53	36	95.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	11	12	12	12	10	12	11	12
M410	NANU OYA	06	56	35	80	44	25	1,628.0	Mahaweli	9	7	12	12	12	12	7	7																			
M419	NAWALAPITIYA	07	03	48	80	31	31	1,158.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	11	12	12	9	12	12	12	12	12	12
M423	NEW FOREST	07	08	53	80	40	34	1,067.0	Mahaweli	12	11	12	12	12	9	10	12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	12	12	12	12
M430	NORTON BRIDGE	06	54	56	80	31	06	893.0	Kelani																	12	12	12	12	11	11	12	12	12	12	12
M431	NORWOOD	06	50	38	80	35	59	1,122.0	Kelani	12	0	2	12	12	12	12	12	12	12	12	12	12	12	12	12	11	9	11	12	12	12	12				
M433	NUWARA ERIYA MET STATION	06	58	31	80	46	10	1,895.0	Mahaweli	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
M435	OHIYA FOREST	06	49	12	80	50	22	1,774.0	Mahaweli	5																										
M440	OONAGALLA ESTATE	07	02	15	80	35	49	1,219.0	Mahaweli	12	12	12	12	11	3			12	11	12	11	12	12	12	12	12	12	12								
M470	PATHIGAMA ESTATE	07	10	04	80	41	52	1,067.0	Mahaweli	12	12	11	12	12	12	12	12	12	12	8	12	9	12	12	12	12	12	12	12	12	12	12	11	12	12	10
M475	PERADENIYA GARDENS	07	16	15	80	35	28	469.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	10	12	12	12	12	10	12	5	4	12	12	12
M610	WRIYAPOLA	07	27	47	80	37	37	365.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	12	12	12	12	12
M612	WATAGOGD	06	58	01	80	38	57	1,910.0	Mahaweli	12	12	12	12	12	12	12	12	12	11	12	10	11	10	3	0	9	4									
M614	WATAWALA	06	57	43	80	31	22	960.0	Mahaweli	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12	12	12	12	12	12	12	11	12	6
M620	WELIMADA GROUP	06	54	26	80	53	48	1,155.0	Mahaweli	11	12	11	11	12	12	12	11	12	12	11	12	12	12	11	12	12	12	11	12	12	12	12	12	12	12	12
M626	WEWLITALAWA	07	03	14	80	22	57		Kelani	11	12	12	12	12	12	12	12	12	12	12	12	8	12	12	12	12	12	12	12	12	12	12	11	12	12	12
M627	WEWESSE ESTATE	06	58	08	81	06	18	914.0	Mahaweli	12	12	12	12	11	8	7	11	12	12	12	12	12	12	12	12	12	11	12	4	9	12	12	11	12	12	12
M628	WIHARAGAMA ESTATE	07	29	48	80	38	31	1,067.0	Mahaweli	12	6	11	12	12	12	12	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12	12	12
M631	WOODSIDE ESTATE	07	15	52	80	49	39	1,067.0	Mahaweli				11				9	12	12	12	12	12	11	11	12	12	11	12	12	12	12	12	11	12	12	12
0105	DERANIYAGALA	06	55	30	80	20	15	82.0	Kelani	10	12	12	12	12	11	12	12	12	11	0	0	0	0	0	0	12	12	12	12	9	12	12	12	12	12	12
0106	KITULUGALA	06	59	30	80	24	45	56.0	Kelani	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
0107	MOUSAKELLE	06	50	15	80	33	00	1,158.0	Kelani	4																										

[Note]   12: Conplete months of records   1 to 11: Nunber (1 to 11) of compl

Table 1 List of Rainfall and Runoff Data in Gauging Stations (3 / 3)

Sta. No.	Station No.	Latitude			Longitude			Elevation	River Basin	95/96	96/97	97/98	98/99	99/00	00/01
M001	ABERGELDIE	06	55	06	80	33	49	1,097.0	Mahaweli	10	11	12	12	12	12
M008	ALUPOTA	06	41	53	80	35	00	543.0	Kalu	12	12	12	12	12	12
M015	AMBAWELA	06	53	29	80	47	47	1,828.0	Mahaweli	11	11	12	12		
M021	ANGAMEDILLA	07	51	33	80	54	15	70.0	Mahaweli	12	11	12	12	12	12
M023	ANNRFIELD	06	52	27	80	37	59	1,311.0	Kelani	12	10	12	12	12	
M031	ARDLENEA	06	57	25	80	29	21	457.0	Kelani						
M038	BADULLA	06	59	27	81	03	15	677.0	Mahaweli	12	11	12	12	12	12
M040	BAKAMUNA	07	46	54	80	48	27	137.0	Mahaweli	12	12	12	12	12	12
M041	BALANGODA	06	39	08	80	41	46	549.0	Walawe	12	11	12	12	12	12
M059	BLACKWATER	07	00	13	80	29	42	671.0	Mahaweli						
M060	BLACKWOOD ESTATE	06	45	41	80	55	33	1,158.0	Walawe						
M068	CALEDONIA	06	54	04	80	42	25	1,301.0	Mahaweli						
M069	CAMPION	06	46	48	80	41	47	1,524.0	Kelani	12	12	12	12	12	
M096	DELWITA ESTATE	07	31	37	80	31	12	149.0	Deduru	12	12	12	12	12	12
M100	DETANAGALA	06	44	29	80	41	04	1,024.0	Walawe	12	12	12	12	11	12
M103	DIGALLE ESTATE	06	57	31	80	17	46	122.0	Kelani	4	0	11	12	12	12
M107	DIYATALAWA	06	49	07	80	57	29	1,256.0	Mahaweli	12	12	11	11	8	12
M115	DUNEDIN	07	02	32	80	16	07	122.0	Kelani	11	12	12	12	12	12
M117	DYRAABE ESTATE	06	53	36	80	56	22	1,219.0	Mahaweli	12	12	12	12	12	12
M120	EHELIYAGODA	06	51	12	80	16	35	225.0	Kalu	12	12	12	12	12	12
M126	ELKADUWA	07	25	14	80	41	09	853.0	Mahaweli	12	11	11	9	12	12
M146	GALPHELA	07	21	13	80	42	14	701.0	Mahaweli	12	12	11	10	10	11
M174	HAPUGASTENNA	06	43	36	80	30	22	594.0	Kalu	12	12	12	12	12	12
M180	HELBODA NORTH	07	05	49	80	40	48	1,494.0	Mahaweli	12	12	12	12	12	4
M186	HINGURAKODA AGR.	08	03	13	80	56	57	70.0	Mahaweli	12	12	12	5	9	12
M190	HOLMWOOD ESTATE	06	51	15	80	42	37	1,585.0	Mahaweli	12	12	12	12	12	
M191	HOPE ESTATE	07	06	31	80	44	20	1,356.0	Mahaweli	12	12	12	12	12	11
M205	ILLUKKUMBURA	07	31	41	80	45	00	1,219.0	Mahaweli	12	10	12	12	12	12
M209	INGOYA ESTATE	07	00	35	80	25	51	305.0	Kelani						
M219	KADUGANNAWA	07	15	26	80	20	58	518.0	Maha						
M223	KAL BAR	08	16	04	81	16	04	12.0	Mahaweli	12	12	12	12	12	12
M238	KANDAKETIYA	07	10	20	81	00	25	122.0	Mahaweli	12	12	12	12	12	12
M263	KEENAKELLE	07	03	10	81	00	52	1,177.0	Mahaweli	9	12	12	12	12	12
M270	KRNILWORTH	06	59	37	80	28	30	762.0	Mahaweli	12	12	12	12	12	12
M280	KIRIKLEES ESTATE	06	59	13	80	56	03	1,433.0	Mahaweli	11	11	12	12	12	12
M283	KOBANELLA	07	21	15	80	50	21	1,372.0	Mahaweli	12	12	12	12	12	12
M309	LEGERWATTA ESTATE	07	01	49	80	00	38	1,219.0	Mahaweli	12	11	12	12	12	12
M313	LIDDESDLE ESTATE	07	01	47	80	51	12	509.0	Mahaweli	12	12	12	12	11	12
M314	LIMYAGALA ESTATE	06	55	57	80	21	41	259.0	Kelani	12	9	8			
M317	LOWER SPRING VALLEY	06	55	21	81	05	51	1,113.0	Mahaweli	12	12	12	12	12	12
M328	MAHADOWA ESTATE	07	03	37	80	38	34	1,390.0	Mahaweli	12	11	10	12	12	12
M337	MAHAWELATENNA	06	35	31	80	44	44	549.0	Walawe						
M377	MILLAWANA	07	39	44	80	33	08	183.0	Deduru	12	12	12	12	12	12
M382	MINNERIYA TANK	08	02	33	80	53	36	95.0	Mahaweli	12	12	12	12	12	12
M410	NANU OYA	06	56	35	80	44	25	1,628.0	Mahaweli						
M419	NAWALAPITIYA	07	03	48	80	31	31	1,158.0	Mahaweli	11	12	12	10	12	12
M423	NEW FOREST	07	08	53	80	40	34	1,067.0	Mahaweli	12	12	12	12	12	12
M430	NORTON BRIDGE	06	54	56	80	31	06	893.0	Kelani	12	12	12	12	12	12
M431	NORWOOD	06	50	38	80	35	59	1,122.0	Kelani						
M433	NUWARA ERIYA MET STATION	06	58	31	80	46	10	1,895.0	Mahaweli	12	12	12	12	12	
M435	OHIYA FOREST	06	49	12	80	50	22	1,774.0	Mahaweli						
M440	OONAGALLA ESTATE	07	02	15	80	35	49	1,219.0	Mahaweli						
M470	PATHIGAMA ESTATE	07	10	04	80	41	52	1,067.0	Mahaweli						
M475	PERADENIYA GARDENS	07	16	15	80	35	28	469.0	Mahaweli	11	12	2	12	10	12
M610	WRIYAPOLA	07	27	47	80	37	37	365.0	Mahaweli	12	12	12	12	12	12
M612	WATAGOGD	06	58	01	80	38	57	1,910.0	Mahaweli						
M614	WATAWALA	06	57	43	80	31	22	960.0	Mahaweli	9					
M620	WELIMADA GROUP	06	54	26	80	53	48	1,155.0	Mahaweli	12	11	12	12	12	12
M626	WEWLITALAWA	07	03	14	80	22	57		Kelani	12	12	12	12	12	12
M627	WEWESSE ESTATE	06	58	08	81	06	18	914.0	Mahaweli	12	12	12	12	11	12
M628	WIHARAGAMA ESTATE	07	29	48	80	38	31	1,067.0	Mahaweli	12	12	12	12	12	12
M631	WOODSIDE ESTATE	07	15	52	80	49	39	1,067.0	Mahaweli	12	12	12	12	12	12
0105	DERANIYAGALA	06	55	30	80	20	15	82.0	Kelani	12	12	12			
0106	KITULUGALA	06	59	30	80	24	45	56.0	Kelani	12	12	12			
0107	MOUSAKELLE	06	50	15	80	33	00	1,158.0	Kelani						

[Note] 12: Conplete months of records 1 to 11: Nunber (1 to 11) of compl

Table 2 Selected Gauging Stations in and around the Target River Basin

Station Code	Station Name	Latitude	Longitude	Elevation	River Basin
Kelani and Walawe River Basin					
M008	ALUPOTA	06-41-53N	80-35-00E	543	Kalu
M023	ANNEFIELD	06-52-27N	80-37-59E	1,311	Kelani
M031	ARDLENEA	06-57-25N	80-29-21E	457	Kelani
M041	BALANGODA	06-39-08N	80-41-46E	549	Walawe
M069	CAMPION	06-46-48N	80-41-47E	1,524	Kelani
M100	DETANAGALA	06-44-29N	80-41-04E	1,024	Walawe
M103	DIGALLE ESTATE	06-57-31N	80-17-46E	122	Kelani
M115	DUNEDIN	07-02-32N	80-16-07E	122	Kelani
M174	HAPUGASTENNA	06-43-36N	80-30-22E	594	Kalu
M209	INGOYA ESTATE	07-00-35N	80-25-51E	305	Kelani
M430	NORTON BRIDGE	06-54-56N	80-31-06E	803	Kelani
M431	NORWOOD	06-50-38N	80-35-59E	1,122	Kelani
M626	WEWLITALAWA	07-03-14N	80-22-57E	-	Kelani
Mahaweli River Basin					
M001	ABERGELDIE	06-55-06N	80-33-49E	1,097	Mahaweli
M015	AMBAWELA	06-53-29N	80-47-47E	1,828	Mahaweli
M180	HELBODA NORTH	07-05-49N	80-40-48E	1,494	Mahaweli
M190	HOLMWOOD ESTATE	06-51-15N	80-42-37E	1,585	Mahaweli
M191	HOPE ESTATE	07-06-31N	80-44-20E	1,356	Mahaweli
M433	NUWARA ELIYA	06-58-51N	80-46-10E	1,895	Mahaweli
M470	PATHIGAMA ESTATE	07-10-04N	80-41-52E	1,067	Mahaweli
M475	PERADENIYA GARDENS	07-16-15N	80-35-28E	465	Mahaweli
M614	WATAWLA	06-57-43N	80-31-22E	960	Mahaweli
M631	WOODSUDE ESTATE	07-15-52N	80-49-39E	1,067	Mahaweli
M038	BADULLA	06-59-27N	81-03-15E	677	Mahaweli
M107	DIYATALAWA	06-49-07N	80-57-29E	1,256	Mahaweli
M238	KANDAKETIYA	07-10-20N	81-00-25E	122	Mahaweli
M263	KEENAKELLE	07-03-10N	81-00-52	1,177	Mahaweli
M280	KIRKLESS ESTATE	06-59-13N	80-56-03E	1,433	Mahaweli
M313	LIDDESDLE	07-01-47N	80-51-12E	509	Mahaweli
M317	LOWER SPRING VALLEY	06-55-21N	81-05-51E	1,113	Mahaweli
M328	MAHADOWA ESTATE	07-03-37N	80-38-34E	1,390	Mahaweli
M620	WELIMADA GROUP	06-54-26N	80-53-48E	1,155	Mahaweli
M021	ANGAMEDILLA	07-51-33N	80-54-15E	70	Mahaweli
M040	BAKAMUNA	07-46-54N	80-48-27E	137	Mahaweli
M096	DELWITA ESTATE	07-31-37N	80-31-12E	149	Deduru
M146	GALPHELA	07-21-13N	80-42-14E	701	Mahaweli
M186	HINGURAKGODA	08-03-13N	80-56-57E	70	Mahaweli
M205	ILLUKKUMBURA	07-31-41N	80-45-00E	1,219	Mahaweli
M283	KOBANELLA	07-21-15N	80-50-21E	1,372	Mahaweli
M377	MILLAWANA	07-39-44N	80-33-08E	183	Deduru
M382	MINNERIYA TANK	08-02-33N	80-02-36E	95	Mahaweli
M628	WIHARAGAMA ESTATE	07-29-48N	80-38-31E	1,067	Mahaweli

Table 3 Results of Frequency Analysis of 2-days Rainfall (1/2)

Data Type : 2-days Toatal Rainfall
STATION : Intake Site D STREAM : Kelani Ganga
RIVER SYSTEM : Kelani RS
KIND OF RECORD : PEAK DISCHRGE IN EACH YEAR
PERIOD : Oct.1950 to Sep.2001

RETURN PERIOD	PROBABILITY	HAZEN	Log-Pearson III	GUMBEL
1.01	0.9901	59	60	49
1.5	0.6667	130	127	128
2	0.5000	154	151	153
5	0.2000	212	211	215
10	0.1000	250	252	256
20	0.0500	284	291	296
30	0.0333	304	314	319
40	0.0250	318	330	335
50	0.0200	328	342	347
80	0.0125	350	369	373
100	0.0100	360	382	385
200	0.0050	392	422	423
1000	0.0010	465	518	512
10000	0.0001	568	666	638

Data Type : 2-days Toatal Rainfall
STATION : Intake Site E STREAM : Maskeli Oya
RIVER SYSTEM : Kelani RS
KIND OF RECORD : PEAK DISCHRGE IN EACH YEAR
PERIOD : Oct.1950 to Sep.2001

RETURN PERIOD	PROBABILITY	HAZEN	Log-Pearson III	GUMBEL
1.01	0.9901	69	70	61
1.5	0.6667	148	143	144
2	0.5000	173	169	170
5	0.2000	234	232	236
10	0.1000	272	274	279
20	0.0500	306	315	321
30	0.0333	326	338	344
40	0.0250	339	355	361
50	0.0200	350	367	374
80	0.0125	371	395	402
100	0.0100	381	408	415
200	0.0050	412	448	455
1000	0.0010	481	544	548
10000	0.0001	577	691	681

Table 4 Results of Frequency Analysis of 2-days Rainfall (2/2)

Data Type : 2-days Toatal Rainfall
STATION : Weir Site STREAM : Kehelgamu Oya
RIVER SYSTEM : Kelani RS
KIND OF RECORD : PEAK DISCHRGE IN EACH YEAR
PERIOD : Oct.1950 to Sep.2001

RETURN PERIOD	PROBABILITY	HAZEN	Log-Pearson III	GUMBEL
1.01	0.9901	57	59	45
1.5	0.6667	120	120	120
2	0.5000	143	141	144
5	0.2000	199	197	203
10	0.1000	237	236	243
20	0.0500	274	274	280
30	0.0333	295	296	302
40	0.0250	310	312	317
50	0.0200	322	324	329
80	0.0125	346	351	354
100	0.0100	358	363	366
200	0.0050	395	404	402
1000	0.0010	484	503	486
10000	0.0001	621	660	607

Table 5 Results of Frequency Analysis of Peak Discharge

Data Type : Runoff Discharge
STATION : Kitukugala GS STREAM : Kelani Ganga
RIVER SYSTEM : Kelani RS DRAINAGE AREA : 388km^2
KIND OF RECORD : PEAK DISCHRGE IN EACH YEAR
PERIOD : Oct.1950 to Sep.1985

RETURN PERIOD	PROBABILITY	HAZEN	Log-Pearson III	GUMBEL
1.01	0.9901	235	235	119
1.5	0.6667	592	570	572
2	0.5000	720	696	718
5	0.2000	1,039	1,030	1,075
10	0.1000	1,249	1,263	1,312
20	0.0500	1,449	1,496	1,540
30	0.0333	1,563	1,634	1,671
40	0.0250	1,643	1,732	1,763
50	0.0200	1,704	1,810	1,834
80	0.0125	1,833	1,975	1,984
100	0.0100	1,894	2,054	2,055
200	0.0050	2,083	2,307	2,274
1000	0.0010	2,520	2,931	2,783
10000	0.0001	3,150	3,927	3,510

Table 6 Monthy Flood Peaks in Kelani Ganga at Kitulugala Gauging Station

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1985	41	41	43	66	880	844	925	210	210	306	470	181
1986	78	180	35	52	53	142	113	264	188	268	70	36
1987	29	29	41	40	47	171	51	211	57	105	100	66
1988	33	27	34	130	565	174	481	808	105	68	116	36
1989	32	32	34	52	1,936	1,646	727	251	226	169	186	123
1990	50	37	46	41	704	127	113	158	25	54	247	45
1991	47	59	57	47	37	122	158	105	84	278	96	46
1992	50	39	41	41	57	886	832	398	158	626	374	113
1993	43	45	44	42	247	853	234	142	68	577	101	71
1994	33	41	31	31	75	77	413	240	165	268	288	59
1995	48	41	47	68	174	704	139	136	260	727	195	44
1996	44	43	41	96	45	247	384	168	429	264	139	45
1997	43	46	51	92	57	70	310	67	337	192	195	101
1998	49	45	46	44	108	168	104	113	406	202	119	115
1999	61	34	34	150	762	441	55	100	113	139	47	37
2000	53	53	36	33	289	94	94	98	113	217	36	36
2001	36	70	17	30	63	47	228	56	142	94	59	37
2002	37	34	18	41	61	365	183	276	36	94	142	43

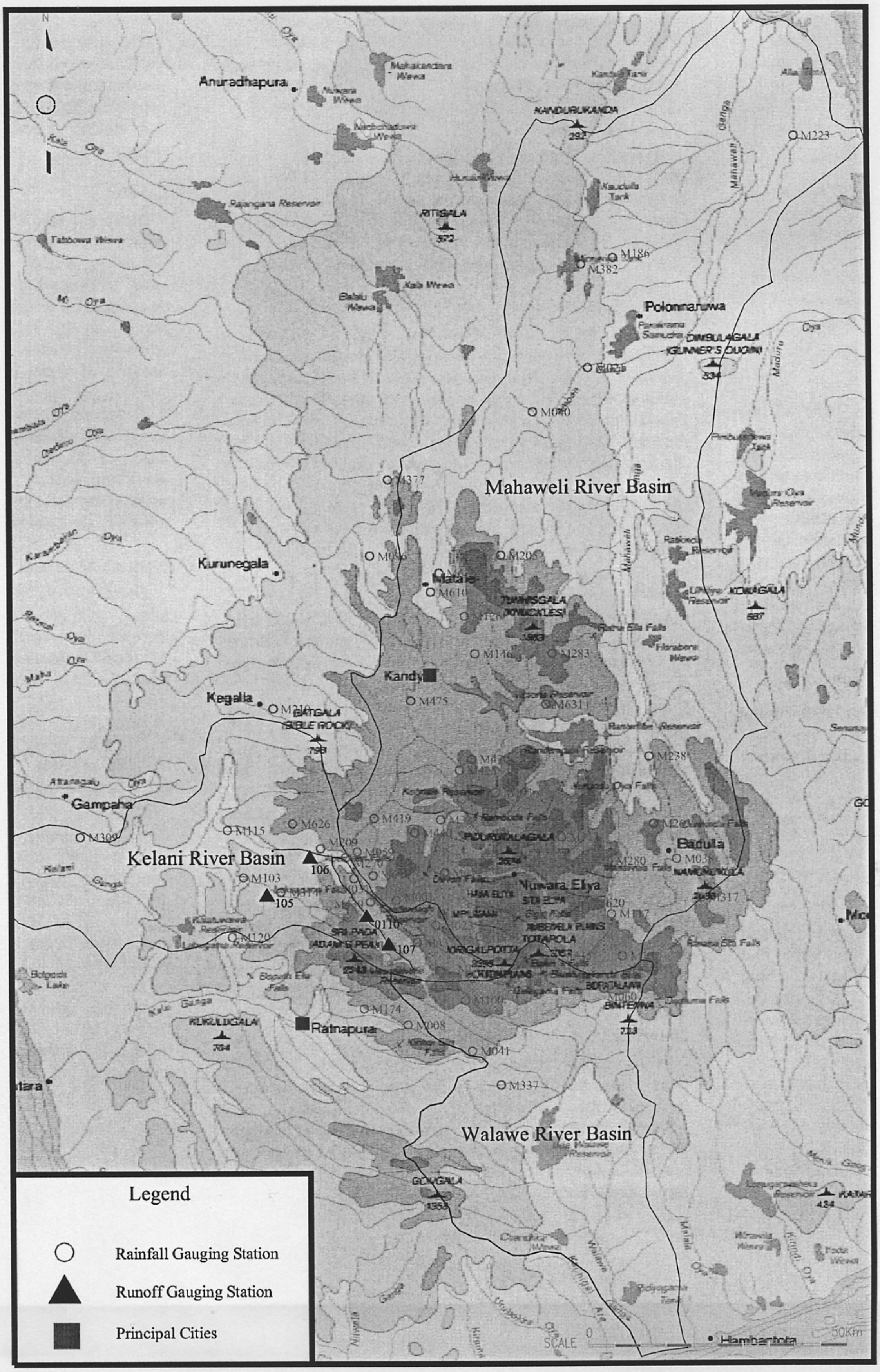
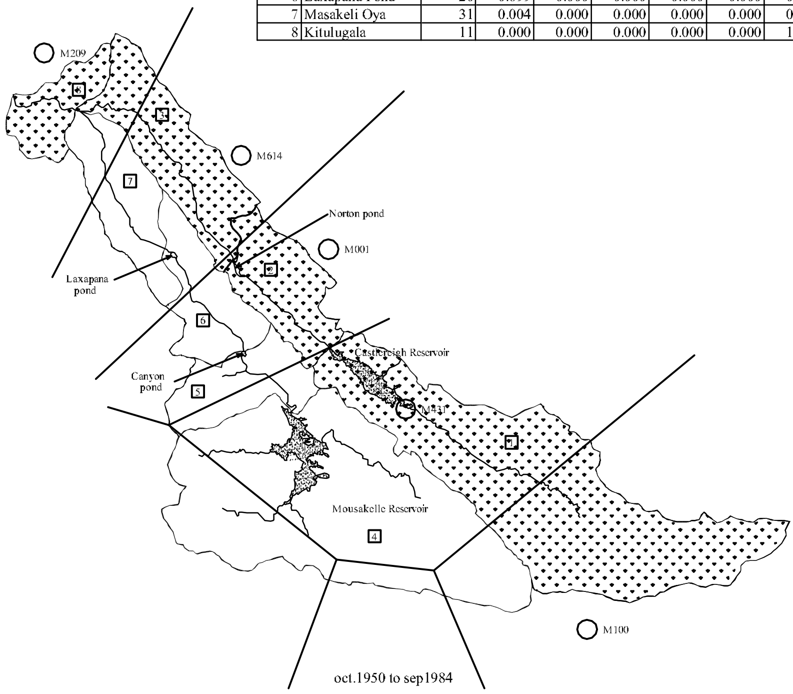


Figure 1 Location Map of Ganging Station

Oct.1950 to Sep.1984

No.	Basin Name	CA (km^2)	Tiessen Weight									
			M001	M008	M100	M103	M174	M209	M430	M431	M614	M626
1	Castlereigh	110	0.002	0.000	0.532	0.000	0.000	0.000	0.000	0.466	0.000	0.000
2	Norton Pond	20	0.920	0.000	0.000	0.000	0.000	0.000	0.000	0.020	0.060	0.000
3	Kehelgamu Oya	46	0.014	0.000	0.000	0.000	0.000	0.257	0.000	0.000	0.730	0.000
4	Mousakelle	130	0.000	0.048	0.115	0.000	0.228	0.000	0.000	0.609	0.000	0.000
5	Canyon Pond	20	0.578	0.000	0.000	0.000	0.000	0.000	0.000	0.422	0.000	0.000
6	Laxapana Pond	20	0.699	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.301	0.000
7	Masakeli Oya	31	0.004	0.000	0.000	0.000	0.000	0.278	0.000	0.000	0.719	0.000
8	Kitulugala	11	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000



Oct.1984 to Sep.2001

No.	Basin Name	CA (km^2)	Tiessen Weight									
			M001	M008	M100	M103	M174	M209	M430	M431	M614	M626
1	Castlereigh	110	0.002	0.000	0.532	0.000	0.000	0.000	0.000	0.466	0.000	0.000
2	Norton Pond	20	0.502	0.000	0.000	0.000	0.000	0.000	0.478	0.020	0.000	0.000
3	Kehelgamu Oya	46	0.000	0.000	0.000	0.000	0.000	0.257	0.189	0.000	0.554	0.000
4	Mousakelle	130	0.000	0.048	0.115	0.000	0.221	0.000	0.031	0.586	0.000	0.000
5	Canyon Pond	20	0.031	0.000	0.000	0.000	0.000	0.000	0.778	0.191	0.000	0.000
6	Laxapana Pond	20	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000
7	Masakeli Oya	31	0.000	0.000	0.000	0.000	0.000	0.278	0.523	0.000	0.199	0.000
8	Kitulugala	11	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000

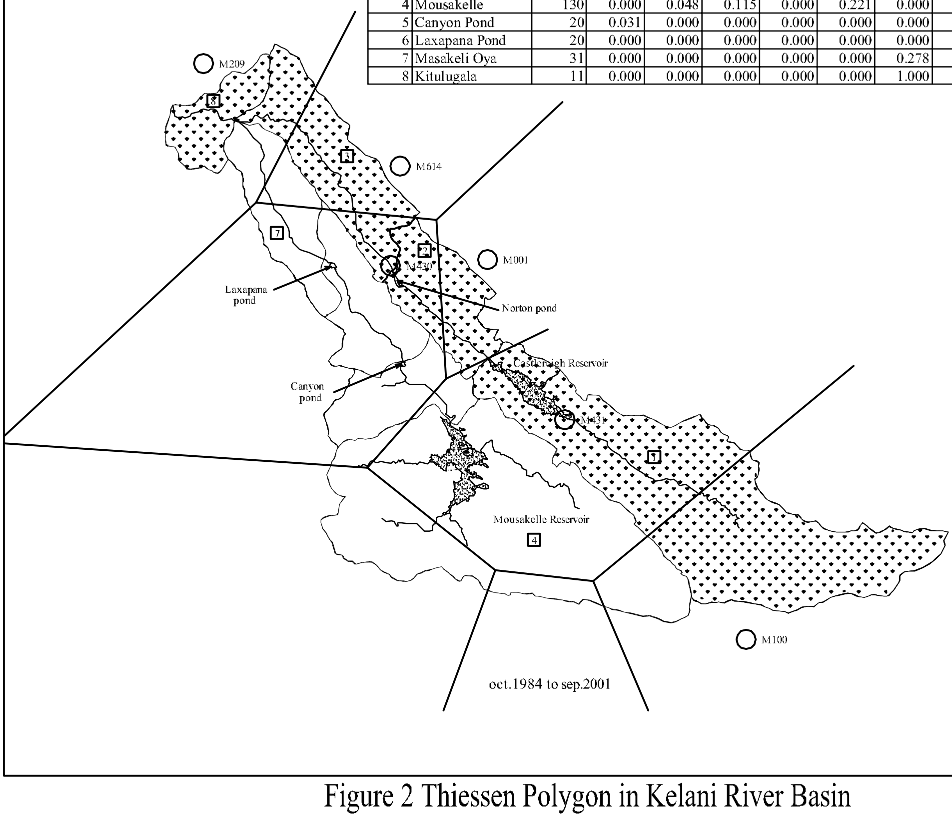


Figure 2 Thiessen Polygon in Kelani River Basin

River Basin	CA (km^2)	M001	M008	M015	M023	M031	M038	M041	M069	M096	M100	M107	M146	M174	M190	M191	M205	M209
Ktomale	554.0	0.068		0.140	0.157										0.190	0.038		
Porgla	772.0	0.048			0.007	0.009				0.001			0.103			0.011		0.036
Victoria	575.0												0.279			0.123	0.027	
Randenigala	439.0															0.174		
Rantambe	788.0			0.098			0.012					0.193						
Samanarawewa	341.7		0.155	0.012				0.389	0.132		0.305			0.006				

River Basin	CA (km^2)	M238	M263	M280	M283	M313	M328	M377	M430	M431	M433	M470	M475	M614	M620	M628	M631	
Ktomale	554.0						0.223				0.184							
Porgla	772.0						0.208		0.000	0.003		0.129	0.304	0.131		0.009		
Victoria	575.0				0.136							0.196	0.058			0.005	0.177	
Randenigala	439.0	0.074			0.045	0.257					0.054	0.000					0.396	
Rantambe	788.0	0.085	0.066	0.172		0.121					0.050				0.192		0.011	
Samanarawewa	341.7																	

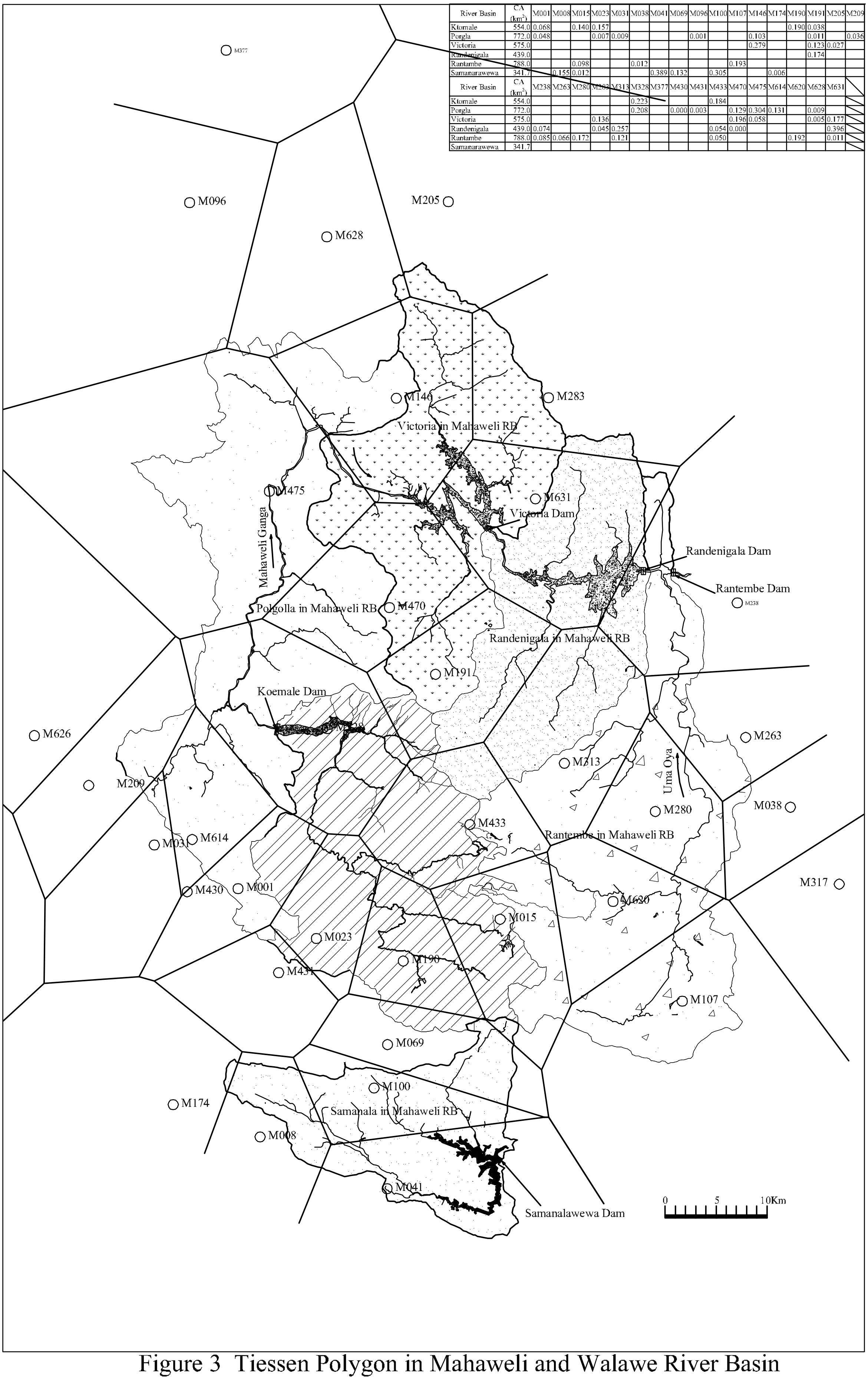


Figure 3 Tiessen Polygon in Mahaweli and Walawe River Basin

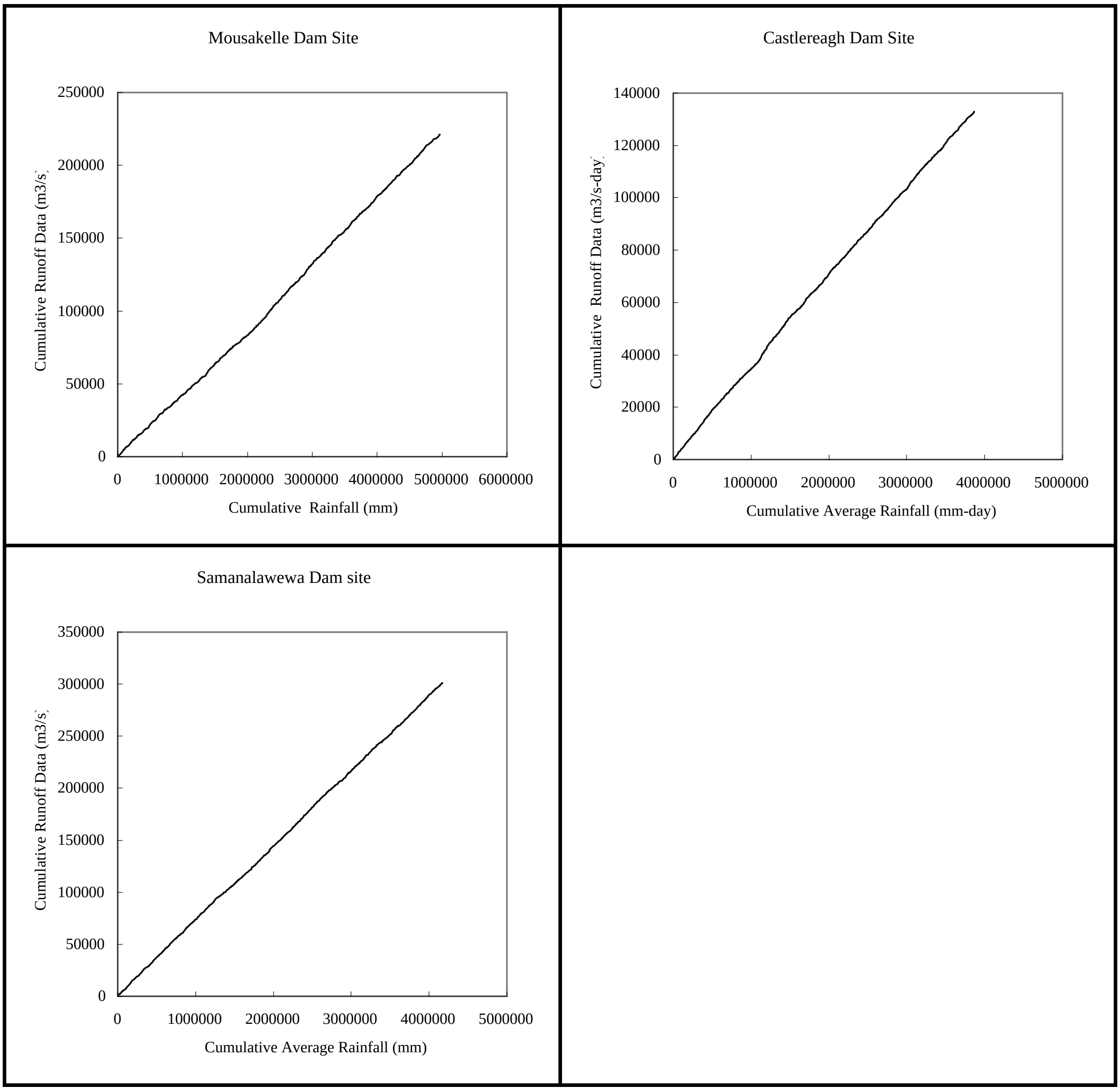


Figure 4 Double Mass Curve Analysis in Kelani and Walawe River Basins

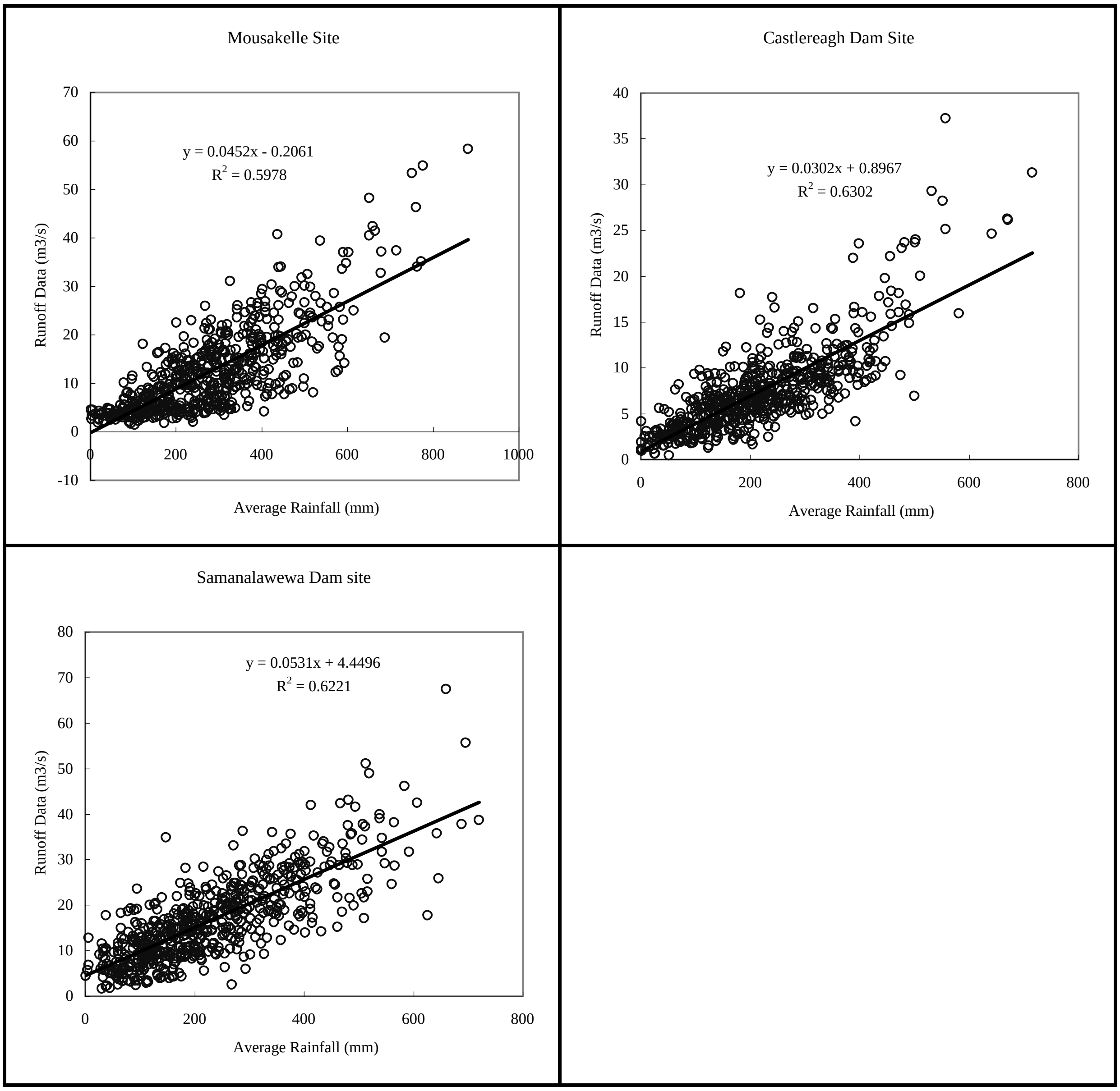
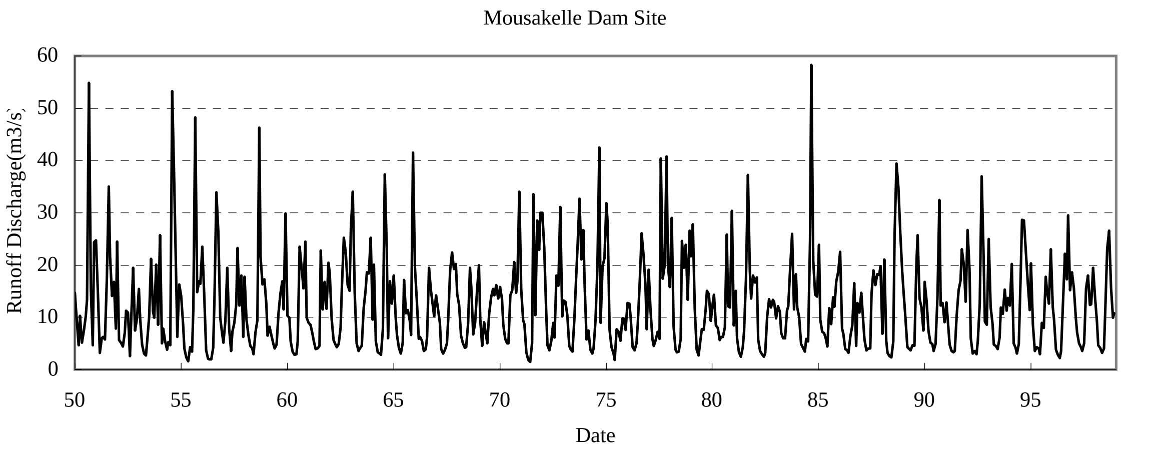
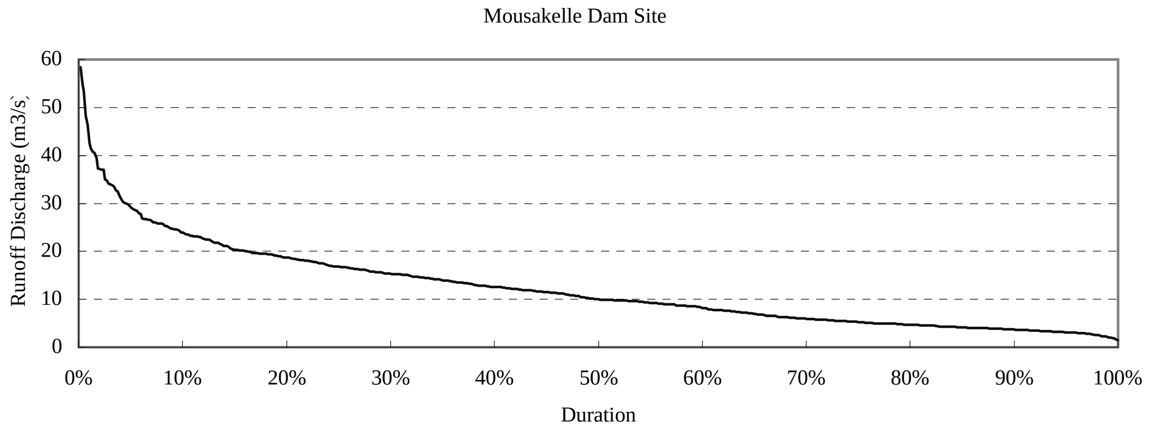
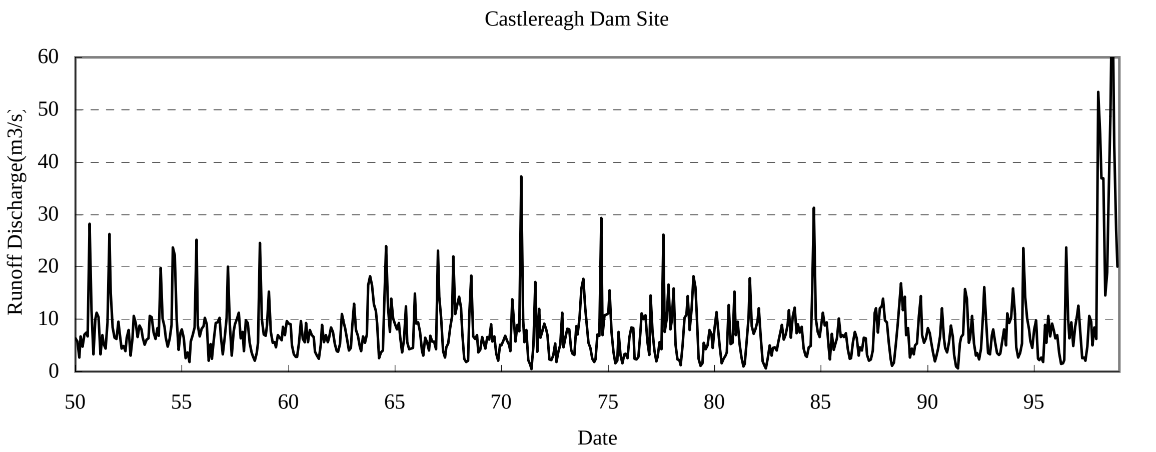


Figure 5 Correlation Analysis in Kelani and Walawe River Basins







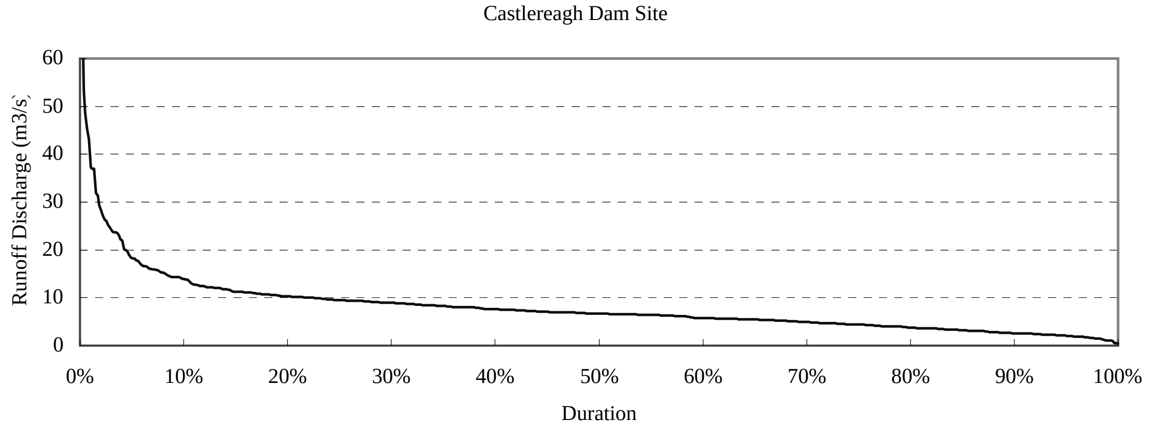
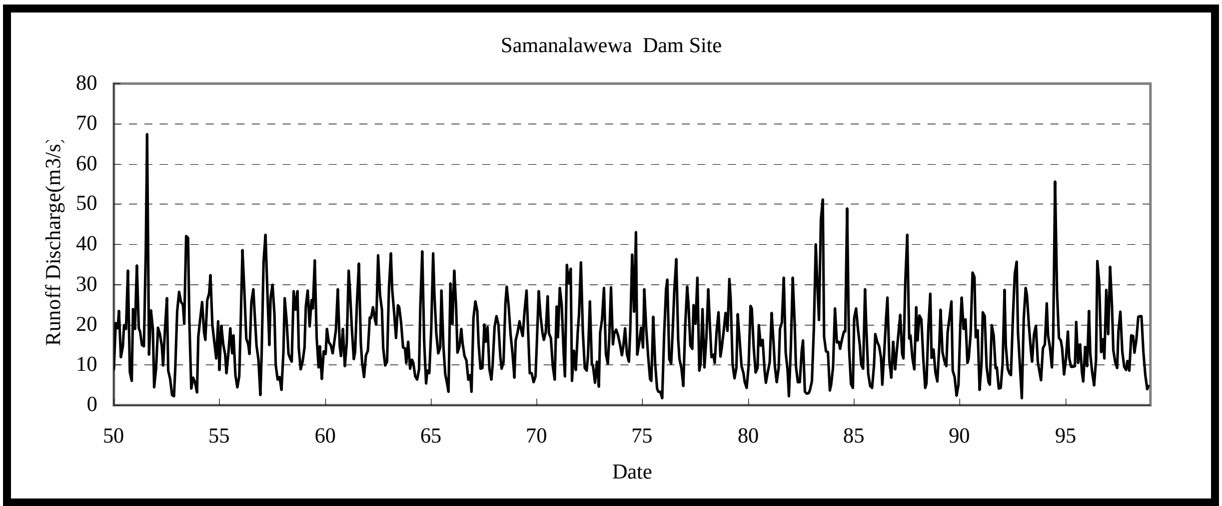


Figure 6 Hydrograph and Duration Curve in Kelan and Walale River Basins (1/2)



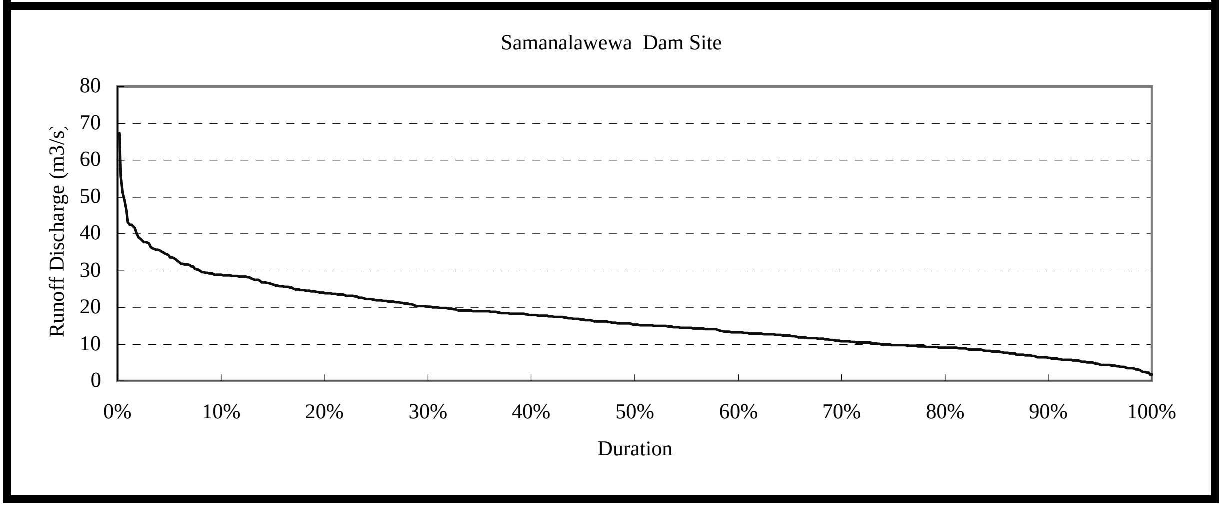


Figure 7 Hydrograph and Duration Curve in Kelani and Walawe River Basins (2/2)

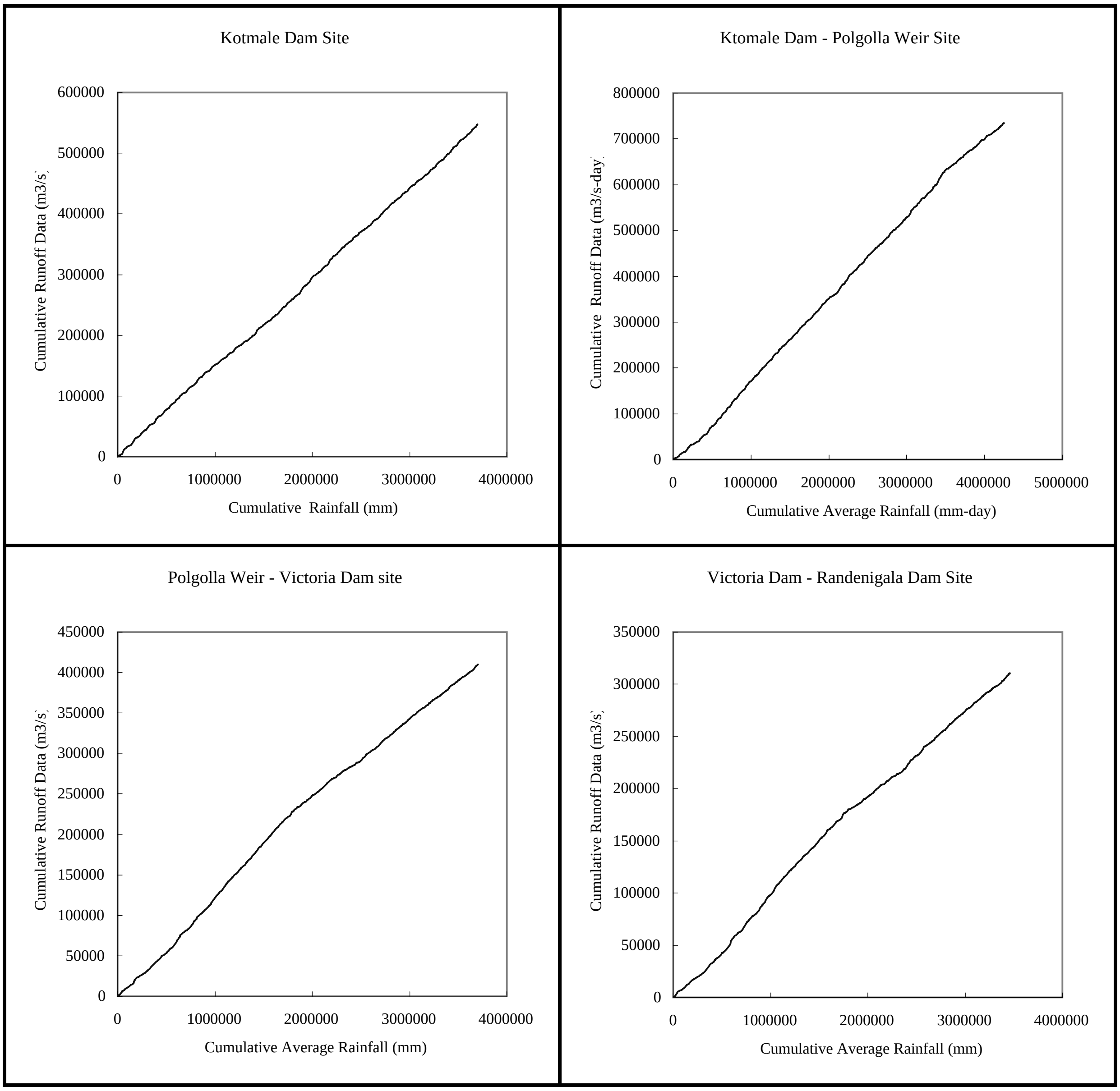


Figure 8 Double Mass Curve Analysis in Mahaweli River Basin

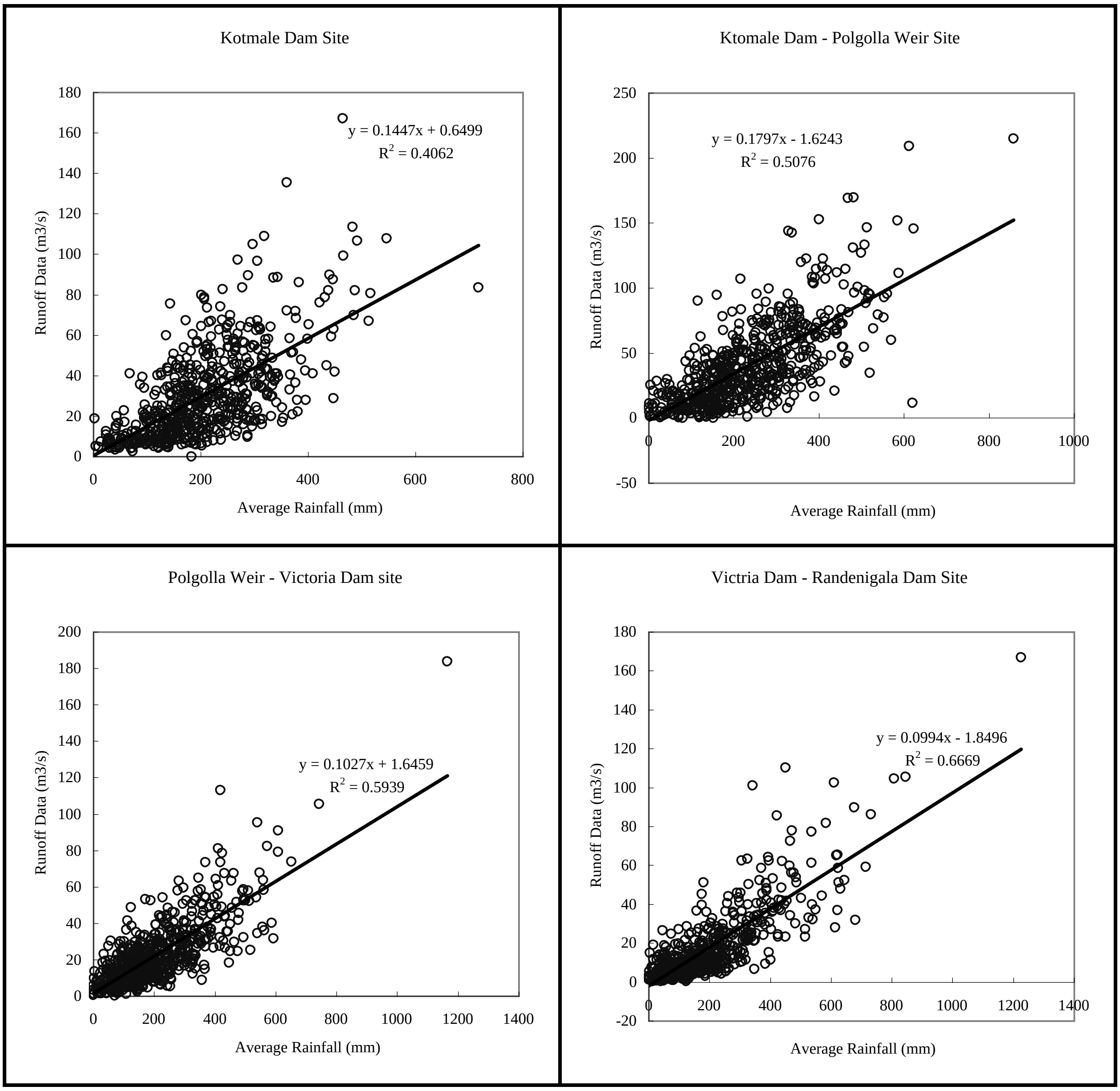


Figure 9 Correlation Analysis in Mahaweli River Basin

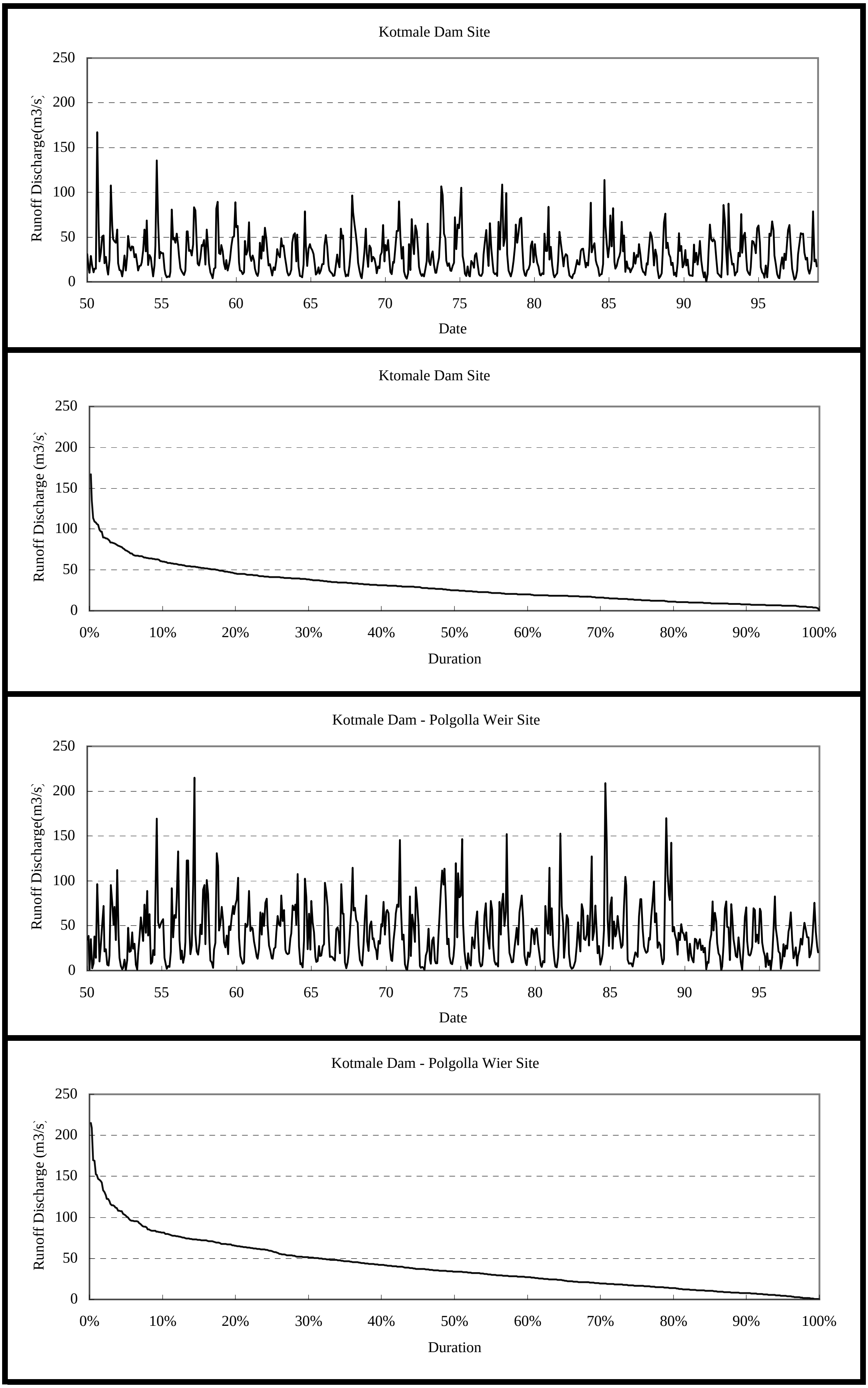
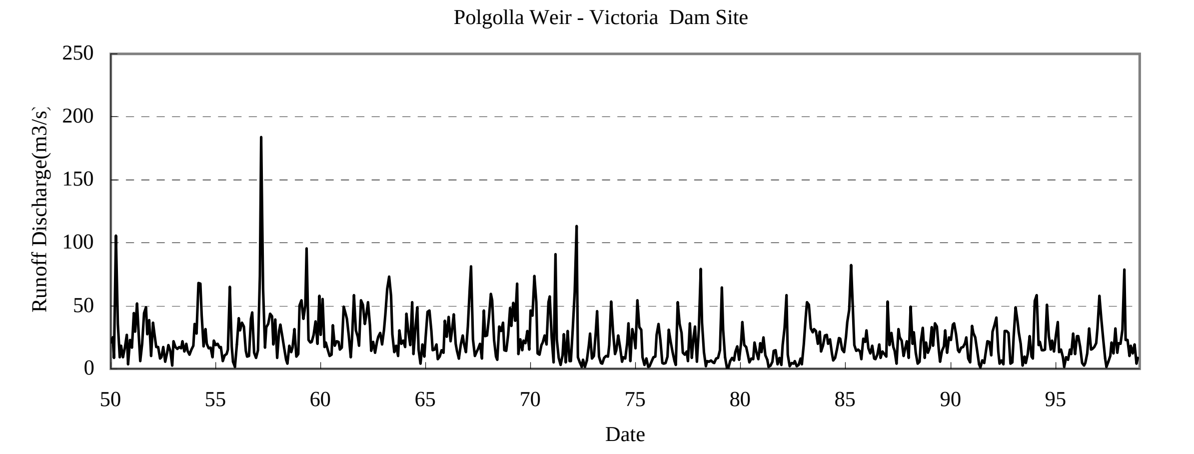
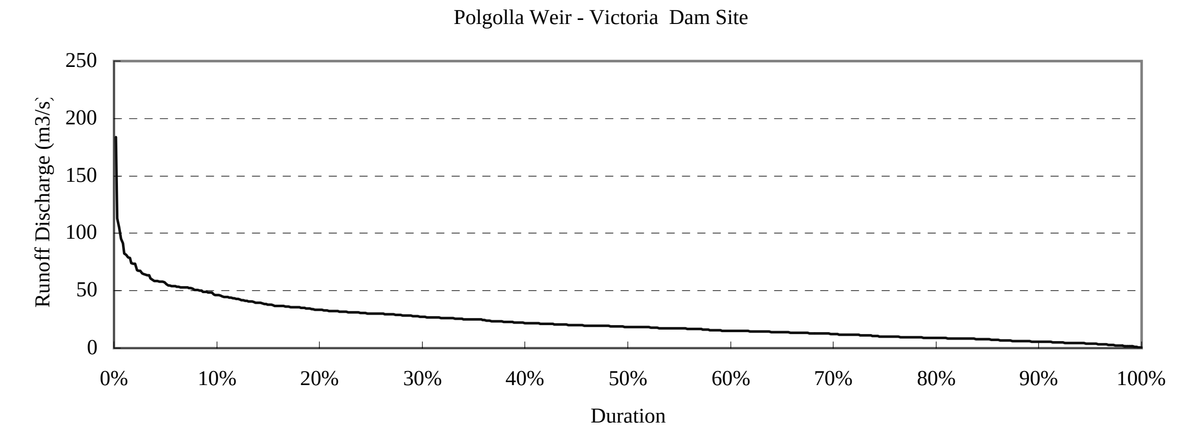
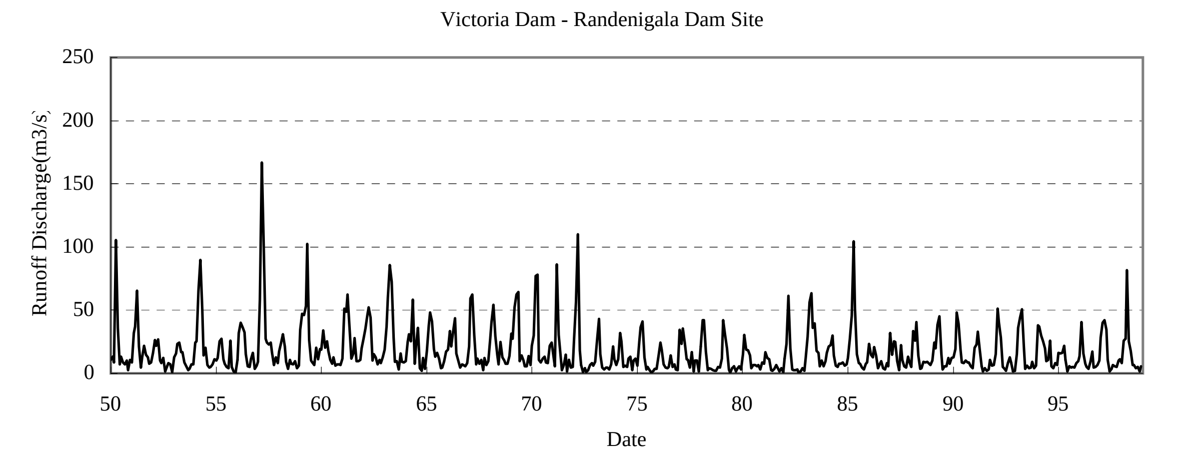


Figure 10 Hydrograph and Duration Curve in Mahaweli River Basin (1/2)







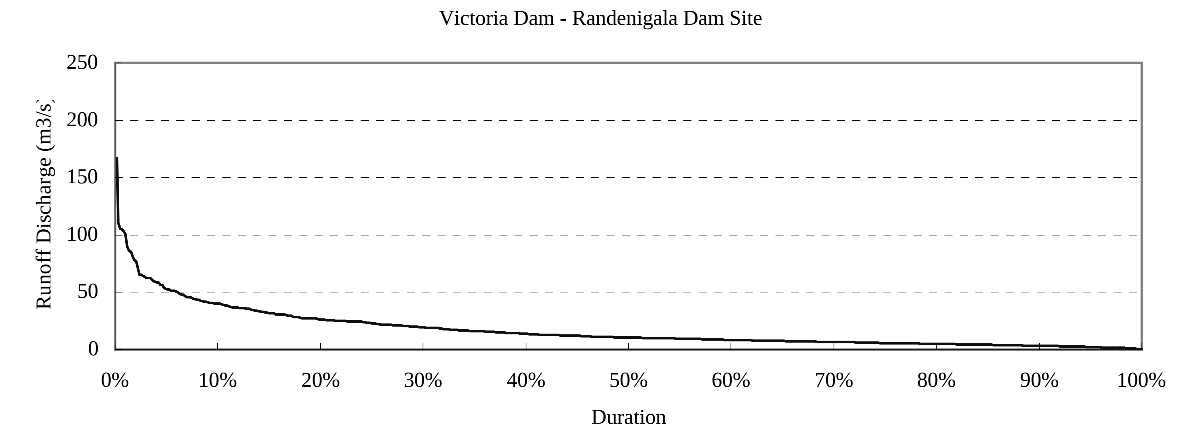


Figure 11   Hydrograph and Duration Curve in Mahaweli River Basin (2/2)

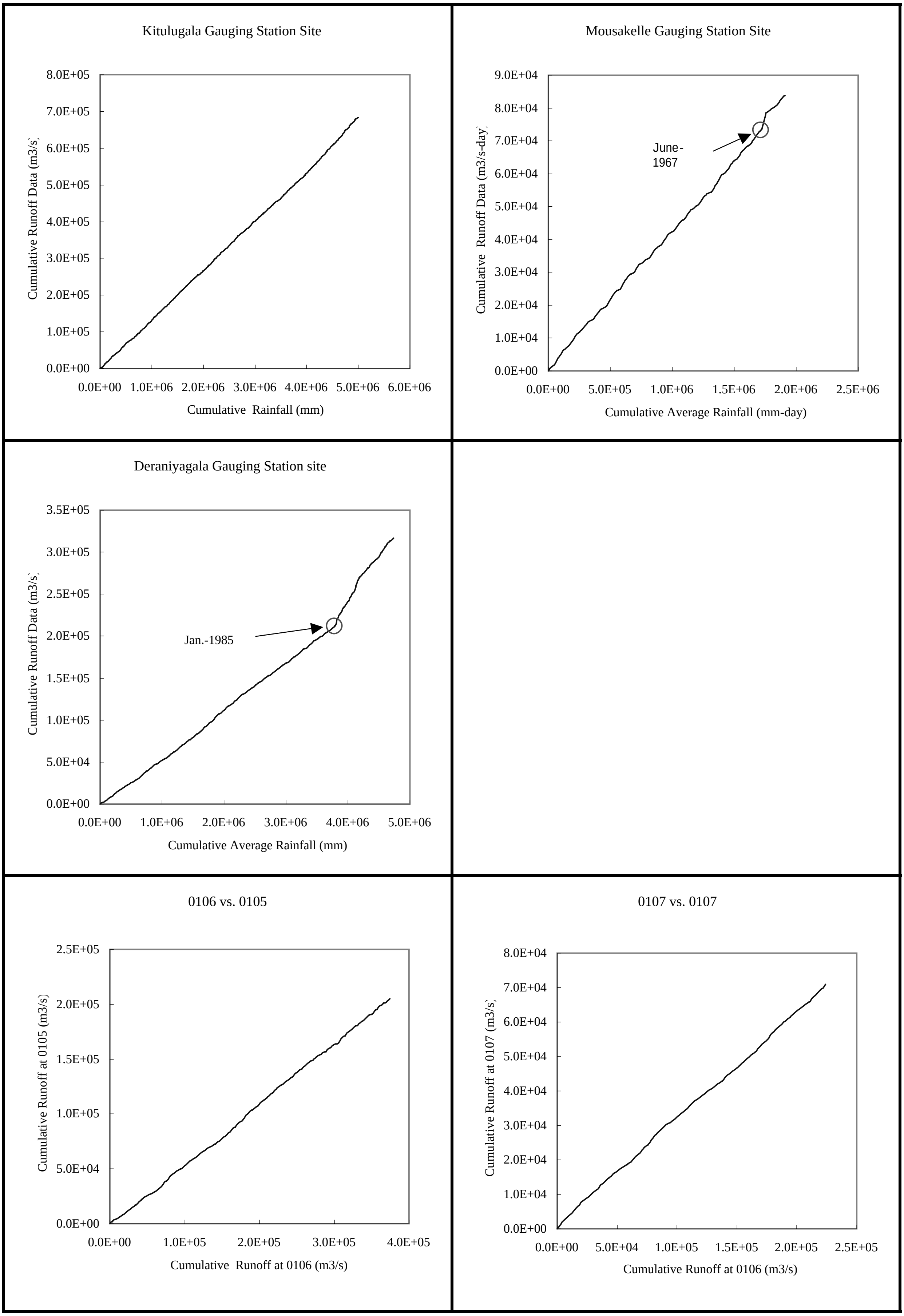


Figure 12 Double Mass Curve Analysis for Runoff Records in Kelani River Basin

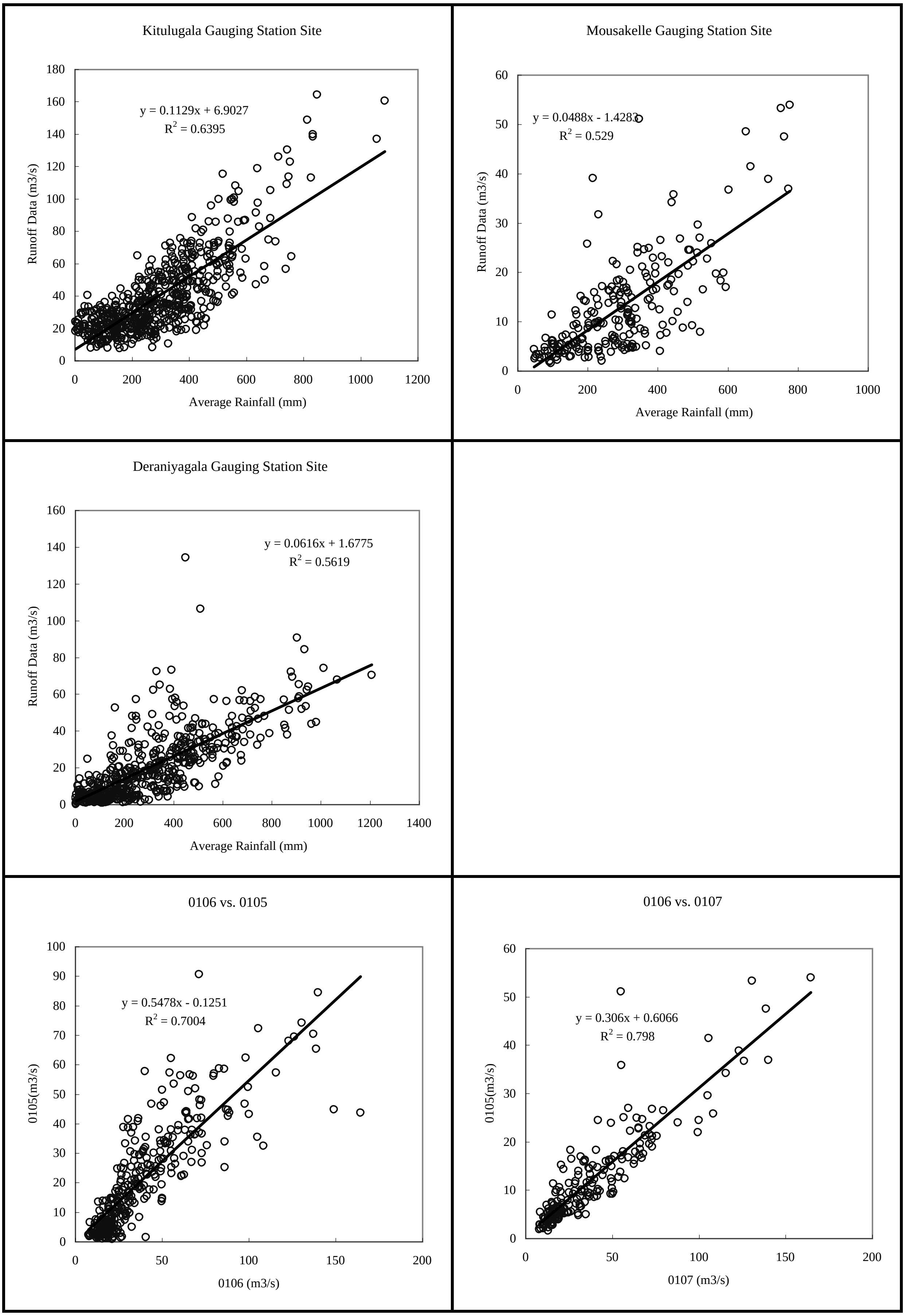
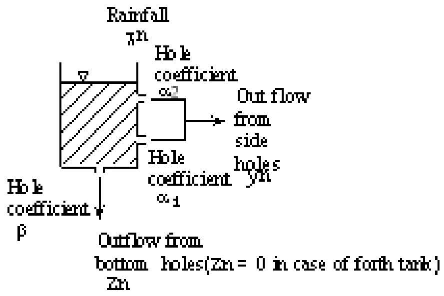
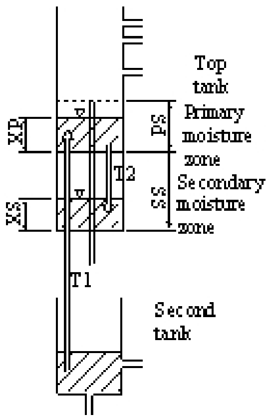


Figure 13 Correlation Analysis for Runoff Records in Kelani River Basin



Tank model for Secondary to Forth Tanks



Parameters for Soil Moisture Model

PS : Primary soil moisture capacity (=150 mm)

SS : Secondary soil moisture capacity (=500 mm)

XP : Primary soil moisture depth

XS : Secondary soil moisture depth

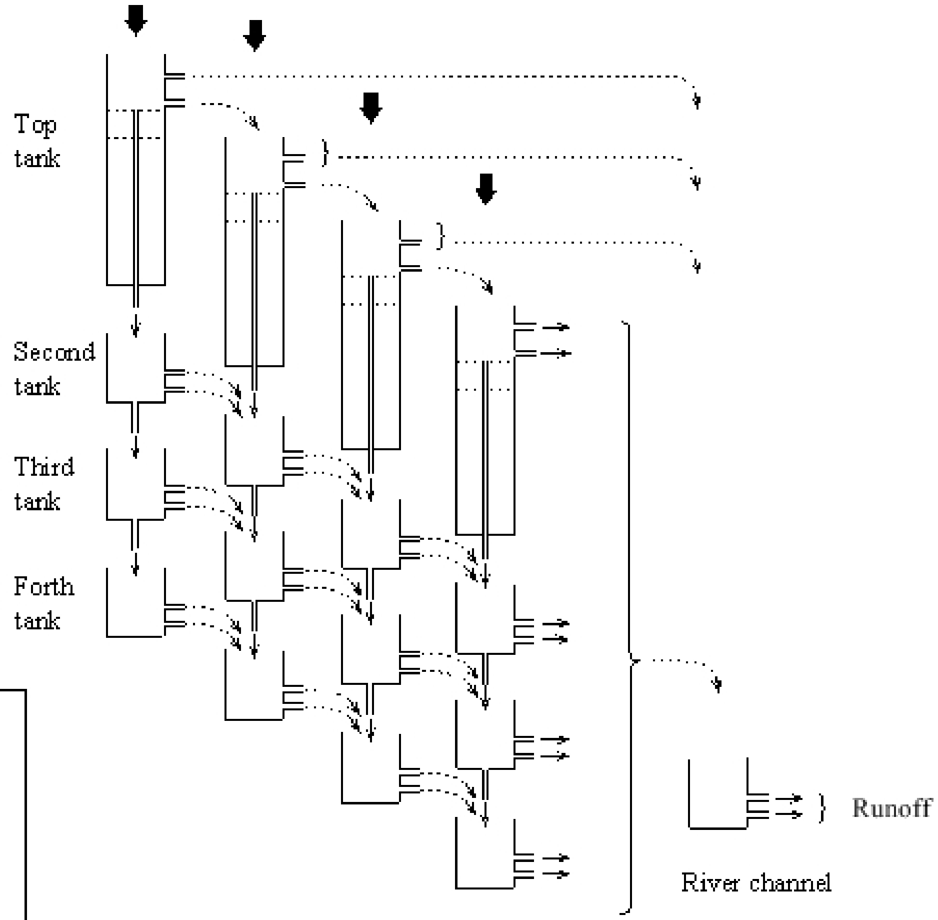
T1 : Transfer by capitary action from lower tanks

$$T1 = TB \times \left(1 - \frac{XP}{PS}\right) \quad : TB = \text{constant}$$

T2 : Transfer of moisture between primary and secondary zones

$$T2 = TC \times \left(\frac{XP}{PS} - \frac{XS}{SS}\right) : TC = \text{constant}$$

Soil Moisture Model for Top Tank



Structure of Composite Tank Model

Figure 14 Outline of Tank Model Analysis

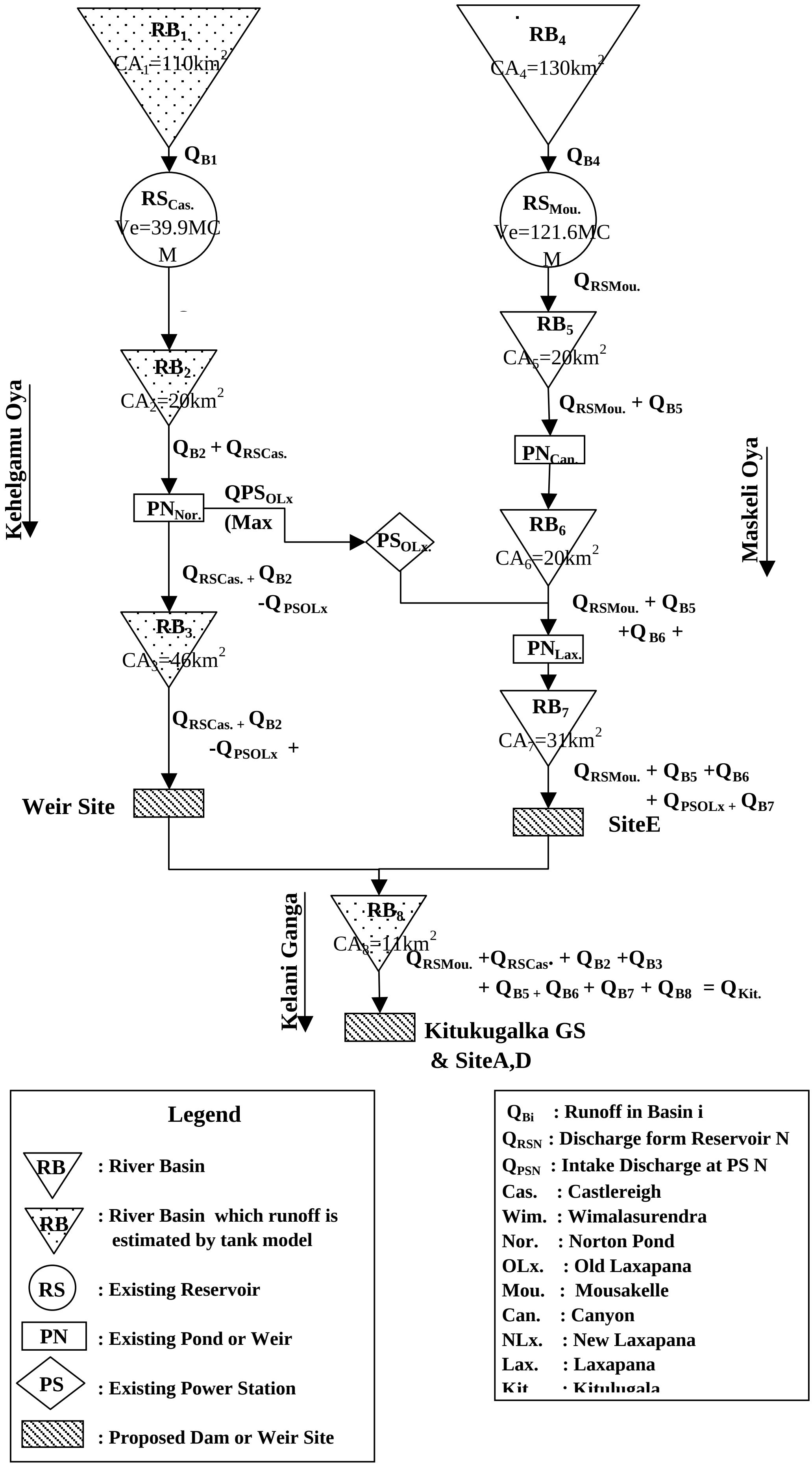
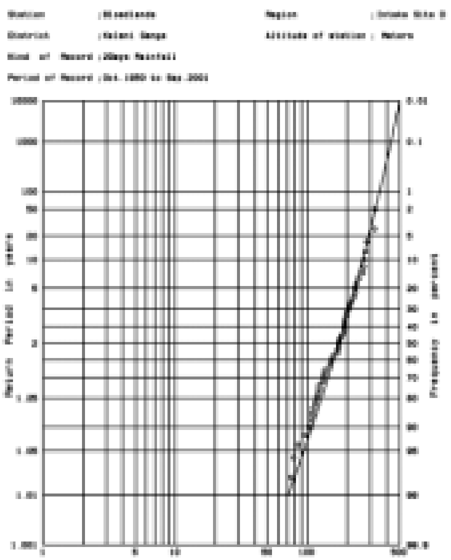


Figure 15 Schematic Diagram of Waterbalance Model in Kelani River Basin



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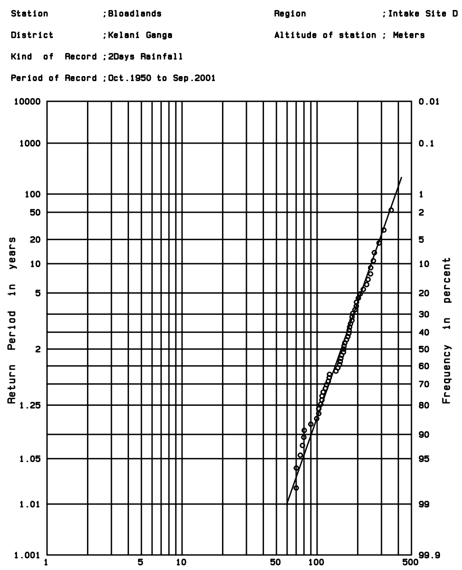
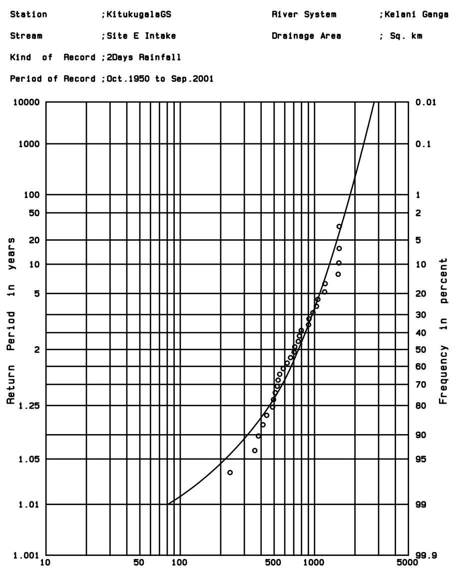
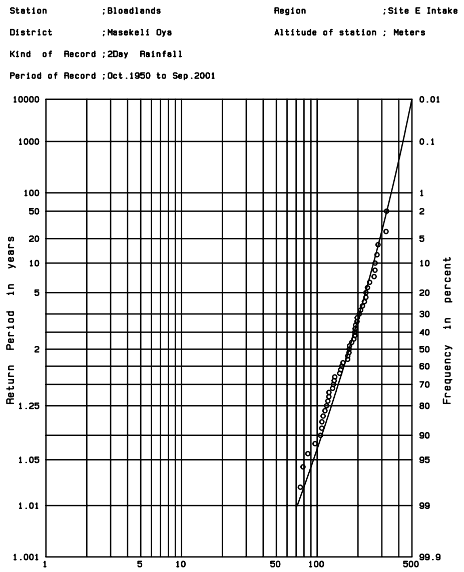


Third Type of Pearson



Gumbel

Figure 16 Frequency Analysis of Historical Rainfall in damsite A, D



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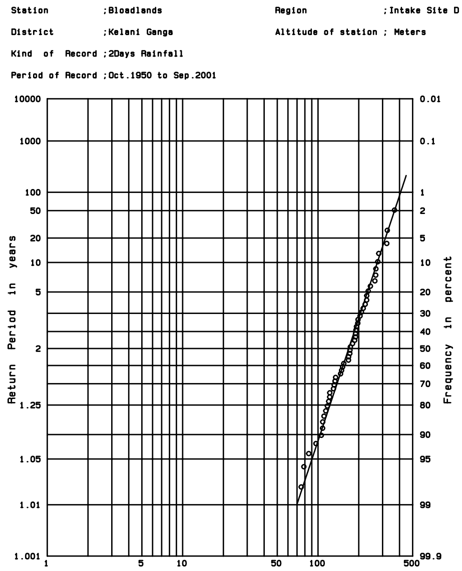
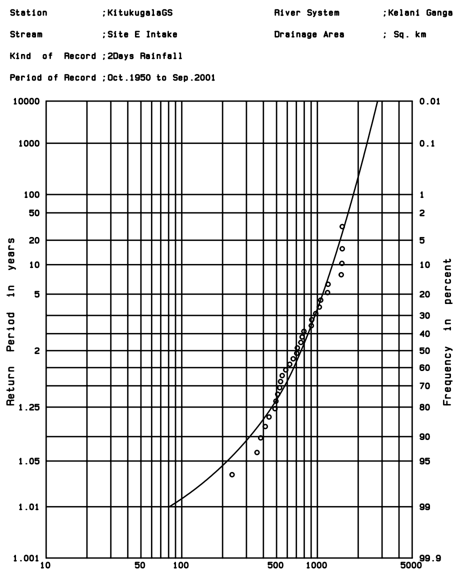
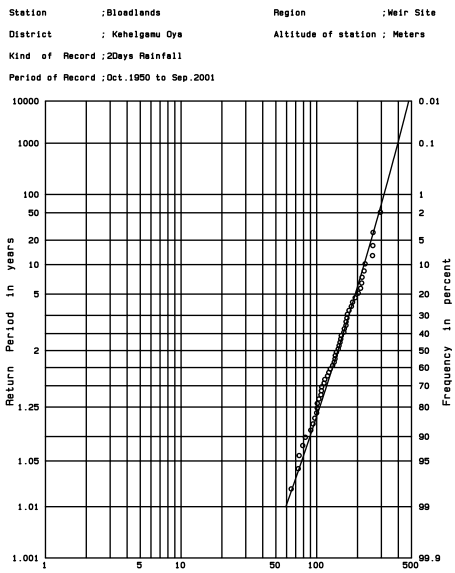


Third Type of Pearson



Gumbel

Figure 17 Frequency Analysis of Historical Rainfall in damsite E



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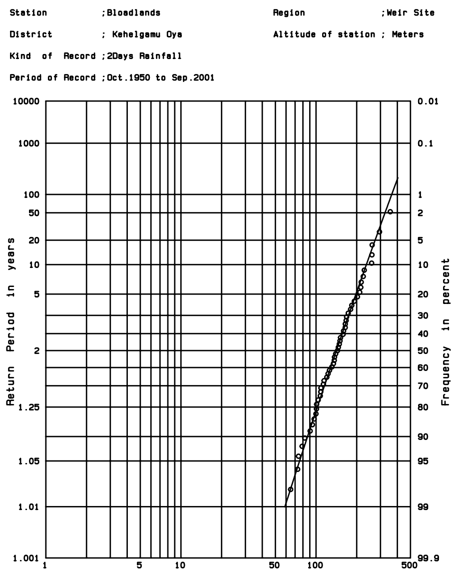

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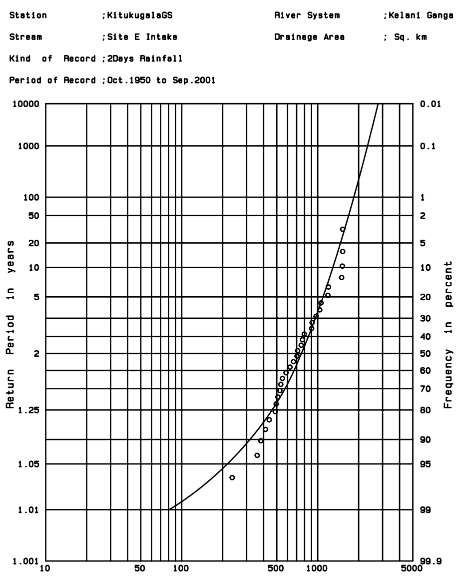
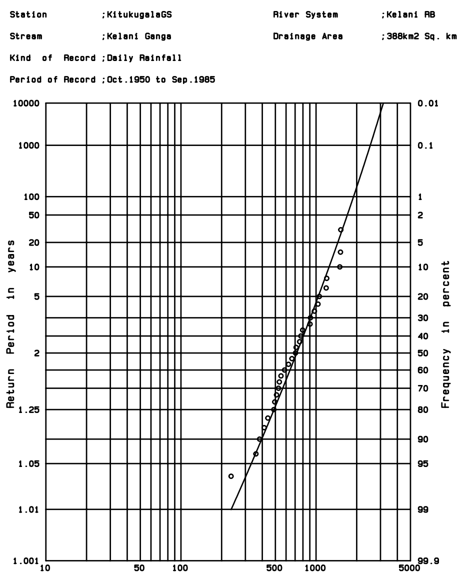


Gumbel

Figure 18 Frequency Analysis of Historical Rainfall in Weir Site



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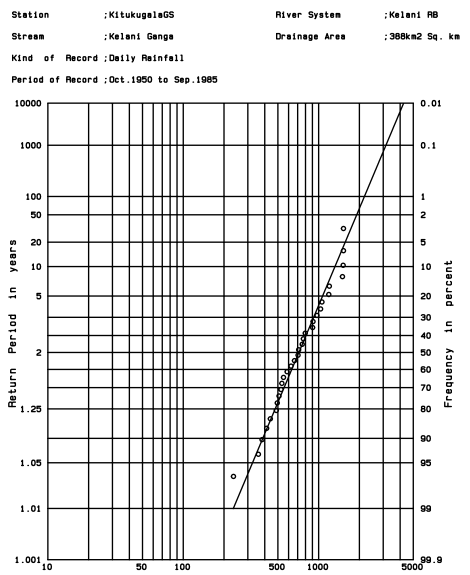
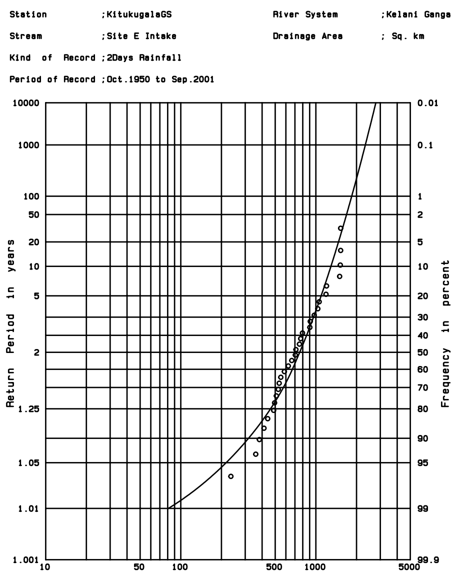


Third Type of Pearson



Gumbel

Figure 19 Frequency Analysis of Historical Flood in Kitulugala GS Site

I-B PROJECT DESIGN DOCUMENT FOR BROADLANDS HYDROPOWER PROJECT

PROJECT DESIGN DOCUMENT

FOR

BROADLANDS HYDROPOWER PROJECT

A. General description of project activity

A.1. Title of the project activity

Broadlands Hydropower Project

A.2. Description of the project activity

The objective of the project activity is to generate clean electricity using hydroelectric resources and provide and sell it to the national grid. The reduction of emissions of CO2 through renewable electricity generation will prevent emissions that would result from fossil fuel-fired power generation.

Broadlands will generate clean electricity in Sri Lanka, increasing employment opportunities in the area.

The project is expected to have an installed capacity of 35 MW.

The plant will deliver electricity to the Sri Lanka National Electric Grid.

A.3. Project participants

1. Ceylon Electricity Board (Generation Planning Branch)

   The CEB is a state-owned vertically-integrated organization having generation, transmission and distribution functions. The CEB has seven divisions, which are the generation, transmission, distribution and operation, distribution development, commercial, human resources, and finance manager divisions, under the Chairman, General Manager and other board members. Though the CEB has been established as an independent body, executives are to be the assigned by the Ministry of Power and Energy, and approval by the Government is required for investments and setting tariffs.

2. JICA (Annex Ⅰ Country participant)

   See contact information for Annex I.

A.4. Technical description of the project activity

A.4.1. Location of the project activity

A.4.1.1 Host country

Host country: Sri Lanka

Country that acquires CER: Japan

A.4.1.2. Region/State/Province etc.

Dam and weir: Central Province

Power house: Sabaragamuwa Province

A.4.1.3. City/Town/Community etc.

Dam and weir: Polpitiya, Pitawala

Power house: Parawalatenna, Kitulgala

A.4.1.4. Detail on physical location, including information allowing the unique identification of this project activity

The Broadlands Hydropower Project is located in the Kelani River basin, close to the township of Kitulgala, in the wet zone of Sri Lanka. It will be the last of the major hydropower schemes cascaded along the two tributaries of the Kelani River, namely Kehelgamu Oya and Maskeliya Oya.

In this project, a diversion weir will be erected in Kehelgamu Oya to divert its water to the Maskeliya Oya via an approximately 1-km ring tunnel. This weir is located approximately 1 km above the confluence of two streams.

The other diversion, which is the main dam of the project, will be erected in Maskeliya Oya. The purpose of this dam is to divert water collected from both streams to the proposed powerhouse. The dam will be located downstream of the said tunnel; this location will be about 0.5 km downstream of the existing Polpitiya Power Station.

Water from the said main dam will be conveyed to the proposed 35 MW powerhouse, first via an aqueduct and then through a tunnel. The combined length of the aqueduct and tunnel is approximately 3 km. The tailrace of the powerhouse will join the Kattaran Oya at a location close to its confluence with Maskeliya Oya. This location is situated approximately 3.5 km downstream of the confluence of Kehelgamu Oya and Maskeliya Oya. The 35 MW plant is expected to deliver an average annual power generation of 126.8 GWh. (See Fig. 1.)

A.4.2. Category of project activity

There is neither a list of categories of project activities nor a list of registered CDM project activities available yet on the UNFCCC web site.

A.4.3. Technology to be employed by the project activity

The main components of the project consist of:

- Work to divert Kehelgamu Oya
- Dam and spillway
- Intake structure
- Conduit, free-flow tunnel and penstock
- Powerhouse and switchyard

Table 1 Characteristics of Technologies

Power plant characteristics	
Installed capacity	35.0 MW
Full supply level	121.0m MSL
Normal tailwater level	56.9m MSL
Active storage	0.198 MCM
Hydraulic turbine	
Type	Francis, vertical shaft
Number of units	2
Rated power output	18.0MW
Rated speed	300rpm
Maximum discharge	$70m^3/s$
Rated effective head	56.9m
Generator	
Type	Synchronous, vertical shaft
Number of unit	2
Rated power output	21,900kVA
Rated voltage	11kV
Frequency	50Hz
Power factor	0.8 (lagging)
Rated speed	300rpm

A.4.4. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

The project activity will reduce CO2 emissions in electricity generation through the use of a renewable energy resource. It is expected that the project activity will serve to displace fossil fuel-fired plants with clean energy provided by hydroelectricity.

The inclusion of the project in the interconnected grid will redistribute the dispatch of all the power plants giving rise to the most efficient electricity generation by the whole system. In the absence of the CDM project activity, no other project would have been implemented, so that emission reductions would not occur.

From a prospective dispatch analysis, it is estimated that the project has the potential to achieve a reduction of about 1.77 million tons CO2e over a period of 21 years.

Generation Expansion Plan

To meet growing power demand in the future, the CEB has made efforts a) to promote a well-balanced combination of power sources without excessive dependence on hydropower, b) to encourage private investment in the power sector, c) to implement demand-side management under effective energy conservation programs, d) to establish investment plans in accordance with economic needs, and e) to reduce distribution line losses.

According to the latest LTGEP, the power development plan up to 2017 is as shown in Table 2. The plan calls for power generation facilities with a total capacity of 2,190 MW to be commissioned within 15 years. The total present value cost up to 2017 is estimated to be US$3,015.5 million (Rs241,357.7 million).

Table 2 Generation Expansion Plan Sequence

Year	Hydro Additions	Thermal Additions	Thermal Retirements	Capacity (MW)
2003		20MW ACE power Horana Diesel Plant		20
2004	70MW Kukule			70
		163 MW AES Combined Cycle Plant at Kelanitissa		163
2005		200MW Medium-term Diesel Power Plants		200
2006		2×150MW Combined Cycle Plant at Kerawarapitiya		300
2007				
2008		300MW Coal Steam		300
			3×16MW Gas Turbine at Kelanitissa	-48
2009	150MW Upper Kotmale			150
2010				
2011		300MW Coal Steam		
2012		300MW Coal Steam		300
			22.5 MW Lakdhanavi Plant	-22.5
			20 MW ACE Power Matara	-20
2013		105 MW Gas Turbines		105
			4×18 MW Sapugaskanda Diesel Plant	-72
			20 MW ACE Power Horana	-20
2014		300 MW Coal Steam		
2015		300 MW Coal Steam		300
		210 MW Gas Turbines		210
			60MW Colombo Power Plant	-60
			200 MW Medium-term Diesel Power Plant	-200
2016		300 MW Coal Steam		300
2017		210 MW Gas Turbine		210

Source: CEB Data

The present installed capacity of the system is 1,758.5 MW and it will be increased to 4,524 MW by 2017. Within the next 15 years, capacity of 3228 MW needs to be added to the system, while 442.5 MW of thermal plant capacity will be retired. The present share of thermal capacity (37%) will be increased to 54% by 2010 and to 67% by 2017. New capacity added to the system is in the form of gas turbine, combined-cycle and coal-fired plants. The expansion plan shows that the consumption of fossil fuels in the power sector is rising considerably. Hence, thermal power plants that burn fossil fuels will play an important role in supplying the future electricity demand of Sri Lanka.

From the analysis above it is clear that the project itself is not an attractive option to be developed unless other incentives are involved. The low profitability of the project is an important barrier to going further with it. The CDM potential of the project is a crucial incentive to consideration of the opportunity to develop a project activity for registration under the CDM, based on the carbon credit revenues and the contribution to sustainable development in Sri Lanka.

A.4.5. Public funding of the project activity

B. Baseline methodology

B.1. Title and reference of the methodology applied to the project activity

B.2. Justification of the choice of the methodology and why it is applicable to the project activity

The baseline for the proposed project activity corresponds to the scenario that would occur if the proposed project activity were not carried out and its corresponding availability to generate electricity were not included in the system dispatch.

The baseline considers the emissions coming from dispatching power plants, without and with the proposed project activity, according to market rules (least costs of generation). The baseline is considered the foreseen demand growth and the capacity expansion to satisfy such demand as it was officially analyzed by the CEB. The reason those emissions correspond to the baseline is that in the absence of the CDM registration opportunity, the project would not have been chosen to be developed by the project sponsor and no other foreseeable alternative project would have been developed in place of the proposed one, to be considered as the baseline. Therefore, the baseline considers emissions that would not have occurred in the absence of the project and are directly attributable to its absence, i.e., the part of the system emissions that would have been replaced by the presence of the proposed project activity. It includes emissions of all the power plants serving the national system, in the base year as well as in the future, excluding this project from and including the project in this system.

Summarizing, the main characteristics of the proposed project activity and the selected baseline for this case are:

- The Sri Lankan power system is presently hydro dominated. Hence, it is necessary to assess the energy-generating potential of the hydro power system. However, this assessment is difficult because of irrigation requirements, climatic conditions and so on.
- Emissions to be accounted for are those generated by all thermal plants serving the national grid according to "Long-term generation expansion plan".
- The Sri Lankan system is an interconnected hydrothermal grid.
- Power plants are dispatched based on economic pricing for investments and operations.

Taking these conditions into account, the best alternative is to consider a computational model able to simulate the dispatch under the constraints and characteristics of the interconnected system. Thus, a proven model was selected to estimate baseline emissions, according to its ability to deal with the features of the system. The model is able to handle power plants centrally dispatched in hydrothermal interconnected systems with a high hydraulic component, based on least costs of generation, with the flexibility to incorporate the set of conditions and constraints determining the actual dispatch (hydrology, electricity demand, transmission constraints, generation costs, etc.).

However, confirmation is sufficient whether or not the methodology mentioned above allows conventional treatment of baseline emissions rather than considering that displaced power plants are those of lowest efficiency or taking the average of the thermal generation of the system.

B.3. Description of how the methodology is applied in the context of the project activity

The project would displace energy produced by burning fossil fuels and substitute for it energy that would be generated from hydropower. As such, the generation of the interconnected national grid as a whole would result in the production of carbon dioxide emissions lower than the production that would occur if the proposed project were not implemented.

The methodology is based on a comparison of simulations of the centrally-planned dispatch of all the power plants serving the interconnected national system, without and with the proposed project activity and others.

The simulation method is applied to the current project activity in a straightforward manner, taking into account all relevant parameters and variables determining the dispatch decisions, as they are taken by the manager of the wholesale electricity market.

(*) Emission reductions were also calculated using another methodology as a comparison. The methodology takes the average of the thermal generation of the system (average method). In the actual case, detailed analysis and comparison of methods are needed.

B.4. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (i.e. explanation of how and why this project is additional and therefore not the baseline scenario):

As for the baseline, it must represent the situation that would occur if the project were not implemented. This is the scenario in which the whole national system, including the expected additions in the "Long-Term Generation Expansion Plan," will manage to supply electricity in order to satisfy the demand (almost the part of the demand that could be supplied by the project). In this scenario, demand is met through the use of less-efficient power plants than those that would be dispatched if power generated by the project were available in the interconnected system. The project is relatively small and in this sense it is not necessarily true that another specific project would have been developed to cover the part of the generation provided by the project. If one could assure that, then such an alternative project could have been considered as the baseline, but it is too difficult to demonstrate this fact. Moreover, there are enough reasons to argue that no particular project would have added new power plants by other companies, instead of this project. But any new capacity added by another project would be mainly thermal, thus contributing to GHG emissions to a greater extent than would the displaced power plants (since the most recent ones are a mixture of fossil-fuel based and hydro plants). Furthermore, the dispatch with these new plants would not differ significantly with respect to the one selected as the baseline.

The baseline chosen is more conservative than this hypothetical alternative option, since in the dispatch analysis under consideration the project is going to replace a combination of power plants. The conservative proposal selected here takes into account the inclusion of new plants, but only those discussed in the official "Long-Term Generation Expansion Plan". This is because, as was mentioned before, the proposed project is not strictly to cover the expected increase in electricity demand but was conceived to add efficiency to the system as a whole and to contribute to sustainable development.

The other important point to be handled in the baseline analysis is that emission reductions arising from the project implementation are real and measurable. This comes under Article 12 of the Kyoto Protocol. And this is the case for the proposed project activity, since emissions from the whole national system are avoided due to the project contribution to electricity dispatch, through clean energy without burning fossil fuels.

B.5. Description of how the definition of the project boundary related to the baseline methodology is applied to the project activity

This project boundary definition is the one that can be best identified with the concept "under the control of the project participants". The project boundary encompasses the physical, geographical site of the hydropower generation source, which is represented by the Kerani River basin close to the power plant facility. Fig.2 shows the project boundary in which all sources are included. The dashed line indicates the project boundary.

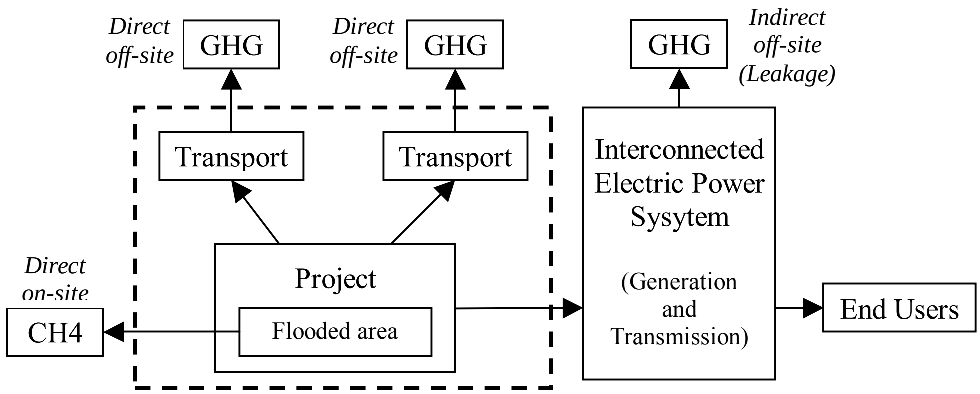


Fig. 2 Project boundary

GHG emission sources of the project

Direct on-site emissions

The project generates only a small amount of methane from the flooding of the areas during generation of electricity as direct on-site emissions.

Direct off-site emissions

There are anthropogenic GHG emissions in the upstream lifecycle stages of the electricity generation process. The stages with the most important sources of GHG emissions are materials processing, component manufacture and transportation of materials and fuel burning during the use of construction machinery.

Emissions by transport refers to emissions caused by the transportation of materials and people by trucks and vehicles and fuel consumption of machinery used. Default values are as provided by the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories.

(*) In this case, emissions by transport is not calculated because a detailed construction plan has not decided on yet.

Construction refers to emissions arising in the cement manufacturing industry that provides the concrete for the construction of the plants. These last emissions are relative to the volume of concrete used in the plant through a default emission factor also taken from the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories. They are considered emissions under the control of project participants since the participants decide on the amount of concrete to be used, but obviously they do not have any control over the manufacturing process.

Indirect on-site and off-site emissions (Leakage)

No other emissions beyond the ones reported in direct on-site emissions are seen to be included. Since methane emissions of hydro plants serving the system are at the same level as avoided carbon dioxide emissions of thermal power plants, they are included in off-site emissions under the project boundary. Therefore, baseline emissions are going to be accounted as leakage. Since baseline emissions are almost emission reductions of the project (except for the small amount of direct emissions), all reductions are due to leakage effects.

B.6. Details of baseline development

B.6.1. Date of completing the final draft of this baseline section (DD/MM/YYYY)

DD/MM/YYYY

B.6.2. Name of person/entity determining the baseline

Name:

Entity:

Address:

Tel:

E-mail:

C. Duration of the project activity/Crediting period

C.1. Duration of the project activity

C.1.1. Starting date of the project activity

Construction is expected to begin in 20xx. Generation expected in early 20xx.

Time required before becoming operational:

20xx: Tunnel construction and civil works

20xx: Plant construction is expected to be completed and operations are expected to begin in XXXX, after proofs by YYYY

20xx:

(*) In the tentative plan, it takes about four years to construct a power plant and generate electricity, and the starting year has not been decided yet.
Therefore, in this PDD it is assumed that commissioning will be started in 2007.

C.1.2. Expected operational lifetime of the project activity

50 years

C.2. Choice of the crediting period and related information

C.2.1. Renewable crediting period

C.2.1.1. Starting date of the first crediting period (DD/MM/YYYY)

C.2.1.2. Length of the first crediting period (DD/MM/YYYY)

7 years

C.2.2. Fixed crediting period: Not Selected

C.2.2.1. Starting date (DD/MM/YYYY)

C.2.2.2. Length

D. Monitoring methodology and plan

D.1. Name and reference of approved methodology applied to the project activity

D.2. Justification of the choice of the methodology and why it is applicable to the project activity

According to the baseline methodology applied to this project, the selection of the monitoring plan is quite straightforward. Thus the chosen monitoring methodology accounts for all data collection relevant to determine verifiable emission reductions achieved by the project. For this reason, the choice of the monitoring methodology is applicable for the project activity.

According to the monitoring methodology, the main data is divided into two categories, one related to specific GHG abatement matters and the other related to environmental, social and economic project performance.

GHG-related data:

- Monthly electricity generation of Broadlands hydroelectric plant, as routinely measured by the CEB.
- Annual electricity generation of all thermal plants serving the interconnected national system.

Non-GHG-related data:

-
-

While emissions factors remain unchanged, baseline emissions depend on electricity generation of the hydroelectric plant and electricity generation of all thermal plants and are determined in dynamic manner from data. The spreadsheet thus also determines emissions reductions as a result of project implementation.

D.3. Data to be collected in order to monitor emissions from the project activity and how this data will be archived

There are no project emissions that require monitoring.

D.4. Potential sources of emissions which are significant and reasonably attributable to the project activity, but which are not included in the project boundary and identification if and how data will be collected and archived on these emission sources

As was explained in Section B.5, emissions of all thermal power plants serving the interconnected national system are not considered leakage but direct off-site emissions. So it was decided to include that relevant data in Section D.5. The following datum can be included in Section D.5. instead of Section D.4., but conceptually there is not any significant difference.

Table 3 Information to be provided for monitoring data

ID number	Date type	Date variable	Date unit	Measured (m) calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived (electronic/paper)	For how long is archived data to be kept	Comment
1	Electricity generation of the Broadlands hydropower plant	g_p	MWh	m	monthly	All	Electronic (spreadsheet)	5 years	Provided by the CEB
2	Electricity generated by Thermal power plant *n*	g_n	MWh	m	monthly	All	Electronic (spreadsheet)	5 years	Provided by the CEB

D.5. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHG within the project boundary and identification if and how such data will be collected and archived

There are no baseline emissions within the project boundary. All baseline emissions are at other power plants, outside the project boundary, and included in D.4, above.

D.6. Quality control (QC) and quality assurance (QA) procedure are being undertaken for data monitored.

The System Control Center (SCC) can monitor on line through SCADA and the data are recorded and printed at the SCC of both the generating and grid sub-stations. Monthly energy data are sent to the SCC.

(*) SCADA: Supervisory Control And Data Acquisition, which consists of two units to export the data from the power plant to the SCC.
On the other hand, grid consumption data is recorded by a meter.

D.7. Name of person/entity determining the monitoring methodology

Name:
Entity:
Address:
Tel.:
E-mail:

E. Calculation of GHG emissions by sources

E.1. Description of formulae used to estimate anthropogenic emissions

a) Methane emissions due to biomass decomposition in flooding areas by the project

Annual emissions of methane are calculated according to equation (E.1). The fact is that the flooded area does not give rise to organic matter decomposition, so a precautionary value is even reported.

Annual CH4 Emissions Produced (tCH4/year)

= Area of Flooded (m^2) × Duration of Flooding (days /year)

× Average Daily CH4 Emission Rate (mg CH4-C/m^2-day)

× Conversion Factor (t/mg) × Molicular/Atomic Weight Ratio (tCH4/tCH4-C)

-------- (E.1)

Where, Emission Rate: 75 mg CH4-C/m2-day (*)

Area of Flooded Land: 38,000m^2

Duration of Flooding: 365.25 days (assumed)

Conversion Factor: 10-9

Molecular/Atomic Weight Ratio: 16 tCH4/12 tCH4-C

(*) Average value as proposed for floodplains in the Greenhouse Gas Emissions, Paper No. 064, Sept. 1998, World Bank

Applying equation (E.1) maximum project methane emissions are obtained: 29.15tonne CO2e/year.

b) Emissions due to the concrete used in the construction

Emissions attributed to the construction of the hydroelectric power plants can be estimated according to equation (E.2).

Emissions (tCO2)

= Concrete used (m3) × Concrete emission factor (tCO2/t cement)

× CF (t cement/m3) -------- (E.2)

Where, Concrete used: 100,000m^3

Concrete emission factor: 0.4985 tCO2/t cement (*)

Conversion Factor: 0.3 t/m^3

c) Emissions from the transportation of materials and machinery used during the construction

(*) As was explained in Section B.5, emissions by transport is not calculated because a detailed construction plan has not been decided on yet.

E.2. Description of formulae used to estimate leakage, defined as: the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and that is measurable and attributable to the project activity: *(for each gas, source, formulae/algorithm, emissions in units of CO_2 equivalent)*

1. Estimation of the emission factor per unit of generated energy of the thermal power plant n, ef_n, according to

$$ef_n(tCO_2e/GWh) = sc_n(ktfuel/GWh) \times EF_n(tCO_2e/TJ) \times LHV_f(TJ/ktfuel) \times OF_f \quad \text{-------- (E.3)}$$

Where, sc_n : specific consumption of the plant n

EF_n : carbon dioxide equivalent emission factor of the fuel f including CO2,CH4, and N2O

$EF_f = CEF_f + MEF_f + NEF_f$

LHV_f : lower heating value of the fuel f

OF_f : combustion efficiency default values for the different fuels burned in thermal power plants

$$\tilde{e}_{n\pm}(tCO_2e/yr) = \tilde{g}_{n\pm}(GWh/yr) \times ef_n(tCO_2e/GWh) \quad \text{-------- (E.4)}$$

Where, $\tilde{g}_{n\pm}$: electricity generated by the thermal power plant n in a year

(−): without the project

(+): with the project

$$\tilde{E}_{\pm}^{(th)}(tCO_2e/yr) = \sum_{n=1(th)}^{N} \tilde{e}_{n\pm}(tCO_2e/yr) \quad \text{-------- (E.5)}$$

Where, N : number of thermal plants in the system

$$\tilde{G}_{\pm}^{(th)}(GWh/t) = \sum_{n=1(th)}^{N} \tilde{g}_{n\pm}(GWh/yr) \quad \text{-------- (E.6)}$$

$$\left\langle \tilde{E} \right\rangle_{\pm}(tCO_2e/yr) = \tilde{E}_{\pm}^{(th)}(tCO_2e/GWh) / \tilde{G}_{\pm}^{(th)}(GWh/yr) \quad \text{-------- (E.7)}$$

Where, $\left\langle \tilde{E} \right\rangle_{\pm}$: average CO2e emissions of the thermal plants serving the system

$$F = \frac{\widetilde{G}_{-}^{(th)} - \widetilde{G}_{+}^{(th)}}{\widetilde{g}_P}$$ -------- (E.8)

Where, F : the rate between the annual displaced thermal generation of the national grid and the annual generation of the project

$$\widetilde{E}_B(tCO_2e) = \widetilde{E}_{-}^{(th)}(tCO_2e/yr) - E_{+}^{(th)}(tCO_2e/yr)$$ -------- (E.9)

Where, B: baseline emissions

$$E_B(tCO_2e/yr) = \left[g_P(GWh/yr) \times F + G_{+}^{(th)}(GWh/yr)\right] \times \left\langle \widetilde{E} \right\rangle_{-}(tCO_2e/GWh) - E_{+}^{(th)}(tCO_2e/yr)$$ -------- (E.10)

E.3. The sum of E.1 and E.2 representing the project activity emissions

Emissions derived in section E.2 are not project emissions but baseline ones. These are considered leakage since they are reasonably attributable to the project activity that corresponds to avoided emissions by the project, which are accounted as baseline emissions, so Section E.3 does not apply as the title proposes in a direct way. Only E.1 is involved. Therefore, the sum accounts for emissions of methane from the reservoir (E.1.a), construction emissions (E.1.b), and transport emissions (E.1.c). It gives:

$$E_P(tCO_2e) = \left[E_{resercoir} + E_{transport} + E_{construction}\right](tCO_2e)$$ -------- (E.11)

Where, Ep is project emissions. Applying the results obtained above, these emissions are:

$$E_P = [(a) + (b) + (c)](tCO_2e) = 14{,}984.15 tCO_2e$$

--- in the first year (2007)

$E_P = 29.15 tCO_2e$ --- for the rest of the crediting period (2008-2017)

E.4. Description of formulae used to estimate the anthropogenic emissions by sources of greenhouse

Equation (E.10) represents baseline emissions as described in Section E.2.

E.5. Difference between E4. and E3 representing the emission reductions of the project activity

Emission reductions are obtained as the difference between equation (E.10), representing baseline emissions, and emissions of equation (E.11), representing project emissions. Equation (E.12) shows emission reductions, ER, of the project activity:

$$ER(tCO_2e/yr) = E_B(tCO_2e/yr) - E_P(tCO_2e/yr)$$ -------- (E.12)

Table 4 Table providing values obtained when applying formulae above:

year	E_B (tCO2e)	E_P (tCO2e)	ER (tCO2e)
2007	68,168.00	14,984.15	53,184.12
2008	62,300.81	29.15	62,271.66
2009	62,351.34	29.15	62,322.19
2010	67,529.11	29.15	67,499.97
2011	63,676.96	29.15	63,647.81
2012	63,222.19	29.15	63,193.04
2013	72,735.92	29.15	72,706.77
2014	69,431.00	29.15	69,401.86
2015	81,871.23	29.15	81,842.08
2016	79,666.15	29.15	79,637.01
2017	99,669.32	29.15	99,640.17
2018	99,669.32	29.15	99,640.17
2019	99,669.32	29.15	99,640.17
2020	99,669.32	29.15	99,640.17
2021	99,669.32	29.15	99,640.17
2022	99,669.32	29.15	99,640.17
2023	99,669.32	29.15	99640.17
2024	99,669.32	29.15	99,640.17
2025	99,669.32	29.15	99,640.17
2026	99,669.32	29.15	99,640.17
2027	99,669.32	29.15	99,640.17
TOTAL	**1,787,315.48**	**15,567.09**	**1,771,748.39**

It is assumed that annual emissions after 2017 are the same as those produced in 2017. This is due to model limitations.

F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts, including transboundary impacts

The Broadlands Hydropower Project needs the procedure of the Environmental Impact Assessment (EIA) to be approved according to The National Environmental Act in Sri Lanka. The Central Environmental Authority (CEA) was appointed as the Project Approving Agency (PAA) for the EIA for the project. The fundamental study for the EIA was subcontracted to the local consultant, National Building Research Organization (NBRO), which had been selected through competitive bidding.

The study is phased as below:

- Phase 1 (Sept. 2002 - Feb. 2003, mainly the study on the natural environment)
- Phase 2 (May 2003 - Sept. 2003, mainly the study on the social environment)

Information regarding the EIA is included in a separate document.

F.2. If impacts are considered significant by the project participants or the host Party:

Please provide conclusions and all references to support documentation of an environmental impact assessment that has been undertaken in accordance with the procedures as required by the host Party.

G. Stakeholders comments

It seems that the ministries and municipalities below are stakeholders in the implementation of the project, according to the interview of the CEB officer.

- Ministry of Central Region Development
- Ministry of Environment and Natural Resources
- Ministry of Finance
- Ministry of Irrigation and Water Management
- Ministry of Land
- Ministry of Power and Energy
- Ministry of Plantation Industries
- Ministry of Tourism
- Local government bodies (Ambagamuwa Pradesheeya Sabha and Yatiyanthota Pradeshiya Sabha and members of the bodies)
- Provincial councils (Central provincial council, Sabaragamuwa provincial council and councilors)
- Government administrators of the area: District Secretaries (Nuwara Eliya and Kegalle), Divisional Secretaries (Ambagamuwa and Yatiyantota)

So far, there are no objections. But it is expected that sightseeing in the area will be affected by the project and it is confirmed that there are illegal sightseeing tours by residents.

G.1. Brief description of the process on how comments by local stakeholders have been invited and compiled

The study area is determined in the TOR as below.

- The river area: from 2 km upstream of the proposed dam site in the Maskeliya River and the proposed weir site in the Kehelgomu River, respectively, to about 5 km downstream of the powerhouse
- The bank area: both banks with about 2 km width each along the above river area
- The other area where a significant impact on the environment caused by the project is anticipated

The study area includes the border between the Sabaragamuwa Province and the Central Province, and consists of two administrative units:

- West part Paradishiya Sabah: Yatiyanthota
  Divisional Secretary's Division: Yatiyanthota

District: Kegalle

Province: Sabaragamuwa

- East Part — Pradishiya Sabah: Ambagamuwa

  Divisional Secretary's Division: Ambagamuwa

  District: Nuwara Eriya

  Province: Central

The CEB is responsible for conducting consultations with the stakeholders. The first consultation program was carried out from the middle of September to the middle of October 2002. The CEB staff visited the Pradishiya Sabah office and the Divisional Secretary's Division office in Yatiyanthota and Ambagamuwa, respectively, and explained the proposed project to the officials on Sept. 18, 2002, and the officials agreed to give their fullest support if and when necessary.

The CEB staff met the Grama Niladaries of 316C (Kalugala), 316F (Dagampitiya), and 318 (Polpitiya) on Sept. 26. The public consultation was held at the Club House, Polpitiya Power Station on the same day, and 27 people participated from these three villages. The CEB staff member explained the project, and then a question-and-answer session was held. (The person in charge from the JICA study team accompanied the CEB staff on Sept. 18 and 26). The CEB staff member in association with members of Pradishiya and Grama Niladaries met the people living around the proposed site of the power station.

The result of the phase study was reported at a meeting with the PAA in May 2003. A discussion was held, and the PAA raised some points to be kept in mind during the Phase 2 study.

G.2. Summary of the comments received

G.3. Report on how due account was taken of any comments received

Annex 1: Contact information on participants in the project activity

Organization:	Ceylon Electricity Board (CEB)
Street/P.O.Box:	540, Colombo-2
Building:	
City:	Colombo
State/Region:	
Postfix/ZIP:	
Country:	Sri Lanka
Telephone:	94-1-449572
FAX:	
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

Organization:	Japan International Cooperation Association (JICA)
Street/P.O.Box:	
Building:	
City:	
State/Region:	
Postfix/ZIP:	
Country:	Japan
Telephone:	
FAX:	
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

Annex 2: Information regarding public funding

Annex 3: New baseline methodology

Annex 4: New monitoring methodology

Annex 5: Table baseline data

BASELINE EMISSIONS
(100 stochastic hydrological series, including transmission network)

	without the project		
year	G- (GWh)	E- (tonne CO_2e)	<E>- (tonne CO_2e/GWh)
2007	5,554	3,326,220	598.89
2008	6,311	4,499,857	713.02
2009	6,570	4,642,769	706.66
2010	7,421	5,081,250	684.71
2011	8,325	6,308,926	757.83
2012	9,282	7,457,136	803.40
2013	10,297	8,005,909	777.50
2014	11,376	9,278,855	815.65
2015	12,528	10,394,692	829.72
2016	13,749	11,627,042	845.66
2017	15,040	12,503,766	831.37

	with the project			
year	G+ (GWh)	g_P (GWh)	E+ (tonne CO_2e)	<E>+ (tonne CO_2e/GWh)
2007	5,427	127.00	3,258,052	600.34
2008	6,184	127.00	4,437,556	717.59
2009	6,443	127.00	4,580,418	710.91
2010	7,294	127.00	5,013,721	687.38
2011	8,198	127.00	6,245,249	761.80
2012	9,155	127.00	7,393,914	807.64
2013	10,170	127.00	7,933,173	780.06
2014	11,249	127.00	9,209,424	818.69
2015	12,401	127.00	10,312,821	831.61
2016	13,622	127.00	11,547,376	847.70
2017	14,913	127.00	12,404,097	831.76

	Baseline emissions		
year	DG (GWh)	E_B (tonne CO_2e)	F
2007	127.00	68,168	1.00
2008	127.00	62,301	1.00
2009	127.00	62,351	1.00
2010	127.00	67,529	1.00
2011	127.00	63,677	1.00
2012	127.00	63,222	1.00
2013	127.00	72,736	1.00
2014	127.00	69,431	1.00
2015	127.00	81,871	1.00
2016	127.00	79,666	1.00
2017	127.00	99,669	1.00
average		790,622	**1.00**

means fixed parameters in the baselin

means variables to be determine *ex post*

Baseline emissions

$$E_B = \left[g_P \times F + G_+^{(th)}\right] \times \left\langle \tilde{E} \right\rangle_- - E_+^{(th)}$$

$$E_B = E_-^{(th)} - E_+^{(th)}$$

in the ideal case (actuall case is the same value as those estimated in ideal conditions)

Thermal power plant	g (GWh), 2000	g (GWh), 2001	g (GWh), 2002	ef (tCO2e/GWh)	e (tCO_2e), 2000	e (tCO_2e), 2001	e (tCO_2e), 2002
System Losses	21%	20%	19%				
Diesel							
K.P.S.(Steam)	213.38	185.88	63.05	1051.85731	224445.31	195519.24	66319.60
Diesel Sapu	441.98	446.69	509.49	670.8319814	296492.98	299653.94	341782.19
Diesel Sapu-Ext	517.80	455.63	454.66	609.8472558	315780.13	277864.71	277273.15
C.P.S	6.16	5.11	5.90	914.7708838	5634.99	4674.48	5397.15
Koolair-K.K.S	52.41	68.89	31.93	613.5834308	32160.83	42268.49	19593.66
DSL Lakdanavi	243.59	239.87	238.85	640.3396186	155978.10	153598.58	152947.97
Lakdanavi Emergency	101.42	93.05	0.00	613.5834308	62228.76	57094.59	0.00
DSL Asia Power	433.36	426.87	456.81	640.3396186	277495.98	273340.49	292511.97
Colombo power 60	335.12	628.63	621.23	640.3396186	214589.54	402537.58	397795.14
ACE Power Horana 20MW	0.00	0.00	10.95	670.8319814	0.00	0.00	7343.45
ACE Power Matara 20MW	0.00	0.00	184.61	670.8319814	0.00	0.00	123841.81
Mediumterm Putt				670.8319814	0.00	0.00	0.00
Mediumterm Embi				670.8319814	0.00	0.00	0.00
PELIYAGODA	170.18	104.94	879.44	661.5220218	112577.41	69420.27	581766.04
AMBATALE	69.77	42.15		693.0230704	48351.14	29211.40	0.00
KOTUGODA	222.77	145.73		693.0230704	154385.44	100994.09	0.00
KOSGAMA		131.90		724.5241191	0.00	95565.90	0.00
LAKDANAVI			171.86	693.0230704	0.00	0.00	119103.91
ALSTOM			40.57	724.5241191	0.00	0.00	29393.44
GT							
Gas Turbine-KPS	372.10	398.75	177.77	1165.5388	433696.99	464758.60	207197.83
Gas Turbine 115MW	601.82	281.24	226.75	693.0230704	417075.14	194905.81	157142.98
Gas Turbin 105MW(2013)				850.5283137	0.00	0.00	0.00
Gas Turbin 210MW(2015)				850.5283137	0.00	0.00	0.00
Gas Turbin 210MW(2017)				850.5283137	0.00	0.00	0.00
CCY							
CCY JBIC 165MW	300.00	69.83	470.41	484.987251	145496.18	33866.66	228142.85
CCY AES 163MW				535.5178272	0.00	0.00	0.00
Keraw CCY 300MW				535.5178272	0.00	0.00	0.00
Coal							
COAL 300MW(2008)				864.0426652	0.00	0.00	0.00
COAL 300MW(2011)				864.0426652	0.00	0.00	0.00
COAL 300MW(2012)				864.0426652	0.00	0.00	0.00
COAL 300MW(2014)				864.0426652	0.00	0.00	0.00
COAL 300MW(2015)				864.0426652	0.00	0.00	0.00
COAL 300MW(2016)				864.0426652	0.00	0.00	0.00
	4,081.85	**3,725.16**	**4,544.27**		**2896388.91**	**2695274.80**	**3007553.16**

<E>, 2000	<E>, 2001	<E>, 2002	Average ($t CO_2e/GWh$)
709.58	**723.53**	**661.83**	**698.31**

Project	Capacity (GW)	UF	hours/year	g_P (GWh)
Broadlands				127.00
				127.00

Emission reductions by the project ($t CO_2e/year$)	**88,686**
7-years	**620,801**
14-years	**1,241,603**
21-years	**1,862,404**

PROJECT EMISSIONS

Cement

Emission factor (ton CO_2/ton cement)
0.4985

Total concrete used (m^3)
100,000

conversion factor (ton/m^3)
0.3

Emissions (ton CO_2) **14955.00**

Methane from flooding

Flooded area (m^2) Total
38,000

Days **365.25**

Methane GWP **21**

Methane emissions (ton CO_2e)
29.15

Emission rate
(mg CH_4-C/m^2- **75**

Molecular/atomic weight ratio **1.333333333**

conversion factor **0.000000001**

Total project emissions (ton CO_2e)
14984.15

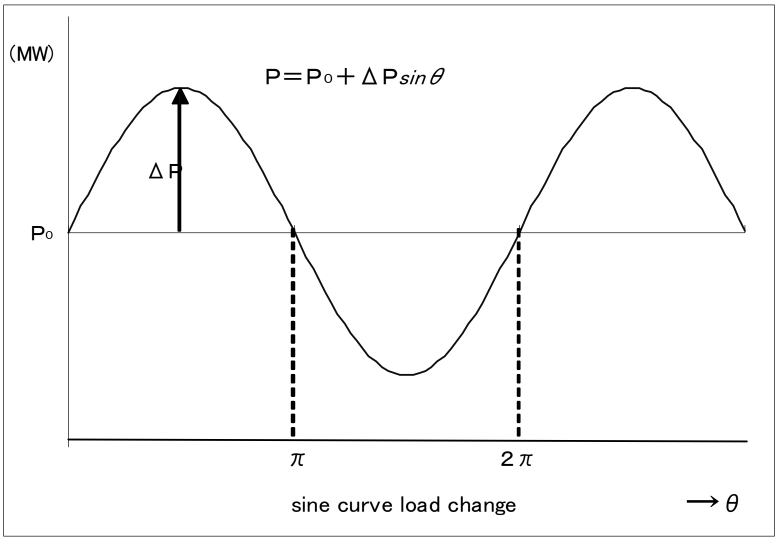
I-C IMPROVEMENT OF FREQUENCY CONTROL SYSTEM

IMPROVEMENT
OF
FREQUENCY CONTROL SYSTEM

1. Fuel Expenditure Reduction Effect when Load Changes are Absorbed by Multiple Water Turbines

1.1 Examination Method

As described in “Chapter 8 Economic Operation of the Existing Hydro Power Stations”, when an amount of water is given, it is the most efficient to share the discharge equally among the water turbines that have been designed the same, running in parallel. In the case of Victoria, New Laxapana and Kotmale, at present only one unit can absorb load changes even if two or three water turbines are running in parallel. Load change absorption should be shared equally among all water turbines running in parallel. When a water turbine absorbs load changes, it has to be operated at low efficiency output. Therefore, discharge used for frequency control operation is greater than that used at constant load operation. Its calculation method is explained next.



(1) Discharge Q0 operated at the constant load P0 is expressed as follows:

$$Q_0 = aP_0^{\,2} + bP_0 + C$$

(2) Assuming that the water turbine absorbs the cyclic load is estimated by;

$$P = P_0 + \Delta P \cdot \sin(2\pi t)$$

the mean value of discharge used during one cycle is calculated thus:

$$
\begin{aligned}
Q_{mean} &= \frac{1}{2\pi} Q_{total} \\
&= \frac{1}{2\pi} \int_0^{2\pi} Q d\theta \\
&= \frac{1}{2\pi} \int_0^{2\pi} \left(a(P_0 + \Delta P \cdot \sin\theta)^2 + b(P_o + \Delta P \cdot \sin\theta) + c \right) d\theta \\
&= \left(aP_0^2 + bP_o + c \right) + a \frac{(\Delta P)^2}{2}
\end{aligned}
$$

(3) The increase of discharge caused by AFC operation

$$
\Delta Q = a \frac{\Delta P^2}{2} \qquad (1)
$$

(4) When n units of water turbines absorb load change equally at the same time

$$
\begin{aligned}
\Delta Q &= n \times a \frac{(\Delta P / n)^2}{2n} \\
&= \frac{1}{n} \cdot a \cdot \frac{\Delta P^2}{2} \qquad (2)
\end{aligned}
$$

(5) The difference of discharge between "at constant load" and "at cyclic load" decreases to 1/n.

Formula (1) states that load change increases discharge. And formula (2) states that load changes must be absorbed by as many water turbines as possible; the more, the better. Quantitative analysis is shown as below.

Fuel expenditure stated next is calculated on the following condition:

1) actual results in 2001 are used as fuel cost
2) to simplify operating pattern round number near results calculated by SYSIM are used as plant factor
3) When New Laxapana is used for frequency control during the period mid-night to 6 AM., instead of Victoria, Victoria can be operated only at night peak and semi-peak. Peak shift effect is not counted in this chapter. In other words, only generated MWh increased by the rise in efficiency is counted in this chapter.

1.2 Estimation of Fuel Cost Reduction by Effective Frequency Control

Actual results calculated are shown below:

(1) Victoria

As shown in the P-Q curve for Victoria in the attached figures, "a" coefficient at EL.420m is as follows:

EL.420m; for 3 units $a_3 = 0.00095$

for 2 units $a_2 = 0.001425$

for 1 unit $a_1 = 0.00285$

When we substitute $a_3 = 0.00095$ and $\Delta P = \pm 35MW$ into formula (1), we get

$$\Delta Q_3 = 0.581875m^3/s$$

So, compared with constant load operation of three units, load change operation needs $0.581875m^3/s$ discharge increase. Load change operation of 2 units needs $0.8728125m^3/s$ discharge increase, and that of one unit needs $1.745625m^3/s$ more.

Assume that power/discharge ratio is $210MW/105m^3/sec$, losses caused by frequency control are 1.16375MW for three units, 2.3275MW for two units and 3.49125MW for one unit, respectively.

(2) New Laxapana

As shown in the P-Q curve for New Laxapana in the attached figures, "a" coefficient is as follows;

"a" : coefficient for two units is $a_2 = 0.0007$

discharge increase caused by ±35MW load change operation is

$$\Delta Q_2 = (0.0007/2) \times (35MW)^2 = 0.42875m^3/s$$

Assume that the power/discharge ratio is $100MW/22.7m^3/s$, losses caused by frequency control are 1.889MW for two units and 3.778MW for one unit, respectively. (Rated output of one unit is 50MW, so one unit alone cannot absorb ±35MW load change but this assumption is made in order to compare with other water turbines.)

(3) Samanalawewa power station

As shown in the P-Q curve of Samanalawewa in the attached figures, "a" coefficient is as follows:

"a" coefficient for two units is $a_2 = 0.0016$.

Discharge increase caused by ±35MW load change operation is

$$\Delta Q_2 = (0.0016/2) \times (35MW)^2 = 0.98m^3/s$$

Assume that the power/discharge ratio is $120MW / 42.0m^3/s$. Losses caused by frequency control are 2.8MW for two units, 5.6MW for one unit. (Rated output of one unit is 60MW. So one unit alone cannot absorb ±35MW load change, but to compare with other water turbines, this assumption is made.)

(4) Kotmale power station

As shown in the P-Q curve of Kotmale in the attached figures, "a" coefficient is as follows:

"a" coefficient for three units is $a_3 = 0.0014$.

Discharge increase caused by ±35MW load change operation is

$$\Delta Q_3 = (0.0014/2) \times (35\text{MW})^2 = 0.8575\text{m}^3/\text{s}$$

Assume that the power/discharge ratio is 201MW/105m^3/s. Losses caused by frequency control are 1.6415MW for three units, 3.283MW for two units and 4.9245MW for one unit, respectively. (Rated output of one unit is 67MW. So one unit alone cannot absorb ±35MW load change but to compare with other water turbines, this assumption is made.)

When the results calculated above are arranged in order of loss power caused by load changes from smaller to bigger,

Victoria × 3 units (1.16375MW) < Kotmale × 3 units (1.6415MW)
< New Laxapana × 2 units (1.889MW) < Victoria × 2 units (2.3275MW)
< Samanalawewa × 2 units (2.8MW) < Kotmale × 2 units (3.283MW)
< Victoria × 1 unit (3.49125MW) < New Laxapana × 1 unit (3.778MW)
< Kotmale × 1 unit (4.9245MW) < Samanalawewa × 1 unit (5.6MW)

Note : Loss KW described above are for ±35MW load change. Loss KW for ±25MW is loss KW for ±35MW multiplied by $(25\text{MW}/35\text{MW})^2$=51%. The order is not changed.

The results calculated above state that:

1) Under the present situation, only Samanalawewa power station has capacity for governor joint operation. At night peak and semi-peak when two water turbine units at Samanalawewa power station are operated together, Samanalawewa is more efficient than one turbine unit at Victoria. So, Samanalawewa should be operated for frequency control predominantly prior to Victoria.

   Electric energy recovered per year and fuel cost merits are as follows:

   - Power loss decrease when power station for frequency control is changed from one unit at Victoria to two units at Samanalawewa

     3.5MW – 2.8MW = 0.7MW

   - Yearly plant factor of Samanalawewa is 33%
   - Running time at full power is 2,890.8 hours. To absorb ±35MW fluctuation, the base load must be decreased to 85MW. Therefore, operating hours at a load of 85MW a year is

     2,890.8 hours × 120MW/(120-35)MW = 4,081 hours

   - Electric energy recovered per year:

$0.7MW \times 4{,}081hours = 2{,}856MWh/year$

- Fuel cost merits are:
  - at gas turbines to decrease average fuel costs

    $9.43\ Rs/kWh \times 2{,}856MWh = 27MRs/year$
  - at thermal plants

    $5.27\ Rs/kWh \times 2{,}856MWh = 15MRs/year$

2) After Victoria is united with the "Centralized AFC system", two or three units of water turbines can be operated in joint operation mode. Recovered MWh and fuel cost merits are calculated as follows.

- yearly plant factor is 50%.
  - three units operation hours are 8 hours every day
  - two units operation hours are 8 hours every day
  - one unit operation hours are 8 hours every day
  - one unit is always running for frequency control
- electric energy recovered by governor joint operation
  - three units operation

    $(3.49125MW - 1.16375MW) \times 8hr = 18.62MWh/day$
  - two units operation

    $(3.49125MW - 2.3275MW) \times 8hr = 9.31MWh/day$
  - total 27.93MWh/day
- 10,473MWh is recovered a year. When only one New Laxapana unit absorbs load changes, this value becomes bigger.
- fuel cost merits are:
  - at gas turbines to decrease average fuel costs

    $9.43Rs/KWh \times 10{,}473MWh = 99MRs/year$
  - at thermal plants

    $5.27Rs/KWh \times 10{,}473MWh = 55MRs/year$

3) New Laxapana

After the reconstruction for governor joint operation is over, two units of New Laxapana water turbine is more efficient than one unit of Victoria. It is preferable that the governor reconstruction for joint operation at New Laxapana be executed as soon as possible.

New Laxapana×2 (1.889MW) < Victoria×1 (3.49125MW)

< New Laxapana×1 (3.778MW)

- Assume that
  - yearly plant factor of New Laxapana is 75%、
  - running time at full power of two units is 14 hours,
  - running time at full power of one unit is 8 hours
  - shut off time is two hours.
- In order to absorb ±35MW load change, 8 hours at full power of one unit is changed into 8 hours at half power of two units.
- Power loss decrease when the power station for frequency control is changed from one unit at Victoria into two units at New Laxapana represents

  3.5MW – 1.889MW=1.661MW
- kWh recovered a day and

  (3.49125MW − 1.889MW)×8hr = 12.818MWh/day
- This represents 4,678.57MWh/year recovered.
- fuel cost merits are:
  - at gas turbines to decrease average fuel costs;

    9.43Rs/KWh×4,678.57MWh = 44MRs/year
  - at thermal plants;

    5.27 Rs/kWh×4,678.57MWh = 25MRs/year

4) Kotmale

Kotmale has an oscillation problem, so the response band is very narrow.

2. Fuel Cost Reduction Effect when Load Changes are absorbed by some Water Turbines at the different Power Stations

The biggest weak-point of the present frequency control is that load changes cannot be absorbed by water turbines at different power stations together at the same time. When some economical sources for AFC are scattered over some different power stations, load changes cannot be absorbed together.

(1) At night peak

The biggest effect caused by the "Centralized AFC system" is obtained when all of the 8 turbines at Victoria, Samanalawewa and Kotmale power stations are used for frequency control together at the same time. So, this case is examined as follows:

When there are two power stations for frequency control, A and B, and those heads are given HA, HB, and "a" coefficients of P-Q curves are given aA, aB, a sharing ratio between two power stations

$a_B H_B / (a_A H_A + a_B H_B) : a_A H_A / (a_A H_A + a_B H_B)$

is the most economical. It is rather hard to keep this ratio with actual operation, but the next calculation is based on this ratio.

Net heads and "a" coefficients of three power stations are as follows:

Victoria :	$a_V = 0.00095$	$H_V = 190m$、	$a_V H_V = 0.1805$
Kotmale :	$a_K = 0.0014$	$H_K = 201.5m$、	$a_K H_K = 0.2821$
Samanalawewa :	$a_S = 0.0016$	$H_S = 320m$、	$a_S H_S = 0.512$

thus

$\Delta P_V : \Delta P_K = 61\% : 39\%$

$\Delta P_K : \Delta P_S = 65\% : 35\%$

$\Delta P_V : \Delta P_K : \Delta P_S = 50.4\% : 32.2\% : 17.4\%$

When ±35MW load change is shared with three power stations according to this ratio, each of the three power stations shares ±17.64MW, ±11.2MW, ±6.09MW respectively. Energy losses caused by this load change spread eight hours per day are calculated next.

1) Victoria

$\Sigma MWh = (0.00095/2) \times (17.64)^2 \times 8 \text{ hours} \times 210MW/105m^3/s = 2.365MWh$

2) Kotmale

$\Sigma MWh = (0.0014/2) \times (11.2)^2 \times 8 \text{ hours} \times 201MW/105m^3/s = 1.3447MWh$

3) Samanalawewa

$\Sigma MWh = (0.0016/2) \times (6.09)^2 \times 8 \text{ hours} \times 120MW/42.0m^3/s = 0.6782MWh$

4) Total

$\Sigma MWh = 4.3878MWh$

5) Comparison

When only one water turbine unit at Victoria is operated for frequency control, energy loss caused by load changes is 83.79MWh (=3.5MW×24hours) per day and 27.93MWh per 8 hours. When all of the 8 water turbines at the three reservoir pond type power stations absorb load changes, energy loss caused by load changes decreases to 16%, and recovered energy is 23.54MWh per day, or 8,592.1MWh per year.

・Fuel cost merits are:

- at gas turbines to decrease average fuel costs;

  9.43 Rs/kWh × 8,592.1MWh = 81MRs/year

-at thermal plants;

5.27Rs/KWh × 8,592.1MWh = 45MRs/year

Although 8 water turbines can be used for frequency control at night peak, at present only one unit is ever used. Both fuel expenditure decrease and frequency fluctuation improvement can be achieved by using all turbines at the same time.

(2) During the mid-night period

As described before, from the stand point of economic operation, operation of reservoir pond type power stations during the mid-night period, mid-night to 6 a.m., is not reasonable and it is necessary to secure AFC running capacity for frequency control. Yearly plant factors of regulating pond type power stations in the Kelani river complex are very high, and these three power stations are operated during the mid-night period every day. Laxapana pond located at the middle is very small, so operating patterns of New Laxapana, Old Laxapana and Polpitiya must be similar, and different patterns are troublesome. When a "Centralized AFC system" under which the "Main Controller" installed at the control center sends control signals to AFC power stations is adopted, these three power stations can absorb load changes together and at least 112.5MW AFC running capacity is secured.

1) New Laxapana, Old Laxapana and Polpitiya absorb load changes together

The case when New Laxapana 1 unit, Old Laxapana 12.5MW 2 units (or 8.33MW 3 units) and Polpitiya 1 unit are used for AFC is examined.

<u>Examination condition</u>

"a" coefficients, basic net heads and power/discharge ratios are as follows:

- New Laxapana $a_{n2} = 0.0007$ 578m $100MW/22.7m^3/s$

  $a_{n1} H_n = 0.8092$

- Old Laxapana $a_{o5} = 0.0005$ 449m $50MW/14.2m^3/s$

  $a_{o2.5} H_o = 0.4490$

- Polpitiya $a_{p2} = 0.0035$ 259m 75MW/34.0m3/s

  $a_{p1} H_p = 1.8130$

$\Delta P_N : \Delta P_O : \Delta P_P =$ 30.8% : 55.5% : 13.7%.

When ±35MW load change is shared with three power stations according to this ratio, each of three power stations shares ±10.8MW, ±19.4MW, ±4.8MW respectively.

However, Old Laxapana cannot absorb load changes more than ±12.5MW, so the remainder

±6.9MW (= 19.4MW − 12.5MW) must be absorbed by the other two stations. Thus, load changes absorbed by the three stations are ±15.77MW, ±12.5MW, ±6.9MW. Energy loss caused by this load change spread, eight hours per day are calculated next.

The sharing ratio of Polpitiya is low and especially lower than Old Laxapana, which is smaller than Polpitiya. This is because Francis water turbines are used at Polpitiya and

Pelton turbines are used at the others. As described before, the efficiency curve of a Francis water turbine is very much sharper than that of a Pelton turbine.

a) New Laxapana

Σ MWh=(2×0.0007/2)$(15.77)^2$×8 hours×100MW/22.7m3/s = 5.9828MWh

b) Old Laxapana

Σ MWh=(2×0.0005/2)$(12.5)^2$×8 hours×50MW/14.2m3/s = 2.2007MWh

c) Polipitiya

Σ MWh=(2×0.0035/2)$(6.9)^2$×8 hours×75MW/34.0m3/s =2.9637MWh

d) Total

Σ MWh=11.1472MWh

<u>Comparison</u>

As described before, when only one water turbine unit at Victoria is operated for frequency control, energy loss caused by load changes is 83.79MWh per day or 27.93MWh per 8 hours.

When half the number of water turbines at the Kelani river complex are operated for frequency control, energy loss can be decreased to about 40% of Victoria and 16.78MWh per day or 6,126MWh per year can be recovered.

・Fuel cost merits are:

- at gas turbines to decrease average fuel costs;

9.43Rs/KWh×6,126MWh = 58MRs/year

-at thermal plants;

5.27 Rs/kWh×6,126MWh = 32MRs/year

<u>Peak shift effect</u>

Victoria can be operated only at night peak and semi-peak, and big fuel expenditure reduction can be obtained. Its generated power is 35MW × 8hours/day × 365 days=102.2GWh /year.

2) New Laxapana and Old Laxapana absorb load changes together

Polpitiya has an oscillation problem. Until this problem is solved, Polpitiya must be excluded as an AFC power station. Here is examination of the case when Polpitiya is excluded from case 1) examined just before.

$a_N H_N$=0.8092 $a_O H_O$=0.445 $\Delta P_N : \Delta P_O$ =35.7% : 64.3%

When ±35MW load change is shared with two power stations according to this ratio, each of two power stations shares ±12.5MW and ±22.5MW respectively. However, Old Laxapana cannot absorb load changes more than ±12.5MW. Therefore, the remainder

±10.0MW (=22.5MW−12.5MW) must be absorbed by New Laxapana. Thus, load changes absorbed by the two stations are ±22.5MW and ±12.5MW.

Energy losses caused by this load change spread, eight hours per day are calculated next.

a) New Laxapana

ΣMWh=(2×0.0007/2)$(22.5)^2$×8 hours×100MW/22.7m^3/s =12.489MWh

b) Old Laxapana

ΣMWh=(2×0.0005/2)(12.5)2×8hours×50MW/14.2m3/s =2.2007MWh

c) Total

ΣMWh=14.69MWh.

Comparison

As described before, when only one water turbine unit at Victoria is operated for frequency control, energy loss caused by load changes is 83.79MWh per day or 27.93MWh per 8 hours.

When half the number of water turbines at New Laxapana and Old Laxapana are used for frequency control, their running capacity is nearly equal to one unit of Victoria. Energy loss can be decreased to about half of Victoria and 13.24MWh per day or 4,832MWh per year can be recovered.

・Fuel cost merits are

- at gas turbines to decrease average fuel costs;

9.43 Rs/kWh×4,832MWh = 46MRs/year

-at thermal plants;

5.27 Rs/kWh×4,832MWh = 25MRs/year

Peak shift effect

As written before, Victoria can be operated only at night peak and semi-peak, and big fuel expenditure reduction can be obtained. Its generated power is 35MW×8hours/day×365 days=102.2GWh.

3) Victoria and New Laxapana absorb load changes together

While oscillation problems at Polpitiya are not solved and renewal at Old Laxapana is delayed, shortage of running capacity for AFC may happen during the mid-night period. To avoid over-flow after heavy rain, Victoria may be operated during the mid-night period. According to drought requirements, New Laxapana may be operated at half load at semi-peak. Effects of such operations are calculated as follows:

a) Two unit water turbine operation at New Laxapana

Constants for Victoria

a_{v1} =0.00285, H_v = 190m, $a_{v1}H_v$ = 0.5415, power/discharge ratio 210MW/105m^3/s

Constants for New Laxapana

a_{n2} =0.0007, H_n =578m, $a_{n2}H_n$ = 0.4046, power/discharge ratio 100MW/22.7m^3/s

$\Delta P_v : \Delta P_n = 0.4046 / 0.9461 : 0.5415 / 0.9461 = 42.7 : 57.3$

$\Sigma \Delta Q_v = (0.00285/2) \times (\pm 35 \times 0.427)^2 \times 8$ hours = 2.546m^3/s-h

$\Sigma \Delta MWh_v$ = 2.546m^3/s-h×210MW/105m^3/s = 5.09MWh

$\Sigma \Delta Q_n = (0.0007/2) \times (\pm 35 \times 0.573)^2 \times 8$ hours =1.126m^3/s-h

$\Sigma \Delta MWh_n$=1.126m^3/s-h×100MW/22.7m^3/s = 4.961MWh

Total loss at both power stations is 10.05MWh and 17.88MWh smaller per night than the case when only one unit at Victoria absorbs the load change (27.93MWh).

b) One unit operation at New Laxapana

Constants of New Laxapana

a_{n1}=0.0014, H_n=578m, $a_{n1} H_n$=0.8092, power/discharge ratio 100MW/22.7m^3/s

$\Delta P_v : \Delta P_n$ = 59.9% : 40.1%

$\Sigma \Delta Q_v = (0.00285/2) \times (\pm 35MW \times 0.599)^2 \times 8$ hours = 5.01m^3/s-h

$\Sigma \Delta MWh_v$ = 5.01m^3/s-h×210MW/105m^3/s =10.02MWh

$\Sigma \Delta Q_n = (0.0014/2) \times (\pm 35MW \times 0.401)^2 \times 8$ hours=1.103m^3/s-h

$\Sigma \Delta MWh_n$=1.103m^3/s-h×100MW/22.7m^3/s = 4.86MWh

Total loss at both power stations is 14.88MWh and 13.05MWh smaller in one night than the case when only one unit at Victoria absorbs the load change (27.93MWh).

Judging from operation records, it is supposed that the probability of one unit operation at middle load is 5/18 and that of two units operation at middle load is 11/18. Expected generated KWh increase and fuel expense decrease are as follows:

$(17.88 \times 11/18 + 13.05 \times 5/18) \times 365$ days = 5,311MWh

When both Victoria and New Laxapana are running during the mid-night period, mid-night to 6 a.m., both fuel expense decrease and frequency fluctuation improvement can be achieved by using both power stations at the same time.

(3) At semi-peak

As the power system becomes bigger, the load curve becomes sharper than now. The operating hours of reservoir pond type power stations will be concentrated at the night peak. It is necessary to secure AFC running capacity at semi-peak. It is supposed that, at last stage, reservoir type power stations will be operated only at night peak, at most 8 hours a day. On the way, when one unit of the water turbines at each of the reservoir pond type power stations are running parallel, a bundle of these water turbines can be used for AFC. It is unclear how many hours a day one water turbine unit at each reservoir pond type power station is operated daily but the merit per day is calculated.

"a" coefficients and net heads of three power stations are as follows;

	a_i	H_i (m)	$a_i H_i$
Victoria	$a_V = 0.00285$	$H_v = 190$	$a_V H_v = 0.5415$
Kotmale	$a_K = 0.0042$	$H_k = 201.5$m	$a_K H_k = 0.8463$
Samanalawewa	$a_S = 0.0032$	H_s =3 20m	$a_S Hs = 1.024$

$\Delta P_V : \Delta P_K : \Delta \Delta P_S = 46\% : 29.5\% : 24.3\%$

When ±35MW load change is shared with three power stations according to this ratio, each of three power stations shares ±16.1MW, ±10.32MW, ±8.5MW respectively. Energy loss caused by this load change spread, eight hours per day are calculated.

1) Victoria

Σ MWh = $(0.00285/2) \times (16.1)^2 \times 8$ hours $\times$ 210MW/105m^3/s= 5.91MWh

2) Kotmale

Σ MWh = $(0.0042/2) \times (10.32)^2 \times 8$ hours $\times$ 201MW/105m^3/s = 3.425MWh

3) Samanalawewa

Σ MWh=$(0.0032/2) \times (8.5)^2 \times 8$ hours $\times$ 120MW/42.0m^3/s = 2.642MWh

4) Total

Σ MWh=11.977MWh

Comparison

As described before, when only one water turbine unit at Victoria is operated for frequency control, energy loss caused by load changes is 83.79MWh per day or 27.93MWh per 8 hours.

Even if only one water turbine unit at each reservoir pond type power stations absorbs load changes, energy loss can be decreased to 43%.

3. Conclusion

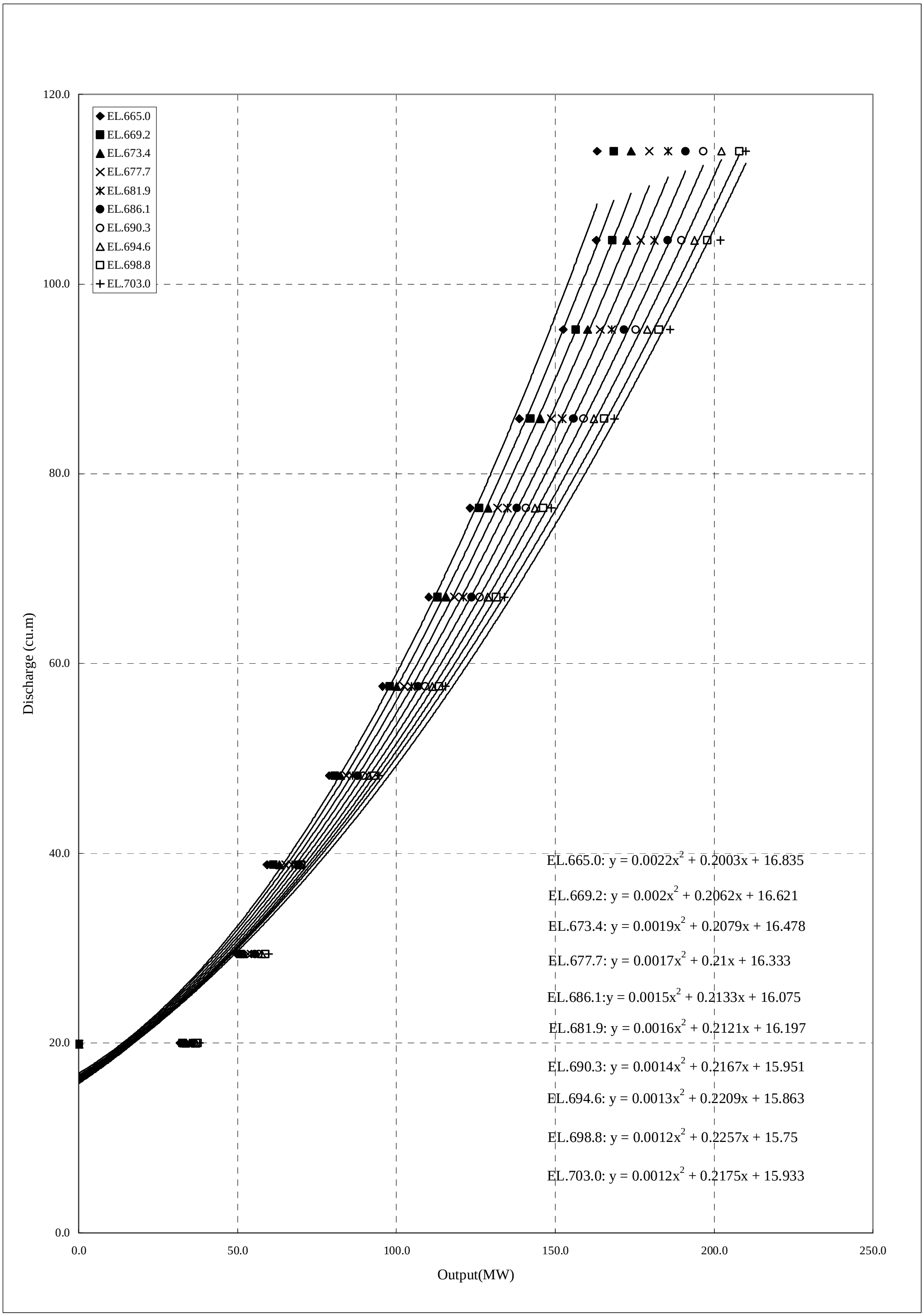
The difference between the production cost of regulating thermal units at light load time and that of regulating thermal units at heavy load time will become larger, and an expansion plan for three regulating pond type power stations in the Kelani river complex will be under study. Construction of storage pump stations will be under study, too.

Randenigala is a variable middle head power station, and its net head varies about 30%. This site is very suitable for construction of a storage pump station because the existing

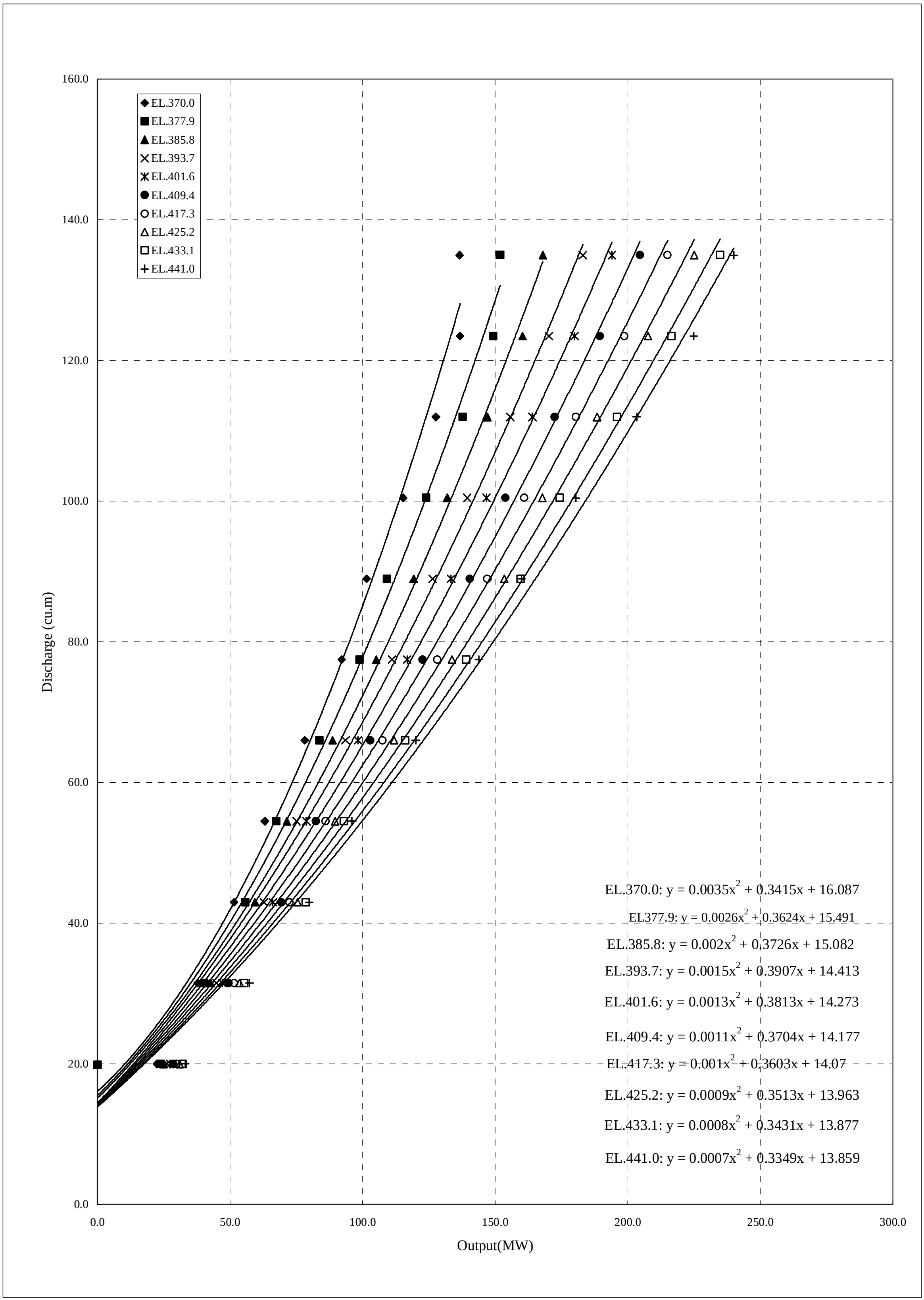
Randenigala reservoir pond is very near to the existing Rantambe regulating pond. Therefore, construction of an upper regulating pond and lower regulating pond is not needed.

If Deriaz type pump turbines (maximum 61MW with 6 units at the most when the unit size is just the same as now) are installed here, AFC operation is capable even in the pumping mode. Therefore, AFC running capacity can be secured without loss of economy. However, a variable speed pump turbine should be ordered to be used for AFC in the pumping mode. When a Francis type pump turbine is planned to be installed at another site in the future, a variable speed Francis water turbine should be ordered. Therefore, AFC operation can be done, even in the pump mode, without loss of economy. Inter-connection with India is supposed to be a big dream in the long-term future.

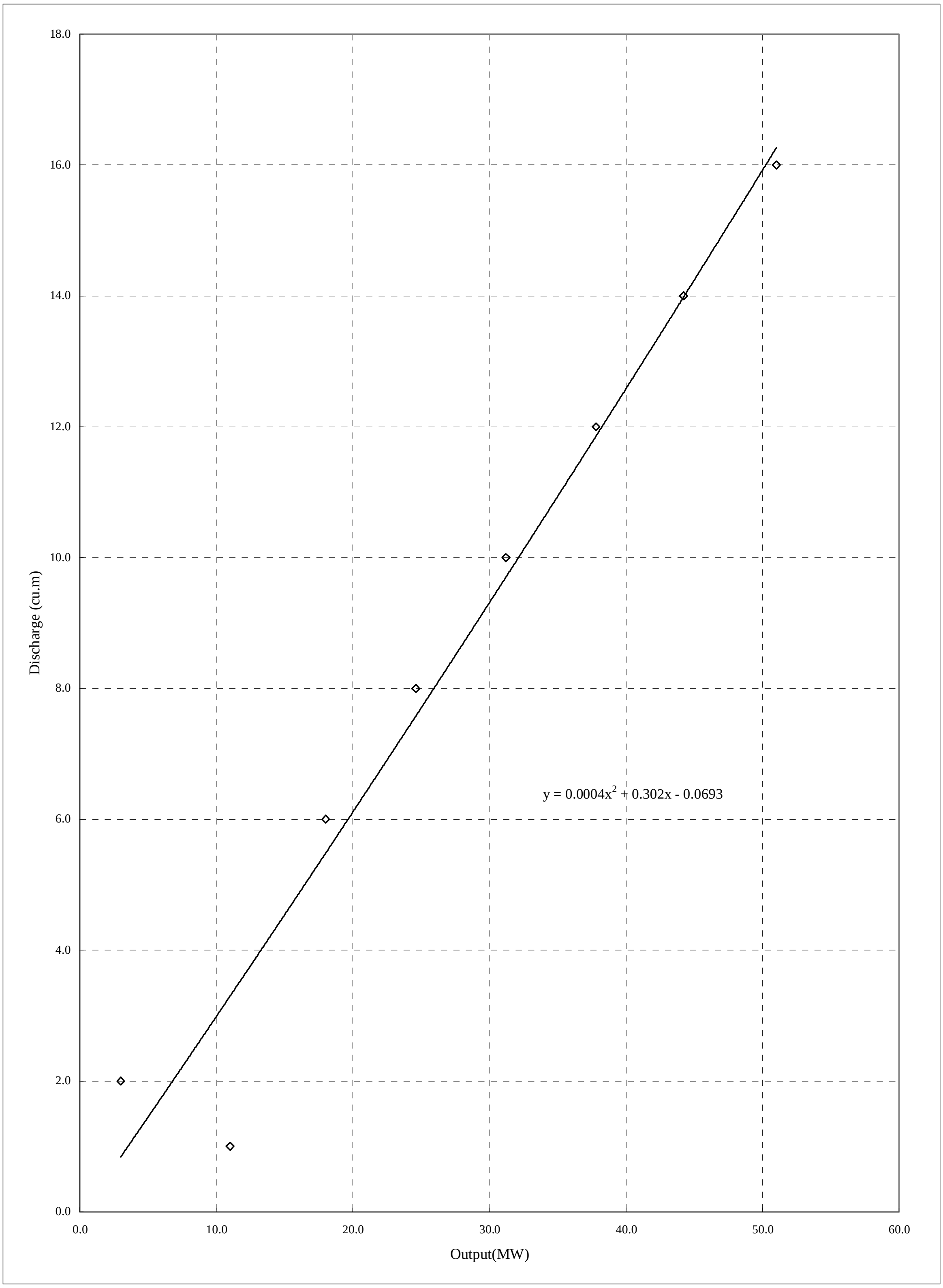
In order to operate a small capacity power system, isolated from others, stably and economically, skill and effort are needed more than with any other power system.



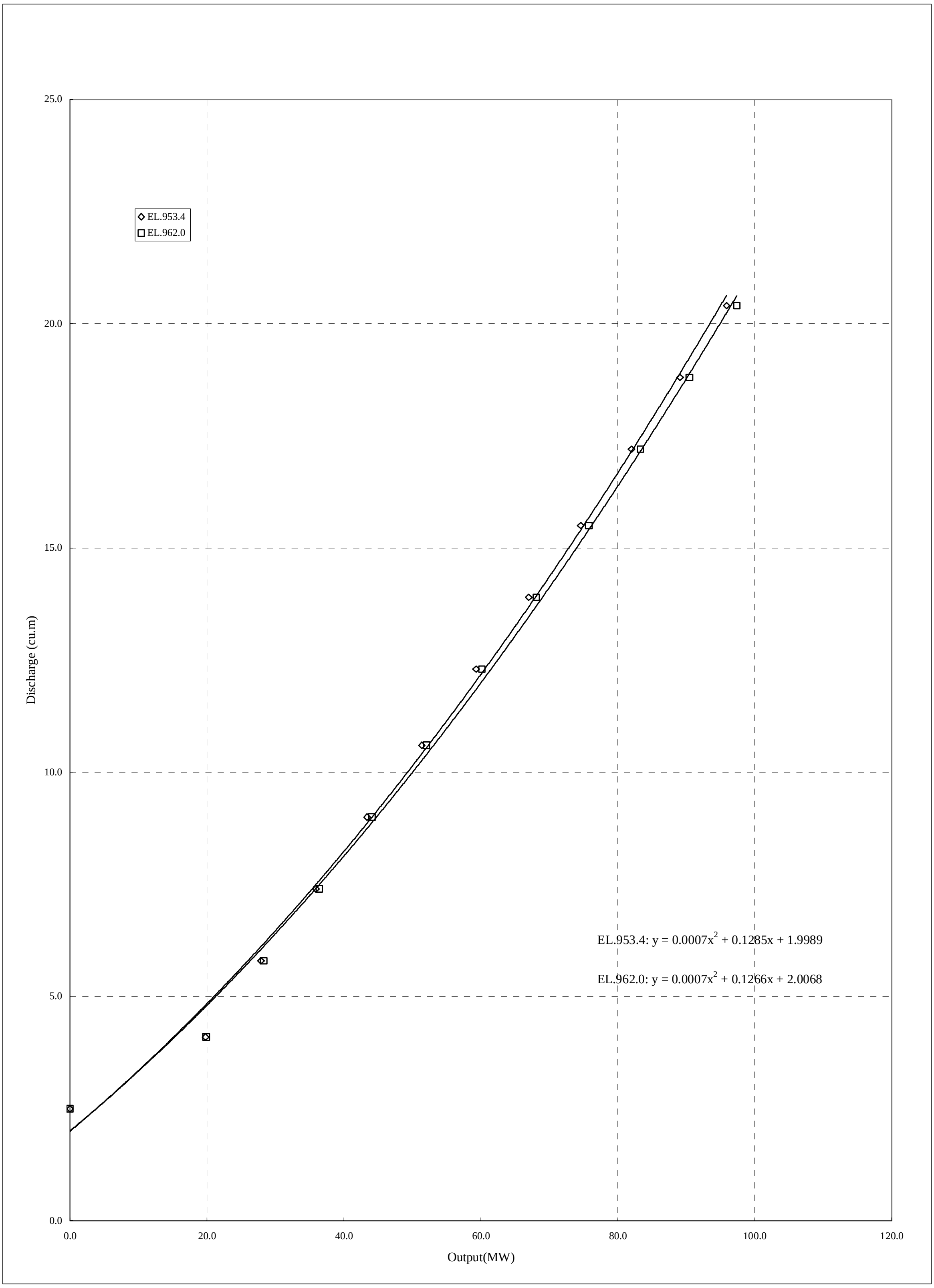
(1) P-Q curve of the Kotmale Hydropower Station



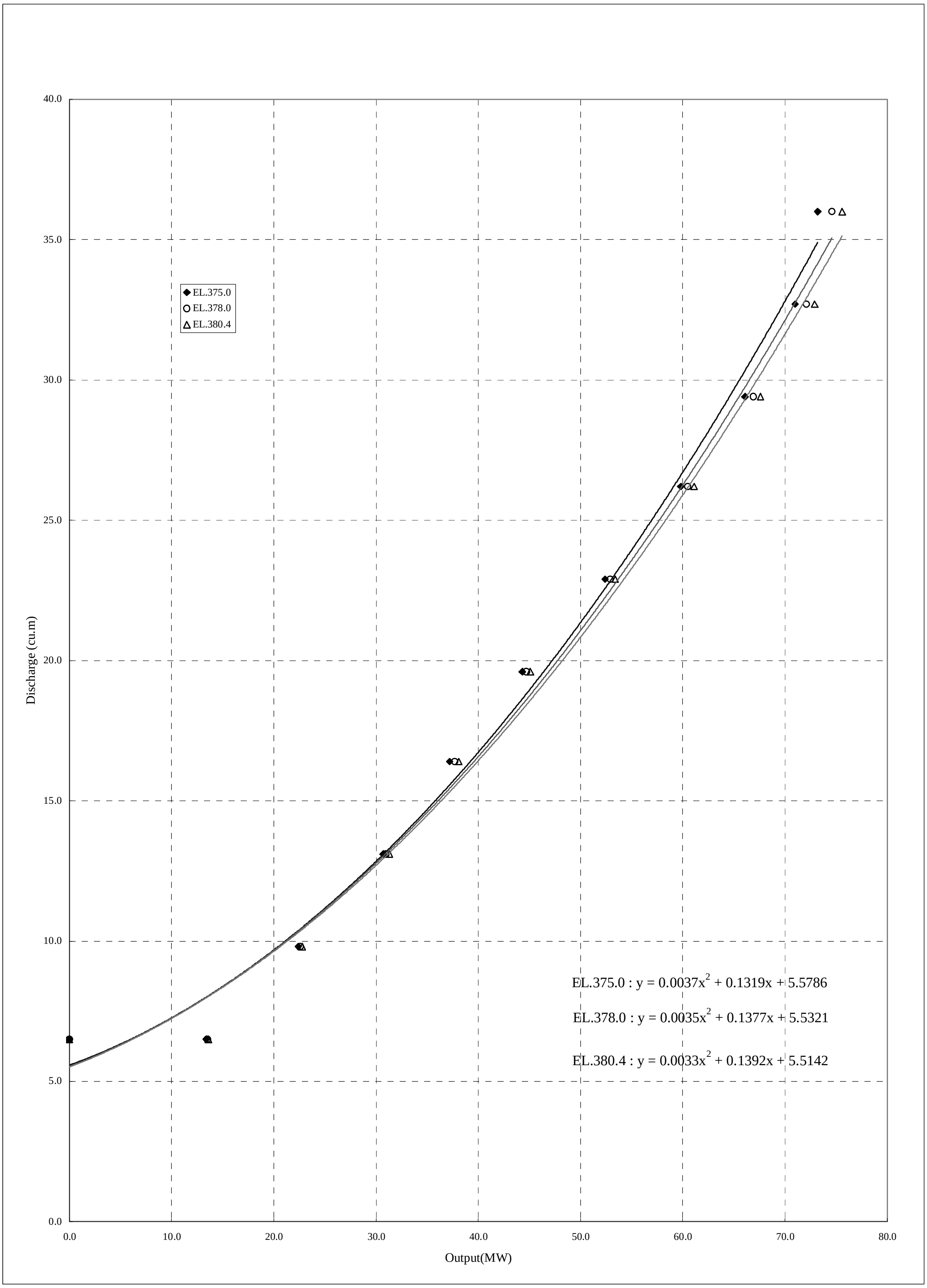
(2) P-Q curve of the Victoria Hydropower Station



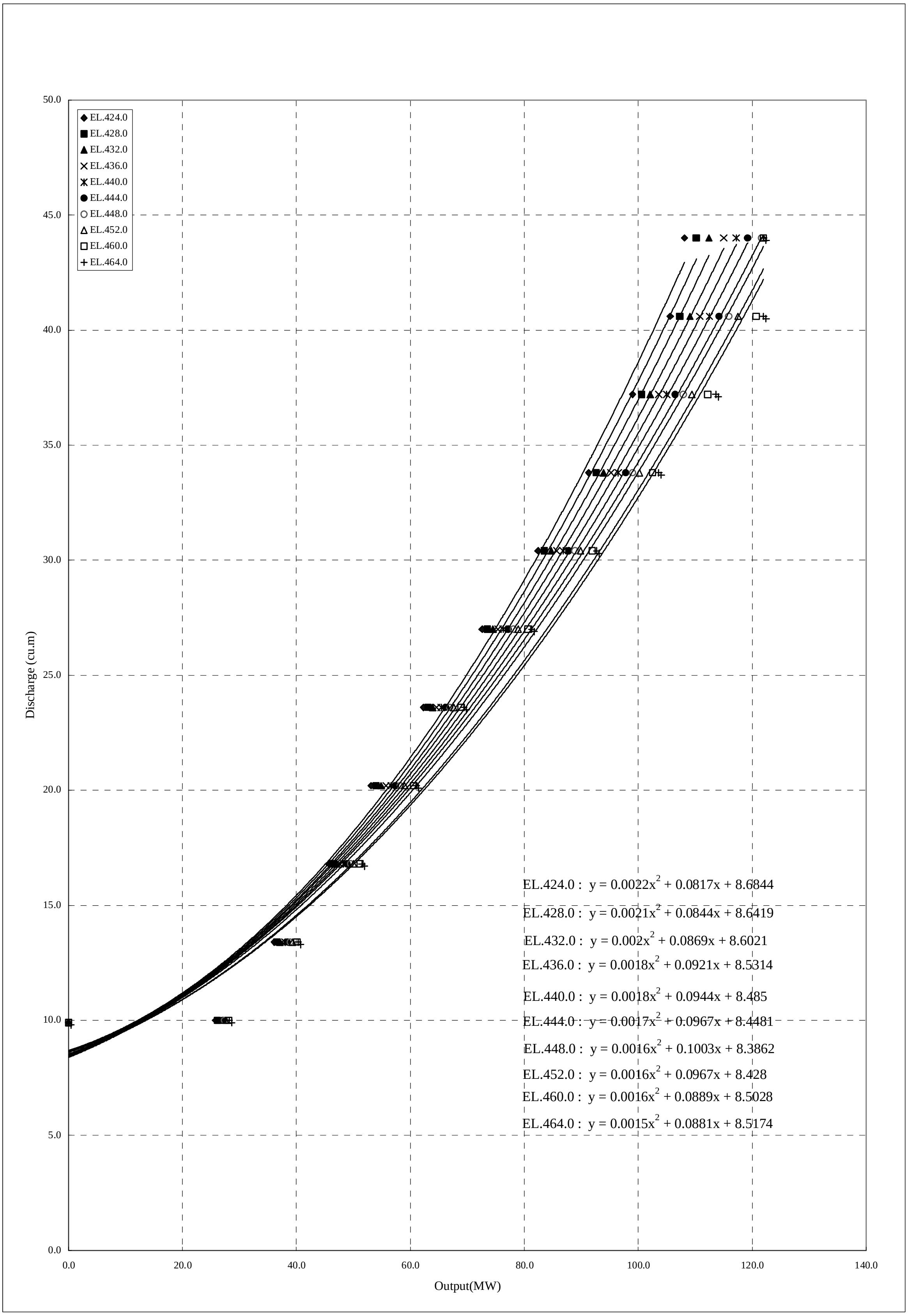
(3) P-Q curve of the Old Laxapana Hydropower Station



(4) P-Q curve of the New Laxapana Hydropower Station



(5) P-Q curve of the Polpitiya Hydropower Station



(6) P-Q curve of the Samanalawewa Hydropower Station